Oregon
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August 16, 2024

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 433 – In the Matter of PACIFICORP DBA PACIFIC POWER, Request for a General Rate Revision.

Attached for Rebuttal Testimony filing are the following exhibits:
Exh 2300 Scala
Exh 2400-2414 Muldoon REDACTED
Exh 2500 Chipanera
Exh 2600-2601 Ayres
Exh 2700 Dlouhy
Exh 2800-2802 Dyck REDACTED
Exh 2900-2904 Farrell
Exh 3000-3001 Mondragon
Exh 3100 Moore
Exh 3200-3201 Nottingham
Exh 3300 Pal REDACTED
Exh 3400-3401 Peng
Exh 3500 Peterson REDACTED
Exh 3600-3602 Pileggi REDACTED
Exh 3700 Rossow
Exh 3800 Stevens
Exh 3900 Yamada
Exh 4000-4003 Bolton REDACTED
Exh 4100-4101 Shierman
Exh 4200-4201 Mondragon Peterson Stevens REDACTED

Confidential and Non-confidential exhibits and Excel exhibits included with this filing are:

Confidential exhibits:
Exh 2400-2414 Muldoon CONF
Exh 2800-2802 Dyck CONF
Exh 3300 Pal CONF
Exh 3500 Peterson CONF
Exh 3600-3602 Pileggi CONF
Exh 4000-4003 Bolton CONF
Exh 4003 Bolton - CONF OR UM 1968 … CONF.xlsx
Exh 4200-4201 Mondragon Peterson Stevens CONF

Non-Confidential exhibits:
Exh 2601 Ayres - OPUC DR 704 Attach.xlsx
Exh 2601 Ayres - OR CY2025 LID … OPUC 438 20gwh.xlsx
Exh 2601 Ayres - OR CY2025 LID … OPUC 438 nocap.xlsx
Exh 2801 Dyck - OPUC 641-1 Attach.xlsx
Exh 2801 Dyck - OPUC 642 Attach.xlsx
Exh 2801 Dyck - OPUC 645 1st SUPP Attach.xlsx
Exh 2901 Farrell - Uncollectible Workpaper.xlsx
Exh 2902 Farrell - PacifiCorp Response to OPUC DR 691.xlsx
Exh 3001 Mondragon - OPUC 356 Attach.xlsx
Exh 3001 Mondragon - OPUC 615 Attach.xlsx
Exh 3001 Mondragon - OPUC 687 Attach – folder
Exh 3001 Mondragon - OPUC 751 Attach.xlsx
Exh 3401 Peng - AFUDC Adj Calc.xlsx

/s/ Mark Brown
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CERTIFICATE OF SERVICE

UE 433

I certify that this day I served the foregoing document upon all the following parties or attorneys of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid or by electronic mail pursuant to OAR 860-001-0180 (which may include a link to a secure shared file service).

Dated this 16th day of August, 2024, at Salem, Oregon.

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CASE: UE 433
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2300

Rebuttal Testimony
Overview

April 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Michelle Scala. I am the Energy Justice Program Manager employed in the Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is provided in Exhibit Staff/300 and my Witness Qualification Statement was provided in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. This testimony is intended to elevate some of the practical impacts and major considerations across issues discussed within PacifiCorp's (Company) request for a general rate revision, docketed as UE 433. I articulate some of Staff's overarching concerns regarding the overall magnitude of PacifiCorp's requested increase and its impact on customers and how this impact is aggravated by the Company's apparent lack of prioritization of its Oregon customers in making investment and operational decisions.

I also provide a brief introduction to Staff-sponsored adjustments and issues regarding PacifiCorp's Reply Testimony. Specific line-item details about revenue, expense, and rate base components of Staff's proposed adjustments are found in Itayi Chipanera's testimony in Exhibit Staff/2500.

Q. Please summarize PacifiCorp's proposed rate increase in this docket, as updated by the Company's Reply Testimony, filed July 26, 2024.

A. In Reply Testimony, PacifiCorp has revised its initial request from $322.3 million to $214.5 million, for an overall net rate increase of 11.9 percent.[1] For the average single-family residential customer, Staff estimates this will result in a roughly 15.6 percent, or $20.23, increase to the average single-family residential customer bill.

In addition to the request made in this docket, UE 433, the Company has also requested changes in power cost recovery that would bring the total January 1, 2025 overall rate change from 11.9 to approximately 14 percent across all customers.[2,3]

Notable changes from the Company's initial filing include a revised return on equity (ROE) request from 10.3 percent to 9.65 percent and the removal of $77.7 million for proposed funding of the Catastrophic Fire Fund (CFF) for the purposes of this proceeding. PacifiCorp also removed $6.3 million of revenue requirement related to a customer service system upgrade due to a delayed in-service date.

Q. Please describe what concerns Staff would like to highlight.

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1 The proposed increase as modified by PacifiCorp's reply testimony includes: a base rate increase of $127.6 million, the recovery of forecasted and deferred insurance premiums through the Insurance Cost Adjustment (ICA) of $66.0 million, the estimated true-up of $21.2 million for the Wildfire Mitigation Plan automatic adjustment clause, and the rebalancing of the Rate Mitigation Adjustment for a reduction of $0.4 million.

2 See Docket No. UE 434, *In the Matter of PacifiCorp dba Pacific Power, 2025 Transition Adjustment Mechanism*, and UE 439, *In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Power Cost Adjustment Mechanism*. As proposed, the combined impacts of the 2024 power cost proceedings would add approximately $41.2 million, recovered across all customers.

3 Staff estimates that the 14 percent overall increase to revenues would increase the average residential monthly bill by approximately 17.6 percent.

A. Staff appreciates the modifications the Company made in response to parties' opening testimony, particularly its recognition that the CFF proposal was not ready for consideration. However, the Company's Reply Testimony contains a concerning level of proposed increases to its initial proposal and rejects valid concerns about the customer impacts of its investment and operational decisions.

Staff finds that PacifiCorp's UE 433 proposal, even as modified by the Company's July 26, 2024, Reply, asks Oregon customers to bear costs and pressures for decisions that deprioritized their interests. As the company navigates increasing pressures from wildfire and extreme weather, large customer load growth, regional transmission and capacity constraints, inflation and supply chain challenges, and uncertain thermal resource economics, a lack of priority for Oregon customer interests exacerbates the affordability issues and impacts felt by users of the system.

Staff is also concerned with PacifiCorp's response to the real world, human impacts its proposed increase may have on the Company's residential customers experiencing high energy burdens.

Q. Why is Staff concerned that the Company is asking Oregon customers to pay for decisions that deprioritize their interests?

A. Staff's greatest concerns relate to the Company's wildfire-related expenses and investments and its resource investment decisions.

Despite a jury verdict of gross negligence, recklessness, and willful misconduct against the Company in the Labor Day wildfires, Staff's position offered cost sharing mechanisms that sought to achieve a reasonable measure of "balance between affordability, reliability and reduction of [utility] risk".[4] However, in Reply Testimony, PacifiCorp maintains that these costs should fall entirely on its customers, including those directly harmed by the wildfires, and further denies any relationship between its increased wildfire liability insurance premiums and the findings of gross negligence in *Jeanyne James, et. al. v. PacifiCorp.* [5] Further, the Company did not engage meaningfully in Staff's concerns about a mismatch between the states in which the Company prioritized wildfire-related transmission investments and Oregon's high proportionate share of high consequence fire areas.[6]

Staff is equally concerned about costs associated with resource decisions that deprioritize least cost, least risk economic and policy outcomes for Oregon customers and the Company's willingness to overexpose its customers to higher costs and risks associated with its coal operations and market reliance.[7,8,9] At the same time that the Company is leaning into higher cost coal operations, it has pulled back on its plans for acquiring nearly 2 GW of non-emitting resources by 2027, actions Staff argues are not in the best interest of Oregon customers, even after the stay of the Ozone Transport Rule

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4 Docket No. UE 428, Order No. 24-155, at 7 (May 30, 2024).

5 *Jeanyne James, et. al. v. PacifiCorp*, In the Circuit Court of the State Oregon for the County of Multnomah, Case No. 20CV33885, Final Verdict (June 9, 2023); See also *Jeanyne James, et. al. v. PacifiCorp*, In the Circuit Court of the State Oregon for the County of Multnomah, Case No. 20CV33885, Final Jury Instructions, Trial Date February 26, 2024 (filed March 5, 2024).

6 *See* Staff/3000, Mondragon/8-13.

7 LC 82, *In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.*

8 UE 439, *In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Power Cost Adjustment Mechanism.*

(OTR).[10] These actions impede Oregon customers' ability to realize the benefits previously attributed to PacifiCorp's Gateway South (GSW) transmission line and associated projects in the context of coal retirements and emissions reductions.[11]

The Company also rejected Alliance of Western Energy Consumers' (AWEC) proposal to align the Company's coal decommissioning exit dates with the appropriate level of cost and risk exposure for Oregon customers. Staff continues to advocate for the economic and environmental benefits of decommissioning coal plants; however, the unfortunate reality is that PacifiCorp's decision to lean into coal and delay non-emitting resource procurements, despite the economic risks, does not allow Oregon to realize these benefits as planned. Moving out the Exit Dates to align with actual retirement is a practical and economic response to the Company's post-IRP pivot back to coal and avoids disproportionate inflation of the economics of continued coal operations for the rest of PacifiCorp's system.

Q. Why is Staff concerned with PacifiCorp's response to the real world, human impacts its proposed increase may have on the Company's residential customers?

A. Staff is concerned with the Company's consistent reluctance to engage with the humanity of the case, including the impact the UE 433 proposal will have on arrearages and disconnections, and the associated harms energy insecurity

[10] Staff/3300/Pal/15-16.
[11] Staff/3300, Pal/9-11.

can have on individuals and families. PacifiCorp rebuffs parties' arguments that the proposed UE 433 rate increase pushes many customers beyond what they can reasonably bear and rejects equity and affordability driven proposals as unsupported rather than engaging in a discussion of mitigation and alternative solutions. The Company did not respond with requested customer segment analysis and diverts parties' proposals to make incremental improvements to its existing and/or planned mitigations as ill-suited for the rate case. For example, the Company tabled all requests to expand the Low-Income Discount (LID) in this proceeding arguing that changes to the LID should occur after the Energy Burden Assessment (EBA) is published in October and that the issues are "too complex and far-reaching [such that they] may be difficult to address in the confines of this GRC".[12]

While it is true that there are assistance programs and customer protections available, and there is an EBA scheduled to be published in the upcoming months where parties and UM 2211 stakeholders expect to evaluate and modify the LID, arrearages and disconnections are at pre-pandemic highs, including over 20,000 LID enrolled customers with past due balances over 30 days old. Further evidence is documented in the hundreds of public comments Staff has received in this case, expressing strong and consistent concerns about the financial strain and disproportionate impacts of PacifiCorp's rate increases on communities and individuals.[13] The Company's response in

[12] PAC/2000, McVee/46.
[13] Staff/3200, Nottingham/2-3.

Reply Testimony lacks the warranted urgency, commitments, and frankly, any measure of concern for its customers that simply cannot afford to stay connected.

These and related issues are discussed in length in Staff/2600 where Staff highlights the extent of financial hardship evidenced across PacifiCorp's customers and identifies strategic, near-term improvements to the LID and other offerings.

Q. Staff previously noted that the Company had included some adjustments in its Reply Testimony to reduce the overall impacts of this case. However, Staff seems unconvinced of their significance. Please explain.

A. The Company's adjusted UE 433 proposal represents a reduction of approximately $107.8 million from its original request that sought to add over $322 million to its authorized revenues. The large majority of this reduction comes from the removal of the Company's $77.7 million Catastrophic Fire Fund proposal, which the Company intends to bring forward in a future proceeding. The same can be said for the $6.3 million attributed to a customer service system upgrade that encountered a delayed in-service date. While Staff can appreciate the immediate effects of these changes on the overall impacts of the UE 433 proceeding, cost recovery of these issues is still very much in PacifiCorp's sights.

Regarding the Company's downward adjustment of ROE to 9.65 percent, Staff appreciates the Company's concession in response to affordability concerns and notes that PacifiCorp's adjusted position still sits above Staff's range of reasonable ROEs of 8.77 percent to 9.44 percent (mid-point of 9.1 percent).[14] Further, the Company makes very clear in its reply testimony that the revision is an act of benevolence and their analysis continues to support an ROE between 10.25 and 11.25 percent.[15]

Staff believes that given the affordability crisis facing Oregon customers, a more holistic approach to rate pressure across issues is warranted. For example, regarding CUB's call for a rate shock policy,[16] Staff supports exploring mechanisms that can mitigate rate pressure and respond to the statewide call to address the rising rates and energy insecurity faced by increasing numbers of Oregon utility customers. Staff views CUB's request as one such effort and deserving of dialogue.

Regarding Staff's proposal to limit the residential impacts to a level within or below Staff's opening testimony adjustments,[17] the Company balks at the absence of precedent and asserts that ratemaking should not include an assessment of risk tolerance between the Company and its customers. It also argues that Staff' fails to consider how *PacifiCorp* has been impacted by risk and that should the Company be forced to absorb any costs on behalf of customers, it should be commensurately compensated through its authorized ROE.[18]

14 Staff/2400, Muldoon/8.
15 PAC/2000, McVee/3.
16 https://www.opb.org/article/2024/05/31/oregon-electric-utilities-gas-service-heat-electricity/.
17 Staff/300, Scala/6.
18 PAC/2000, McVee/18.

To this end, Staff carries forward its residential impact threshold proposal through Rebuttal and offers the clarification that the “limit” is not a formalized mechanism to establish a specific treatment of costs; rather, setting a threshold offers a tool within larger and evolving affordability frameworks and policies as they relate to ratemaking principles. It should not be assumed that utilizing the threshold in this case would necessarily result in excess revenue requirement being spread across nonresidential schedules or the Company. Rate spread represents just one of many levers that can influence the outcomes of this proceeding. Ultimately, application or consideration of the eight percent threshold as a residential affordability check point is discretionary to the Commission as it makes interrelated decisions across elements of this proceeding.

Q. Are there any other notable issues that Staff wishes to reference?

A. Yes. Staff/2700 discusses the significant issue of Very Large Customer Proposals.[19] The implications of setting policies and precedent within this topic are nontrivial and Staff would note that with very large loads comes significant risk exposure for the utility and customers associated with stranded assets and dangerous cost shifting. Staff appreciates several of the Company’s proposals aimed at mitigating these risks through very large customer incentive structures that limit consequential deviations from load forecasts. In this instance, utility and broad non-very large customer interests are generally aligned and thus the benefits of the proposals are shared. Here, Staff agrees with the Company

[19] Staff/2700, Dlouhy/2-18.

that it is important to take steps that both protect broad customers interests from these sizeable costs and risks, while simultaneously ensuring that these very large and sophisticated energy users have a reasonable level of flexibility.

INTRODUCTION TO OTHER STAFF'S REBUTTAL TESTIMONY

Q. Please describe the opening testimony submitted by Staff in this rate case.

A. The Staff exhibit number, respective Staff witness, and topics published on this date, August 16, 2024, are identified below. These exhibits provide Staff's response to PacifiCorp's Reply Testimony and other intervening parties' opening testimony positions on the topics identified, as applicable.

In **Exhibit 2400, Matt Muldoon**, Accounting and Finance Program Manager, discusses Rate of Return, and Pension and Post-Retirement Medical Expenses.

In **Exhibit 2500, Itayi Chipanera**, Senior Financial Analyst, discusses revenue requirements and cash working capital, including any adjustments and/or response.

In **Exhibit 2600, Kate Ayres**, Senior Utility and Energy Analyst, reviews PacifiCorp's low-income discount program and cost recovery, as well as residential arrearages and disconnection rates.

In **Exhibit 2700, Dr. Curtis Dlouhy Ph.D.**, Senior Utility and Energy Analyst, discusses the Company's very large customer rate design proposals, the Company's proposed Time of Use (TOU) changes, and the proposed amortization of costs deferred in UM 2211 related to PacifiCorp's Distribution System Plan.

In **Exhibit 2800, Julie Dyck**, Senior Utility and Energy Analyst, reviews PacifiCorp's fuel stock, and Juniper Ridge Bend service center.

In **Exhibit 2900, Bret Farrell**, Senior Utility and Energy Analyst, reviews PacifiCorp's uncollectible expense, and customer payment fees.

In **Exhibit 3000, Luz Mondragon**, Senior Financial Analyst, reviews PacifiCorp's utility plant in service, electric plant acquisition adjustments, routine vegetation management – Wildfire Mitigation and Vegetation Management mechanism (WMVM), Wildfire Mitigation Capital, Wildfire Mitigation Plan (WMP), Automatic Adjustment Clause (AAC) true-up, UM 2116: 2020 Wildfire Cost Amortization, and State Allocation of Wildfire Insurance.

In **Exhibit 3100, Mitch Moore**, Senior Utility Analyst, discusses the Company's materials and supplies, and incremental Operations and Maintenance (O&M).

In **Exhibit 3200, Melissa Nottingham**, Consumer Services Manager, provides an updated summary of public comments received by the Commission after Staff Opening Testimony was published and thus not previously included in Exhibit 1302.

In **Exhibit 3300, Sudeshna Pal**, Senior Economist, analyzes the Company's transmission projects, including: Gateway South (GWS) timing, appropriate Rate of Return (ROR), and management.

In **Exhibit 3400, Ming Peng**, Senior Economist, analyzes depreciation expense, amortization expense, depreciation reserve, amortization reserve, and Allowance for Funds Used During Construction (AFUDC).

In **Exhibit 3500, Nicola Peterson**, Senior Utility Analyst, analyzes PacifiCorp's Administrative and General (A&G) expense, employee benefits, insurance and risk (non medical), and Directors and Officers (D&O) insurance.

In **Exhibit 3600, Rose Pileggi**, Senior Utility Analyst, analyzes PacifiCorp's Fall Creek Fish Hatchery Project, and Cost of Long-Term (LT) Debt.

In **Exhibit 3700, Paul Rossow**, Utility Analyst, reviews PacifiCorp's memberships, dues, donations, subscriptions, meals, and entertainment and award expenses.

In **Exhibit 3800, Dr. Bret Stevens, Ph.D.** analyzes the Company's load forecasting, marginal cost study, rate spread, residential basic charge, rate base calculations, and embedded cost differential.

In **Exhibit 3900, Steph Yamada**, Senior Utility Analyst examines PacifiCorp's salaries and incentives.

In **Exhibit 4000, Madison Bolton**, Senior Utility Analyst examines coal decommissioning costs and PacifiCorp's approach to Qualifying Facilities (QF) costs in the Company's TAM and PCAM.

In **Exhibit 4100, Eric Shierman**, Senior Utility Analyst responds to Walmart's opening testimony proposal for a new electric vehicle (EV) retail rate for public-facing EV chargers.

In **Exhibit 4200 Joint Testimony: Luz Mondragon, Nicola Peterson,** and **Dr. Bret Stevens**, discuss wildfire restoration costs, wildfire liability insurance, and PacifiCorp's proposal for an insurance cost adjustment.

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

REDACTED
Staff Exhibit 2400
Rebuttal Testimony
Rate of Return, and
Pension & Post-Retirement Medical Expenses
(Subject to Protective Order No. 23-132)

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a Manager employed in the Accounting and Finance Section of the Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is provided in Exhibit Staff/100 and my Witness Qualification Statement was provided in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I update Staff's Return on Equity (ROE) modeling and overall Rate of Return (ROR) to incorporate recent data, and rebut elements of PacifiCorp's (PacifiCorp, PAC, or Company) Reply Testimony regarding the Company's ROE modeling, and pensions and post-retirement medical expense. I also recap intervenor testimony on these issues.

Further detail on Cost of Long-Term (LT) Debt is found in Rose Pileggi's testimony in Exhibit Staff/3600.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits for this testimony?

A. Yes. I prepared the following exhibits:

Other Supporting Exhibits Updating Information from Opening Testimony

4. OVERALL RATE OF RETURN (ROR)

Q. What is PacifiCorp's proposal for its overall Rate of Return in the Company's Reply Testimony?

A. The Company now proposes a rate of return (ROR) of 7.465 percent, with a capital structure comprised of 50 percent equity, 49.99 percent long-term debt and 0.01 percent preferred stock, a 5.28 percent cost of long-term debt, 6.75 percent cost of preferred stock, and a 9.65 percent return on equity (ROE).[1]

Q. Have you prepared tables showing the RORs in PacifiCorp's current Commission-authorized rates, Company-proposed in Opening Testimony, Staff-calculated in Opening Testimony, AWEC proposed in Opening Testimony, Company proposed in Reply Testimony and as Staff calculates in Rebuttal Testimony?

A. Yes. The following tables provide that information.

TABLE 1

PAC Current OPUC Authorized (UE 399 Order No. 22-491)			PAC
Component	Percent of Total	Stipulated or Implied Cost	Weighted Average
Long-Term Debt	49.99%	4.717%	2.358%
Preferred Stock	0.01%	6.75%	0.001%
Common Stock	50.00%	9.50%	4.750%
	100.00%	ROR	7.109%

[1] PacifiCorp proposes to reduce its requested ROE from 10.3 percent to 9.65 percent, See PAC 2100, Kobliha/3, Table 1.

TABLE 2[2]

PAC Requested – UE 433		PAC Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	49.99%	**5.180%**	2.589%	**0.631%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	50.00%	**10.30%**	5.150%	
	100.00%	**ROR**	**7.740%**	

TABLE 3[3]

Staff Proposed – UE 433		Staff Opening Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	49.99%	**5.182%**	2.590%	**0.132%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	50.00%	**9.30%**	4.650%	
	100.00%	**ROR**	**7.241%**	

TABLE 4[4]

AWEC Proposed – UE 433		AWEC Opening Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	55.64%	**5.130%**	2.854%	**-0.151%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	44.35%	**9.25%**	4.102%	
	100.00%	**ROR**	**6.957%**	

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2 PacifiCorp/300, Kobliha/2.
3 Staff/100, Muldoon.
4 AWEC/200, Kaufman/90 Table 15 dated July 18, 2024.

TABLE 5[5]

PAC Requested – UE 433		PAC Reply Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	49.99%	**5.280%**	2.639%	**0.356%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	50.00%	**9.65%**	4.825%	
	100.00%	**ROR**	**7.465%**	

TABLE 6[6]

Staff Proposed – UE 433		Staff Rebuttal Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	49.99%	**5.301%**	2.650%	**0.092%**
Preferred Stock	0.01%	6.75%	0.001%	
Common Stock	50.00%	**9.10%**	4.550%	
	100.00%	**ROR**	**7.201%**	

5 PAC 2100, Kobliha/3, Table 1, with Staff's slight rounding differences.

6 Note that this ROE is for illustrative purposes only. Staff recommends a range of reasonable ROEs of 8.77 percent to 9.44 percent. This example ROE within that range would produce an overall ROR that is 9.2 basis points (bps) higher than the Commission has currently authorized for PacifiCorp in Order No. 22-491 in Docket No. UE 399.

5. CAPITAL STRUCTURE & COST OF LONG-TERM DEBT

Q. Has Staff reviewed both AWEC's Opening Testimony and the Company's Reply Testimony regarding capital Structure?

A. Yes. AWEC calculates a 44.35 percent equity layer for its recommended capital structure shown in Table 4 above. In contrast, in Reply Testimony, the Company recommends a 50 percent equity layer as shown in Table 5 above.

Q. Has Staff's position changed from Opening Testimony?

A. No. Staff will monitor the Company's capital structure going forward. The Company has some flexibility within the durable ring-fencing conditions set when Berkshire Hathaway's MidAmerican Energy Holdings Co. purchased PacifiCorp from ScottishPower. See Exhibit Staff/111 for the durable conditions of Commission Order No. 06-121. As an example, Order 06-121 Condition OR 15a PPW – Consolidated Capital Structure will contain at least 44 percent Common Equity after Dec. 31, 2011.

Over time, Staff would like to see the Company oscillate around a 50 percent equity layer in its capital structure. At any given time, PacifiCorp could have more debt or equity, and still target such a balanced capital structure. In the near term, the Company's requested capital structure appears responsive to Commission Order No. 20-473. As Staff stated in Opening Testimony, the Commission can revisit this issue after reviewing the Company's actual capital structure after sufficient history to identify a definitive trend.

Cost of Long-Term Debt

Q. Did Staff analyze the Company's Cost of Long-Term Debt?

A. Yes. See Exhibit Staff/3600 for Staff Senior Utility Analyst Rose Pileggi's Rebuttal Testimony regarding the Company's outstanding and planned proforma debt issuances, and her recommendations for the Commission of a 5.301 percent Cost of Long-Term Debt. Staff recognizes that this is slightly higher than the value recommended by the Company. Staff also notes that AWEC's calculations in Opening Testimony could not have anticipated potential issuance of junior subordinated notes (JSN) in lieu of first mortgage bonds (FMB). That is a newly authorized flexibility for PacifiCorp that can be used multiple ways.[7] It is a significant change for PacifiCorp from historic practice, and a part of the reason, Staff feels it is premature to shift policy regarding capital structure without first observing how PacifiCorp utilizes these new flexibilities.

[7] See Order 24-240 entered July 24, 2024, in Docket No. UF 4354 (1).

6. RETURN ON EQUITY (ROE)

Q. What range of reasonable ROEs does Staff recommend, and within that range, what point ROE?

A. Staff observes a range of reasonable ROEs of 8.77 percent to 9.44 percent, with a mean ROE of 9.1 percent, derived from Staff's two separate updated Three-Stage Discounted-Cash-Flow (DCF) models. Staff does not have a recommended point ROE estimate in this case, which Staff noted in Opening Testimony is a departure from its typical practice.

Q. Did you perform a check on the results of Staff's Three-Stage DCF models?

A. Yes. Staff employed two simpler models to check the reasonableness of its findings:

1. An updated Single-Stage DCF or Gordon Growth Model; and
2. An updated Capital Asset Pricing Model (CAPM).

Q. What results did these models generate?

A. The Gordon Growth Model generated a mean ROE of 8.6 percent using Staff's peer electric utilities and 8.5 percent with the Company's peer electric utilities. If Staff sensitivity screening permitting a wider range or capital structure than PacifiCorp's is used, Staff's results would be increased by 10 basis points (bps) to 8.7 percent. This model points to the lower end of Staff's three-stage discounted cash flow results.

The CAPM using Staff's geometric market return with reinvested dividends generated a mean ROE of 9.8 percent using Staff's peer electric utilities and 9.7 percent with the Company's peer electric utilities. If Staff sensitivity screening permitting a wider range or capital structure than PacifiCorp's is used, Staff's results would be decreased by 10 basis points (bps) to 9.7 percent. This model points to the upper end of Staff's three-stage discounted cash flow results.

Based on these checks, Staff utilizes the illustrative midpoint estimate of 9.1 percent for ROE in Table 6 above. However, any point within Staff's range of reasonable ROEs from 8.77 percent to 9.44 percent would be supportive of a just and reasonable decision by the Commission regarding ROE.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The range of reasonable ROEs Staff recommends is appropriate for overall rates that are reflective of forward looking conditions in conjunction with Staff's adjustments and meets the *Hope* and *Bluefield* standards, as well as the requirements of ORS 756.040.[8] Staff's recommendations are consistent with establishing, "fair and reasonable rates," that are both, "commensurate with the return on investments in other enterprises having corresponding risks," and, "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[9] CUB recommends that the Commission authorized ROE in this rate case be selected from the lower end of the range of reasonable ROEs.

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8 *See Federal Power Commission v. Hope Natural Electric Co.*, 320 U.S. 591 (1944) and *Bluefield* Water *Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

9 *See* ORS 756.040(1)(a) and (b).

Peer Screen

Q. How did you select comparable companies (peers) in your updated screening to estimate PacifiCorp's ROE?

A. Staff used companies that met the following criteria as peer utilities to the regulated electric utility activities of PacifiCorp:

1. Covered by Value Line (VL) as an electric utility; [10]
2. Forecasted by VL to have positive dividend growth, meaning that the slope of forward dividends projected by VL is positive, even if for a given annual projection the dividend holds steady;
3. LT Issuer Credit Rating from A1 to Baa2 inclusive from Moody's and from A to BBB- inclusive from S&P;
4. No decline in annual dividend in last five years based on VL;
5. Has heavily regulated electric utility revenue according to EEI;[11]
6. Has LT Debt from 45 percent to 55 percent inclusive in VL Capital Structure; and[12]
7. Has no major recent merger and acquisition (M&A) activity.[13]
8. Other screening as shown in Exhibit No. Staff/2401, Muldoon/2.

Q. What peer groups of electric utilities did Staff and Company ROE modeling primarily depend on, and were there similarities?

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10 Note that recent investor interest in artificial intelligence (AI) increased speculative interest in investor-owned electric utilities (electric IOU) rate basing of AI chip data centers that currently have higher energy consumption than earlier Intel chips that data centers relied on. Therefore, Staff did NOT apply a ceiling of a VL beta of 1.0 in selecting its peer group.

11 See Staff/2411 for Edison Electric Institutes (EEI) report with these assessments.

12 Staff also performs sensitivity analysis looking at a peer screen of 40 percent to 60 percent long-term debt in capital structure. Sensitivity analysis does not impact Staff's modeling results but does answer questions looking at alternative inputs and scenarios.

13 See Staff/2410, Muldoon/6 for examples of financial news on mergers and acquisitions (M&A) monitored by Staff.

A. The Company, in its Reply Testimony, and Staff herein now recommended regulated electric utility peer groups both drawing from pertinent electric utilities covered by VL. In Staff Exhibit 2402, page 2, Staff flags electric utilities not selected as it shows how each element of its screening was applied. Table 7 shows a fair amount of overlap between PacifiCorp's and Staff's current peer groups. AWEC in its Opening Testimony did not do its own peer screening and instead utilized the Company's Direct Testimony peer screen and time periods.[14]

Q. Did the Company apply some different criteria?

A. Yes. However, there was much overlap between PacifiCorp's and Staff's screening criteria.

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[14] AWEC/200, Kaufman/56.

1 **TABLE 7[15]**

		Sensitivity
UE 433 PAC	UE 433 Staff	UE 433 Staff
No	No	No
Yes	No	Yes
Yes	Yes	Yes
Yes	No	Yes
No	No	No
Yes	Yes	Yes
No	Yes	Yes
No	No	No
Yes	No	No
No	Yes	Yes
No	No	No
No	No	No
Yes	No	Yes
No	No	No
Yes	No	No
Yes	Yes	Yes
No	No	Yes
No	No	No
No	No	No
No	No	No
No	No	No
Yes	Yes	Yes
No	No	No
Yes	No	No
Yes	Yes	Yes
Yes	Yes	Yes
No	No	No
No	No	No
Yes	Yes	Yes
Yes	Yes	Yes
No	No	No
No	No	No
No	Yes	Yes
No	Yes	Yes
Yes	No	No
No	Yes	Yes
Yes	No	Yes
16	13	18

15 See Exhibit Staff 2401, Muldoon/2 for the full peer screening table. Staff's sensitivity group is selected with a relaxed capital structure requirement as shown therein.

A comparison of the peer groups used by Staff and PacifiCorp are set forth in Table 9 below. Staff excluded some of the companies used by PacifiCorp based on the Staff screening criteria described above. PacifiCorp also excludes some of the companies used by Staff. Eight companies were relied upon by both Staff in its primary screening and PacifiCorp.

Model Results

Q. What are the results of your updated multistage DCF models?

A. See Table 8 below for the results from Staff's Three-Stage DCF modeling.

TABLE 8 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[16]

Staff Range of Reasonable ROEs:	**8.77%**	**to**	**9.44%**	**ROE**
	Midpoint	9.1%	**ROE**	

Supporting Exhibit Staff/2403, Muldoon/1 shows step-by-step how Staff's updated Hamada adjusted[17] Three-Stage DCF modeling, using Staff peers and growth rates, generates a higher recommended ROE than using PacifiCorp's peer electric utility group. Note that Staff results, rounded upward, would generate a top of range value of 9.5 percent ROE, the Company's current Commission-authorized ROE.

Q. Does AWEC's point estimate for ROE fall within Staff's range of reasonable ROEs?

A. Yes. AWEC's recommendation for a 9.25 percent ROE falls therein.

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16 See Exhibit Staff/2403, Muldoon/1 for the results of Staff three-stage DCF modeling.

17 As Staff explains in more detail above, Staff applies the Hamada equation to better compare companies with different capital structures.

Q. Does Staff agree with PacifiCorp's assertion that the Company's requested ROE of 9.65 percent is reasonable and reflective of the Company's efforts to address affordability?[18]

A. No. For customers footing the bill, it would appear rather that PacifiCorp asks for a significant 15 basis point (bps) increase in Commission authorized ROE. Staff notes that raising electricity costs as requested by the Company can harshly impact energy burdened customers, which sentiment is captured in Staff's financial newsfeeds.[1]

Further, PacifiCorp's analysis in support of its ROE recommendation concludes a range of 10.25 percent to 11.25 percent with a recommended point estimate of 10.30 percent would somehow be reasonable.[19] It would appear that even the Company is finding the conclusions of its cost of capital analysis are excessive and generally unsupportable.

Q. Does the Company say that if only "reasonable adjustments" made to Staff's analysis, then Staff's analysis would also support a tremendous jump in PacifiCorp's authorized ROE to a 10.3 percent point ROE within an atmospheric range of reasonable ROEs?[20]

A. Yes, Staff does not agree that the Company makes reasonable adjustments to Staff's ROE modeling work. The PAC/2200 testimony contorts Staff's work prodigiously, which is not reasonable. Staff does not agree with either the

[18] See Exhibit PAC/2000, McVee/3, lines 8,9, "The Company reduced its requested ROE from 10.3 percent to 9.65 percent to mitigate the impact of this rate change on its customers."
[1] See Staff/2410, Muldoon/1, 26, 38, 56, 61, 64, 74, 78, 81, 83, 89, 108, 113, and 143.
[19] See PacifiCorp/400, Bulkley/6.
[20] PAC/2200, Bulkley/7, lines 3-5.

excessive contortions or the Company's conclusions, and instead Staff provides updated ROE analysis herein. Interestingly, PacifiCorp choses to leave its ROE analysis entirely disjointed from its ROE recommendation, rather than remedying the excessive inputs the Company uses to generate outsized ROE modeling results.

Q. Please provide an updated example of an extreme input used in the Company's modeling.

A. Example 1 below shows how important inputs are to ROE modeling. Looking at the difference between PacifiCorp and Staff's updated inputs, one can see how use of an inflated market return can skew results upward.

Example 1 – NOT a Staff Recommendation:

PAC	4.50%	PAC Rf Rate (PAC/2205 Bulkley/1)	
Direct	12.65%	PAC Mkt Return (PAC/2205 Bulkley/1)	
Testimony	8.15%	PAC Mkt Risk Premium (PAC/2205 Bulkley/1)	
Staff	4.179%	R_f Aug 6, 2024 30-Yr UST Yield /WSJ	www.wsj.com/market-data/bonds
	10.14%	30-Year S&P 500 Proxy Market Return	Geometric Return 1993-2023
	5.96%	Staff 30-Yr Mkt Risk Premium (MRP)	

Q. Please show a Capital Asset Pricing Model with Staff's and other more inflated inputs that may be preferred by the Company.

A. In Table 9 below one can see how applying inputs from the table above to all the peer utilities changes ROE results of CAPM modeling.

Q. Has the Commission established a precedent of using a geometric rather than an arithmetic market return for CAPM ROE modeling?

A. Yes.[21] This is a long-standing Commission precedent. Yet it does not generally look like the Company has been overly concerned about Oregon Commission precedent or practice in its ROE modeling and recommendations

Q. The Company also cites the work of Dr. Roger Morin. Has he appeared before the Commission?

A. Yes. The Commission considered his arguments regarding Arithmetic vs. Geometric Means in calculating a Rf Rate for CAPM, and determined in Order No. 94-336 that: "A geometric average should be used to derive the market risk premium when CAPM is focused on a holding period greater than one year." That is consistent with practitioners who have found that use of a geometric average injects an upward bias into ROE modeling.[22]

Q. Is Staff saying that the Company's failure to apply Oregon precedent helps PacifiCorp inflate ROE modeling results?

A. Yes. Please see Staff's updated CAPM modeling example below.

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[21] See: OPUC Docket UT 43 Order 87–406 PAC NW Bell (March 31, 1987), and OPUC Docket UT 113 Order 94-336 GTE NW (February 22, 1994).

[22] "Geometric or Arithmetic Mean: A Reconsideration" by Eric Jacquier, Alex Kane, and Alan J. Marcus notes that "Compounding at the arithmetic average historic return … results in an upwardly biased forecast"- 2005 Journal of Financial Economics as an example.

TABLE 8 – CAPITAL ASSET PRICING MODEL (CAPM) EXAMPLE

$R_{PAC} = R_f + Beta * MRP$

	Screen #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	LT Debt UE 433 Sensitivity	Ticker	VL Q2 2024 Beta	Staff MRP 30 Yr ROE w VL Beta CAPM	PAC MRP PAC/2200 ROE w VL Beta CAPM	Screen #	
1	1	Allete	No	No	No	ALE	0.95	9.84%	12.24%	1	1
2	2	Alliant	Yes	No	Yes	LNT	0.90	9.54%	11.84%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	0.90	9.54%	11.84%	3	3
4	4	AEP	Yes	No	Yes	AEP	0.85	9.25%	11.43%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	0.95	9.84%	12.24%	6	5
6	7	Black Hills	No	Yes	Yes	BKH	1.05	10.44%	13.06%	7	6
7	9	CMS	Yes	No	No	CMS	0.85	9.25%	11.43%	9	7
8	10	Consol Ed	No	Yes	Yes	ED	0.80	8.95%	11.02%	10	8
9	13	Duke	Yes	No	Yes	DUK	0.90	9.54%	11.84%	13	9
10	15	Entergy	Yes	No	No	ETR	1.00	10.14%	12.65%	15	10
11	16	Evergy	Yes	Yes	Yes	EVRG	0.95	9.84%	12.24%	16	11
12	17	Eversource	No	No	Yes	ES	0.95	9.84%	12.24%	17	12
13	20	Fortis	No	No	No	FTS	0.75	8.65%	10.61%	20	13
14	22	IDACORP	Yes	Yes	Yes	IDA	0.85	9.25%	11.43%	22	14
15	24	NextEra	Yes	No	No	NEE	1.05	10.44%	13.06%	24	15
16	25	NorthWestern	Yes	Yes	Yes	NWE	0.95	9.84%	12.24%	25	16
17	26	OGE	Yes	Yes	Yes	OGE	1.05	10.44%	13.06%	26	17
18	27	Otter Tail	No	No	No	OTTR	0.95	9.84%	12.24%	27	18
19	29	PGE	Yes	Yes	Yes	POR	0.90	9.54%	11.84%	29	19
20	30	Pinnacle	Yes	Yes	Yes	PNW	0.95	9.84%	12.24%	30	20
21	32	PPL	No	No	No	PPL	1.15	11.03%	13.87%	32	21
22	33	Public Serv.	No	Yes	Yes	PEG	0.95	9.84%	12.24%	33	22
23	34	Sempra	No	Yes	Yes	SRE	1.00	10.14%	12.65%	34	23
24	35	Southern	Yes	No	No	SO	0.95	9.84%	12.24%	35	24
25	36	WEC	No	Yes	Yes	WEC	0.85	9.25%	11.43%	36	25
26	37	Xcel	Yes	No	Yes	XEL	0.85	9.25%	11.43%	37	26
		No. of Peers:	16	13	18			VL Betas	VL Betas		
					Company Screen		Mean	9.7%	12.1%	ROE	
					Staff Screen		Mean	9.8%	12.1%	ROE	
					Staff Sensitivity Screen		Mean	9.7%	12.0%	ROE	

Staff usually relies on a U.S. Treasury (UST) 30-year bond as reported by the Wall Street Journal (WSJ) and 30-year monthly geometric returns for the Standard and Poor's (S&P) 500 index as a proxy for market returns. If one instead uses **an extreme arithmetic market return** one can inflate the results of a CAPM model with few inputs.[23] One can also boost results by using a starting point for data collection in the Great Depression and then including World War II era boom times unlikely to be repeated in the U.S. economy.

[23] See Staff/2404, Muldoon/1 for this updated CAPM modeling example.

Q. Walmart suggests that the Company's range of reasonable ROEs in its modeling and PacifiCorp's point estimate of 10.3 percent are inconsistent with recent state commission authorized ROEs.[24] Is that accurate?

A. Walmart is correct. Regulatory Research Associates (RRA), an affiliate of Standard and Poor's Global Market Intelligence, in its July 29, 2024, report shows that for the first half of 2024, the average return authorized by state regulatory commissions was 9.68 percent, roughly what PacifiCorp now requests the Commission to authorize for the Company in this rate case.[25] This compares to a 9.60 percent average for full year 2023.

However, awkwardly for PacifiCorp, a 9.65 percent ROE is contrary to and not supported by the Company's ROE testimony in Exhibit No. PAC/2200. Peculiarly, even though PacifiCorp asks for a 15 bps increase in Commission authorized ROE, the Company's stratospheric ROE modeling leaves the Company's request no better supported.

Staff Models

Q. Did Staff update its two three-stage DCF models on which you primarily rely?

A. Yes. Staff's ROE modeling has been updated since its opening testimony to reflect current market conditions and inputs.

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[24] See Exhibit Walmart/104.

[25] Exhibits Staff/2401-2405 show how Staff's recommendations are generated.

Growth Rates Used in Third Stage of DCF Models[26,27]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[28]

A. Staff used three different long-term growth rates, with different methods employed in developing each.

Staff's first method uses the U.S. Congressional Budget Office's (CBO) recently updated 1.70 percent real long-term GDP growth rate estimate.

Staff's second Composite Growth Rate applies a 20 percent weight to each of the following referent entities long-term growth rates: updated Energy Information Administration (EIA), Organization for Economic Co-operation and Development (OECD), the U.S. Social Security Administration (SSA), the updated CBO projection, with the remaining 20 percent as the average annual historical real GDP growth rate, established using regression analysis of updated U.S. Bureau of Economic Analysis (BEA) Nominal Historical, 1994 Q2 – 2024 Q1, for the period 1980 through 2021, to which we apply an updated Treasury Inflation-Protected Securities (TIPS) implied inflation forecast. These growth rates are shown below in Table 9.

[26] See Exhibit Staff/2405, Muldoon1 for updated BEA historical GDP growth rates.

[27] See Exhibit Staff/2406, Muldoon1 for updated TIPS implied long-run inflation rates.

[28] See three-stage DCF models X and Y in Exhibit Staff/2402.

TABLE 9 – GROWTH RATES STAFF RELIED UPON

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)			4.10%	20.0%	0.82%	
Organization for Economic Co-operation and Development (OECD)	1.81%	2.32%	4.17%	20.0%	0.83%	
Social Security Administration (SSA)	1.95%	2.32%	4.10%	20.0%	0.82%	
Congressional Budget Office (CBO)	1.70%	2.32%	4.06%	20.0%	0.81%	
BEA Nominal Historical,1994 Q2 – 2024 Q1	2.21%	2.32%	4.58%	20.0%	0.92%	
Composite				100%	4.20%	Composite
Congressional Budget Office (CBO) Long-Term 20-Year Budget Outlook	1.70%	2.32%	4.06%	100.0%	4.06%	CBO
BEA Nominal Historical,1994 Q2 – 2024 Q1	2.21%	2.32%	4.58%	100.0%	4.58%	BEA

Q. What was the general direction of the above referent entities' updated U.S. Gross Domestic Product (GDP) long-term growth rates?

A. Downward. The CBO underscores long-term U.S. challenges regarding labor productivity and working-age population participating in the workforce. The Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds flags concerns around U.S. birth rates and their importance to a growing GDP.[29]

Q Did the Company's testimony reflect downward expectations for GDP growth, due to the above concerns raised by agencies responsible for monitoring these concerns?

A. No.

Q Did your analysis reflect an updated synthetic forward curve?

A. Yes. Staff utilized an updated synthetic forward curve using U.S. Treasury (UST) TIPS break-even points. This reflects implied market-based inflationary

[29] See Staff/2410, Muldoon 89, and 168.

expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Staff again assumes, for purposes of its three-stage DCF modeling, that investor-owned electric utility growth is bounded by the growth of the U.S. economy, and more specifically impacted by challenges regarding U.S. population, workforce participation, and productivity in the long-run (20-year) modeling period.

Q. Does Staff's updated analysis capture the expectations of an investor who expects GDP growth in the future to be like that of the past 30 years?

A. Yes. Staff's updated analysis of BEA information now examines a 30-year historical record. That is also consistent with accounting and finance matching principles which look for financial practitioners to match time periods where practicable.

Q. In Exhibit No. PAC/2200, the Company is generally skeptical that Staff has access to and is informed by current financial news feeds. Is there any basis for that perspective?

A. No. Staff has access to extensive financial news feeds as exhibited in supporting exhibits hereto.[30] News that investors are seeing is consistent with Staff positions and perspective.

[30] See Exhibit Staff/2410 for news that investors in electric utilities are seeing.

Hamada Equation

Q. PacifiCorp is critical of Staff's use of the Hamada Equation to address differences in peer utility capital structure. Do those criticisms and Company proposed remedies have any merit?

A. No. Staff updates its Hamada Equation adjustments appropriately in this testimony.

Q. Staff standardizes on Value Line and certain other data sources. Why is that?

A. Standardization on data sources helps to prevent "data shopping." As an example, Staff's use of Value Line betas provides a consistent use of data across Commission jurisdictional utility rate cases.

In contrast, the Company may look at beta calculations from a variety of different sources, each with a different method for calculating reversion to mean over time and other factors. Staff's standardization on data sources allows the Commission to avoid choosing among competing opinions in each rate case and instead rely on a standard calculation.

Q. Is that why Staff standardizes on reliance on S&P and Moody's credit ratings?

A. Yes. In addition to variations due to divergent analytic methodologies, Companies with a strong sell-side presence and potentially poor separation between their analytic and marketing group can have a sell-side bias. Standardization on data sources helps to prevent "data shopping." As an example, an investor might have thought in 2017 that a five-star rating by Morningstar would indicate that a mutual fund was a top performer. It wasn't.[31]

> Of funds awarded a coveted Morningstar five-star overall rating, only 12% did well enough over the next five years to earn a top rating for that period; 10% performed so poorly they were branded with a rock-bottom one-star rating. The Wall Street Journal (WSJ) analysis also found Morningstar analysts' ratings of funds were overwhelmingly positive. That bias identified by the WSJ generally causes Staff to avoid excessive reliance on Morningstar owned products – easily avoided by Staff's standardization on S&P and Moody's for credit ratings.

Balanced Approach to ROE

Q. Is picking a best-fit ROE within Staff's suggested range of reasonable ROEs an easy decision for the Commission?

A. No. On the one hand, a lower ROE would reduce the impact of this general rate increase on PacifiCorp's utility customers in Oregon. The impact of raising costs from this GRC, other dockets, and the economy generally, has resulted in this being an important concern for the Commission to consider. This concern has been raised by Staff, and Intervenors, and was a common sentiment in public comment received in this case. Staff notes that raising costs can impact energy burdened customers particularly, during a time of historically high arrears and disconnections.[32]

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[31] See, "The Morningstar Mirage" by Kirsten Grind, Tom McGinty and Sarah Krouse – WSJ – Oct 25, 2017, provided in Exhibit Staff/2414, Muldoon/1 as an example of sell-side bias.

[32] See PacifiCorp response to Staff DR 746 for arrears information.

On the other hand, a higher ROE is more supportive of the Company's credit ratings, which are under pressure based on financial metrics and the Western U.S. challenge of wildfire risks. Staff notes that shareholders and ratepayers both benefit from a utility that is viewed as financially healthy and strong.

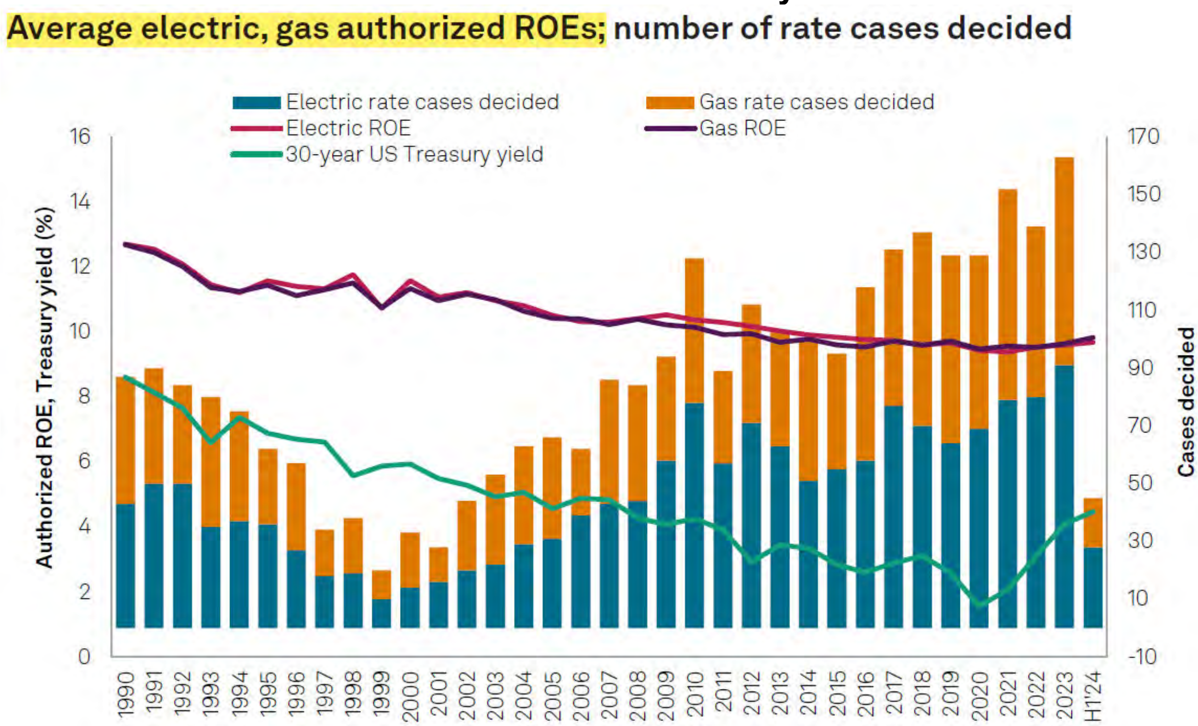
Staff sees tradeoffs and a necessity to identify a middle ground when examining the requests made by the Company to increase the burden placed on ratepayers with the interests and health of the Company and its shareholders. Ultimately, balancing these and other considerations is necessary for the Commission to make decisions consistent with the Hope and Bluefield legal decisions mentioned earlier.

Q. In Opening Testimony, you indicated that financial news was focused on the U.S. Federal Reserve (Fed) lowering rather than raising interest rates. Has that changed?

A. No. The U.S. Federal Reserve still expects to lower interest rates in the next year.[33] Further, interest rates and ROEs are likely still both declining when looked at over a 30-year time frame. The downward glide path for ROE in updated Figure 1 below is not linear and may fluctuate through these uncertainties, but long-run GDP growth rates are mostly determined by the long future U.S. working age population and its productivity. These are downward pressures on GDP growth.

33 See Staff/2410, Muldoon/18, 31, 35, 44, 70, 74, 98, 119, 127, 131, 140, and 160.

FIGURE 1 – Downward Glide Path of Utility ROES[34]



Q. What trend is Staff seeing?

A. Since 1990, according to Regulatory Research Associates (RRA), Electric and Electric Utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed recently raised interest rates, the Fed now anticipates loosening money supply soon.

Q. Is the above trend still informative today?

A. Yes. RRA recompiled this data July 23, 2024.

Q. Is the above trend particularly hard to follow?

A. No. The lines are high at the left and low at the right.

GORDON GROWTH MODEL – As Check on ROE Findings

Q. Did Staff updated its Gordon Growth model as part of this testimony?

[34] See Exhibit Staff/2412.

A. Yes. Staff updated its Gordon Growth model (or Single Stage DCF model).

Q. What are the results of Staff's Gordon Growth model?

A. Using Staff's peer utility screen, the average required ROE under Staff's Gordon Growth model is 8.6 percent as shown in Table 10 below.

TABLE 10[35]

Staff's Representative Single Stage (Gordon Growth) Discounted Cash Flow (DCF) Model

Presumes the Peer Utility will pay its divident as a fixed multiple of growth into the future as it is now.
The results would be true only if the utility stock's dividends were to grow at a constant rate forever.

Value of Stock (P_0) = D_1 / (k- g) Stock Price Now = Next Year's Dividend / (Required Stock Return - Growth in Dividends)

k = (D_1 / P_0) + g Required Rate of Return on Utility Equity = (Next Year's VL Dividend / Recent Stock Price) - Perpetual Growth

This Model Implies: **Points toward Lower End of Staff's 3-Stage DCF Modeling Results**

	Screen #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	LT Debt UE 433 Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investord ROE (= 9 + 10)	Screen #	
		1	2	3	4	5	6	7	8	9	10	11	12	13
1	1	Allete	No	No	No	ALE	61.77	4.6%	2.93	4.7%	3.7%	8.5%	1	1
2	2	Alliant	Yes	No	Yes	LNT	50.73	3.8%	2.04	4.0%	6.0%	10.1%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	73.00	3.7%	2.86	3.9%	5.7%	9.7%	3	3
4	4	AEP	Yes	No	Yes	AEP	88.50	4.1%	3.81	4.3%	4.6%	8.9%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	35.83	5.4%	2.00	5.6%	4.1%	9.7%	6	5
6	7	Black Hills	No	Yes	Yes	BKH	55.35	4.7%	2.70	4.9%	3.8%	8.7%	7	6
7	9	CMS	Yes	No	No	CMS	60.76	3.4%	2.16	3.6%	3.8%	7.3%	9	7
8	10	Consol Ed	No	Yes	Yes	ED	92.43	3.6%	3.40	3.7%	3.8%	7.4%	10	8
9	13	Duke	Yes	No	Yes	DUK	100.85	4.1%	4.22	4.2%	1.3%	5.5%	13	9
10	15	Entergy	Yes	No	No	ETR	108.17	4.2%	4.70	4.3%	3.4%	7.7%	15	10
11	16	Evergy	Yes	Yes	Yes	EVRG	53.31	4.9%	2.74	5.1%	4.6%	9.7%	16	11
12	17	Eversource	No	No	Yes	ES	59.29	4.8%	3.03	5.1%	5.9%	11.0%	17	12
13	20	Fortis	No	No	No	FTS	39.34	6.1%	2.49	6.3%	4.7%	11.0%	20	13
14	22	IDACORP	Yes	Yes	Yes	IDA	94.30	3.5%	3.46	3.7%	5.7%	9.4%	22	14
15	24	NextEra	Yes	No	No	NEE	72.07	2.9%	2.25	3.1%	9.0%	12.1%	24	15
16	25	NorthWestern	Yes	Yes	Yes	NWE	50.62	5.1%	2.64	5.2%	1.5%	6.7%	25	16
17	26	OGE	Yes	Yes	Yes	OGE	35.53	4.8%	1.73	4.9%	2.0%	6.9%	26	17
18	27	Otter Tail	No	No	No	OTTR	87.64	2.1%	1.97	2.2%	4.9%	7.1%	27	18
19	29	PGE	Yes	Yes	Yes	POR	43.78	4.5%	2.08	4.8%	5.7%	10.4%	29	19
20	30	Pinnacle	Yes	Yes	Yes	PNW	75.86	4.7%	3.61	4.8%	1.8%	6.5%	30	20
21	32	PPL	No	No	No	PPL	28.21	3.7%	1.10	3.9%	1.7%	5.6%	32	21
22	33	Public Serv.	No	Yes	Yes	PEG	72.66	3.3%	2.52	3.5%	5.0%	8.5%	33	22
23	34	Sempra	No	Yes	Yes	SRE	74.54	3.3%	2.58	3.5%	5.2%	8.7%	34	23
24	35	Southern	Yes	No	No	SO	77.30	3.7%	2.96	3.8%	2.3%	6.2%	35	24
25	36	WEC	No	Yes	Yes	WEC	80.49	4.1%	3.57	4.4%	4.7%	9.1%	36	25
26	37	Xcel	Yes	No	Yes	XEL	53.83	4.1%	2.30	4.3%	5.6%	9.9%	37	26
		No. of Peers:	16	13	18							Mean		
											Company Screen	8.5%	ROE	
											Staff Screen	8.6%	ROE	
											Staff Sensitivity Screen	8.7%	ROE	

The average required ROE decreased to 8.5 percent if the Company's Reply Testimony peer screen is used. Staff's sensitivity peer group allowing for debt up to 60 percent of capital structure increases the modeling result to

[35] See Exhibit Staff/2405, Muldoon/1 for Staff's updated Gordon Growth Model.

8.7 percent. Findings in Table 10 above support selection in the lower end of Staff's range of reasonable ROEs.

CAPM – As Check on ROE Findings

Q. Did Staff update its Capital Asset Pricing Model (CAPM)?

A. Yes. Staff updated its CAPM modeling herein.

Q. Did Staff continue to rely on Value Line Beta estimates?

A. Yes. The perils of switching between Beta estimates, known as "Beta shopping," was earlier addressed in this testimony.

Q. For some of the Company's ROE modeling, PacifiCorp suggests growth rates for full earnings should be used in lieu of dividends. Would that double count the same money that the Company uses for both dividend payout to investors and for other corporate purposes?

A. On its face it would appear so. Logically, free cash to the firm would be used for either dividends or retained earnings to create capital appreciation through increasing the value of the Company. Money is fungible but decisions in its use can preclude alternative uses of the same funds.

Q. In Opening Testimony, Staff showed that investors holding peer utility stocks to generate income for other uses of the investors would expect a lower ROE than generated by Staff's three-stage DCF Modeling. What if the investors generally reinvested all dividends received and were instead seeking to maximize the value of their stock holdings over time?

A. Staff's updated CAPM modeling now shows dividends as entirely rather than only partially reinvested in peer utility stocks. Instead of the early scenario envisioned by Staff where some investors reinvested dividends in these stocks, and some needed income, Staff now looks at the scenario where all investors immediately reinvest all dividends back into the peer utility stocks.

Q. Isn't that unlikely to happen with actual investors?

A. Yes. However this allows Staff to look at a most frugal investor scenario to consider maximum reasonable outcomes of its CAPM modeling. This approach boosts Staff's model outputs to 9.8 percent ROE for Staff's peer screen, and 9.7 percent for each of Staff's sensitivity screen and for the Company's peer screen.

Q. What if the Company were to use an arithmetic market return?

A. That could boost modeling results to 12.1 percent ROE as shown earlier in Table 8.

Q. Is it effective to contort CAPM inputs to general outputs in the 12 percent range and then request a 15 bps higher ROE, saying that in comparison the Company's request was reasonable.

A. This does not seem effective. Rather, it seems to largely suggest those doing the Company's modeling don't pay much attention to Commission orders and precedent.

BERKSHIRE CASH HOARD

Q. If PacifiCorp is a wholly owned subsidiary of Berkshire Hathaway (BRK), and if BRK has about $228.94 billion in cash and cash equivalents, why is PacifiCorp asking for a rate increase?[36]

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[36] See Staff/2410, Muldoon/18, 23, 87, and 157.

A. This is a subject that PacifiCorp may want to address further in Surrebuttal Testimony. However, Staff can share some of its operating framework, which may help to explain why Staff makes ROE recommendations as though PacifiCorp were a stand-alone investor-owned utility that for instance incurred a cost to float new common equity. [37]

When Mid-American Energy Holdings (MEH)—division of BRK—purchased PacifiCorp for $5.1 billion in cash and $4.3 billion in debt and preferred stock as reported by NBC News on May 24, 2005, the Commission reviewed that proposed transaction and set ring-fencing conditions/controls that caused PacifiCorp to keep its own books and separately track information for SEC reporting as well as numerous other requirements.[38] The durable portion of those controls in Commission Orders are summarized in Staff's Opening Testimony.[39]

Q. What does ring-fencing mean in terms of separation of PacifiCorp from other companies owned by BRK and BRK itself.

A. Generally, ring fencing served to separate PacifiCorp from the effects of a bankruptcy by a parent company, while also ensuring that PacifiCorp's record keeping is not just rolled into BRK or a parent company. This separation of companies generally works both ways.

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37 See Staff/2410, Muldoon/134.
38 See: *Buffett Buys PacifiCorp for $5.1 billion cash*, The Associated Press (May 24, 2005) available here: Buffett buys PacifiCorp for $5.1 billion cash (nbcnews.com).
39 See Staff/111.

Q. In simpler terms does that mean that BRK money is not necessarily available to PacifiCorp and that in many ways Staff treats PacifiCorp as though it were on its own as a stand-alone electric utility with all the obligations and financing difficulties that entails?

A. That is correct. While I am not an attorney, that is my perspective. However, I understand that PacifiCorp's customers struggling to make ends can have significant difficulty reconciling the Company's request for another rate increase with BRK's substantial cash equivalent resources on hand. While I believe that the Commission can and should take these customers' perspective into account when making determinations in this case, Staff does not believe it is appropriate to treat PacifiCorp as BRK.

7. PENSIONS AND POST RETIRMENT MEDICAL EXPENSE

Q. Has Staff changed its recommended adjustments to the Company's pensions, Qualified Pension Plan ASC 715 and post-retirement medical expense, Post Retirement Welfare Plan FAS 106 in this general rate case.

A. No. Staff considered PacifiCorp's Reply Testimony but did not find it compelling.

Q. Is Staff disagreeing with PacifiCorp's determination that it is unreasonable to consider assumptions from other entities' defined benefit plans in determining net periodic benefit cost for the Company's plans?[40]

A. Not precisely. Staff does not dispute that the Company appropriately has the right to manage its pension and post-retirement medical plans as it determines consistent with Company policy and accounting best practices.

However, Staff is questioning what contributions to pertinent expenses are appropriate for Oregon utility customers of PacifiCorp.

Q. Do other elements of the Company's testimony call in question whether a greater amount of fixed income holdings could cause PacifiCorp customers to need to contribute more for these purposes than other Commission jurisdictional energy utilities?

A. Yes. Staff's CAPM ROE modeling utilized a market-risk premium between the return on U.S. Treasuries and that of common equities in the S&P 500.

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[40] PAC/2100, Kobliha/15.

Exhibit No. 2200/Bulkley criticizes Staff's methodology and suggests that the differential between fixed income with small spreads over UST and the returns an investor would expect over time from common equities is much higher than Staff's calculations.

Q. Wouldn't money to fill any such gap come from investors?

A. No. Staff is concerned that over time Oregon customers of PacifiCorp would be required to fill a gap between the return earned on assets and the amounts needed to address these expenses. Essentially, risk and uncertainty could be reduced for PacifiCorp, but at utility customer expense.

Q. What adjustment in terms of each annual pension expense and annual post-retirement medical expense do you recommend?

A. Staff continues to recommend the adjustments shown in the Table 12 below:

[BEGIN CONFIDENTIAL]

Table 12

[redacted]

[END CONFIDENTIAL]

Q. What is Staff's primary concern that this proposed adjustment is addressing?

A. Staff is concerned that PacifiCorp is shifting risk and cost away from the utility to Oregon utility ratepayers. Essentially, PacifiCorp may be seeking more certain returns from fixed income at lower risk, but leaving a gap in EROA that Oregon ratepayers must fill.

Q. Could there be other considerations or unique characteristics of PacifiCorp's pensions and post-retirement medical expenses?

A. Staff invites the Company to address the above concern in Surrebuttal Testimony. To that end, Staff issued Data Requests asking the Company further about the characteristics of its pensions and post-retirement medical programs.[41] Staff is examining data provided by PacifiCorp and cannot determine at this time that PacifiCorp's Oregon utility customers would not be harmed by PacifiCorp's derisking efforts and the Company's movement toward a greater proportion of fixed income in these retirement plans. Staff has not at this time, found sufficient evidence that would support a different conclusion than the one that led to Staff's original adjustment.

Q. What could PacifiCorp potentially demonstrate in Surrebuttal Testimony?

A. It is possible that the Company can demonstrate in its next round of testimony that PacifiCorp's move to a greater portion of fixed income in its pertinent asset pools, corresponds well to the remaining life expected for the Company's Pension and Post-Retirement Medical programs, addressing entry, vesting, and demographics, and actuarial details. Essentially the Company may demonstrate that time to expected end of plans is consistent with greater portion of fixed income assets.

[41] See responses to Staff DRs 732-735 Dated August 7, 2024, in Exhibit Staff/2413, Muldoon/1-4.

8. CONCLUSION

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission select a point ROE from within Staff's range of reasonable ROEs from 8.77 percent to 9.44 percent from Staff's updated ROE modeling.

Q. What Rate of Return (ROR) is generated by the Staff's aggregated Cost of Capital recommendations on Capital Structure, ROE, and Cost of Long-Term Debt?

A. Staff provides an illustrative 7.201 percent Overall Rate of Return (ROR), based on the midpoint of Staff's range of reasonable ROEs of 9.10 percent, a 50 percent equity layer Capital Structure and a 5.301 percent Cost of Long-Term Debt. The last is reflective of the Company's plans to issue some Junior Subordinated Notes (JSN) rather than First Mortgage Bonds (FMB).

Q. What recommendation does Staff have regarding a point estimate within Staff's range of reasonable ROEs.

A. Staff finds that recommending a range is appropriate rather than any single point estimate. The range is from 8.77 percent to 9.44 percent. The range provides values from which the Commission can balance the interests of shareholders and energy affordability for Oregon utility customers and still meet statutory requirements to provide for a fair return on equity.

Q. Does Staff recommend an adjustment to pensions and post-retirement expense in this general rate case?

A. Yes. Staff maintains its downward adjustment of an aggregate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of annual pension and post-retirement medical expenses to address excessive “derisking” of the Company’s investment assets. However, Staff notes that PacifiCorp may be able to demonstrate in its Surrebuttal Testimony that a greater portion of fixed income assets is reasonable if the Company can show that based on the expected remaining life of the plans and pertinent actuarial factors, “de-risking” would not increase costs to the Company’s Oregon utility customers. Were the plans soon to expire, with falling numbers of participants that could be the case.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2401

ROE – Three-Stage DCF: Peer Screen, Dividends, Earnings per Share (EPS), and Hamada Equation

August 16, 2024

Acronyms and Abbreviations Used

BOE U.S. Bureau of Economic Analysis
CBO U.S. Congressional Budget Office
CIK SEC Central Index Key
EDGAR SEC Electronic Data Gathering, Analysis and Retrieval System
EEI Edison Electric Institute
EIN IRS Employer Identification Number
IRS U.S. Internal Revenue Service
SEC U.S. Securities and Exchange Commission
SIC Standard Industrial Code
SPG Standard & Poors Global Market Intelligence
TIPS UST Treasury Inflation-Protected Securities
U.S. United States of America
UST U.S. Treasuries
VL Value Line Investment Survey

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		
Aa2		AA		AA		AA	R-1M	High grade
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C	CCC	C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC				CC		

S Small Cap Under 2 Billion
M Mid Cap 2 to 10 Billion
L Large Cap Over 10 Billion

1	2	3	4	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
VL #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	LT Debt Sensitivity UE 433 Staff	VL 7/12/2024 Beta	VL $B 7/12/2024 Mkt Cap $ Billions	VL 7/12/2024 S,M,L CAP	Yahoo Fin. 7/15/2024 Beta	Yahoo Fin. 7/15/2024 Mkt Cap $ Billions	Covered by Value Line 7/12/2024 (VL)	VL 7/12/2024 No Div Declines 5 years	Moody's 7/15/2024 A1 to Baa2 Local LT Unsecured Debt Rating	S&P 7/15/2024 A to BBB- Local LT Unsecured Debt Rating	+ / - 2 Notches S&P & Moody's	SEC 10-K 2/10/2023 Percentage Regulated Revenue	EEI 7/18/2024 80%+ Regulated Assets	VL 7/12/2024 LT Debt 45% - 55% of Capital	Sensitivity VL 7/12/2024 LT Debt 40% - 60% of Capital	VL 8/4/2024 Div. Growth 5 Yr Rate Forecast > 0%
1	Allete	No	No	No	0.95	3.60	M	0.79	3.67	Yes	Pass	Baa1	BBB	Pass	80%	50% to 80%	39.5%	39.5%	Yes
2	Alliant	Yes	No	Yes	0.90	12.80	L	0.56	13.74	Yes	Pass	Baa2	A-	Pass	97%	80% +	56.5%	56.5%	Yes
3	Ameren	Yes	Yes	Yes	0.90	19.00	L	0.45	19.38	Yes	Pass	Baa1	BBB+	Pass	100%	80% +	53.5%	53.5%	Yes
4	AEP	Yes	No	Yes	0.85	46.90	L	0.52	47.94	Yes	Pass	Baa2	BBB+	Pass	83%	80% +	58.0%	58.0%	Yes
5	Avangrid	No	No	No	0.95	14.20	L	0.56	13.70	Yes	Pass	Baa2	BBB+	Pass	N/A	50% to 80%	36.5%	36.5%	Yes
6	Avista	Yes	Yes	Yes	0.95	2.80	M	0.46	2.80	Yes	Pass	Baa2	BBB	Pass	99%	80% +	51.0%	51.0%	Yes
7	Black Hills	No	Yes	Yes	1.05	3.70	M	0.68	3.94	Yes	Pass	Baa2	BBB+	Pass	100%	80% +	54.5%	54.5%	Yes
8	CenterPoint	No	No	No	1.15	18.90	L	0.92	18.09	Yes	Fail	Baa2	BBB+	Pass	80%	80% +	63.5%	63.5%	Yes
9	CMS	Yes	No	No	0.85	18.30	L	0.38	18.01	Yes	Pass	Baa2	BBB+	Pass	94%	80% +	65.0%	65.0%	Yes
10	Consol Ed	No	Yes	Yes	0.80	32.50	L	0.34	31.22	Yes	Pass	Baa1	A-	Pass	84%	80% +	51.0%	51.0%	Yes
11	Dominion	No	No	No	0.90	42.80	L	0.59	42.77	Yes	Fail	Baa2	BBB+	Pass	95%	80% +	53.0%	44.0%	Fail
12	DTE	No	No	No	1.00	23.40	L	0.67	23.41	Yes	Fail	Baa2	BBB+	Pass	52%	80% +	61.5%	61.5%	Yes
13	Duke	Yes	No	Yes	0.90	76.10	L	0.44	81.28	Yes	Pass	Baa2	BBB+	Pass	100%	80% +	58.5%	58.5%	Yes
14	Edison Int'l	No	No	No	1.00	27.20	L	0.92	28.11	Yes	Pass	Baa2	BBB	Pass	100%	80% +	64.0%	64.0%	Yes
15	Entergy	Yes	No	No	1.00	23.30	L	0.71	22.81	Yes	Pass	Baa2	BBB+	Pass	98%	80% +	61.0%	61.0%	Yes
16	Evergy	Yes	Yes	Yes	0.95	12.30	L	0.58	12.44	Yes	Pass	Baa2	BBB+	Pass	100%	80% +	51.5%	51.5%	Yes
17	Eversource	No	No	Yes	0.95	21.10	L	0.60	20.88	Yes	Pass	Baa2	A-	Pass	100%	80% +	62.5%	62.5%	Yes
18	Exelon	No	No	No	NMF	37.70	L	0.59	35.35	Yes	Fail	Baa2	BBB+	Pass	67%	80% +	61.0%	61.0%	Yes
19	First Energy	No	No	No	0.90	22.30	L	0.48	22.37	Yes	Pass	Baa3	BBB	Pass	100%	80% +	65.5%	65.5%	Yes
20	Fortis	No	No	No	0.75	26.80	L	0.19	19.49	Yes	Pass	Baa3	A-	Pass	55%	N/A	53.0%	53.0%	Yes
21	Hawaiian	No	No	No	1.00	1.20	S	0.58	1.17	Yes	Fail	Ba3	B-	Fail	77%	50% to 80%	60.0%	60.0%	Fail
22	IDACORP	Yes	Yes	Yes	0.85	4.70	M	0.58	4.74	Yes	Pass	Baa2	BBB	Pass	99%	80% +	49.0%	49.0%	Yes
23	MGE	No	No	No	0.80	2.80	M	0.69	2.89	Yes	Pass	A1	AA-	Fail	99%	80% +	37.0%	37.0%	Yes
24	NextEra	Yes	No	No	1.05	138.00	L	0.54	145.81	Yes	Pass	Baa1	A-	Pass	70%	50% to 80%	58.5%	58.5%	Yes
25	NorthWestern	Yes	Yes	Yes	0.95	3.10	M	0.47	3.16	Yes	Pass	Baa2	BBB	Pass	99%	80% +	50.0%	50.0%	Yes
26	OGE	Yes	Yes	Yes	1.05	7.10	M	0.73	7.28	Yes	Pass	Baa1	BBB	Pass	100%	80% +	52.0%	52.0%	Yes
27	Otter Tail	No	No	No	0.95	3.80	M	0.55	3.71	Yes	Pass	Baa2	BBB	Pass	80%	50% to 80%	41.0%	41.0%	Yes
28	PG&E	No	No	No	1.10	35.90	L	1.09	46.21	Yes	Fail	Ba1	BB	Fail	N/A	80% +	64.0%	64.0%	Yes
29	PGE	Yes	Yes	Yes	0.90	4.20	M	0.59	4.65	Yes	Pass	A3	BBB+	Pass	100%	80% +	58.5%	58.5%	Yes
30	Pinnacle	Yes	Yes	Yes	0.95	8.40	M	0.50	9.04	Yes	Pass	Baa2	BBB+	Pass	100%	80% +	52.5%	52.5%	Yes
31	PNM	No	No	No	0.90	3.40	M	0.36	3.48	Yes	Pass	Baa3	BBB	Pass	100%	80% +	66.0%	66.0%	Yes
32	PPL	No	No	No	1.15	20.30	L	0.83	20.64	Yes	Fail	Baa1	BBB+	Pass	100%	80% +	51.0%	51.0%	Yes
33	Public Serv.	No	Yes	Yes	0.95	34.20	L	0.61	37.13	Yes	Pass	Baa2	BBB+	Pass	80%	80% +	54.5%	54.5%	Yes
34	Sempra	No	Yes	Yes	1.00	44.70	L	0.75	48.11	Yes	Pass	Baa2	BBB+	Pass	80%	80% +	50.0%	50.0%	Yes
35	Southern	Yes	No	No	0.95	81.20	L	0.50	87.53	Yes	Pass	Baa2	BBB+	Pass	96%	80% +	64.0%	64.0%	Yes
36	WEC	No	Yes	Yes	0.85	25.50	L	0.41	25.14	Yes	Pass	Baa1	A-	Pass	100%	80% +	55.0%	55.0%	Yes
37	Xcel	Yes	No	Yes	0.85	30.00	L	0.38	29.58	Yes	Pass	Baa1	BBB+	Pass	100%	80% +	60.5%	60.5%	Yes
	No. of Peers:	16	13	18	0.94														

	Moody's	S&P
PAC	Baa1	BBB+
Range	A2 to Baa3	A to BBB-

Edision Electric Instutute (EEI)

Assets	EEI	Meaning
80% Plus	R	Regulated
50% to 80%	MR	Mostly Regulated
Under 50%	D	Diversified

EEI Updates each June to end of prior year.

*PacifiCorp removed Allete as a Peer Utility in Co. Reply Testimony after news re: proposed sale and taking Allete private.
** PacifiCorp removed PPL in Reply Testimony re M&A activity

1	2	3	4	28	
S	Small Cap	Under 2 Billion			
M	Mid Cap	2 to 10 Billion			
L	Large Cap	Over 10 Billion			
VL #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	No M&A Executed in Last 5 Years	#
1	Allete	No	No	Proposed sale to investors wanting to take Co private - July 2024 financial news	1
2	Alliant	Yes	No		2
3	Ameren	Yes	Yes		3
4	AEP	Yes	No	Sale of KY Power Subsidiary for **$1.45 Billion** expected to be completed in 2022 Q2, & 2024 Sale of Distributed Energy Bix for **$315 Million**.	4
5	Avangrid	No	No	Avangrid terminated the attempt to buy PNM for $8.3 Billion.	5
6	Avista	Yes	Yes	H1 Failed to Buy Avista 2019	6
7	Black Hills	No	Yes		7
8	CenterPoint	No	No	CenterPoint Acquired Vectren Feb 2019 $6 B Deal, Sold 2 Gas Utilities in AR and OK 2022 In 2024 Sold Gas Utilities in LA and MS to Bernard Capital 's Delta Utilities for $1.2B	8
9	CMS	Yes	No		9
10	Consol Ed	No	Yes		10
11	Dominion	No	No	2019 Purchase of Scana, 2020 Sale gas pipeline / storage $9.7B to Berkshire Energy, 9/2023 Sell several gas distribution utilities for $14 billion.	11
12	DTE	No	No	2021 Spun Off subsidiary into DT Midstream NYSE:DTM	12
13	Duke	Yes	No	12/27/22 GIC Pte. Ltd purchased minor stake in Duke Energy Indiana LLC all-cash valued at $2.05B for a total interest to 19.9%.	13
14	Edison Int'l	No	No	Aug **2000** Bought Citizens Power, Nuclear Gen w San Onofre Nuclear Generation Station (SONGS)	14
15	Entergy	Yes	No	Sold Natural Gas for $1.2B Gas Utility Assets to Bernard Capital 's Delta Ultilities	15
16	Evergy	Yes	Yes		16
17	Eversource	No	No		17
18	Exelon	No	No	Exelon completed Spin Off of Nonutility Opertions on Feb. 1, 2022	18
19	First Energy	No	No		19
20	Fortis	No	No		20
21	Hawaiian	No	No		21
22	IDACORP	Yes	Yes		22
23	MGE	No	No		23
24	NextEra	Yes	No		24
25	NorthWestern	Yes	Yes		25
26	OGE	Yes	Yes		26
27	Otter Tail	No	No		27
28	PG&E	No	No	2019 Chapter 11 bankruptcy liability for 2017 and 2018 wildfires in CA	28
29	PGE	Yes	Yes	Note: PGE has 50% Notional Debt authorized in last GRC before OPUC	29
30	Pinnacle	Yes	Yes		30
31	PNM	No	No	Avangrid terminated attempt to buy PNM for $8.3B 2/6/2023.	31
32	PPL	No	No	2021 Sold operations in UK, Buying Narragansett Electric for $3.8B	32
33	Public Serv.	No	Yes		33
34	Sempra	No	Yes		34
35	Southern	Yes	No		35
36	WEC	No	Yes		36
37	Xcel	Yes	No		37
	No. of Peers:	16	13	*20% of MKT Cap will pass the M&A screen test.	

*PacifiCorp removed Allete as a Pe
** PacifiCorp removed PPL in Reply

Value Line
Historical and Near Term
Dividends Declared per Share
(Div)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	Screen #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	Staff Sensitivity UE 433 LT Debt	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr
1	1	Allete	No	No	No	0.6175	0.6175	0.6175	0.6175	2.47	0.6300	0.6300	0.6300	0.6300	2.52	0.650	0.650	0.650	0.650	2.60
2	2	Alliant	Yes	No	Yes	0.38	0.38	0.38	0.38	1.52	0.4025	0.4025	0.4025	0.4025	1.61	0.4275	0.4275	0.4275	0.4275	1.71
3	3	Ameren	Yes	Yes	Yes	0.4950	0.4950	0.4950	0.515	2.00	0.55	0.55	0.55	0.55	2.20	0.59	0.59	0.59	0.59	2.36
4	4	AEP	Yes	No	Yes	0.70	0.70	0.70	0.74	2.84	0.74	0.74	0.74	0.78	3.00	0.78	0.78	0.78	0.83	3.17
5	6	Avista	Yes	Yes	Yes	0.405	0.405	0.405	0.405	1.62	0.4225	0.4225	0.4225	0.4225	1.69	0.44	0.44	0.44	0.44	1.76
6	7	Black Hills	No	Yes	Yes	0.535	0.535	0.535	0.565	2.17	0.565	0.565	0.565	0.595	2.29	0.595	0.595	0.595	0.625	2.41
7	9	CMS	Yes	No	No	0.4075	0.4075	0.4075	0.4075	1.63	0.435	0.435	0.435	0.435	1.74	0.46	0.46	0.46	0.46	1.84
8	10	Consol Ed	No	Yes	Yes	0.765	0.765	0.765	0.765	3.06	0.775	0.775	0.775	0.775	3.10	0.79	0.79	0.79	0.79	3.16
9	13	Duke	Yes	No	Yes	0.945	0.945	0.965	0.965	3.82	0.965	0.965	0.985	0.985	3.90	0.985	0.985	1.005	1.005	3.98
10	15	Entergy	Yes	No	No	0.93	0.93	0.93	0.95	3.74	0.95	0.95	0.95	1.01	3.86	1.01	1.01	1.01	1.07	4.10
11	16	Evergy	Yes	Yes	Yes	0.505	0.505	0.505	0.535	2.05	0.535	0.535	0.535	0.5725	2.18	0.5725	0.5725	0.5725	0.6125	2.33
12	17	Eversource	No	No	Yes	0.5675	0.5675	0.5675	0.5675	2.27	0.6025	0.6025	0.6025	0.6025	2.41	0.6375	0.6375	0.6375	0.6375	2.55
13	20	Fortis	No	No	No	0.4775	0.4775	0.4775	0.505	1.94	0.505	0.505	0.505	0.535	2.05	0.535	0.535	0.535	0.565	2.17
14	22	IDACORP	Yes	Yes	Yes	0.67	0.67	0.67	0.71	2.72	0.71	0.71	0.71	0.75	2.88	0.75	0.75	0.75	0.79	3.04
15	24	NextEra	Yes	No	No	0.35	0.35	0.35	0.35	1.40	0.385	0.385	0.385	0.385	1.54	0.425	0.425	0.425	0.425	1.70
16	25	NorthWestern	Yes	Yes	Yes	0.60	0.60	0.60	0.60	2.40	0.62	0.62	0.62	0.62	2.48	0.63	0.63	0.63	0.63	2.52
17	26	OGE	Yes	Yes	Yes	0.3875	0.3875	0.3875	0.4025	1.57	0.4025	0.4025	0.4025	0.41	1.62	0.41	0.41	0.41	0.4141	1.64
18	27	Otter Tail	No	No	No	0.370	0.370	0.370	0.3700	1.48	0.390	0.390	0.390	0.390	1.56	0.413	0.413	0.413	0.413	1.65
19	29	PGE	Yes	Yes	Yes	0.385	0.385	0.385	0.4075	1.56	0.4075	0.4075	0.43	0.43	1.68	0.43	0.43	0.4525	0.4525	1.77
20	30	Pinnacle	Yes	Yes	Yes	0.783	0.783	0.783	0.83	3.18	0.83	0.83	0.83	0.85	3.34	0.85	0.85	0.85	0.865	3.42
21	32	PPL	No	No	No	0.4125	0.415	0.415	0.415	1.66	0.415	0.415	0.415	0.415	1.66	0.415	0.20	0.225	0.225	1.07
22	33	Public Serv.	No	Yes	Yes	0.49	0.49	0.49	0.49	1.96	0.51	0.51	0.51	0.51	2.04	0.54	0.54	0.54	0.54	2.16
23	34	Sempra	No	Yes	Yes	0.484	0.523	0.523	0.523	2.05	0.523	0.55	0.55	0.55	2.17	0.55	0.573	0.573	0.573	2.27
24	35	Southern	Yes	No	No	0.62	0.64	0.64	0.64	2.54	0.64	0.66	0.66	0.66	2.62	0.66	0.68	0.68	0.68	2.70
25	36	WEC	No	Yes	Yes	0.6325	0.6325	0.6325	0.6325	2.53	0.6775	0.6775	0.6775	0.6775	2.71	0.7275	0.7275	0.7275	0.7275	2.91
26	37	Xcel	Yes	No	Yes	0.405	0.43	0.43	0.43	1.70	0.43	0.4575	0.4575	0.4575	1.80	0.4575	0.4875	0.4875	0.4875	1.92
		No. of Peers:	16	13	18															

2	21	22	23	24	25	26	27	28	29	30	31	32	33	34		
							Value Line Estimated Dividends						VL	VL % Div Growth		
Abbreviated Utility	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021 - 23 Average	2024 Yr	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	2027 - 29 Average	2027 - 29 vs. 2021 - 23	Screen #	
Allete	0.6775	0.6775	0.6775	0.6775	2.71	2.61	2.82	2.93	3.03	3.14	3.25	3.36	3.25	3.7%	1	1
Alliant	0.4525	0.4525	0.4525	0.4525	1.81	1.71	1.92	2.04	2.16	2.29	2.43	2.57	2.43	6.0%	2	2
Ameren	0.63	0.63	0.63	0.63	2.52	2.36	2.68	2.86	3.00	3.15	3.30	3.45	3.30	5.7%	3	3
AEP	0.83	0.83	0.83	0.88	3.37	3.18	3.60	3.81	3.92	4.04	4.16	4.28	4.16	4.6%	4	4
Avista	0.46	0.46	0.46	0.46	1.84	1.76	1.92	2.00	2.08	2.16	2.25	2.34	2.25	4.1%	6	5
Black Hills	0.625	0.625	0.625	0.625	2.50	2.40	2.60	2.70	2.80	2.90	3.00	3.10	3.00	3.8%	7	6
CMS	0.4875	0.4875	0.4875	0.4875	1.95	1.84	2.08	2.16	2.21	2.25	2.30	2.35	2.30	3.8%	9	7
Consol Ed	0.81	0.81	0.81	0.81	3.24	3.17	3.32	3.40	3.57	3.76	3.95	4.14	3.95	3.8%	10	8
Duke	1.005	1.005	1.025	1.025	4.06	3.98	4.14	4.22	4.25	4.27	4.30	4.33	4.30	1.3%	13	9
Entergy	1.07	1.07	1.07	1.13	4.34	4.10	4.56	4.70	4.80	4.90	5.00	5.10	5.00	3.4%	15	10
Evergy	0.6125	0.6125	0.6125	0.6425	2.48	2.33	2.61	2.74	2.84	2.94	3.05	3.16	3.05	4.6%	16	11
Eversource	0.675	0.675	0.675	0.675	2.70	2.55	2.86	3.03	3.21	3.40	3.60	3.80	3.60	5.9%	17	12
Fortis	0.565	0.565	0.565	0.59	2.29	2.17	2.38	2.49	2.60	2.72	2.85	2.98	2.85	4.7%	20	13
IDACORP	0.79	0.79	0.79	0.83	3.20	3.04	3.34	3.46	3.71	3.97	4.25	4.53	4.25	5.7%	22	14
NextEra	0.4675	0.4675	0.4675	0.4675	1.87	1.70	2.06	2.25	2.43	2.63	2.85	3.07	2.85	9.0%	24	15
NorthWestern	0.64	0.64	0.64	0.64	2.56	2.52	2.60	2.64	2.68	2.72	2.76	2.80	2.76	1.5%	25	16
OGE	0.4141	0.4141	0.4141	0.4182	1.66	1.64	1.69	1.73	1.77	1.81	1.85	1.89	1.85	2.0%	26	17
Otter Tail	0.4375	0.4375	0.4375	0.4375	1.75	1.65	1.87	1.97	2.04	2.12	2.20	2.28	2.20	4.9%	27	18
PGE	0.4525	0.4525	0.475	0.475	1.86	1.77	1.98	2.08	2.20	2.33	2.46	2.59	2.46	5.7%	29	19
Pinnacle	0.865	0.865	0.865	0.88	3.48	3.41	3.55	3.61	3.67	3.73	3.79	3.85	3.79	1.8%	30	20
PPL	0.225	0.24	0.24	0.24	0.95	1.22	1.03	1.10	1.18	1.26	1.35	1.44	1.35	1.7%	32	21
Public Serv.	0.57	0.57	0.57	0.57	2.28	2.16	2.40	2.52	2.64	2.77	2.90	3.03	2.90	5.0%	33	22
Sempra	0.573	0.595	0.595	0.595	2.36	2.27	2.48	2.58	2.74	2.90	3.08	3.26	3.08	5.2%	34	23
Southern	0.68	0.70	0.70	0.70	2.78	2.70	2.86	2.96	3.01	3.05	3.10	3.15	3.10	2.3%	35	24
WEC	0.78	0.78	0.78	0.78	3.12	2.91	3.34	3.57	3.65	3.74	3.83	3.92	3.83	4.7%	36	25
Xcel	0.4875	0.52	0.52	0.52	2.05	1.92	2.19	2.30	2.42	2.54	2.67	2.80	2.67	5.6%	37	26

	Mean
Company Screen	4.2%
Staff Screen	4.1%
Staff LT Screen	4.3%

Value Line
Historical and Near Term
Earnings Per Share
(EPS)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
					Staff Sensitivity	Value Line Estimated EPS														
	Screen #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	UE 433 LT Debt	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr
1	1	Allete	No	No	No	0.99	0.53	0.53	1.18	3.23	1.24	0.67	0.59	0.90	3.40	1.02	0.90	1.49	0.89	4.30
2	2	Alliant	Yes	No	Yes	0.68	0.57	1.02	0.35	2.62	0.77	0.63	0.90	0.43	2.73	0.65	0.64	1.02	0.47	2.78
3	3	Ameren	Yes	Yes	Yes	0.91	0.80	1.65	0.48	3.84	0.97	0.80	1.74	0.63	4.14	1.00	0.90	1.87	0.60	4.37
4	4	AEP	Yes	No	Yes	1.15	1.15	1.59	1.07	4.96	1.22	1.20	1.62	1.05	5.09	1.11	1.13	1.77	1.23	5.24
5	6	Avista	Yes	Yes	Yes	0.98	0.20	0.20	0.71	2.09	0.99	0.16	-0.08	1.05	2.12	0.73	0.23	0.19	1.08	2.23
6	7	Black Hills	No	Yes	Yes	1.54	0.40	0.70	1.11	3.75	1.82	0.52	0.54	1.11	3.99	1.73	0.35	0.67	1.17	3.92
7	9	CMS	Yes	No	No	1.09	0.55	0.54	0.40	2.58	1.20	0.50	0.56	0.58	2.84	0.69	0.67	0.60	1.05	3.01
8	10	Consol Ed	No	Yes	Yes	1.44	0.53	1.41	1.00	4.38	1.47	0.64	1.63	0.81	4.55	1.82	0.61	1.61	1.00	5.04
9	13	Duke	Yes	No	Yes	1.26	1.15	1.88	0.94	5.23	1.30	1.14	1.78	1.11	5.33	1.20	0.91	1.94	1.51	5.56
10	15	Entergy	Yes	No	No	1.66	1.30	2.63	1.28	6.87	1.36	0.78	2.74	0.51	5.39	1.47	1.84	3.14	4.66	11.11
11	16	Evergy	Yes	Yes	Yes	0.84	0.81	1.95	0.23	3.83	0.53	0.84	1.86	0.03	3.26	0.62	0.78	1.53	0.24	3.17
12	17	Eversource	No	No	Yes	1.15	0.79	1.02	0.91	3.87	1.30	0.86	1.01	0.92	4.09	1.41	1.00	0.97	0.95	4.33
13	20	Fortis	No	No	No	0.76	0.54	0.62	0.69	2.61	0.74	0.59	0.68	0.77	2.78	0.90	0.61	0.81	0.78	3.10
14	22	IDACORP	Yes	Yes	Yes	0.89	1.38	1.93	0.65	4.85	0.91	1.27	2.10	0.83	5.11	1.11	1.35	2.07	0.61	5.14
15	24	NextEra	Yes	No	No	0.67	0.71	0.75	0.41	2.54	0.74	0.81	0.85	0.51	2.91	0.84	0.88	0.94	0.52	3.18
16	25	NorthWestern	Yes	Yes	Yes	1.24	0.59	0.70	0.97	3.50	1.08	0.58	0.47	1.16	3.29	1.10	0.32	0.48	1.32	3.22
17	26	OGE	Yes	Yes	Yes	0.26	0.56	1.26	0.28	2.36	0.33	0.36	1.31	0.25	2.25	0.19	0.44	1.20	0.24	2.07
18	27	Otter Tail	No	No	No	0.73	1.01	1.26	1.23	4.23	1.72	2.05	2.01	1.00	6.78	1.49	1.95	2.19	1.37	7.00
19	29	PGE	Yes	Yes	Yes	1.07	0.36	0.56	0.73	2.72	0.67	0.72	0.65	0.70	2.74	0.80	0.44	0.46	0.67	2.37
20	30	Pinnacle	Yes	Yes	Yes	0.32	1.91	3.00	0.24	5.47	0.15	1.45	2.88	-0.21	4.27	-0.03	0.94	3.50	Nil	4.41
21	32	PPL	No	No	No	0.26	-0.20	0.27	0.19	0.52	0.41	0.30	0.41	0.28	1.40	0.48	0.29	0.43	0.40	1.60
22	33	Public Serv.	No	Yes	Yes	1.28	0.70	0.98	0.69	3.65	1.33	0.64	0.86	0.64	3.47	1.39	0.70	0.85	0.54	3.48
23	34	Sempra	No	Yes	Yes	1.48	0.82	0.85	1.08	4.23	1.46	0.99	0.99	1.18	4.62	1.46	0.94	1.08	1.13	4.61
24	35	Southern	Yes	No	No	1.09	0.67	1.22	0.44	3.42	0.97	1.07	1.31	0.26	3.61	0.79	0.79	1.42	0.64	3.64
25	36	WEC	No	Yes	Yes	1.61	0.87	0.92	0.71	4.11	1.79	0.91	0.96	0.80	4.46	1.61	0.92	1.00	1.10	4.63
26	37	Xcel	Yes	No	Yes	0.67	0.58	1.13	0.58	2.96	0.70	0.60	1.18	0.69	3.17	0.76	0.52	1.23	0.83	3.34
		No. of Peers:	16	13	18															

	1	2	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37		
																		VL	VL EPS Growth		
	Screen #	Abbreviated Utility	2021 - 23 Average	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2024 Yr	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	2027 - 29 Average	2027 - 29 vs. 2021 - 23	Screen #	
1	1	Allete	3.64	0.88	0.85	0.80	1.22	3.75	1.05	0.90	0.90	1.25	4.10	4.42	4.77	5.15	5.53	5.15	5.9%	1	1
2	2	Alliant	2.71	0.62	0.66	1.10	0.67	3.05	0.74	0.69	1.14	0.68	3.25	3.45	3.67	3.90	4.13	3.90	6.3%	2	2
3	3	Ameren	4.12	0.98	0.95	2.00	0.67	4.60	1.20	0.95	2.00	0.75	4.90	5.23	5.58	5.95	6.32	5.95	6.3%	3	3
4	4	AEP	5.10	1.27	1.25	1.80	1.28	5.60	1.50	1.40	1.80	1.30	6.00	6.38	6.78	7.20	7.62	7.20	5.9%	4	4
5	6	Avista	2.15	0.95	0.20	0.20	1.05	2.40	1.00	0.25	0.25	1.10	2.60	2.70	2.80	2.90	3.00	2.90	5.1%	6	5
6	7	Black Hills	3.89	1.70	0.40	0.58	1.22	3.90	1.75	0.40	0.65	1.30	4.10	4.31	4.52	4.75	4.98	4.75	3.4%	7	6
7	9	CMS	2.81	0.96	0.65	0.70	0.99	3.30	0.80	0.90	0.80	1.00	3.50	3.58	3.66	3.75	3.84	3.75	4.9%	9	7
8	10	Consol Ed	4.66	1.85	0.65	1.80	1.00	5.30	1.90	0.70	1.90	1.10	5.60	5.92	6.25	6.60	6.95	6.60	6.0%	10	8
9	13	Duke	5.37	1.40	1.05	2.05	1.50	6.00	1.40	1.35	2.10	1.50	6.35	6.74	7.16	7.60	8.04	7.60	5.9%	13	9
10	15	Entergy	7.79	0.35	1.05	2.95	0.95	5.30	1.60	1.15	3.05	1.05	6.85	7.23	7.63	8.05	8.47	8.05	0.5%	15	10
11	16	Evergy	3.42	0.53	0.85	1.75	0.47	3.60	0.70	0.85	2.00	0.45	4.00	4.19	4.39	4.60	4.81	4.60	5.1%	16	11
12	17	Eversource	4.10	1.45	1.03	1.07	1.05	4.60	1.50	1.10	1.15	1.10	4.85	5.15	5.46	5.80	6.14	5.80	6.0%	17	12
13	20	Fortis	2.83	0.93	0.65	0.80	0.82	3.20	0.95	0.75	0.80	0.85	3.35	3.55	3.77	4.00	4.23	4.00	5.9%	20	13
14	22	IDACORP	5.03	1.10	1.35	2.10	0.85	5.40	1.15	1.45	2.25	0.90	5.75	6.04	6.34	6.65	6.96	6.65	4.8%	22	14
15	24	NextEra	2.88	0.91	0.93	0.99	0.57	3.40	0.97	1.00	1.06	0.62	3.65	3.93	4.23	4.55	4.87	4.55	7.9%	24	15
16	25	NorthWestern	3.34	1.25	0.50	0.60	1.15	3.50	1.30	0.55	0.65	1.20	3.70	3.87	4.06	4.25	4.44	4.25	4.1%	25	16
17	26	OGE	2.23	0.09	0.45	1.30	0.26	2.10	0.40	0.35	1.30	0.25	2.30	2.43	2.56	2.70	2.84	2.70	3.3%	26	17
18	27	Otter Tail	6.00	1.77	1.70	1.75	1.13	6.35	1.10	1.15	1.20	1.20	4.65	4.51	4.38	4.25	4.12	4.25	-5.6%	27	18
19	29	PGE	2.61	0.95	0.60	0.70	0.80	3.05	1.00	0.65	0.75	0.85	3.25	3.44	3.64	3.85	4.06	3.85	6.7%	29	19
20	30	Pinnacle	4.72	0.05	1.25	3.40	Nil	4.70	0.05	1.33	3.62	Nil	5.00	5.31	5.65	6.00	6.35	6.00	4.1%	30	20
21	32	PPL	1.17	0.50	0.30	0.45	0.45	1.70	0.50	0.35	0.50	0.45	1.80	1.94	2.09	2.25	2.41	2.25	11.5%	32	21
22	33	Public Serv.	3.53	1.31	0.77	0.95	0.62	3.65	1.41	0.82	1.01	0.66	3.90	4.14	4.39	4.65	4.91	4.65	4.7%	33	22
23	34	Sempra	4.49	1.46	0.99	1.13	1.22	4.80	1.55	1.05	1.22	1.33	5.15	5.51	5.89	6.30	6.71	6.30	5.8%	34	23
24	35	Southern	3.56	0.90	1.00	1.45	0.65	4.00	1.00	1.10	1.50	0.70	4.30	4.55	4.82	5.10	5.38	5.10	6.2%	35	24
25	36	WEC	4.40	1.97	0.75	1.05	1.13	4.90	2.00	1.00	1.10	1.15	5.25	5.61	5.99	6.40	6.81	6.40	6.4%	36	25
26	37	Xcel	3.16	0.80	0.60	1.30	0.85	3.55	0.85	0.65	1.40	0.90	3.80	4.08	4.38	4.70	5.02	4.70	6.9%	37	26

	Mean
Company Screen	5.3%
Staff Screen	5.1%
Staff Sensitivity Screen	5.4%

$$B_U = \frac{B_L}{[1 + (1 - T_C) \times (D/E)]}$$

	1	2	3	4		5	6	7	8	9	10	11	13	14	15	19	20	22	24	26	27		
							Yahoo Finance $ Stock Closing Price 1st Trading Day of Month					VL	VL Cap Structure Percentages								Hamada		
	Screen #	Abbreviated Utility	PAC No	Staff No	LT Debt Staff Sensitivity	Ticker	May 5/1/2024	Jun. 6/3/2024	Jul. 7/1/2024	3-Day Avg $ Stock Price	Div Yield at Recent Price	2024 Return on Common Equity	2024 % LT Debt	2024 Common Equity	2024 Preferred Stock	VL Beta	VL 2024 Tax Rate	2024 Unlevered Beta	2024 Relevered Beta Equity at 50.0%	Equity Risk Premium	2024 Adjustment Equity at 50.0%	Screen #	
1	1	Allete	No	No	No	ALE	60.34	62.83	62.14	61.77	4.6%	8.0%	39.5	60.5	0.0	0.95	0.0%	0.57	115%	4.50%	0.90%	1	1
2	2	Alliant	Yes	No	Yes	LNT	50.36	51.10	50.74	50.73	3.8%	11.0%	56.5	43.5	0.0	0.90	2.0%	0.40	78%	4.50%	-0.52%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	74.49	73.77	70.75	73.00	3.7%	11.0%	53.5	46.0	0.5	0.90	12.0%	0.44	83%	4.50%	-0.30%	3	3
4	4	AEP	Yes	No	Yes	AEP	88.15	90.08	87.28	88.50	4.1%	10.0%	58.0	42.0	0.0	0.85	21.0%	0.41	73%	4.50%	-0.55%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	36.64	36.64	34.20	35.83	5.4%	7.5%	51.0	49.0	0.0	0.95	15.0%	0.50	93%	4.50%	-0.08%	6	5
6	7	Black Hills	No	Yes	Yes	BKH	55.60	56.34	54.10	55.35	4.7%	8.0%	54.5	45.5	0.0	1.05	8.5%	0.50	96%	4.50%	-0.41%	7	6
7	9	CMS	Yes	No	No	CMS	60.84	62.64	58.80	60.76	3.4%	12.5%	65.0	35.0	0.0	0.85	15.5%	0.33	61%	4.50%	-1.08%	9	7
8	10	Consol Ed	No	Yes	Yes	ED	94.80	93.68	88.81	92.43	3.6%	8.5%	51.0	49.0	0.0	0.80	18.0%	0.43	79%	4.50%	-0.07%	10	8
9	13	Duke	Yes	No	Yes	DUK	99.78	103.41	99.35	100.85	4.1%	9.0%	58.5	41.0	0.5	0.90	9.0%	0.39	74%	4.50%	-0.70%	13	9
10	15	Entergy	Yes	No	No	ETR	106.98	111.78	105.74	108.17	4.2%	1.0%	61.0	39.0	0.0	1.00	23.0%	0.45	80%	4.50%	-0.89%	15	10
11	16	Evergy	Yes	Yes	Yes	EVRG	52.94	54.29	52.71	53.31	4.9%	9.0%	51.5	48.5	0.0	0.95	9.0%	0.48	92%	4.50%	-0.12%	16	11
12	17	Eversource	No	No	Yes	ES	61.62	59.68	56.56	59.29	4.8%	11.0%	62.5	37.0	0.5	0.95	24.0%	0.41	73%	4.50%	-1.00%	17	12
13	20	Fortis	No	No	No	FTS	39.52	39.88	38.61	39.34	6.1%	7.0%	53.0	43.5	3.5	0.75	14.5%	0.36	66%	4.50%	-0.41%	20	13
14	22	IDACORP	Yes	Yes	Yes	IDA	95.97	94.70	92.22	94.30	3.5%	9.0%	49.0	51.0	0.0	0.85	13.0%	0.46	87%	4.50%	0.07%	22	14
15	24	NextEra	Yes	No	No	NEE	68.61	77.71	69.90	72.07	2.9%	14.0%	58.5	41.5	0.0	1.05	18.0%	0.49	89%	4.50%	-0.74%	24	15
16	25	NorthWestern	Yes	Yes	Yes	NWE	50.85	51.82	49.19	50.62	5.1%	7.5%	50.0	50.0	0.0	0.95	6.0%	0.49	95%	4.50%	0.00%	25	16
17	26	OGE	Yes	Yes	Yes	OGE	35.05	36.19	35.36	35.53	4.8%	12.5%	52.0	48.0	0.0	1.05	12.0%	0.54	101%	4.50%	-0.18%	26	17
18	27	Otter Tail	No	No	No	OTTR	86.71	89.90	86.30	87.64	2.1%	13.0%	41.0	58.5	0.5	0.95	20.0%	0.61	109%	4.50%	0.63%	27	18
19	29	PGE	Yes	Yes	Yes	POR	43.92	44.39	43.02	43.78	4.5%	9.0%	58.5	41.5	0.0	0.90	17.5%	0.42	76%	4.50%	-0.63%	29	19
20	30	Pinnacle	Yes	Yes	Yes	PNW	74.94	76.92	75.72	75.86	4.7%	8.0%	52.5	47.5	0.0	0.95	14.0%	0.49	91%	4.50%	-0.20%	30	20
21	32	PPL	No	No	No	PPL	28.00	29.26	27.36	28.21	3.7%	8.5%	51.0	49.0	0.0	1.15	21.0%	0.63	113%	4.50%	-0.09%	32	21
22	33	Public Serv.	No	Yes	Yes	PEG	69.81	74.54	73.63	72.66	3.3%	11.5%	54.5	45.5	0.0	0.95	20.0%	0.49	87%	4.50%	-0.35%	33	22
23	34	Sempra	No	Yes	Yes	SRE	71.95	76.71	74.97	74.54	3.3%	10.0%	50.0	48.5	1.5	1.00	19.0%	0.54	97%	4.50%	-0.12%	34	23
24	35	Southern	Yes	No	No	SO	74.52	80.39	77.00	77.30	3.7%	13.0%	64.0	36.0	0.0	0.95	15.0%	0.38	70%	4.50%	-1.13%	35	24
25	36	WEC	No	Yes	Yes	WEC	82.59	81.18	77.69	80.49	4.1%	12.5%	55.0	44.5	0.5	0.85	19.0%	0.42	77%	4.50%	-0.38%	36	25
26	37	Xcel	Yes	No	Yes	XEL	53.78	55.28	52.43	53.83	4.1%	10.5%	60.5	39.5	0.0	0.85	0.0%	0.34	67%	4.50%	-0.80%	37	26
		No. of Peers:	16	13	18																		

Unlevered Beta = Levered Beta / (1 + ((1 – Tax Rate) x (Debt/Equity)))

Levered Beta = Unlevered Beta x (1 + ((1 – Tax Rate) x (Debt/Equity)))

	Mean (2024 Common Equity)	Mean (Hamada 2024 Adjustment Equity at 50.0%)
Company Screen	43.7%	-0.49%
Staff Screen	47.3%	-0.21%
Staff Sensitivity Screen	45.4%	-0.35%

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2402

ROE – Three-Stage DCF: Models X and Model Y

August 16, 2024

4.20% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows   Staff   Model X

	1	2	3	4		5	6	7	8	9	10	11	12	13	14	15	16	17	18
										2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Screen #	Abbreviated Utility	PAC No	Staff No	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage				
1	1	Allete	No	No	No	9.1%	26.8%	0.00	(61.77)	2.93	3.03	3.14	3.25	3.36	3.61	3.84	4.06	4.26	4.44
2	2	Alliant	Yes	No	Yes	8.9%	28.9%	0.00	(50.73)	2.04	2.16	2.29	2.43	2.57	2.80	3.03	3.23	3.40	3.55
3	3	Ameren	Yes	Yes	Yes	8.6%	31.1%	0.00	(73.00)	2.86	3.00	3.15	3.30	3.45	3.76	4.06	4.32	4.55	4.74
4	4	AEP	Yes	No	Yes	8.6%	30.4%	0.00	(88.50)	3.81	3.92	4.04	4.16	4.28	4.62	4.95	5.25	5.52	5.75
5	6	Avista	Yes	Yes	Yes	10.1%	20.8%	0.00	(35.83)	2.00	2.08	2.16	2.25	2.34	2.52	2.69	2.84	2.99	3.11
6	7	Black Hills	No	Yes	Yes	9.2%	25.7%	0.00	(55.35)	2.70	2.80	2.90	3.00	3.10	3.33	3.55	3.75	3.94	4.11
7	9	CMS	Yes	No	No	7.7%	38.6%	0.00	(60.76)	2.16	2.21	2.25	2.30	2.35	2.52	2.68	2.84	2.98	3.10
8	10	Consol Ed	No	Yes	Yes	8.2%	33.9%	0.00	(92.43)	3.40	3.57	3.76	3.95	4.14	4.45	4.74	5.01	5.26	5.48
9	13	Duke	Yes	No	Yes	8.0%	35.5%	0.00	(100.85)	4.22	4.25	4.27	4.30	4.33	4.56	4.78	5.01	5.23	5.45
10	15	Entergy	Yes	No	No	8.4%	31.6%	0.00	(108.17)	4.70	4.80	4.90	5.00	5.10	5.46	5.80	6.13	6.43	6.70
11	16	Evergy	Yes	Yes	Yes	9.6%	23.6%	0.00	(53.31)	2.74	2.84	2.94	3.05	3.16	3.41	3.65	3.87	4.07	4.24
12	17	Eversource	No	No	Yes	10.1%	21.2%	0.00	(59.29)	3.03	3.21	3.40	3.60	3.80	4.15	4.47	4.77	5.02	5.24
13	20	Fortis	No	No	No	11.0%	16.4%	0.00	(39.34)	2.49	2.60	2.72	2.85	2.98	3.22	3.44	3.65	3.84	4.00
14	22	IDACORP	Yes	Yes	Yes	8.6%	31.0%	0.00	(94.30)	3.46	3.71	3.97	4.25	4.53	4.94	5.32	5.67	5.97	6.22
15	24	NextEra	Yes	No	No	8.3%	34.1%	0.00	(72.07)	2.25	2.43	2.63	2.85	3.07	3.42	3.75	4.05	4.29	4.47
16	25	NorthWestern	Yes	Yes	Yes	9.1%	26.5%	0.00	(50.62)	2.64	2.68	2.72	2.76	2.80	2.95	3.11	3.26	3.40	3.55
17	26	OGE	Yes	Yes	Yes	8.9%	27.9%	0.00	(35.53)	1.73	1.77	1.81	1.85	1.89	2.00	2.11	2.22	2.32	2.42
18	27	Otter Tail	No	No	No	6.6%	52.2%	(0.00)	(87.64)	1.97	2.04	2.12	2.20	2.28	2.47	2.65	2.81	2.96	3.08
19	29	PGE	Yes	Yes	Yes	9.6%	23.7%	0.00	(43.78)	2.08	2.20	2.33	2.46	2.59	2.83	3.04	3.24	3.42	3.56
20	30	Pinnacle	Yes	Yes	Yes	8.7%	29.5%	0.00	(75.86)	3.61	3.67	3.73	3.79	3.85	4.07	4.29	4.50	4.70	4.90
21	32	PPL	No	No	No	8.6%	30.6%	0.00	(28.21)	1.10	1.18	1.26	1.35	1.44	1.52	1.60	1.68	1.75	1.83
22	33	Public Serv.	No	Yes	Yes	8.0%	35.8%	0.00	(72.66)	2.52	2.64	2.77	2.90	3.03	3.29	3.53	3.75	3.94	4.11
23	34	Sempra	No	Yes	Yes	8.2%	34.4%	0.00	(74.54)	2.58	2.74	2.90	3.08	3.26	3.53	3.80	4.04	4.25	4.43
24	35	Southern	Yes	No	No	7.8%	37.2%	(0.00)	(77.30)	2.96	3.01	3.05	3.10	3.15	3.34	3.53	3.71	3.89	4.05
25	36	WEC	No	Yes	Yes	8.7%	30.0%	0.00	(80.49)	3.57	3.65	3.74	3.83	3.92	4.23	4.54	4.81	5.06	5.27
26	37	Xcel	Yes	No	Yes	9.0%	27.9%	0.00	(53.83)	2.30	2.42	2.54	2.67	2.80	3.05	3.28	3.49	3.68	3.84
		No. of Peers:	16	13	18														

	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40		
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054				
	Final Stage																			Terminal Value	2054 Div	2054 Perpetuity	Screen #	
1	4.63	4.82	5.02	5.24	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	225.40	10.11	215.29	1	1
2	3.69	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	188.02	8.07	179.94	2	2
3	4.94	5.15	5.37	5.59	5.83	6.07	6.33	6.59	6.87	7.16	7.46	7.77	8.10	8.44	8.79	9.16	9.55	9.95	10.37	268.09	10.80	257.29	3	3
4	5.99	6.24	6.51	6.78	7.06	7.36	7.67	7.99	8.33	8.68	9.04	9.42	9.82	10.23	10.66	11.11	11.57	12.06	12.57	321.64	13.09	308.55	4	4
5	3.24	3.38	3.52	3.67	3.82	3.98	4.15	4.33	4.51	4.70	4.90	5.10	5.31	5.54	5.77	6.01	6.27	6.53	6.80	132.79	7.09	125.70	6	5
6	4.28	4.46	4.65	4.84	5.04	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	202.41	9.35	193.06	7	6
7	3.24	3.37	3.51	3.66	3.81	3.97	4.14	4.31	4.50	4.68	4.88	5.09	5.30	5.52	5.75	6.00	6.25	6.51	6.78	217.23	7.07	210.16	9	7
8	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	9.35	9.74	10.15	10.58	11.02	11.49	11.97	335.55	12.47	323.08	10	8
9	5.68	5.92	6.17	6.43	6.70	6.98	7.27	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.53	10.98	11.44	11.92	356.43	12.42	344.01	13	9
10	6.98	7.27	7.58	7.89	8.23	8.57	8.93	9.31	9.70	10.10	10.53	10.97	11.43	11.91	12.41	12.93	13.48	14.04	14.63	389.18	15.25	373.93	15	10
11	4.42	4.61	4.80	5.00	5.21	5.43	5.66	5.90	6.14	6.40	6.67	6.95	7.24	7.55	7.86	8.19	8.54	8.90	9.27	196.55	9.66	186.89	16	11
12	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.54	10.98	11.44	223.45	11.92	211.53	17	12
13	4.17	4.35	4.53	4.72	4.92	5.12	5.34	5.56	5.80	6.04	6.30	6.56	6.84	7.12	7.42	7.73	8.06	8.40	8.75	148.33	9.12	139.22	20	13
14	6.49	6.76	7.04	7.34	7.65	7.97	8.30	8.65	9.01	9.39	9.79	10.20	10.63	11.07	11.54	12.02	12.53	13.05	13.60	348.84	14.17	334.67	22	14
15	4.66	4.85	5.06	5.27	5.49	5.72	5.96	6.21	6.47	6.75	7.03	7.33	7.63	7.95	8.29	8.64	9.00	9.38	9.77	268.94	10.18	258.76	24	15
16	3.70	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	181.26	8.07	173.19	25	16
17	2.52	2.62	2.74	2.85	2.97	3.09	3.22	3.36	3.50	3.65	3.80	3.96	4.13	4.30	4.48	4.67	4.87	5.07	5.28	127.76	5.50	122.25	26	17
18	3.21	3.34	3.48	3.63	3.78	3.94	4.11	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	311.36	7.01	304.34	27	18
19	3.71	3.86	4.03	4.20	4.37	4.56	4.75	4.95	5.15	5.37	5.60	5.83	6.08	6.33	6.60	6.87	7.16	7.46	7.78	163.67	8.10	155.57	29	19
20	5.11	5.32	5.54	5.78	6.02	6.27	6.54	6.81	7.10	7.39	7.70	8.03	8.37	8.72	9.08	9.46	9.86	10.28	10.71	271.22	11.16	260.07	30	20
21	1.90	1.98	2.07	2.15	2.24	2.34	2.44	2.54	2.65	2.76	2.87	2.99	3.12	3.25	3.39	3.53	3.68	3.83	3.99	102.68	4.16	98.52	32	21
22	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.02	7.31	7.62	7.94	8.27	8.62	8.98	264.03	9.36	254.67	33	22
23	4.62	4.81	5.01	5.22	5.44	5.67	5.91	6.16	6.42	6.69	6.97	7.26	7.56	7.88	8.21	8.56	8.92	9.29	9.68	272.75	10.09	262.66	34	23
24	4.22	4.40	4.58	4.77	4.97	5.18	5.40	5.63	5.86	6.11	6.37	6.63	6.91	7.20	7.50	7.82	8.15	8.49	8.85	274.82	9.22	265.60	35	24
25	5.49	5.73	5.97	6.22	6.48	6.75	7.03	7.33	7.64	7.96	8.29	8.64	9.00	9.38	9.77	10.19	10.61	11.06	11.52	#VALUE!	12.01	280.12	36	25
26	4.00	4.17	4.34	4.52	4.71	4.91	5.12	5.33	5.56	5.79	6.03	6.29	6.55	6.82	7.11	7.41	7.72	8.04	8.38	198.88	8.73	190.15	37	26

Mean			
8.74%	29.90%	0.00%	Company Screen
8.88%	28.77%	0.00%	Staff Screen
8.89%	28.77%	0.00%	Staff Sensitivity Screen

B.O.Y. Cash Flows   Staff   Model X

	1	2	3	4		5	6	7	8	9	10	11	12	13	14	15	16	17	18
										2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Screen #	Abbreviated Utility	PAC No	Staff No	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage				
1	1	Allete	No	No	No	9.3%	25.3%	0.00	(61.77)	3.03	3.14	3.25	3.36	3.61	3.84	4.06	4.26	4.44	4.63
2	2	Alliant	Yes	No	Yes	9.1%	27.1%	0.00	(50.73)	2.16	2.29	2.43	2.57	2.80	3.03	3.23	3.40	3.55	3.69
3	3	Ameren	Yes	Yes	Yes	8.8%	29.4%	0.00	(73.00)	3.00	3.15	3.30	3.45	3.76	4.06	4.32	4.55	4.74	4.94
4	4	AEP	Yes	No	Yes	8.8%	28.9%	0.00	(88.50)	3.92	4.04	4.16	4.28	4.62	4.95	5.25	5.52	5.75	5.99
5	6	Avista	Yes	Yes	Yes	10.3%	19.4%	0.00	(35.83)	2.08	2.16	2.25	2.34	2.52	2.69	2.84	2.99	3.11	3.24
6	7	Black Hills	No	Yes	Yes	9.5%	24.3%	0.00	(55.35)	2.80	2.90	3.00	3.10	3.33	3.55	3.75	3.94	4.11	4.28
7	9	CMS	Yes	No	No	7.8%	37.1%	(0.00)	(60.76)	2.21	2.25	2.30	2.35	2.52	2.68	2.84	2.98	3.10	3.24
8	10	Consol Ed	No	Yes	Yes	8.4%	32.2%	0.00	(92.43)	3.57	3.76	3.95	4.14	4.45	4.74	5.01	5.26	5.48	5.71
9	13	Duke	Yes	No	Yes	8.1%	34.3%	0.00	(100.85)	4.25	4.27	4.30	4.33	4.56	4.78	5.01	5.23	5.45	5.68
10	15	Entergy	Yes	No	No	8.6%	30.2%	0.00	(108.17)	4.80	4.90	5.00	5.10	5.46	5.80	6.13	6.43	6.70	6.98
11	16	Evergy	Yes	Yes	Yes	9.8%	22.2%	0.00	(53.31)	2.84	2.94	3.05	3.16	3.41	3.65	3.87	4.07	4.24	4.42
12	17	Eversource	No	No	Yes	10.4%	19.5%	0.00	(59.29)	3.21	3.40	3.60	3.80	4.15	4.47	4.77	5.02	5.24	5.46
13	20	Fortis	No	No	No	11.3%	15.0%	0.00	(39.34)	2.60	2.72	2.85	2.98	3.22	3.44	3.65	3.84	4.00	4.17
14	22	IDACORP	Yes	Yes	Yes	8.8%	29.1%	0.00	(94.30)	3.71	3.97	4.25	4.53	4.94	5.32	5.67	5.97	6.22	6.49
15	24	NextEra	Yes	No	No	8.5%	32.0%	0.00	(72.07)	2.43	2.63	2.85	3.07	3.42	3.75	4.05	4.29	4.47	4.66
16	25	NorthWestern	Yes	Yes	Yes	9.2%	25.3%	0.00	(50.62)	2.68	2.72	2.76	2.80	2.95	3.11	3.26	3.40	3.55	3.70
17	26	OGE	Yes	Yes	Yes	9.1%	26.6%	0.00	(35.53)	1.77	1.81	1.85	1.89	2.00	2.11	2.22	2.32	2.42	2.52
18	27	Otter Tail	No	No	No	6.7%	50.7%	0.00	(87.64)	2.04	2.12	2.20	2.28	2.47	2.65	2.81	2.96	3.08	3.21
19	29	PGE	Yes	Yes	Yes	9.9%	22.0%	0.00	(43.78)	2.20	2.33	2.46	2.59	2.83	3.04	3.24	3.42	3.56	3.71
20	30	Pinnacle	Yes	Yes	Yes	8.8%	28.2%	0.00	(75.86)	3.67	3.73	3.79	3.85	4.07	4.29	4.50	4.70	4.90	5.11
21	32	PPL	No	No	No	8.8%	28.9%	0.00	(28.21)	1.18	1.26	1.35	1.44	1.52	1.60	1.68	1.75	1.83	1.90
22	33	Public Serv.	No	Yes	Yes	8.2%	34.1%	0.00	(72.66)	2.64	2.77	2.90	3.03	3.29	3.53	3.75	3.94	4.11	4.28
23	34	Sempra	No	Yes	Yes	8.4%	32.6%	0.00	(74.54)	2.74	2.90	3.08	3.26	3.53	3.80	4.04	4.25	4.43	4.62
24	35	Southern	Yes	No	No	8.0%	35.8%	0.00	(77.30)	3.01	3.05	3.10	3.15	3.34	3.53	3.71	3.89	4.05	4.22
25	36	WEC	No	Yes	Yes	8.9%	28.5%	0.00	(80.49)	3.65	3.74	3.83	3.92	4.23	4.54	4.81	5.06	5.27	5.49
26	37	Xcel	Yes	No	Yes	9.2%	26.2%	0.00	(53.83)	2.42	2.54	2.67	2.80	3.05	3.28	3.49	3.68	3.84	4.00
		No. of Peers:	16	13	18														

	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40		
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2046				
	Final Stage																			Terminal Value	2054 Div	2054 Perpetuity	Screen #	
1	4.82	5.02	5.24	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	225.60	10.54	215.06	1	1
2	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	8.07	187.43	8.41	179.01	2	2
3	5.15	5.37	5.59	5.83	6.07	6.33	6.59	6.87	7.16	7.46	7.77	8.10	8.44	8.79	9.16	9.55	9.95	10.37	10.80	267.64	11.26	256.38	3	3
4	6.24	6.51	6.78	7.06	7.36	7.67	7.99	8.33	8.68	9.04	9.42	9.82	10.23	10.66	11.11	11.57	12.06	12.57	13.09	322.00	13.64	308.36	4	4
5	3.38	3.52	3.67	3.82	3.98	4.15	4.33	4.51	4.70	4.90	5.10	5.31	5.54	5.77	6.01	6.27	6.53	6.80	7.09	132.82	7.39	125.43	6	5
6	4.46	4.65	4.84	5.04	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	9.35	202.59	9.74	192.85	7	6
7	3.37	3.51	3.66	3.81	3.97	4.14	4.31	4.50	4.68	4.88	5.09	5.30	5.52	5.75	6.00	6.25	6.51	6.78	7.07	217.68	7.37	210.32	9	7
8	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	9.35	9.74	10.15	10.58	11.02	11.49	11.97	12.47	335.19	13.00	322.19	10	8
9	5.92	6.17	6.43	6.70	6.98	7.27	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.53	10.98	11.44	11.92	12.42	358.32	12.94	345.38	13	9
10	7.27	7.58	7.89	8.23	8.57	8.93	9.31	9.70	10.10	10.53	10.97	11.43	11.91	12.41	12.93	13.48	14.04	14.63	15.25	390.25	15.89	374.37	15	10
11	4.61	4.80	5.00	5.21	5.43	5.66	5.90	6.14	6.40	6.67	6.95	7.24	7.55	7.86	8.19	8.54	8.90	9.27	9.66	196.64	10.07	186.57	16	11
12	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.54	10.98	11.44	11.92	222.68	12.42	210.25	17	12
13	4.35	4.53	4.72	4.92	5.12	5.34	5.56	5.80	6.04	6.30	6.56	6.84	7.12	7.42	7.73	8.06	8.40	8.75	9.12	148.19	9.50	138.69	20	13
14	6.76	7.04	7.34	7.65	7.97	8.30	8.65	9.01	9.39	9.79	10.20	10.63	11.07	11.54	12.02	12.53	13.05	13.60	14.17	347.43	14.77	332.67	22	14
15	4.85	5.06	5.27	5.49	5.72	5.96	6.21	6.47	6.75	7.03	7.33	7.63	7.95	8.29	8.64	9.00	9.38	9.77	10.18	267.37	10.61	256.76	24	15
16	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	8.07	182.19	8.41	173.78	25	16
17	2.62	2.74	2.85	2.97	3.09	3.22	3.36	3.50	3.65	3.80	3.96	4.13	4.30	4.48	4.67	4.87	5.07	5.28	5.50	128.21	5.74	122.47	26	17
18	3.34	3.48	3.63	3.78	3.94	4.11	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	311.32	7.31	304.01	27	18
19	3.86	4.03	4.20	4.37	4.56	4.75	4.95	5.15	5.37	5.60	5.83	6.08	6.33	6.60	6.87	7.16	7.46	7.78	8.10	163.18	8.44	154.74	29	19
20	5.32	5.54	5.78	6.02	6.27	6.54	6.81	7.10	7.39	7.70	8.03	8.37	8.72	9.08	9.46	9.86	10.28	10.71	11.16	272.42	11.63	260.79	30	20
21	1.98	2.07	2.15	2.24	2.34	2.44	2.54	2.65	2.76	2.87	2.99	3.12	3.25	3.39	3.53	3.68	3.83	3.99	4.16	102.43	4.33	98.10	32	21
22	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.02	7.31	7.62	7.94	8.27	8.62	8.98	9.36	263.71	9.75	253.96	33	22
23	4.81	5.01	5.22	5.44	5.67	5.91	6.16	6.42	6.69	6.97	7.26	7.56	7.88	8.21	8.56	8.92	9.29	9.68	10.09	272.03	10.51	261.52	34	23
24	4.40	4.58	4.77	4.97	5.18	5.40	5.63	5.86	6.11	6.37	6.63	6.91	7.20	7.50	7.82	8.15	8.49	8.85	9.22	275.77	9.61	266.16	35	24
25	5.73	5.97	6.22	6.48	6.75	7.03	7.33	7.64	7.96	8.29	8.64	9.00	9.38	9.77	10.19	10.61	11.06	11.52	12.01	292.67	12.51	280.16	36	25
26	4.17	4.34	4.52	4.71	4.91	5.12	5.33	5.56	5.79	6.03	6.29	6.55	6.82	7.11	7.41	7.72	8.04	8.38	8.73	198.49	9.10	189.39	37	26

Mean			
8.94%	28.37%	0.00%	Company Screen
9.09%	27.23%	0.00%	Staff Screen
9.09%	27.22%	0.00%	Staff Sensitivity Screen

Average B.O.Y. & E.O.Y. Cash Flows Model X

	1	2	3	4		5	6	7	8	9		
							Terminal Value as	Average 2020- 2024 Dividend Growth Rates				
	Screen #	Abbreviated Utility	PAC No	Staff No	LT Debt Staff Sensitivity	Average IRR	% of NPV_{DIV}	EOY	BOY	Average	Screen #	
1	1	Allete	No	No	No	9.2%	26.0%	3.5%	4.4%	4.0%	1	1
2	2	Alliant	Yes	No	Yes	9.0%	28.0%	5.9%	6.7%	6.3%	2	2
3	3	Ameren	Yes	Yes	Yes	8.7%	30.3%	4.8%	5.8%	5.3%	3	3
4	4	AEP	Yes	No	Yes	8.7%	29.6%	3.0%	4.2%	3.6%	4	4
5	6	Avista	Yes	Yes	Yes	10.2%	20.1%	4.0%	4.9%	4.4%	6	5
6	7	Black Hills	No	Yes	Yes	9.4%	25.0%	3.5%	4.5%	4.0%	7	6
7	9	CMS	Yes	No	No	7.8%	37.8%	2.1%	3.4%	2.7%	9	7
8	10	Consol Ed	No	Yes	Yes	8.3%	33.1%	5.1%	5.6%	5.3%	10	8
9	13	Duke	Yes	No	Yes	8.0%	34.9%	0.6%	1.8%	1.2%	13	9
10	15	Entergy	Yes	No	No	8.5%	30.9%	2.1%	3.3%	2.7%	15	10
11	16	Evergy	Yes	Yes	Yes	9.7%	22.9%	3.6%	4.7%	4.1%	16	11
12	17	Eversource	No	No	Yes	10.2%	20.3%	5.8%	6.6%	6.2%	17	12
13	20	Fortis	No	No	No	11.2%	15.7%	4.6%	5.4%	5.0%	20	13
14	22	IDACORP	Yes	Yes	Yes	8.7%	30.1%	7.0%	7.4%	7.2%	22	14
15	24	NextEra	Yes	No	No	8.4%	33.1%	8.0%	8.9%	8.5%	24	15
16	25	NorthWestern	Yes	Yes	Yes	9.2%	25.9%	1.5%	2.5%	2.0%	25	16
17	26	OGE	Yes	Yes	Yes	9.0%	27.2%	2.2%	3.1%	2.7%	26	17
18	27	Otter Tail	No	No	No	6.7%	51.4%	3.7%	4.8%	4.3%	27	18
19	29	PGE	Yes	Yes	Yes	9.8%	22.9%	5.7%	6.5%	6.1%	29	19
20	30	Pinnacle	Yes	Yes	Yes	8.8%	28.9%	1.6%	2.6%	2.1%	30	20
21	32	PPL	No	No	No	8.7%	29.7%	6.9%	6.6%	6.8%	32	21
22	33	Public Serv.	No	Yes	Yes	8.1%	35.0%	4.7%	5.6%	5.2%	33	22
23	34	Sempra	No	Yes	Yes	8.3%	33.5%	6.0%	6.6%	6.3%	34	23
24	35	Southern	Yes	No	No	7.9%	36.5%	1.5%	2.7%	2.1%	35	24
25	36	WEC	No	Yes	Yes	8.8%	29.3%	2.4%	3.8%	3.1%	36	25
26	37	Xcel	Yes	No	Yes	9.1%	27.1%	5.0%	6.0%	5.5%	37	26
		No. of Peers:	16	13	18	Mean						
						8.84%	29.13%	3.67%	Company Screen			
						8.98%	28.00%	4.01%	Staff Screen			
						8.99%	28.00%	4.03%	Staff Sensitivity Screen			

4.20% Annual Growth Rate - Stage 3 | **EPS Growth to Determine a Sale Terminal Value** | **EPS Growth**

E.O.Y. Cash Flows Staff Model Y

	Screen #	Abbreviated Utility	PAC Peers	Staff Peers	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2046 Terminal Value	2054 Div	2054 Sale	2055	Screen #	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		
										Initial Stage					Transition Stage					Final Stage																								
1	1	Allete	No	No	No	9.5%	30.0%	0.00	(61.77)	2.93	3.03	3.14	3.25	3.36	3.61	3.84	4.06	4.26	4.44	4.63	4.82	5.02	5.24	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	282.47	10.11	272.36		1	1
				e	e					4.10	4.42	4.77	5.15	5.53	6.03	6.51	6.94	7.31	7.62	7.94	8.27	8.62	8.98	9.36	9.75	10.16	10.59	11.03	11.50	11.98	12.48	13.01	13.55	14.12	14.72	15.33	15.98	16.65		17.35		18.08		
2	2	Alliant	Yes	No	Yes	9.2%	31.2%	0.00	(50.73)	2.04	2.16	2.29	2.43	2.57	2.80	3.03	3.23	3.40	3.55	3.69	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	220.21	8.07	212.14		2	2
				e	e					3.25	3.45	3.67	3.90	4.13	4.52	4.88	5.21	5.50	5.73	5.97	6.22	6.48	6.75	7.04	7.33	7.64	7.96	8.29	8.64	9.01	9.38	9.78	10.19	10.62	11.06	11.53	12.01	12.52		13.04		13.59		
3	3	Ameren	Yes	Yes	Yes	8.9%	33.8%	0.00	(73.00)	2.86	3.00	3.15	3.30	3.45	3.76	4.06	4.32	4.55	4.74	4.94	5.15	5.37	5.59	5.83	6.07	6.33	6.59	6.87	7.16	7.46	7.77	8.10	8.44	8.79	9.16	9.55	9.95	10.37	321.22	10.80	310.42		3	3
				e	e					4.90	5.23	5.58	5.95	6.32	6.92	7.48	7.99	8.43	8.78	9.15	9.53	9.94	10.35	10.79	11.24	11.71	12.20	12.72	13.25	13.81	14.39	14.99	15.62	16.28	16.96	17.67	18.42	19.19		20.00		20.84		
4	4	AEP	Yes	No	Yes	8.9%	32.9%	0.00	(88.50)	3.81	3.92	4.04	4.16	4.28	4.62	4.95	5.25	5.52	5.75	5.99	6.24	6.51	6.78	7.06	7.36	7.67	7.99	8.33	8.68	9.04	9.42	9.82	10.23	10.66	11.11	11.57	12.06	12.57	380.88	13.09	367.79		4	4
				e	e					6.00	6.38	6.78	7.20	7.62	8.32	8.97	9.57	10.09	10.51	10.95	11.41	11.89	12.39	12.91	13.45	14.02	14.61	15.22	15.86	16.52	17.22	17.94	18.69	19.48	20.30	21.15	22.04	22.96		23.93		24.93		
5	6	Avista	Yes	Yes	Yes	10.2%	21.5%	0.00	(35.83)	2.00	2.08	2.16	2.25	2.34	2.52	2.69	2.84	2.99	3.11	3.24	3.38	3.52	3.67	3.82	3.98	4.15	4.33	4.51	4.70	4.90	5.10	5.31	5.54	5.77	6.01	6.27	6.53	6.80	140.44	7.09	133.35		6	5
				e	e					2.60	2.70	2.80	2.90	3.00	3.26	3.50	3.72	3.91	4.08	4.25	4.43	4.61	4.81	5.01	5.22	5.44	5.67	5.91	6.15	6.41	6.68	6.96	7.26	7.56	7.88	8.21	8.55	8.91		9.29		9.68		
6	7	Black Hills	No	Yes	Yes	9.4%	26.8%	0.00	(55.35)	2.70	2.80	2.90	3.00	3.10	3.33	3.55	3.75	3.94	4.11	4.28	4.46	4.65	4.84	5.04	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	218.72	9.35	209.37		7	6
				e	e					4.10	4.31	4.52	4.75	4.98	5.33	5.66	5.98	6.27	6.54	6.81	7.10	7.40	7.71	8.03	8.37	8.72	9.08	9.47	9.86	10.28	10.71	11.16	11.63	12.12	12.63	13.16	13.71	14.28		14.88		15.51		
7	9	CMS	Yes	No	No	7.7%	38.8%	(0.00)	(60.76)	2.16	2.21	2.25	2.30	2.35	2.52	2.68	2.84	2.98	3.10	3.24	3.37	3.51	3.66	3.81	3.97	4.14	4.31	4.50	4.68	4.88	5.09	5.30	5.52	5.75	6.00	6.25	6.51	6.78	220.71	7.07	213.64		9	7
				e	e					3.50	3.58	3.66	3.75	3.84	4.15	4.45	4.73	4.98	5.19	5.40	5.63	5.87	6.11	6.37	6.64	6.92	7.21	7.51	7.83	8.16	8.50	8.85	9.23	9.61	10.02	10.44	10.88	11.33		11.81		12.31		
8	10	Consol Ed	No	Yes	Yes	8.5%	36.1%	0.00	(92.43)	3.40	3.57	3.76	3.95	4.14	4.45	4.74	5.01	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	9.35	9.74	10.15	10.58	11.02	11.49	11.97	388.11	12.47	375.64		10	8
				e	e					5.60	5.92	6.25	6.60	6.95	7.59	8.19	8.73	9.21	9.59	10.00	10.41	10.85	11.31	11.78	12.28	12.79	13.33	13.89	14.47	15.08	15.72	16.38	17.06	17.78	18.53	19.31	20.12	20.96		21.84		22.76		
9	13	Duke	Yes	No	Yes	8.4%	38.4%	0.00	(100.85)	4.22	4.25	4.27	4.30	4.33	4.56	4.78	5.01	5.23	5.45	5.68	5.92	6.17	6.43	6.70	6.98	7.27	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.53	10.98	11.44	11.92	430.24	12.42	417.83		13	9
				e	e					6.35	6.74	7.16	7.60	8.04	8.78	9.47	10.10	10.64	11.09	11.55	12.04	12.55	13.07	13.62	14.19	14.79	15.41	16.06	16.73	17.44	18.17	18.93	19.73	20.55	21.42	22.32	23.25	24.23		25.25		26.31		
10	15	Entergy	Yes	No	No	8.5%	32.3%	0.00	(108.17)	4.70	4.80	4.90	5.00	5.10	5.46	5.80	6.13	6.43	6.70	6.98	7.27	7.58	7.89	8.23	8.57	8.93	9.31	9.70	10.10	10.53	10.97	11.43	11.91	12.41	12.93	13.48	14.04	14.63	409.42	15.25	394.17		15	10
				e	e					6.85	7.23	7.63	8.05	8.47	8.87	9.27	9.68	10.10	10.52	10.96	11.42	11.90	12.40	12.92	13.47	14.03	14.62	15.24	15.88	16.54	17.24	17.96	18.72	19.50	20.32	21.17	22.06	22.99		23.96		24.96		
11	16	Evergy	Yes	Yes	Yes	9.7%	24.9%	0.00	(53.31)	2.74	2.84	2.94	3.05	3.16	3.41	3.65	3.87	4.07	4.24	4.42	4.61	4.80	5.00	5.21	5.43	5.66	5.90	6.14	6.40	6.67	6.95	7.24	7.55	7.86	8.19	8.54	8.90	9.27	215.88	9.66	206.22		16	11
				e	e					4.00	4.19	4.39	4.60	4.81	5.21	5.60	5.95	6.26	6.52	6.80	7.08	7.38	7.69	8.01	8.35	8.70	9.06	9.44	9.84	10.25	10.68	11.13	11.60	12.09	12.60	13.12	13.68	14.25		14.85		15.47		
12	17	Eversource	No	No	Yes	10.3%	23.0%	0.00	(59.29)	3.03	3.21	3.40	3.60	3.80	4.15	4.47	4.77	5.02	5.24	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.54	10.98	11.44	257.38	11.92	245.46		17	12
				e	e					4.85	5.15	5.46	5.80	6.14	6.70	7.22	7.70	8.12	8.46	8.82	9.19	9.58	9.98	10.40	10.83	11.29	11.76	12.26	12.77	13.31	13.87	14.45	15.06	15.69	16.35	17.03	17.75	18.49		19.27		20.08		
13	20	Fortis	No	No	No	11.2%	18.0%	0.00	(39.34)	2.49	2.60	2.72	2.85	2.98	3.22	3.44	3.65	3.84	4.00	4.17	4.35	4.53	4.72	4.92	5.12	5.34	5.56	5.80	6.04	6.30	6.56	6.84	7.12	7.42	7.73	8.06	8.40	8.75	171.56	9.12	162.44		20	13
				e	e					3.35	3.55	3.77	4.00	4.23	4.62	4.98	5.31	5.60	5.83	6.08	6.33	6.60	6.87	7.16	7.46	7.78	8.10	8.44	8.80	9.17	9.55	9.95	10.37	10.81	11.26	11.73	12.23	12.74		13.28		13.83		
14	22	IDACORP	Yes	Yes	Yes	8.8%	32.3%	0.00	(94.30)	3.46	3.71	3.97	4.25	4.53	4.94	5.32	5.67	5.97	6.22	6.49	6.76	7.04	7.34	7.65	7.97	8.30	8.65	9.01	9.39	9.79	10.20	10.63	11.07	11.54	12.02	12.53	13.05	13.60	379.44	14.17	365.27		22	14
				e	e					5.75	6.04	6.34	6.65	6.96	7.53	8.07	8.57	9.01	9.39	9.78	10.19	10.62	11.07	11.53	12.02	12.52	13.05	13.59	14.17	14.76	15.38	16.03	16.70	17.40	18.13	18.89	19.69	20.51		21.38		22.27		
15	24	NextEra	Yes	No	No	10.5%	23.7%	0.00	(72.07)	3.46	3.71	3.97	4.25	4.53	5.06	5.55	5.98	6.34	6.61	6.89	7.18	7.48	7.79	8.12	8.46	8.81	9.18	9.57	9.97	10.39	10.83	11.28	11.76	12.25	12.76	13.30	13.86	14.44	341.75	15.05	326.70		24	15
				e	e					3.65	3.93	4.23	4.55	4.87	5.40	5.89	6.33	6.69	6.97	7.27	7.57	7.89	8.22	8.57	8.93	9.30	9.69	10.10	10.52	10.96	11.43	11.90	12.40	12.93	13.47	14.03	14.62	15.24		15.88		16.55		
16	25	NorthWestern	Yes	Yes	Yes	9.2%	27.9%	0.00	(50.62)	2.64	2.68	2.72	2.76	2.80	2.95	3.11	3.26	3.40	3.55	3.70	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	200.06	8.07	191.99		25	16
				e	e					3.70	3.87	4.06	4.25	4.44	4.78	5.10	5.40	5.68	5.91	6.16	6.42	6.69	6.97	7.27	7.57	7.89	8.22	8.57	8.92	9.30	9.69	10.10	10.52	10.96	11.42	11.90	12.40	12.92		13.47		14.03		
17	26	OGE	Yes	Yes	Yes	9.1%	29.4%	0.00	(35.53)	1.73	1.77	1.81	1.85	1.89	2.00	2.11	2.22	2.32	2.42	2.52	2.62	2.74	2.85	2.97	3.09	3.22	3.36	3.50	3.65	3.80	3.96	4.13	4.30	4.48	4.67	4.87	5.07	5.28	141.89	5.50	136.39		26	17
				e	e					2.30	2.43	2.56	2.70	2.84	3.04	3.23	3.40	3.57	3.72	3.88	4.04	4.21	4.39	4.57	4.76	4.96	5.17	5.39	5.61	5.85	6.10	6.35	6.62	6.90	7.19	7.49	7.80	8.13		8.47		8.83		
18	27	Otter Tail	No	No	No	5.6%	45.8%	0.00	(87.64)	1.97	2.04	2.12	2.20	2.28	2.47	2.65	2.81	2.96	3.08	3.21	3.34	3.48	3.63	3.78	3.94	4.11	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	208.74	7.01	201.72		27	18
				e	e					4.65	4.51	4.38	4.25	4.12	4.10	4.13	4.20	4.33	4.51	4.70	4.90	5.10	5.32	5.54	5.77	6.02	6.27	6.53	6.81	7.09	7.39	7.70	8.03	8.36	8.71	9.08	9.46	9.86		10.27		10.70		
19	29	PGE	Yes	Yes	Yes	9.9%	25.7%	0.00	(43.78)	2.08	2.20	2.33	2.46	2.59	2.83	3.04	3.24	3.42	3.56	3.71	3.86	4.03	4.20	4.37	4.56	4.75	4.95	5.15	5.37	5.60	5.83	6.08	6.33	6.60	6.87	7.16	7.46	7.78	189.60	8.10	181.50		29	19
				e	e					3.25	3.44	3.64	3.85	4.06	4.46	4.83	5.16	5.45	5.68	5.92	6.17	6.43	6.70	6.98	7.27	7.57	7.89	8.22	8.57	8.93	9.30	9.70	10.10	10.53	10.97	11.43	11.91	12.41		12.93		13.47		
20	30	Pinnacle	Yes	Yes	Yes	9.0%	31.7%	0.00	(75.86)	3.61	3.67	3.73	3.79	3.85	4.07	4.29	4.50	4.70	4.90	5.11	5.32	5.54	5.78	6.02	6.27	6.54	6.81	7.10	7.39	7.70	8.03	8.37	8.72	9.08	9.46	9.86	10.28	10.71	315.58	11.16	304.42		30	20
				e	e					5.00	5.31	5.65	6.00	6.35	6.84	7.30	7.73	8.12	8.46	8.81	9.18	9.57	9.97	10.39	10.82	11.28	11.75	12.25	12.76	13.30	13.86	14.44	15.04	15.68	16.33	17.02	17.73	18.48		19.26		20.06		
21	32	PPL	No	No	No	9.2%	35.3%	0.00	(28.21)	1.10	1.18	1.26	1.35	1.44	1.52	1.60	1.68	1.75	1.83	1.90	1.98	2.07	2.15	2.24	2.34	2.44	2.54	2.65	2.76	2.87	2.99	3.12	3.25	3.39	3.53	3.68	3.83	3.99	140.98	4.16	136.82		32	21
				e	e					1.80	1.94	2.09	2.25	2.41	2.74	3.05	3.32	3.53	3.68	3.83	4.00	4.16	4.34	4.52	4.71	4.91	5.11	5.33	5.55	5.79	6.03	6.28	6.55	6.82	7.11	7.41	7.72	8.04		8.38		8.73		
22	33	Public Serv.	No	Yes	Yes	8.3%	37.9%	0.00	(72.66)	2.52	2.64	2.77	2.90	3.03	3.29	3.53	3.75	3.94	4.11	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.02	7.31	7.62	7.94	8.27	8.62	8.98	301.81	9.36	292.45		33	22
				e	e					3.90	4.14	4.39	4.65	4.91	5.31	5.69	6.04	6.35	6.62	6.89	7.18	7.49	7.80	8.13	8.47	8.82	9.19	9.58	9.98	10.40	10.84	11.29	11.77	12.26	12.78	13.32	13.87	14.46		15.06		15.70		
23	34	Sempra	No	Yes	Yes	8.6%	37.2%	0.00	(74.54)	2.58	2.74	2.90	3.08	3.26	3.53	3.80	4.04	4.25	4.43	4.62	4.81	5.01	5.22	5.44	5.67	5.91	6.16	6.42	6.69	6.97	7.26	7.56	7.88	8.21	8.56	8.92	9.29	9.68	327.03	10.09	316.94		34	23
				e	e					5.15	5.51	5.89	6.30	6.71	7.31	7.89	8.40	8.86	9.23	9.62	10.02	10.44	10.88	11.34	11.81	12.31	12.83	13.36	13.93	14.51	15.12	15.76	16.42	17.11	17.83	18.57	19.35	20.17		21.01		21.90		
24	35	Southern	Yes	No	No	8.2%	39.9%	0.00	(77.30)	2.96	3.01	3.05	3.10	3.15	3.34	3.53	3.71	3.89	4.05	4.22	4.40	4.58	4.77	4.97	5.18	5.40	5.63	5.86	6.11	6.37	6.63	6.91	7.20	7.50	7.82	8.15	8.49	8.85	327.20	9.22	317.99		35	24
				e	e					4.30	4.55	4.82	5.10	5.38	5.88	6.36	6.78	7.15	7.46	7.77	8.09	8.43	8.79	9.16	9.54	9.94	10.36	10.80	11.25	11.72	12.21	12.73	13.26	13.82	14.40	15.00	15.63	16.29		16.98		17.69		
25	36	WEC	No	Yes	Yes	9.1%	32.9%	0.00	(80.49)	3.57	3.65	3.74	3.83	3.92	4.23	4.54	4.81	5.06	5.27	5.49	5.73	5.97	6.22	6.48	6.75	7.03	7.33	7.64	7.96	8.29	8.64	9.00	9.38	9.77	10.19	10.61	11.06	11.52	356.71	12.01	344.70		36	25
				e	e					5.25	5.61	5.99	6.40	6.81	7.46	8.07	8.62	9.09	9.48	9.87	10.29	10.72	11.17	11.64	12.13	12.64	13.17	13.72	14.30	14.90	15.53	16.18	16.86	17.57	18.30	19.07	19.87	20.71		21.58		22.48		
26	37	Xcel	Yes	No	Yes	9.4%	31.0%	0.00	(53.83)	2.30	2.42	2.54	2.67	2.80	3.05	3.28	3.49	3.68	3.84	4.00	4.17	4.34	4.52	4.71	4.91	5.12	5.33	5.56	5.79	6.03	6.29	6.55	6.82	7.11	7.41	7.72	8.04	8.38	245.47	8.73	236.73		37	26
				e	e					3.80	4.08	4.38	4.70	5.02	5.52	5.98	6.40	6.76	7.04	7.34	7.65	7.97	8.30	8.65	9.02	9.39	9.79	10.20	10.63	11.07	11.54	12.02	12.53	13.06	13.60	14.18	14.77	15.39		16.04		16.71		

No. of Peers:	PAC Peers	Staff Peers	LT Debt Staff Sensitivity
	16	13	18

Mean			
9.10%	30.96%	0.00%	Company Screen
9.12%	30.63%	0.00%	Staff Screen
9.15%	30.81%	0.00%	Staff Sensitivity Screen

B.O.Y. Cash Flows Staff Model Y EPS Growth

	#	Abbreviated Utility	PAC Peers	Staff Peers	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2046 Terminal Value	2054 Div	2054 Sale	2055	#	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42		
										Initial Stage					Transition Stage					Final Stage																								
1	1	Allete	No	No	No	9.7%	28.4%	0.00	(61.77)	3.03	3.14	3.25	3.36	3.61	3.84	4.06	4.26	4.44	4.63	4.82	5.02	5.24	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	282.89	10.54	272.36		1	1
				e	e					4.10	4.42	4.77	5.15	5.53	6.03	6.51	6.94	7.31	7.62	7.94	8.27	8.62	8.98	9.36	9.75	10.16	10.59	11.03	11.50	11.98	12.48	13.01	13.55	14.12	14.72	15.33	15.98	16.65		17.35		18.08		
2	2	Alliant	Yes	No	Yes	9.4%	29.4%	0.00	(50.73)	2.16	2.29	2.43	2.57	2.80	3.03	3.23	3.40	3.55	3.69	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	8.07	220.55	8.41	212.14		2	2
				e	e					3.25	3.45	3.67	3.90	4.13	4.52	4.88	5.21	5.50	5.73	5.97	6.22	6.48	6.75	7.04	7.33	7.64	7.96	8.29	8.64	9.01	9.38	9.78	10.19	10.62	11.06	11.53	12.01	12.52		13.04		13.59		
3	3	Ameren	Yes	Yes	Yes	9.1%	32.1%	0.00	(73.00)	3.00	3.15	3.30	3.45	3.76	4.06	4.32	4.55	4.74	4.94	5.15	5.37	5.59	5.83	6.07	6.33	6.59	6.87	7.16	7.46	7.77	8.10	8.44	8.79	9.16	9.55	9.95	10.37	10.80	321.67	11.26	310.42		3	3
				e	e					4.90	5.23	5.58	5.95	6.32	6.92	7.48	7.99	8.43	8.78	9.15	9.53	9.94	10.35	10.79	11.24	11.71	12.20	12.72	13.25	13.81	14.39	14.99	15.62	16.28	16.96	17.67	18.42	19.19		20.00		20.84		
4	4	AEP	Yes	No	Yes	9.1%	31.4%	0.00	(88.50)	3.92	4.04	4.16	4.28	4.62	4.95	5.25	5.52	5.75	5.99	6.24	6.51	6.78	7.06	7.36	7.67	7.99	8.33	8.68	9.04	9.42	9.82	10.23	10.66	11.11	11.57	12.06	12.57	13.09	381.43	13.64	367.79		4	4
				e	e					6.00	6.38	6.78	7.20	7.62	8.32	8.97	9.57	10.09	10.51	10.95	11.41	11.89	12.39	12.91	13.45	14.02	14.61	15.22	15.86	16.52	17.22	17.94	18.69	19.48	20.30	21.15	22.04	22.96		23.93		24.93		
5	6	Avista	Yes	Yes	Yes	10.4%	20.1%	0.00	(35.83)	2.08	2.16	2.25	2.34	2.52	2.69	2.84	2.99	3.11	3.24	3.38	3.52	3.67	3.82	3.98	4.15	4.33	4.51	4.70	4.90	5.10	5.31	5.54	5.77	6.01	6.27	6.53	6.80	7.09	140.74	7.39	133.35		6	5
				e	e					2.60	2.70	2.80	2.90	3.00	3.26	3.50	3.72	3.91	4.08	4.25	4.43	4.61	4.81	5.01	5.22	5.44	5.67	5.91	6.15	6.41	6.68	6.96	7.26	7.56	7.88	8.21	8.55	8.91		9.29		9.68		
6	7	Black Hills	No	Yes	Yes	9.6%	25.3%	0.00	(55.35)	2.80	2.90	3.00	3.10	3.33	3.55	3.75	3.94	4.11	4.28	4.46	4.65	4.84	5.04	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	9.35	219.11	9.74	209.37		7	6
				e	e					4.10	4.31	4.52	4.75	4.98	5.33	5.66	5.98	6.27	6.54	6.81	7.10	7.40	7.71	8.03	8.37	8.72	9.08	9.47	9.86	10.28	10.71	11.16	11.63	12.12	12.63	13.16	13.71	14.28		14.88		15.51		
7	9	CMS	Yes	No	No	7.9%	37.3%	0.00	(60.76)	2.21	2.25	2.30	2.35	2.52	2.68	2.84	2.98	3.10	3.24	3.37	3.51	3.66	3.81	3.97	4.14	4.31	4.50	4.68	4.88	5.09	5.30	5.52	5.75	6.00	6.25	6.51	6.78	7.07	221.00	7.37	213.64		9	7
				e	e					3.50	3.58	3.66	3.75	3.84	4.15	4.45	4.73	4.98	5.19	5.40	5.63	5.87	6.11	6.37	6.64	6.92	7.21	7.51	7.83	8.16	8.50	8.85	9.23	9.61	10.02	10.44	10.88	11.33		11.81		12.31		
8	10	Consol Ed	No	Yes	Yes	8.7%	34.5%	0.00	(92.43)	3.57	3.76	3.95	4.14	4.45	4.74	5.01	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	7.31	7.61	7.93	8.27	8.61	8.97	9.35	9.74	10.15	10.58	11.02	11.49	11.97	12.47	388.63	13.00	375.64		10	8
				e	e					5.60	5.92	6.25	6.60	6.95	7.59	8.19	8.73	9.21	9.59	10.00	10.41	10.85	11.31	11.78	12.28	12.79	13.33	13.89	14.47	15.08	15.72	16.38	17.06	17.78	18.53	19.31	20.12	20.96		21.84		22.76		
9	13	Duke	Yes	No	Yes	8.5%	37.1%	0.00	(100.85)	4.25	4.27	4.30	4.33	4.56	4.78	5.01	5.23	5.45	5.68	5.92	6.17	6.43	6.70	6.98	7.27	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.53	10.98	11.44	11.92	12.42	430.77	12.94	417.83		13	9
				e	e					6.35	6.74	7.16	7.60	8.04	8.78	9.47	10.10	10.64	11.09	11.55	12.04	12.55	13.07	13.62	14.19	14.79	15.41	16.06	16.73	17.44	18.17	18.93	19.73	20.55	21.42	22.32	23.25	24.23		25.25		26.31		
10	15	Entergy	Yes	No	No	8.7%	30.9%	0.00	(108.17)	4.80	4.90	5.00	5.10	5.46	5.80	6.13	6.43	6.70	6.98	7.27	7.58	7.89	8.23	8.57	8.93	9.31	9.70	10.10	10.53	10.97	11.43	11.91	12.41	12.93	13.48	14.04	14.63	15.25	410.06	15.89	394.17		15	10
				e	e					6.85	7.23	7.63	8.05	8.47	8.87	9.27	9.68	10.10	10.52	10.96	11.42	11.90	12.40	12.92	13.47	14.03	14.62	15.24	15.88	16.54	17.24	17.96	18.72	19.50	20.32	21.17	22.06	22.99		23.96		24.96		
11	16	Evergy	Yes	Yes	Yes	10.0%	23.4%	0.00	(53.31)	2.84	2.94	3.05	3.16	3.41	3.65	3.87	4.07	4.24	4.42	4.61	4.80	5.00	5.21	5.43	5.66	5.90	6.14	6.40	6.67	6.95	7.24	7.55	7.86	8.19	8.54	8.90	9.27	9.66	216.29	10.07	206.22		16	11
				e	e					4.00	4.19	4.39	4.60	4.81	5.21	5.60	5.95	6.26	6.52	6.80	7.08	7.38	7.69	8.01	8.35	8.70	9.06	9.44	9.84	10.25	10.68	11.13	11.60	12.09	12.60	13.12	13.68	14.25		14.85		15.47		
12	17	Eversource	No	No	Yes	10.6%	21.3%	0.00	(59.29)	3.21	3.40	3.60	3.80	4.15	4.47	4.77	5.02	5.24	5.46	5.68	5.92	6.17	6.43	6.70	6.98	7.28	7.58	7.90	8.23	8.58	8.94	9.31	9.70	10.11	10.54	10.98	11.44	11.92	257.88	12.42	245.46		17	12
				e	e					4.85	5.15	5.46	5.80	6.14	6.70	7.22	7.70	8.12	8.46	8.82	9.19	9.58	9.98	10.40	10.83	11.29	11.76	12.26	12.77	13.31	13.87	14.45	15.06	15.69	16.35	17.03	17.75	18.49		19.27		20.08		
13	20	Fortis	No	No	No	11.5%	16.6%	0.00	(39.34)	2.60	2.72	2.85	2.98	3.22	3.44	3.65	3.84	4.00	4.17	4.35	4.53	4.72	4.92	5.12	5.34	5.56	5.80	6.04	6.30	6.56	6.84	7.12	7.42	7.73	8.06	8.40	8.75	9.12	171.94	9.50	162.44		20	13
				e	e					3.35	3.55	3.77	4.00	4.23	4.62	4.98	5.31	5.60	5.83	6.08	6.33	6.60	6.87	7.16	7.46	7.78	8.10	8.44	8.80	9.17	9.55	9.95	10.37	10.81	11.26	11.73	12.23	12.74		13.28		13.83		
14	22	IDACORP	Yes	Yes	Yes	9.0%	30.4%	0.00	(94.30)	3.71	3.97	4.25	4.53	4.94	5.32	5.67	5.97	6.22	6.49	6.76	7.04	7.34	7.65	7.97	8.30	8.65	9.01	9.39	9.79	10.20	10.63	11.07	11.54	12.02	12.53	13.05	13.60	14.17	380.03	14.77	365.27		22	14
				e	e					5.75	6.04	6.34	6.65	6.96	7.53	8.07	8.57	9.01	9.39	9.78	10.19	10.62	11.07	11.53	12.02	12.52	13.05	13.59	14.17	14.76	15.38	16.03	16.70	17.40	18.13	18.89	19.69	20.51		21.38		22.27		

15	24	NextEra	Yes	No	No	10.8%	21.8%	0.00	(72.07)	3.71	3.97	4.25	4.53	5.06	5.55	5.98	6.34	6.61	6.89	7.18	7.48	7.79	8.12	8.46	8.81	9.18	9.57	9.97	10.39	10.83	11.28	11.76	12.25	12.76	13.30	13.86	14.44	15.05	342.38	15.68	326.70		24	15
				e	e					3.65	3.93	4.23	4.55	4.87	5.40	5.89	6.33	6.69	6.97	7.27	7.57	7.89	8.22	8.57	8.93	9.30	9.69	10.10	10.52	10.96	11.43	11.90	12.40	12.93	13.47	14.03	14.62	15.24		15.88		16.55		
16	25	NorthWestern	Yes	Yes	Yes	9.4%	26.7%	0.00	(50.62)	2.68	2.72	2.76	2.80	2.95	3.11	3.26	3.40	3.55	3.70	3.85	4.01	4.18	4.36	4.54	4.73	4.93	5.14	5.35	5.58	5.81	6.05	6.31	6.57	6.85	7.14	7.44	7.75	8.07	200.40	8.41	191.99		25	16
				e	e					3.70	3.87	4.06	4.25	4.44	4.78	5.10	5.40	5.68	5.91	6.16	6.42	6.69	6.97	7.27	7.57	7.89	8.22	8.57	8.92	9.30	9.69	10.10	10.52	10.96	11.42	11.90	12.40	12.92		13.47		14.03		
17	26	OGE	Yes	Yes	Yes	9.3%	28.0%	0.00	(35.53)	1.77	1.81	1.85	1.89	2.00	2.11	2.22	2.32	2.42	2.52	2.62	2.74	2.85	2.97	3.09	3.22	3.36	3.50	3.65	3.80	3.96	4.13	4.30	4.48	4.67	4.87	5.07	5.28	5.50	142.12	5.74	136.39		26	17
				e	e					2.30	2.43	2.56	2.70	2.84	3.04	3.23	3.40	3.57	3.72	3.88	4.04	4.21	4.39	4.57	4.76	4.96	5.17	5.39	5.61	5.85	6.10	6.35	6.62	6.90	7.19	7.49	7.80	8.13		8.47		8.83		
18	27	Otter Tail	No	No	No	5.8%	44.3%	0.00	(87.64)	2.04	2.12	2.20	2.28	2.47	2.65	2.81	2.96	3.08	3.21	3.34	3.48	3.63	3.78	3.94	4.11	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.01	209.03	7.31	201.72		27	18
				e	e					4.65	4.51	4.38	4.25	4.12	4.10	4.13	4.20	4.33	4.51	4.70	4.90	5.10	5.32	5.54	5.77	6.02	6.27	6.53	6.81	7.09	7.39	7.70	8.03	8.36	8.71	9.08	9.46	9.86		10.27		10.70		
19	29	PGE	Yes	Yes	Yes	10.1%	24.0%	0.00	(43.78)	2.20	2.33	2.46	2.59	2.83	3.04	3.24	3.42	3.56	3.71	3.86	4.03	4.20	4.37	4.56	4.75	4.95	5.15	5.37	5.60	5.83	6.08	6.33	6.60	6.87	7.16	7.46	7.78	8.10	189.94	8.44	181.50		29	19
				e	e					3.25	3.44	3.64	3.85	4.06	4.46	4.83	5.16	5.45	5.68	5.92	6.17	6.43	6.70	6.98	7.27	7.57	7.89	8.22	8.57	8.93	9.30	9.70	10.10	10.53	10.97	11.43	11.91	12.41		12.93		13.47		
20	30	Pinnacle	Yes	Yes	Yes	9.1%	30.4%	0.00	(75.86)	3.67	3.73	3.79	3.85	4.07	4.29	4.50	4.70	4.90	5.11	5.32	5.54	5.78	6.02	6.27	6.54	6.81	7.10	7.39	7.70	8.03	8.37	8.72	9.08	9.46	9.86	10.28	10.71	11.16	316.05	11.63	304.42		30	20
				e	e					5.00	5.31	5.65	6.00	6.35	6.84	7.30	7.73	8.12	8.46	8.81	9.18	9.57	9.97	10.39	10.82	11.28	11.75	12.25	12.76	13.30	13.86	14.44	15.04	15.68	16.33	17.02	17.73	18.48		19.26		20.06		
21	32	PPL	No	No	No	9.4%	33.6%	0.00	(28.21)	1.18	1.26	1.35	1.44	1.52	1.60	1.68	1.75	1.83	1.90	1.98	2.07	2.15	2.24	2.34	2.44	2.54	2.65	2.76	2.87	2.99	3.12	3.25	3.39	3.53	3.68	3.83	3.99	4.16	141.15	4.33	136.82		32	21
				e	e					1.80	1.94	2.09	2.25	2.41	2.74	3.05	3.32	3.53	3.68	3.83	4.00	4.16	4.34	4.52	4.71	4.91	5.11	5.33	5.55	5.79	6.03	6.28	6.55	6.82	7.11	7.41	7.72	8.04		8.38		8.73		
22	33	Public Serv.	No	Yes	Yes	8.5%	36.2%	0.00	(72.66)	2.64	2.77	2.90	3.03	3.29	3.53	3.75	3.94	4.11	4.28	4.46	4.65	4.84	5.05	5.26	5.48	5.71	5.95	6.20	6.46	6.73	7.02	7.31	7.62	7.94	8.27	8.62	8.98	9.36	302.20	9.75	292.45		33	22
				e	e					3.90	4.14	4.39	4.65	4.91	5.31	5.69	6.04	6.35	6.62	6.89	7.18	7.49	7.80	8.13	8.47	8.82	9.19	9.58	9.98	10.40	10.84	11.29	11.77	12.26	12.78	13.32	13.87	14.46		15.06		15.70		
23	34	Sempra	No	Yes	Yes	8.8%	35.4%	0.00	(74.54)	2.74	2.90	3.08	3.26	3.53	3.80	4.04	4.25	4.43	4.62	4.81	5.01	5.22	5.44	5.67	5.91	6.16	6.42	6.69	6.97	7.26	7.56	7.88	8.21	8.56	8.92	9.29	9.68	10.09	327.46	10.51	316.94		34	23
				e	e					5.15	5.51	5.89	6.30	6.71	7.31	7.89	8.40	8.86	9.23	9.62	10.02	10.44	10.88	11.34	11.81	12.31	12.83	13.36	13.93	14.51	15.12	15.76	16.42	17.11	17.83	18.57	19.35	20.17		21.01		21.90		
24	35	Southern	Yes	No	No	8.3%	38.5%	0.00	(77.30)	3.01	3.05	3.10	3.15	3.34	3.53	3.71	3.89	4.05	4.22	4.40	4.58	4.77	4.97	5.18	5.40	5.63	5.86	6.11	6.37	6.63	6.91	7.20	7.50	7.82	8.15	8.49	8.85	9.22	327.59	9.61	317.99		35	24
				e	e					4.30	4.55	4.82	5.10	5.38	5.88	6.36	6.78	7.15	7.46	7.77	8.09	8.43	8.79	9.16	9.54	9.94	10.36	10.80	11.25	11.72	12.21	12.73	13.26	13.82	14.40	15.00	15.63	16.29		16.98		17.69		
25	36	WEC	No	Yes	Yes	9.2%	31.4%	0.00	(80.49)	3.65	3.74	3.83	3.92	4.23	4.54	4.81	5.06	5.27	5.49	5.73	5.97	6.22	6.48	6.75	7.03	7.33	7.64	7.96	8.29	8.64	9.00	9.38	9.77	10.19	10.61	11.06	11.52	12.01	357.21	12.51	344.70		36	25
				e	e					5.25	5.61	5.99	6.40	6.81	7.46	8.07	8.62	9.09	9.48	9.87	10.29	10.72	11.17	11.64	12.13	12.64	13.17	13.72	14.30	14.90	15.53	16.18	16.86	17.57	18.30	19.07	19.87	20.71		21.58		22.48		
26	37	Xcel	Yes	No	Yes	9.6%	29.3%	0.00	(53.83)	2.42	2.54	2.67	2.80	3.05	3.28	3.49	3.68	3.84	4.00	4.17	4.34	4.52	4.71	4.91	5.12	5.33	5.56	5.79	6.03	6.29	6.55	6.82	7.11	7.41	7.72	8.04	8.38	8.73	245.83	9.10	236.73		37	26
				e	e					3.80	4.08	4.38	4.70	5.02	5.52	5.98	6.40	6.76	7.04	7.34	7.65	7.97	8.30	8.65	9.02	9.39	9.79	10.20	10.63	11.07	11.54	12.02	12.53	13.06	13.60	14.18	14.77	15.39		16.04		16.71		

No. of Peers:	16	13	18

Mean			
9.30%	29.42%	0.00%	Company Screen
9.32%	29.06%	0.00%	Staff Screen
9.35%	29.24%	0.00%	Staff Sensitivity Screen

Average B.O.Y. & E.O.Y. Cash Flows

Model Y **EPS Growth**

	1	2	3	4		5	6	7	8	9		
	Screen #	Abbreviated Utility	PAC Peers	Staff Peers	LT Debt Staff Sensitivity	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2017 - 2021 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	Allete	No	No	No	9.6%	29.2%	3.5%	4.4%	4.0%	1	1
2	2	Alliant	Yes	No	Yes	9.3%	30.3%	5.9%	6.7%	6.3%	2	2
3	3	Ameren	Yes	Yes	Yes	9.0%	33.0%	4.8%	5.8%	5.3%	3	3
4	4	AEP	Yes	No	Yes	9.0%	32.1%	3.0%	4.2%	3.6%	4	4
5	6	Avista	Yes	Yes	Yes	10.3%	20.8%	4.0%	4.9%	4.4%	6	5
6	7	Black Hills	No	Yes	Yes	9.5%	26.1%	3.5%	4.5%	4.0%	7	6
7	9	CMS	Yes	No	No	7.8%	38.1%	2.1%	3.4%	2.7%	9	7
8	10	Consol Ed	No	Yes	Yes	8.6%	35.3%	5.1%	5.6%	5.3%	10	8
9	13	Duke	Yes	No	Yes	8.4%	37.7%	0.6%	1.8%	1.2%	13	9
10	15	Entergy	Yes	No	No	8.6%	31.6%	2.1%	3.3%	2.7%	15	10
11	16	Evergy	Yes	Yes	Yes	9.9%	24.2%	3.6%	4.7%	4.1%	16	11
12	17	Eversource	No	No	Yes	10.4%	22.1%	5.8%	6.6%	6.2%	17	12
13	20	Fortis	No	No	No	11.4%	17.3%	4.6%	5.4%	5.0%	20	13
14	22	IDACORP	Yes	Yes	Yes	8.9%	31.4%	7.0%	7.4%	7.2%	22	14
15	24	NextEra	Yes	No	No	10.7%	22.8%	7.0%	8.1%	7.5%	24	15
16	25	NorthWestern	Yes	Yes	Yes	9.3%	27.3%	1.5%	2.5%	2.0%	25	16
17	26	OGE	Yes	Yes	Yes	9.2%	28.7%	2.2%	3.1%	2.7%	26	17
18	27	Otter Tail	No	No	No	5.7%	45.1%	3.7%	4.8%	4.3%	27	18
19	29	PGE	Yes	Yes	Yes	10.0%	24.8%	5.7%	6.5%	6.1%	29	19
20	30	Pinnacle	Yes	Yes	Yes	9.0%	31.0%	1.6%	2.6%	2.1%	30	20
21	32	PPL	No	No	No	9.3%	34.5%	6.9%	6.6%	6.8%	32	21
22	33	Public Serv.	No	Yes	Yes	8.4%	37.0%	4.7%	5.6%	5.2%	33	22
23	34	Sempra	No	Yes	Yes	8.7%	36.3%	6.0%	6.6%	6.3%	34	23
24	35	Southern	Yes	No	No	8.3%	39.2%	1.5%	2.7%	2.1%	35	24
25	36	WEC	No	Yes	Yes	9.1%	32.2%	2.4%	3.8%	3.1%	36	25
26	37	Xcel	Yes	No	Yes	9.5%	30.1%	5.0%	6.0%	5.5%	37	26
		No. of Peers:	16	13	18							

Mean			
9.20%	30.19%	3.60%	Company Screen
9.22%	29.84%	4.01%	Staff Screen
9.25%	30.02%	4.03%	Staff Sensitivity Screen

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 2403

ROE – Three-Stage DCF: Summary and Recommendation

August 16, 2024

UE 433 Staff ROE Summary

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)			4.10%	20.0%	0.82%	
Organization for Economic Co-operation and Development (OECD)	1.81%	2.32%	4.17%	20.0%	0.83%	
Social Security Administration (SSA)	1.95%	2.32%	4.10%	20.0%	0.82%	
Congressional Budget Office (CBO)	1.70%	2.32%	4.06%	20.0%	0.81%	
BEA Nominal Historical,1994 Q2 – 2024 Q1	2.21%	2.32%	4.58%	20.0%	0.92%	
Composite				100%	4.20%	Composite
Congressional Budget Office (CBO) Long-Term 20-Year Budget Outlook	1.70%	2.32%	4.06%	100.0%	4.06%	CBO
BEA Nominal Historical,1994 Q2 – 2024 Q1	2.21%	2.32%	4.58%	100.0%	4.58%	BEA

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity

	X	CBO	4.06%	Composite	4.20%	BEA	4.58%
1	Company Peer Screen	8.72%		8.84%		9.16%	
2	Staff Peer Screen	8.86%		8.98%		9.31%	
3	Staff Sensitivity Peer Screen	8.87%		8.99%		9.32%	

Hamada →

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)

X	CBO	4.06%	Composite	4.20%	BEA	4.58%	
Company Peer Screen	8.23%		8.35%		8.67%		1
Staff Peer Screen	8.65%		8.77%		9.10%		2
Staff Sensitivity Peer Screen	8.52%		8.64%		8.97%		3

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale

	Y	CBO	4.06%	Composite	4.20%	BEA	4.58%
1	Company Peer Screen	9.09%		9.20%		9.50%	
2	Staff Peer Screen	9.11%		9.22%		9.53%	
3	Staff Sensitivity Peer Screen	9.14%		9.25%		9.56%	

Hamada →

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)

Y	CBO	4.06%	Composite	4.20%	BEA	4.58%	
Company Peer Screen	8.60%		8.71%		9.01%		1
Staff Peer Screen	8.90%		9.01%		9.32%		2
Staff Sensitivity Peer Screen	8.79%		8.90%		9.21%		3

Best Fit Range of Reasonable ROEs	8.65%	to	9.32%	ROE	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
Staff Range of Reasonable ROEs:	8.77%	to	9.44%	ROE	
	Midpoint	9.1%	ROE		Testimony

CAPM and Single Stage DCF point respectively to upper and to lower end of Staff's Three Stage DCF Modeling Results

CASE: UE 433
WITNESS: MATT MULDOON

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ROE:
Capital Asset Pricing Model (CAPM)

August 16, 2024

Staff's CAPM Modeling Results

PAC	4.50%	PAC Rf Rate (PAC/2205 Bulkley/1)		
Direct	12.65%	PAC Mkt Return (PAC/2205 Bulkley/1)		
Testimony	8.15%	PAC Mkt Risk Premium (PAC/2205 Bulkley/1)		
Staff	4.179%	R_f Aug 6, 2024 30-Yr UST Yield /WSJ	www.wsj.com/market-data/bonds	
	10.14%	30-Year S&P 500 Proxy Market Return	Geometric Return 1993-2023	(with dividends reinvested)
	5.96%	Staff 30-Yr Mkt Risk Premium (MRP)		

$R_{PAC} = R_f + Beta^*MRP$

	Screen #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	LT Debt UE 433 Sensitivity	Ticker	VL Q2 2024 Beta	Staff MRP 30 Yr ROE w VL Beta CAPM	PAC MRP PAC/2200 ROE w VL Beta CAPM	Screen #	
1	1	Allete	No	No	No	ALE	0.95	9.84%	12.24%	1	1
2	2	Alliant	Yes	No	Yes	LNT	0.90	9.54%	11.84%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	0.90	9.54%	11.84%	3	3
4	4	AEP	Yes	No	Yes	AEP	0.85	9.25%	11.43%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	0.95	9.84%	12.24%	6	5
6	7	Black Hills	No	Yes	Yes	BKH	1.05	10.44%	13.06%	7	6
7	9	CMS	Yes	No	No	CMS	0.85	9.25%	11.43%	9	7
8	10	Consol Ed	No	Yes	Yes	ED	0.80	8.95%	11.02%	10	8
9	13	Duke	Yes	No	Yes	DUK	0.90	9.54%	11.84%	13	9
10	15	Entergy	Yes	No	No	ETR	1.00	10.14%	12.65%	15	10
11	16	Evergy	Yes	Yes	Yes	EVRG	0.95	9.84%	12.24%	16	11
12	17	Eversource	No	No	Yes	ES	0.95	9.84%	12.24%	17	12
13	20	Fortis	No	No	No	FTS	0.75	8.65%	10.61%	20	13
14	22	IDACORP	Yes	Yes	Yes	IDA	0.85	9.25%	11.43%	22	14
15	24	NextEra	Yes	No	No	NEE	1.05	10.44%	13.06%	24	15
16	25	NorthWester	Yes	Yes	Yes	NWE	0.95	9.84%	12.24%	25	16
17	26	OGE	Yes	Yes	Yes	OGE	1.05	10.44%	13.06%	26	17
18	27	Otter Tail	No	No	No	OTTR	0.95	9.84%	12.24%	27	18
19	29	PGE	Yes	Yes	Yes	POR	0.90	9.54%	11.84%	29	19
20	30	Pinnacle	Yes	Yes	Yes	PNW	0.95	9.84%	12.24%	30	20
21	32	PPL	No	No	No	PPL	1.15	11.03%	13.87%	32	21
22	33	Public Serv.	No	Yes	Yes	PEG	0.95	9.84%	12.24%	33	22
23	34	Sempra	No	Yes	Yes	SRE	1.00	10.14%	12.65%	34	23
24	35	Southern	Yes	No	No	SO	0.95	9.84%	12.24%	35	24
25	36	WEC	No	Yes	Yes	WEC	0.85	9.25%	11.43%	36	25
26	37	Xcel	Yes	No	Yes	XEL	0.85	9.25%	11.43%	37	26
		No. of Peers:	16	13	18			VL Betas	VL Betas		
					Company Screen		Mean	9.7%	12.1%	ROE	
					Staff Screen		Mean	9.8%	12.1%	ROE	
					Staff Sensitivity Screen		Mean	9.7%	12.0%	ROE	

Points to Upper End of Staff's 3-Stage DCF Results

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2405

ROE:
Gordon Growth – Single Stage DCF

August 16, 2024

Staff's Representative Single Stage (Gordon Growth) Discounted Cash Flow (DCF) Model

Presumes the Peer Utility will pay its divident as a fixed multiple of growth into the future as it is now.

The results would be true only if the utility stock's dividends were to grow at a constant rate forever.

Value of Stock $(P_0) = D_1 / (k - g)$ Stock Price Now = Next Year's Dividend / (Required Stock Return - Growth in Dividends)

$k = (D_1 / P_0) + g$ Required Rate of Return on Utility Equity = (Next Year's VL Dividend / Recent Stock Price) - Perpetual Growth

This Model Implies: **Points toward Lower End of Staff's 3-Stage DCF Modeling Results**

		1	2	3	4	5	6	7	8	9	10	11 = 9 + 10	12
	Screen #	Abbreviated Utility	UE 433 PAC	UE 433 Staff	LT Debt UE 433 Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #
1	1	Allete	No	No	No	ALE	61.77	4.6%	2.93	4.7%	3.7%	8.5%	1
2	2	Alliant	Yes	No	Yes	LNT	50.73	3.8%	2.04	4.0%	6.0%	10.1%	2
3	3	Ameren	Yes	Yes	Yes	AEE	73.00	3.7%	2.86	3.9%	5.7%	9.7%	3
4	4	AEP	Yes	No	Yes	AEP	88.50	4.1%	3.81	4.3%	4.6%	8.9%	4
5	6	Avista	Yes	Yes	Yes	AVA	35.83	5.4%	2.00	5.6%	4.1%	9.7%	6
6	7	Black Hills	No	Yes	Yes	BKH	55.35	4.7%	2.70	4.9%	3.8%	8.7%	7
7	9	CMS	Yes	No	No	CMS	60.76	3.4%	2.16	3.6%	3.8%	7.3%	9
8	10	Consol Ed	No	Yes	Yes	ED	92.43	3.6%	3.40	3.7%	3.8%	7.4%	10
9	13	Duke	Yes	No	Yes	DUK	100.85	4.1%	4.22	4.2%	1.3%	5.5%	13
10	15	Entergy	Yes	No	No	ETR	108.17	4.2%	4.70	4.3%	3.4%	7.7%	15
11	16	Evergy	Yes	Yes	Yes	EVRG	53.31	4.9%	2.74	5.1%	4.6%	9.7%	16
12	17	Eversource	No	No	Yes	ES	59.29	4.8%	3.03	5.1%	5.9%	11.0%	17
13	20	Fortis	No	No	No	FTS	39.34	6.1%	2.49	6.3%	4.7%	11.0%	20
14	22	IDACORP	Yes	Yes	Yes	IDA	94.30	3.5%	3.46	3.7%	5.7%	9.4%	22
15	24	NextEra	Yes	No	No	NEE	72.07	2.9%	2.25	3.1%	9.0%	12.1%	24
16	25	NorthWestern	Yes	Yes	Yes	NWE	50.62	5.1%	2.64	5.2%	1.5%	6.7%	25
17	26	OGE	Yes	Yes	Yes	OGE	35.53	4.8%	1.73	4.9%	2.0%	6.9%	26
18	27	Otter Tail	No	No	No	OTTR	87.64	2.1%	1.97	2.2%	4.9%	7.1%	27
19	29	PGE	Yes	Yes	Yes	POR	43.78	4.5%	2.08	4.8%	5.7%	10.4%	29
20	30	Pinnacle	Yes	Yes	Yes	PNW	75.86	4.7%	3.61	4.8%	1.8%	6.5%	30
21	32	PPL	No	No	No	PPL	28.21	3.7%	1.10	3.9%	1.7%	5.6%	32
22	33	Public Serv.	No	Yes	Yes	PEG	72.66	3.3%	2.52	3.5%	5.0%	8.5%	33
23	34	Sempra	No	Yes	Yes	SRE	74.54	3.3%	2.58	3.5%	5.2%	8.7%	34
24	35	Southern	Yes	No	No	SO	77.30	3.7%	2.96	3.8%	2.3%	6.2%	35
25	36	WEC	No	Yes	Yes	WEC	80.49	4.1%	3.57	4.4%	4.7%	9.1%	36
26	37	Xcel	Yes	No	Yes	XEL	53.83	4.1%	2.30	4.3%	5.6%	9.9%	37
		No. of Peers:	16	13	18							Mean	

Company Screen	8.5%	ROE
Staff Screen	8.6%	ROE
Staff Sensitivity Screen	8.7%	ROE

Points toward lower end of Staff's 3 Stage DCF Modeling results.

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 2406

ROE: BEA Historical
GDP Growth

August 16, 2024

Bureau of Economic Analysis (BEA)

Current-Dollar and "Real" Gross Domestic Product (GDP)

Staff Accessed July 22, 2024

Annual https://fred.stlouisfed.org/series/GDPA Quarterly https://fred.stlouisfed.org/series/GDP https://fred.stlouisfed.org/series/GDPC

https://fred.stlouisfed.org/series/GDPCA

(Seasonally adjusted annual rates)

Yr	GDP in billions of current dollars	GDP in billions of chained 2017 dollars
1947	249.616	2184.614
1948	274.468	2274.627
1949	272.475	2261.928
1950	299.827	2458.532
1951	346.914	2656.32
1952	367.341	2764.803
1953	389.218	2894.411
1954	390.549	2877.708
1955	425.478	3083.026
1956	449.353	3148.765
1957	474.039	3215.065
1958	481.229	3191.216
1959	521.654	3412.421
1960	542.382	3500.272
1961	562.209	3590.066
1962	603.922	3810.124
1963	637.45	3976.142
1964	684.46	4205.277
1965	742.289	4478.555
1966	813.414	4773.931
1967	859.959	4904.864
1968	940.651	5145.914
1969	1017.615	5306.594
1970	1073.303	5316.391
1971	1164.85	5491.445
1972	1279.11	5780.048
1973	1425.376	6106.371
1974	1545.243	6073.363
1975	1684.904	6060.875
1976	1873.412	6387.437
1977	2081.826	6682.804
1978	2351.599	7052.711
1979	2627.333	7275.999
1980	2857.307	7257.316
1981	3207.041	7441.485
1982	3343.789	7307.314
1983	3634.038	7642.266
1984	4037.613	8195.295
1985	4338.979	8537.004
1986	4579.631	8832.611
1987	4855.215	9137.745
1988	5236.438	9519.427
1989	5641.58	9869.003
1990	5963.144	10055.129
1991	6158.129	10044.238
1992	6520.327	10398.046
1993	6858.559	10684.179
1994	7287.236	11114.647
1995	7639.749	11413.012
1996	8073.122	11843.599
1997	8577.552	12370.299
1998	9062.817	12924.876
1999	9631.172	13543.774
2000	10250.952	14096.033
2001	10581.929	14230.726
2002	10929.108	14472.712
2003	11456.45	14877.312
2004	12217.196	15449.757
2005	13039.197	15987.957
2006	13815.583	16433.148
2007	14474.228	16762.445
2008	14769.862	16781.485
2009	14478.067	16349.11
2010	15048.97	16789.75
2011	15599.731	17052.41
2012	16253.97	17442.759
2013	16880.683	17812.167
2014	17608.138	18261.714
2015	18295.019	18799.622
2016	18804.913	19141.672
2017	19612.102	19612.102
2018	20656.516	20193.896
2019	21521.395	20692.087
2020	21322.95	20234.074
2021	23594.031	21407.692
2022	25744.108	21822.037
2023	27360.935	22376.906

Quarter	GDP in billions of current dollars	GDP in billions of chained 2017 dollars	Qtr#
1947Q1	243.164	2182.681	1
1947Q2	245.968	2176.892	2
1947Q3	249.585	2172.432	3
1947Q4	259.745	2206.452	4
1948Q1	265.742	2239.682	5
1948Q2	272.567	2276.690	6
1948Q3	279.196	2289.770	7
1948Q4	280.366	2292.364	8
1949Q1	275.034	2260.807	9
1949Q2	271.351	2253.128	10
1949Q3	272.889	2276.424	11
1949Q4	270.627	2257.352	12
1950Q1	280.828	2346.104	13
1950Q2	290.383	2417.682	14
1950Q3	308.153	2511.127	15
1950Q4	319.945	2559.214	16
1951Q1	336.000	2593.967	17
1951Q2	344.090	2638.898	18
1951Q3	351.385	2693.259	19
1951Q4	356.178	2699.156	20
1952Q1	359.820	2727.954	21
1952Q2	361.030	2733.800	22
1952Q3	367.701	2753.517	23
1952Q4	380.812	2843.941	24
1953Q1	387.980	2896.811	25
1953Q2	391.749	2919.206	26
1953Q3	391.171	2902.785	27
1953Q4	385.970	2858.845	28
1954Q1	385.345	2845.192	29
1954Q2	386.121	2848.305	30
1954Q3	390.996	2880.482	31
1954Q4	399.734	2936.852	32
1955Q1	413.073	3020.746	33
1955Q2	421.532	3069.910	34
1955Q3	430.221	3111.379	35
1955Q4	437.092	3130.068	36
1956Q1	439.746	3117.922	37
1956Q2	446.010	3143.694	38
1956Q3	451.191	3140.874	39
1956Q4	460.463	3192.570	40
1957Q1	469.779	3213.011	41
1957Q2	472.025	3205.970	42
1957Q3	479.490	3237.386	43
1957Q4	474.864	3203.894	44
1958Q1	467.540	3120.724	45
1958Q2	471.978	3141.224	46
1958Q3	485.841	3213.884	47
1958Q4	499.555	3289.032	48
1959Q1	510.330	3352.129	49
1959Q2	522.653	3427.667	50
1959Q3	525.034	3430.057	51
1959Q4	528.600	3439.832	52
1960Q1	542.648	3517.181	53
1960Q2	541.080	3498.246	54
1960Q3	545.604	3515.385	55
1960Q4	540.197	3470.278	56
1961Q1	545.018	3493.703	57
1961Q2	555.545	3553.021	58
1961Q3	567.664	3621.252	59
1961Q4	580.612	3692.289	60
1962Q1	594.013	3758.147	61
1962Q2	600.366	3792.149	62
1962Q3	609.027	3838.776	63
1962Q4	612.280	3851.421	64
1963Q1	621.672	3893.482	65
1963Q2	629.752	3937.183	66
1963Q3	644.444	4023.755	67
1963Q4	653.938	4050.147	68
1964Q1	669.822	4135.553	69
1964Q2	678.674	4180.592	70
1964Q3	692.031	4245.918	71
1964Q4	697.319	4259.046	72
1965Q1	717.790	4362.111	73
1965Q2	730.191	4417.225	74
1965Q3	749.323	4515.427	75
1965Q4	771.857	4619.458	76
1966Q1	795.734	4731.888	77
1966Q2	804.981	4748.046	78
1966Q3	819.638	4788.254	79
1966Q4	833.302	4827.537	80
1967Q1	844.170	4870.299	81
1967Q2	848.983	4873.287	82
1967Q3	865.233	4919.392	83
1967Q4	881.439	4956.477	84
1968Q1	909.387	5057.553	85
1968Q2	934.344	5142.033	86
1968Q3	950.825	5181.859	87
1968Q4	968.030	5202.212	88
1969Q1	993.337	5283.597	89
1969Q2	1009.020	5299.625	90
1969Q3	1029.956	5334.600	91
1969Q4	1038.147	5308.556	92
1970Q1	1051.200	5300.652	93
1970Q2	1067.375	5308.164	94
1970Q3	1086.059	5357.077	95
1970Q4	1088.608	5299.672	96
1971Q1	1135.156	5443.619	97
1971Q2	1156.271	5473.059	98
1971Q3	1177.675	5518.072	99
1971Q4	1190.297	5531.032	100
1972Q1	1230.609	5632.649	101
1972Q2	1266.369	5760.470	102
1972Q3	1290.566	5814.854	103
1972Q4	1328.904	5912.220	104
1973Q1	1377.490	6058.544	105
1973Q2	1413.887	6124.506	106
1973Q3	1433.838	6092.301	107
1973Q4	1476.289	6150.131	108
1974Q1	1491.209	6097.258	109
1974Q2	1530.056	6111.751	110
1974Q3	1560.026	6053.978	111
1974Q4	1599.679	6030.464	112
1975Q1	1616.116	5957.035	113
1975Q2	1651.853	5999.610	114
1975Q3	1709.820	6102.326	115
1975Q4	1761.831	6184.530	116
1976Q1	1820.487	6323.649	117
1976Q2	1852.332	6370.025	118
1976Q3	1886.558	6404.895	119
1976Q4	1934.273	6451.177	120
1977Q1	1988.648	6527.703	121
1977Q2	2055.909	6654.466	122
1977Q3	2118.473	6774.457	123
1977Q4	2164.270	6774.592	124
1978Q1	2202.760	6796.260	125
1978Q2	2331.633	7058.920	126
1978Q3	2395.053	7129.915	127
1978Q4	2476.949	7225.750	128
1979Q1	2526.610	7238.727	129
1979Q2	2591.247	7246.454	130
1979Q3	2667.565	7300.281	131
1979Q4	2723.883	7318.535	132
1980Q1	**2789.842**	**7341.557**	**133**
1980Q2	2797.352	7190.289	134
1980Q3	2856.483	7181.743	135
1980Q4	2985.557	7315.677	136
1981Q1	3124.206	7459.022	137
1981Q2	3162.532	7403.745	138
1981Q3	3260.609	7492.405	139
1981Q4	3280.818	7410.768	140
1982Q1	3274.302	7295.631	141
1982Q2	3331.972	7328.912	142
1982Q3	3366.322	7300.896	143
1982Q4	3402.561	7303.817	144
1983Q1	3473.413	7400.066	145
1983Q2	3578.848	7568.456	146
1983Q3	3689.179	7719.746	147
1983Q4	3794.706	7880.794	148
1984Q1	3908.054	8034.847	149
1984Q2	4009.601	8173.670	150
1984Q3	4084.250	8252.465	151
1984Q4	4148.551	8320.199	152
1985Q1	4230.168	8400.820	153
1985Q2	4294.887	8474.787	154

1994 Q2 thru 2024 Q1

Period	Ln(Real GDP)	
1	9.300	1994
2	9.314	
3	9.319	
4	9.331	
5	9.334	1995
6	9.337	
7	9.346	
8	9.353	
9	9.360	1996
10	9.377	
11	9.385	
12	9.396	
13	9.402	1997
14	9.419	
15	9.431	
16	9.440	
17	9.450	1998
18	9.459	
19	9.471	
20	9.487	
21	9.497	1999
22	9.505	
23	9.518	
24	9.534	
25	9.538	2000
26	9.556	
27	9.557	
28	9.563	
29	9.560	2001
30	9.566	
31	9.562	
32	9.565	
33	9.573	2002
34	9.579	
35	9.583	
36	9.584	
37	9.590	2003
38	9.599	
39	9.615	
40	9.627	
41	9.632	2004
42	9.640	
43	9.649	
44	9.660	
45	9.671	2005
46	9.676	
47	9.683	
48	9.689	
49	9.702	2006
50	9.705	
51	9.706	
52	9.715	
53	9.718	2007
54	9.724	
55	9.730	
56	9.736	
57	9.732	2008
58	9.738	
59	9.732	
60	9.710	
61	9.699	2009
62	9.697	
63	9.701	
64	9.711	
65	9.716	2010
66	9.726	
67	9.733	
68	9.739	
69	9.736	2011
70	9.743	
71	9.743	
72	9.754	
73	9.762	2012
74	9.767	
75	9.768	
76	9.769	
77	9.779	2013
78	9.782	
79	9.790	
80	9.799	
81	9.796	2014
82	9.808	
83	9.820	
84	9.826	
85	9.834	2015
86	9.841	
87	9.845	
88	9.847	
89	9.852	2016
90	9.855	
91	9.863	
92	9.868	
93	9.873	2017
94	9.879	
95	9.886	
96	9.898	
97	9.906	2018
98	9.911	
99	9.917	
100	9.919	
101	9.924	2019
102	9.932	
103	9.944	
104	9.950	
105	9.936	2020
106	9.854	
107	9.929	
108	9.939	
109	9.952	2021
110	9.967	
111	9.975	
112	9.992	
113	9.987	2022
114	9.985	
115	9.992	
116	9.998	
117	10.004	2023
118	10.009	
119	10.021	
120	10.029	
121	10.033	2024

Long Run Historical GDP Growth Rate

30 Year Historical Experience

Annualized Real LN GPD Q 1994 Q2 Q2 thru 2024 Q1

2.21%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.989738496
R Square	0.979582291
Adjusted R Square	0.979465618
Standard Error	0.048616772
Observations	177

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	19.84468432	19.84468432	8395.990972	8.1254E-150
Residual	175	0.413628334	0.00236359		
Total	176	20.25831265			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.927174893	0.007339599	1216.302838	0	8.912689369	8.941660417	8.912689369	8.941660417
Period	0.006553296	7.15194E-05	91.62964025	8.1254E-150	0.006412144	0.006694447	0.006412144	0.006694447

SUMMARY OUTPUT 30 Year Stats

Regression Statistics	
Multiple R	0.985818952
R Square	0.971839006
Adjusted R Square	0.971600353
Standard Error	0.032600101
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4.32779052	4.32779052	4072.192969	2.51425E-93
Residual	118	0.125406454	0.001062767		
Total	119	4.453196974			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	9.065308794	0.010524165	861.3803184	5.6114E-226	9.044468081	9.086149506	9.044468081	9.086149506
Period	0.005482352	8.59118E-05	63.81373652	2.51425E-93	0.005312224	0.005652481	0.005312224	0.005652481

Note **July 31, 2013, 14th Comprehensive Significant Revision:**
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

1985Q3	4386.773	8604.220	155
1985Q4	4444.094	8668.188	156
1986Q1	4507.894	8749.127	157
1986Q2	4545.340	8788.524	158
1986Q3	4607.669	8872.601	159
1986Q4	4657.627	8920.193	160
1987Q1	4722.156	8986.367	161
1987Q2	4806.160	9083.256	162
1987Q3	4884.555	9162.024	163
1987Q4	5007.994	9319.332	164
1988Q1	5073.372	9367.502	165
1988Q2	5190.036	9490.594	166
1988Q3	5282.835	9546.206	167
1988Q4	5399.509	9673.405	168
1989Q1	5511.253	9771.725	169
1989Q2	5612.463	9846.293	170
1989Q3	5695.365	9919.228	171
1989Q4	5747.237	9938.767	172
1990Q1	5872.701	10047.386	173
1990Q2	5960.028	10083.855	174
1990Q3	6015.116	10090.569	175
1990Q4	6004.733	9998.704	176
1991Q1	6035.178	9951.916	177
1991Q2	6126.862	10029.510	178
1991Q3	6205.937	10080.195	179
1991Q4	6264.540	10115.329	180
1992Q1	6363.102	10236.435	181
1992Q2	6470.763	10347.429	182
1992Q3	6566.641	10449.673	183
1992Q4	6680.803	10558.648	184
1993Q1	6729.459	10576.275	185
1993Q2	6808.939	10637.847	186
1993Q3	6882.098	10688.606	187
1993Q4	7013.738	10833.987	188
1994Q1	7115.652	10939.116	189
1994Q2	7246.931	11087.361	190
1994Q3	7331.075	11152.176	191
1994Q4	7455.288	11279.932	192
1995Q1	7522.289	11319.951	193
1995Q2	7580.997	11353.721	194
1995Q3	7683.125	11450.310	195
1995Q4	7772.586	11528.067	196
1996Q1	7868.468	11614.418	197
1996Q2	8032.840	11808.140	198
1996Q3	8131.408	11914.063	199
1996Q4	8259.771	12037.775	200
1997Q1	8362.655	12115.472	201
1997Q2	8518.825	12317.221	202
1997Q3	8662.823	12471.010	203
1997Q4	8765.907	12577.495	204
1998Q1	8866.480	12703.742	205
1998Q2	8969.699	12821.339	206
1998Q3	9121.097	12982.752	207
1998Q4	9293.991	13191.670	208
1999Q1	9411.682	13315.597	209
1999Q2	9526.210	13426.748	210
1999Q3	9686.626	13604.771	211
1999Q4	9900.169	13827.980	212
2000Q1	10002.179	13878.147	213
2000Q2	10247.720	14130.908	214
2000Q3	10318.165	14145.312	215
2000Q4	10435.744	14229.765	216
2001Q1	10470.231	14183.120	217
2001Q2	10599.000	14271.694	218
2001Q3	10598.020	14214.516	219
2001Q4	10660.465	14253.574	220
2002Q1	10783.500	14372.785	221
2002Q2	10887.460	14460.848	222
2002Q3	10984.040	14519.633	223
2002Q4	11061.433	14537.580	224
2003Q1	11174.129	14614.141	225
2003Q2	11312.766	14743.567	226
2003Q3	11566.669	14988.782	227
2003Q4	11772.234	15162.760	228
2004Q1	11923.447	15248.680	229
2004Q2	12112.815	15366.850	230
2004Q3	12305.307	15512.619	231
2004Q4	12527.214	15670.880	232
2005Q1	12767.286	15844.727	233
2005Q2	12922.656	15922.782	234
2005Q3	13142.642	16047.587	235
2005Q4	13324.204	16136.734	236
2006Q1	13599.160	16353.835	237
2006Q2	13753.424	16396.151	238
2006Q3	13870.188	16420.738	239
2006Q4	14039.560	16561.866	240
2007Q1	14215.651	16611.690	241
2007Q2	14402.082	16713.314	242
2007Q3	14564.117	16809.587	243
2007Q4	14715.058	16915.191	244
2008Q1	14706.538	16843.003	245
2008Q2	14865.701	16943.291	246
2008Q3	14898.999	16854.295	247
2008Q4	14608.208	16485.350	248
2009Q1	14430.901	16298.262	249
2009Q2	14381.236	16269.145	250
2009Q3	14448.882	16326.281	251
2009Q4	14651.249	16502.754	252
2010Q1	14764.610	16582.710	253
2010Q2	14980.193	16743.162	254
2010Q3	15141.607	16872.266	255
2010Q4	15309.474	16960.864	256
2011Q1	15351.448	16920.632	257
2011Q2	15557.539	17035.114	258
2011Q3	15647.680	17031.313	259
2011Q4	15842.259	17222.583	260
2012Q1	16068.805	17367.010	261
2012Q2	16207.115	17444.525	262
2012Q3	16319.541	17469.650	263
2012Q4	16420.419	17489.852	264
2013Q1	16648.189	17662.400	265
2013Q2	16728.687	17709.671	266
2013Q3	16953.838	17860.450	267
2013Q4	17192.019	18016.147	268
2014Q1	17197.738	17953.974	269
2014Q2	17518.508	18185.911	270
2014Q3	17804.228	18406.941	271
2014Q4	17912.079	18500.031	272
2015Q1	18063.529	18666.621	273
2015Q2	18279.784	18782.243	274
2015Q3	18401.626	18857.418	275
2015Q4	18435.137	18892.206	276
2016Q1	18525.933	19001.690	277
2016Q2	18711.702	19062.709	278
2016Q3	18892.639	19197.938	279
2016Q4	19089.379	19304.352	280
2017Q1	19280.084	19398.343	281
2017Q2	19438.643	19506.949	282
2017Q3	19692.595	19660.766	283
2017Q4	20037.088	19882.352	284
2018Q1	20328.553	20044.077	285
2018Q2	20580.912	20150.476	286
2018Q3	20798.730	20276.154	287
2018Q4	20917.867	20304.874	288
2019Q1	21104.133	20415.150	289
2019Q2	21384.775	20584.528	290
2019Q3	21694.282	20817.581	291
2019Q4	21902.390	20951.088	292
2020Q1	21706.513	20665.553	293
2020Q2	19913.143	19034.830	294
2020Q3	21647.64	20511.785	295
2020Q4	22024.502	20724.128	296
2021Q1	22600.185	20990.541	297
2021Q2	23292.362	21309.544	298
2021Q3	23828.973	21483.083	299
2021Q4	24654.603	21847.602	300

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2407

ROE: TIPS Implied Inflation

August 16, 2024

2024 through 2054 TIPs-Implied Average Annual Inflation Rate: 2.32%

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2024-Q2	0.023	0.023	0.023	0.025	0.023

Source: Federal Reserve Statistical Release H.15

See H15 Qtrly Avg for data feed

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels 5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Implied Forward Curve/Price Level 5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Implied Price Level	Check
Jun-24	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Jun-25	1	102.33	102.33	102.33	102.48	102.32	102.33					102.33	
Jun-26	2	104.72	104.72	104.71	105.03	104.69	104.72					104.72	
Jun-27	3	107.16	107.16	107.14	107.64	107.12	107.16					107.16	
Jun-28	4	109.67	109.67	109.64	110.31	109.61	109.67					109.67	
Jun-29	5	112.22	112.22	112.19	113.05	112.15	112.22					112.22	
Jun-30	6		114.84	114.80	115.86	114.75		114.84				114.84	
Jun-31	7		117.52	117.47	118.73	117.42		117.52				117.52	
Jun-32	8			120.20	121.68	120.14			120.24			120.24	
Jun-33	9			123.00	124.70	122.93			123.02			123.02	
Jun-34	10			125.86	127.80	125.78			125.86			125.86	
Jun-35	11				130.97	128.70				129.18		129.18	128.78
Jun-36	12				134.23	131.68				132.59		132.59	131.76
Jun-37	13				137.56	134.74				136.09		136.09	134.81
Jun-38	14				140.98	137.86				139.69		139.69	137.93
Jun-39	15				144.48	141.06				143.38		143.38	141.13
Jun-40	16				148.06	144.33				147.16		147.16	144.40
Jun-41	17				151.74	147.68				151.05		151.05	147.75
Jun-42	18				155.51	151.11				155.03		155.03	151.17
Jun-43	19				159.37	154.61				159.13		159.13	154.67
Jun-44	20				163.33	158.20				163.33		163.33	158.25
Jun-45	21					161.87					166.59	166.59	161.92
Jun-46	22					165.63					169.91	169.91	165.67
Jun-47	23					169.47					173.30	173.30	169.51
Jun-48	24					173.40					176.75	176.75	173.44
Jun-49	25					177.42					180.28	180.28	177.45
Jun-50	26					181.54					183.87	183.87	181.56
Jun-51	27					185.75					187.54	187.54	185.77
Jun-52	28					190.06					191.28	191.28	190.07
Jun-53	29					194.47					195.09	195.09	194.48
Jun-54	30					198.98					198.98	198.98	198.98

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis **Quarterly Aggregation**

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	**TIPS-05m**	**TIPS-07m**	**TIPS-10m**	**TIPS-20m**	**TIPS-30m**
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	**-1.04**	**-0.62**	**-0.25**	**0.47**	**0.80**
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	**-0.25**	**0.27**	**0.43**	**0.88**	**1.14**
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	**0.19**	**0.39**	**0.45**	**0.75**	**0.95**
2015-Q1	0.11	0.23	0.27	0.52	0.71
2015-Q2	**-0.10**	**0.22**	**0.30**	**0.67**	**0.91**
2015-Q3	0.26	0.48	0.57	0.92	1.14
2015-Q4	**0.36**	**0.51**	**0.66**	**1.02**	**1.24**
2016-Q1	0.15	0.32	0.49	0.88	1.11
2016-Q2	**-0.24**	**-0.05**	**0.19**	**0.62**	**0.85**
2016-Q3	-0.22	-0.09	0.08	0.44	0.62
2016-Q4	**-0.06**	**0.12**	**0.33**	**0.69**	**0.86**
2017-Q1	0.07	0.33	0.44	0.75	0.95
2017-Q2	**0.10**	**0.30**	**0.44**	**0.76**	**0.94**
2017-Q3	0.17	0.36	0.45	0.75	0.94
2017-Q4	**0.32**	**0.44**	**0.50**	**0.72**	**0.87**
2018-Q1	0.56	0.65	0.68	0.82	0.93
2018-Q2	**0.69**	**0.77**	**0.79**	**0.88**	**0.95**
2018-Q3	0.81	0.81	0.81	0.88	0.93
2018-Q4	**1.06**	**1.06**	**1.06**	**1.15**	**1.23**
2019-Q1	0.73	0.76	0.79	0.96	1.10
2019-Q2	**0.42**	**0.46**	**0.51**	**0.71**	**0.89**
2019-Q3	0.18	0.16	0.15	0.37	0.59
2019-Q4	**0.09**	**0.11**	**0.15**	**0.36**	**0.54**
2020-Q1	-0.14	-0.12	-0.06	0.14	0.29
2020-Q2	**-0.49**	**-0.50**	**-0.48**	**-0.27**	**-0.09**
2020-Q3	-1.19	-1.09	-0.94	-0.58	-0.33
2020-Q4	**-1.32**	**-1.13**	**-0.91**	**-0.50**	**-0.29**
2021-Q1	-1.70	-1.27	-0.86	-0.34	-0.09
2021-Q2	**-1.71**	**-1.18**	**-0.79**	**-0.27**	**-0.03**
2021-Q3	-1.69	-1.31	-1.02	-0.53	-0.30
2021-Q4	**-1.65**	**-1.30**	**-1.00**	**-0.58**	**-0.38**

Average Monthly Nominal UST Rates by Quarter					
Qtr	**UST-05m**	**UST-07m**	**UST-10m**	**UST-20m**	**UST-30m**
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	**0.92**	**1.39**	**2.00**	**2.78**	**3.15**
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	**1.66**	**2.19**	**2.62**	**3.18**	**2.88**
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	**1.60**	**2.00**	**2.28**	**2.69**	**2.97**
2015-Q1	1.45	1.77	1.97	2.32	2.55
2015-Q2	**1.52**	**1.91**	**2.17**	**2.62**	**2.89**
2015-Q3	1.55	1.94	2.22	2.65	2.96
2015-Q4	**1.59**	**1.94**	**2.19**	**2.60**	**2.96**
2016-Q1	1.37	1.69	1.92	2.32	2.72
2016-Q2	**1.24**	**1.54**	**1.75**	**2.15**	**2.57**
2016-Q3	1.13	1.40	1.56	1.91	2.28
2016-Q4	**1.61**	**1.93**	**2.13**	**2.52**	**2.82**
2017-Q1	1.94	2.25	2.44	2.78	3.04
2017-Q2	**1.81**	**2.07**	**2.26**	**2.64**	**2.90**
2017-Q3	1.82	2.06	2.24	2.58	2.82
2017-Q4	**2.07**	**2.25**	**2.37**	**2.62**	**2.82**
2018-Q1	2.54	2.69	2.76	2.91	3.03
2018-Q2	**2.77**	**2.87**	**2.92**	**3.00**	**3.08**
2018-Q3	2.81	2.88	2.93	3.00	3.07
2018-Q4	**2.88**	**2.96**	**3.03**	**3.17**	**3.27**
2019-Q1	2.47	2.55	2.65	2.85	3.01
2019-Q2	**2.12**	**2.22**	**2.33**	**2.58**	**2.78**
2019-Q3	1.63	1.71	1.80	2.08	2.28
2019-Q4	**1.62**	**1.72**	**1.79**	**2.10**	**2.26**
2020-Q1	1.16	1.29	1.38	1.71	1.88
2020-Q2	**0.36**	**0.54**	**0.69**	**1.15**	**1.38**
2020-Q3	0.27	0.46	0.65	1.15	1.36
2020-Q4	**0.37**	**0.61**	**0.86**	**1.40**	**1.62**
2021-Q1	0.60	0.98	1.32	1.92	2.07
2021-Q2	**0.84**	**1.27**	**1.59**	**2.17**	**2.26**
2021-Q3	0.80	1.10	1.32	1.86	1.93
2021-Q4	**1.18**	**1.42**	**1.54**	**1.97**	**1.95**

Implied Market-based Inflationary Expectations					
Qtr	**5-Yr**	**7-Yr**	**10-Yr**	**20-Yr**	**30-Yr**
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	**1.95**	**2.01**	**2.25**	**2.32**	**2.34**
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	**1.90**	**1.92**	**2.20**	**2.30**	**1.74**
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	**1.41**	**1.61**	**1.83**	**1.95**	**2.02**
2015-Q1	1.35	1.54	1.70	1.79	1.85
2015-Q2	**1.63**	**1.69**	**1.86**	**1.95**	**1.97**
2015-Q3	1.29	1.47	1.65	1.73	1.82
2015-Q4	**1.23**	**1.43**	**1.53**	**1.58**	**1.72**
2016-Q1	1.23	1.37	1.43	1.45	1.61
2016-Q2	**1.48**	**1.58**	**1.56**	**1.53**	**1.72**
2016-Q3	1.35	1.49	1.48	1.47	1.66
2016-Q4	**1.67**	**1.80**	**1.80**	**1.83**	**1.96**
2017-Q1	1.87	1.92	2.01	2.03	2.10
2017-Q2	**1.71**	**1.78**	**1.82**	**1.88**	**1.96**
2017-Q3	1.65	1.70	1.79	1.83	1.88
2017-Q4	**1.75**	**1.81**	**1.87**	**1.89**	**1.95**
2018-Q1	1.97	2.04	2.08	2.08	2.11
2018-Q2	**2.07**	**2.11**	**2.13**	**2.12**	**2.14**
2018-Q3	2.01	2.07	2.11	2.11	2.13
2018-Q4	**1.81**	**1.90**	**1.98**	**2.02**	**2.03**
2019-Q1	1.73	1.79	1.86	1.89	1.91
2019-Q2	**1.70**	**1.76**	**1.82**	**1.87**	**1.88**
2019-Q3	1.45	1.55	1.64	1.71	1.69
2019-Q4	**1.53**	**1.61**	**1.64**	**1.74**	**1.72**
2020-Q1	1.30	1.41	1.44	1.58	1.59
2020-Q2	**0.85**	**1.05**	**1.16**	**1.42**	**1.47**
2020-Q3	1.46	1.55	1.59	1.73	1.69
2020-Q4	**1.69**	**1.75**	**1.78**	**1.90**	**1.91**
2021-Q1	2.30	2.25	2.18	2.26	2.16
2021-Q2	**2.55**	**2.45**	**2.39**	**2.44**	**2.29**
2021-Q3	2.49	2.41	2.34	2.39	2.23
2021-Q4	**2.83**	**2.72**	**2.54**	**2.55**	**2.33**

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

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Monthly

TIPS-05m	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.M
TIPS-07m	7				RIFLGFCY07_XII_N.M
TIPS-10m	10				RIFLGFCY10_XII_N.M
TIPS-20m	20				RIFLGFCY20_XII_N.M
TIPS-30m	30				RIFLGFCY30_XII_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.98	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.46	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.98	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.09	2.15	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.46	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.38	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.67	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.26	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.86	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.97	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.48	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.85	-0.46	0.00	0.55	0.78
2011-12	-0.78	-0.44	-0.03	0.56	0.78
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.57	-0.14	0.56	0.87
2012-04	**-1.06**	**-0.65**	**-0.21**	**0.50**	**0.79**
2012-05	**-1.12**	**-0.79**	**-0.34**	**0.44**	**0.68**
2012-06	**-1.05**	**-0.82**	**-0.50**	**0.10**	**0.50**
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.06	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	**-1.47**	**-1.18**	**-0.75**	**-0.01**	**0.41**
2012-11	**-1.38**	**-1.13**	**-0.77**	**-0.06**	**0.35**
2012-12	**-1.40**	**-1.13**	**-0.76**	**0.00**	**0.33**
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.19	0.62
2013-04	**-1.38**	**-0.97**	**-0.65**	**0.07**	**0.48**
2013-05	**-1.14**	**-0.69**	**-0.36**	**0.35**	**0.72**
2013-06	**-0.59**	**-0.21**	**0.25**	**0.98**	**1.21**
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.16	1.44
2013-09	-0.17	0.34	0.66	1.22	1.50
2013-10	**-0.41**	**0.11**	**0.43**	**1.05**	**1.37**
2013-11	**-0.38**	**0.18**	**0.55**	**1.20**	**1.51**
2013-12	**-0.09**	**0.47**	**0.74**	**1.32**	**1.61**
2014-01	-0.09	0.45	0.63	1.17	1.44
2014-02	-0.26	0.30	0.55	1.12	1.40
2014-03	-0.14	0.37	0.56	1.05	1.33
2014-04	**-0.11**	**0.38**	**0.54**	**0.98**	**1.23**
2014-05	**-0.34**	**0.21**	**0.37**	**0.82**	**1.08**
2014-06	**-0.29**	**0.23**	**0.37**	**0.84**	**1.11**
2014-07	-0.27	0.18	0.28	0.72	0.98
2014-08	-0.21	0.15	0.22	0.64	0.90
2014-09	0.10	0.38	0.46	0.81	1.05
2014-10	**0.06**	**0.32**	**0.38**	**0.74**	**0.96**
2014-11	**0.14**	**0.37**	**0.45**	**0.77**	**0.99**
2014-12	**0.37**	**0.47**	**0.51**	**0.73**	**0.89**
2015-01	0.17	0.24	0.27	0.50	0.66
2015-02	0.11	0.22	0.26	0.52	0.73
2015-03	0.04	0.23	0.28	0.55	0.73
2015-04	**-0.26**	**-0.01**	**0.08**	**0.42**	**0.65**
2015-05	**-0.10**	**0.27**	**0.33**	**0.70**	**0.96**
2015-06	**0.05**	**0.39**	**0.50**	**0.89**	**1.13**
2015-07	0.14	0.42	0.50	0.87	1.11
2015-08	0.31	0.49	0.56	0.87	1.08
2015-09	0.33	0.52	0.65	1.01	1.24
2015-10	**0.21**	**0.39**	**0.57**	**0.98**	**1.22**
2015-11	**0.40**	**0.55**	**0.69**	**1.03**	**1.25**
2015-12	**0.46**	**0.59**	**0.73**	**1.06**	**1.26**
2016-01	0.33	0.49	0.67	1.05	1.26
2016-02	0.14	0.30	0.47	0.85	1.09
2016-03	-0.03	0.16	0.34	0.73	0.99
2016-04	**-0.22**	**-0.03**	**0.19**	**0.60**	**0.86**
2016-05	**-0.22**	**-0.04**	**0.21**	**0.64**	**0.86**
2016-06	**-0.27**	**-0.07**	**0.17**	**0.63**	**0.82**
2016-07	-0.32	-0.16	0.04	0.42	0.61
2016-08	-0.17	-0.06	0.09	0.43	0.62
2016-09	-0.17	-0.05	0.12	0.47	0.64
2016-10	**-0.26**	**-0.10**	**0.10**	**0.49**	**0.69**
2016-11	**-0.07**	**0.11**	**0.32**	**0.69**	**0.86**
2016-12	**0.15**	**0.36**	**0.56**	**0.89**	**1.04**
2017-01	0.03	0.27	0.42	0.74	0.92
2017-02	0.01	0.29	0.40	0.73	0.93
2017-03	0.18	0.42	0.49	0.79	0.99
2017-04	**0.08**	**0.28**	**0.39**	**0.72**	**0.91**
2017-05	**0.09**	**0.29**	**0.47**	**0.80**	**0.99**
2017-06	**0.14**	**0.32**	**0.46**	**0.75**	**0.93**
2017-07	0.23	0.42	0.55	0.84	1.01
2017-08	0.16	0.35	0.43	0.74	0.93
2017-09	0.12	0.31	0.37	0.67	0.87
2017-10	**0.25**	**0.42**	**0.50**	**0.77**	**0.94**
2017-11	**0.30**	**0.43**	**0.50**	**0.72**	**0.87**
2017-12	**0.42**	**0.48**	**0.50**	**0.68**	**0.80**

Monthly

UST-05m	5	Year	H.15 ID	RIFLGFCY05_N.M
UST-07m	7			RIFLGFCY07_N.M
UST-10m	10			RIFLGFCY10_N.M
UST-20m	20			RIFLGFCY20_N.M
UST-30m	30			RIFLGFCY30_N.M

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.18	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.58	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.46	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.89	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.96	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**
2012-05	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**
2012-06	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**
2012-11	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**
2012-12	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**
2013-05	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**
2013-06	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**
2013-11	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**
2013-12	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**
2014-05	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**
2014-06	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**
2014-11	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**
2014-12	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**
2015-01	1.37	1.67	1.88	2.20	2.46
2015-02	1.47	1.79	1.98	2.34	2.57
2015-03	1.52	1.84	2.04	2.41	2.63
2015-04	**1.35**	**1.69**	**1.94**	**2.33**	**2.59**
2015-05	**1.54**	**1.93**	**2.20**	**2.69**	**2.96**
2015-06	**1.68**	**2.10**	**2.36**	**2.85**	**3.11**
2015-07	1.63	2.04	2.32	2.77	3.07
2015-08	1.54	1.91	2.17	2.55	2.86
2015-09	1.49	1.88	2.17	2.62	2.95
2015-10	**1.39**	**1.76**	**2.07**	**2.50**	**2.89**
2015-11	**1.67**	**2.02**	**2.26**	**2.69**	**3.03**
2015-12	**1.70**	**2.04**	**2.24**	**2.61**	**2.97**
2016-01	1.52	1.85	2.09	2.49	2.86
2016-02	1.22	1.53	1.78	2.20	2.62
2016-03	1.38	1.68	1.89	2.28	2.68
2016-04	**1.26**	**1.57**	**1.81**	**2.21**	**2.62**
2016-05	**1.30**	**1.60**	**1.81**	**2.22**	**2.63**
2016-06	**1.17**	**1.44**	**1.64**	**2.02**	**2.45**
2016-07	1.07	1.33	1.50	1.82	2.23
2016-08	1.13	1.40	1.56	1.89	2.26
2016-09	1.18	1.46	1.63	2.02	2.35
2016-10	**1.27**	**1.56**	**1.76**	**2.17**	**2.50**
2016-11	**1.60**	**1.93**	**2.14**	**2.54**	**2.86**
2016-12	**1.96**	**2.29**	**2.49**	**2.84**	**3.11**
2017-01	1.92	2.23	2.43	2.75	3.02
2017-02	1.90	2.22	2.42	2.76	3.03
2017-03	2.01	2.30	2.48	2.83	3.08
2017-04	**1.82**	**2.10**	**2.30**	**2.67**	**2.94**
2017-05	**1.84**	**2.11**	**2.30**	**2.70**	**2.96**
2017-06	**1.77**	**2.01**	**2.19**	**2.54**	**2.80**
2017-07	1.87	2.13	2.32	2.65	2.88
2017-08	1.78	2.03	2.21	2.55	2.80
2017-09	1.80	2.03	2.20	2.53	2.78
2017-10	**1.98**	**2.20**	**2.36**	**2.65**	**2.88**
2017-11	**2.05**	**2.23**	**2.35**	**2.60**	**2.80**
2017-12	**2.18**	**2.32**	**2.40**	**2.60**	**2.77**

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Annual

TIPS-05a	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.A
TIPS-07a	7				RIFLGFCY07_XII_N.A
TIPS-10a	10				RIFLGFCY10_XII_N.A
TIPS-20a	20				RIFLGFCY20_XII_N.A
TIPS-30a	30				RIFLGFCY30_XII_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	2.21	
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	-0.09	0.32	0.44	0.86	1.11
2015	0.15	0.36	0.45	0.78	1.00
2016	-0.01	0.07	0.27	0.65	0.86
2017	0.17	0.36	0.46	0.75	0.92
2018	0.78	0.82	0.83	0.93	1.01
2019	0.35	0.37	0.40	0.60	0.78
2020	-0.79	-0.71	-0.60	-0.31	-0.11
2021	-1.69	-1.26	-0.91	-0.43	-0.2
2022	0.22	0.33	0.43	0.64	0.76
2023	1.80	1.73	1.68	1.73	1.8

Annual

UST-05a	5	Year	H.15 ID	RIFLGFCY05_N.A
UST-07a	7			RIFLGFCY07_N.A
UST-10a	10			RIFLGFCY10_N.A
UST-20a	20			RIFLGFCY20_N.A
UST-30a	30			RIFLGFCY30_N.A

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	1.64	2.14	2.54	3.07	3.34
2015	1.53	1.89	2.14	2.55	2.84
2016	1.33	1.63	1.84	2.22	2.59
2017	1.91	2.16	2.33	2.65	2.89
2018	2.75	2.85	2.91	3.02	3.11
2019	1.95	2.05	2.14	2.40	2.58
2020	0.53	0.72	0.89	1.35	1.56
2021	0.86	1.20	1.45	1.98	2.06
2022	3.00	3.01	2.95	3.30	3.11
2023	4.06	4.03	3.96	4.26	4.09

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2408

ROE:
Value Line Electric Utilities

August 16, 2024

ELECTRIC UTILITY (EAST) INDUSTRY

All major electric utilities located in the eastern region of the United States are reviewed in this Issue; western-based electrics, in Issue 11; and the remaining industry participants, in Issue 5. Since our last review of the Electric Utility (East) group three months ago, utility stocks covered in *The Value Line Investment Survey* increased 3.1% in value on average versus a 3.7% gain in the S&P 500. Meanwhile, the industry's Timeliness rank has moved up to 66 (of 93) from 80.

During the past year, utilities under our coverage have declined 12.1% versus a 13.6% increase in *The Value Line Arithmetic Index*. The rise in interest rates through much of 2023 weighed heavily on utility stocks. The equities have only begun to recover some in more recent months as the uptrend in rates has paused. Because U.S. debt securities provide a competitive investment vehicle to the stocks in this industry, it's important to be cognizant of the spread between the benchmark 10-year Treasury rate (4.63%) and the dividend yields on electric utilities (4.0% on average).

Though the aforementioned spread is important, expectations of where interest rates will go next is the key factor that will drive this rate-sensitive group's performance. The other major factor is how investors feel about the prospects for the economy in general. Overall, this is a defensive industry with low-Beta stocks that tend to outperform when investors rotate out of economically-sensitive, higher-Beta stocks.

Portfolio Considerations

With the uptick in share prices over the past three months, 3- to 5-year total annual return potential for electrics has fallen a bit, to 10.2% on average from 10.9%. The new level is still towards the high end of what we've witnessed over the past two to three years, and there are some decent intermediate values to be found among this group. Additionally, if interest rates begin to drop again, it's highly likely that well-positioned electrics will rebound further.

However, while many stocks within the Electric Utility (East) Industry remain depressed relative to their highs of a couple of years ago, we're not overly bullish on this group. Over the past several months, we've lowered our 3- to 5-year targeted earnings multiples and raised our dividend yield expectations, as the higher-for-longer scenario of the world's central banks seems to be the new normal. In other words, interest rates were in a secular downtrend for decades, with cyclical interruptions along the way. If that course has reversed, it's a big negative for rate-sensitive utilities.

Investors in this group can help their cause by being disciplined buyers. New commitments should only be made when the midpoint of our annual total return projection is at or above 12%. Emphasizing utilities with above-average dividend growth prospects is a good practice. The median is about 4.5% at present. Staying away from utilities in below-average regulatory climates and keeping a well-diversified group of dividend payers are also good practices to follow.

At present, we like *Eversource Energy* as it possesses all of the aforementioned qualities. We also think *FirstEnergy* is close to being a good long-term buy at the recent price and is a name to keep on the watch list. Another stock that's particularly notable in this Issue is *Avangrid*, as its majority shareholder, Iberdrola of Spain, has proposed an all-cash buyout of the public float at $34.25 per share.

INDUSTRY TIMELINESS: 66 (of 93)

Topical Subjects

Key challenges this industry is facing include the rise in interest rates and overall inflation. Due to how regulatory mechanisms work, some higher costs can rapidly be passed along to consumers. This is true of fluctuations in natural gas prices, for instance. Conventions differ among states, but most utilities suffer from some degree of regulatory lag and have to go through a rate-filing process with regulators in order to gain "rate relief." That's industry parlance for regulatory approval to charge customers, through higher delivery rates on the electric bill, for certain expenses previously or about to be incurred. Notably, some companies are better situated and benefit from near real-time pricing adjustments with little regulatory lag on grid improvements.

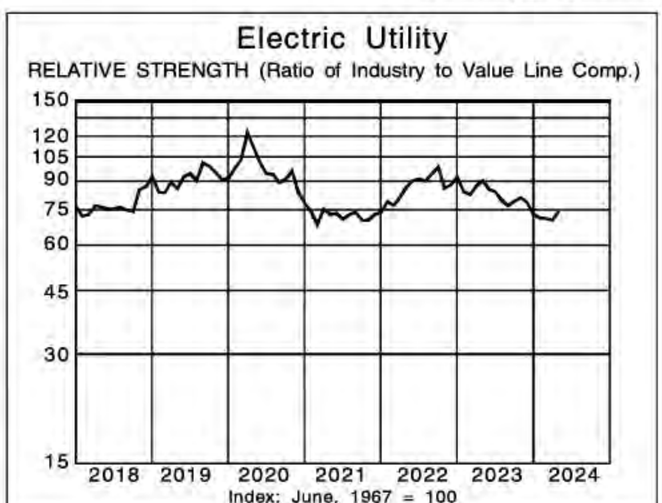
These challenges have been particularly troublesome for companies attempting to build and fund expensive and complicated renewables projects. This has been especially true of offshore wind generation, where the lead times are lengthy. The planning of those ventures took place under a different macroeconomic environment when borrowing, materials, and labor costs were far lower. As a result, many of those projects are only economic at higher electric rates than originally planned for.

Another major problem for this industry is the level of authorized return on equity (ROE) that's being set by some regulators. They're deriving ROEs based on a historically low and now out-of-date cost of capital. Note that the ROE applied to cumulative investments made in grid infrastructure (known as the rate base) is what drives revenue and profit levels for utilities.

Conclusion

Individual companies within this industry vary widely. The regulatory climate and the overall health of the underlying regional and local economies within a utility's service area are impactful. This includes demographics and migratory trends over time. States committing to progressive clean energy goals are generating a lot of invested capital opportunities for utilities, which should translate to improved earnings and dividend growth prospects. Selectivity is key for investors.

Anthony J. Glennon



ELECTRIC UTILITY (CENTRAL) INDUSTRY

All major electric utilities located in the Central region of the United States are reviewed in this Issue; Eastern-based electrics, in Issue 1; and the Western-based electrics, in Issue 11.

Electric Utility (Central) stocks covered in *The Value Line Investment Survey* increased 6.9% in value, on average since our last review three months ago, surpassing the 4.7% jump in the S&P 500.

Utilities, which have been one of the worst-performing sectors over the past few years, have started to recover of late due to elevated power demand from artificial intelligence (AI) innovations and data centers, along with the uptrend in interest rates pausing. While utility equities are typically seen as a safe competitive investment vehicle to U.S. debt securities for conservative investors, the artificial intelligence boom is changing this traditional landscape. Indeed, data centers are set to grow exponentially over the next few years, requiring record levels of electricity. Electric utilities are well positioned to take advantage of the AI boom, as well as bring in new types of investors. Too, the expectation of where interest rates will go next is starting to favor these equities in anticipation of the Federal Reserve's dovish pivot. And, the spread between the 10-year Treasury rate and dividend yields on electric utilities has narrowed since our last report.

Long-Term Prospects

Total return potential for electrics in the 3- to 5-year time frame is at the high end of what we've seen over the past couple of years. And, a number of equities continue to trade at double-digit discounts to historical valuations. But, we remain somewhat concerned with the macroeconomic backdrop, and utility investors should move forward with caution, despite a number of upcoming catalysts. We recommend buying electrics with annual total return potential of at least 12%. Investors should also keep an eye on utilities with above-average dividend growth prospects (4.5%), a strong balance sheet, and a well-diversified portfolio. While equities covered in the Electric Utility (Central) Industry do not stand out for price appreciation potential, the reduced risk of electrics adds to their appeal.

Macro Environment

Well-positioned electrics should rebound nicely for a number of reasons if interest rates begin to drop. Income-oriented investors closely monitor the spread between the yield on government bonds, such as Treasurys, and the yield on the typical electric utility. As interest rates have soared over the past few years, more and more investors have dropped utility equities in favor of Treasurys. But this may be reversing moving forward. What's more, higher interest rates, as well as wage, material, and fuel inflation, continue to negatively impact regulatory recoupments. Some stocks are better positioned than others, with rate cases and real-time pricing adjustments to minimize regulatory lag. And, the regulatory climate varies significantly by territory. Thus, it is important to be selective and look for equities with strong regional economies and regulatory environments. States that are committed to the AI infrastructure build-out and green-energy goals will probably fare better over the coming years. Indeed, *American Electric Power* recently filed a request in Ohio, which is one of the most-favorable climates regarding new data centers. The utility expects data centers to double the current power demand in the Ohio region by 2030.

INDUSTRY TIMELINESS: 81 (of 93)

Artificial Intelligence Boom

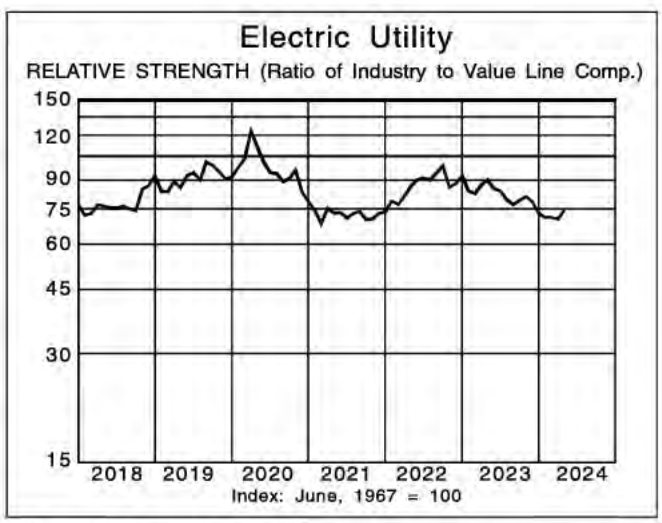
As mentioned earlier, demand for power is expected to reach record levels over the next few years due to technological innovations and the copious amounts of electricity used by AI-focused data centers. A number of electrics anticipate that power demand will more than double over the next five years. *ALLETE* recently agreed to be acquired, in part to be better positioned for the AI boom and record power demand. As a small utility in public markets, *ALLETE* was struggling to raise the necessary capital for its transmission transformation and building the grid. The pending buyout would allow *ALLETE* to take advantage of the biggest demand jump in its history, and build the infrastructure for new data centers. These technological advancements are a strong catalyst for long-term prospects and have brought a whole new group of investors to electric utilities.

Conclusion

Utilities have outpaced the broader-market averages of late. Growing electricity demand from data centers, the emerging AI boom, and the prospect of lower interest rates in the near future are positive factors. That said, other macro challenges continue to negatively impact performance from the group. We recommend that investors stay selective when committing funds.

Utilities currently have strong long-term capital appreciation potential compared to the *Value Line* median. We recommend looking for equities with 12% or greater long-term annual return potential, and average dividend growth of 4.5% or more. The favorable risk profile of electric utilities is also worth considering. Investors should also take note of states with positive data center and green energy transition regulatory environments, as companies in these regions will likely be the best positioned for the future. As always, investors should look out for future rate-setting meetings.

Zachary J. Hodgkinson



All major electric utilities located in the Western region of the United States are reviewed in this Issue; Eastern-based electrics, in Issue 1; and the remainder in Issue 5. Since our January review of the Electric Utility (West) group, utility stocks covered in *The Value Line Investment Survey* fell 3.3% in value on average, compared to a 9.2% increase in the S&P 500.

On a 12-month basis, utilities under our coverage have declined 14.6% versus a 16.2% gain in the *Value Line Arithmetic Index.* The sharp rise in interest rates through mid-October, when the 10-year Treasury yield hit 4.98%, a level last seen in 2007, depressed utility values. Treasurys provide a competitive investment vehicle, so it's important to be mindful of the spread between bond rates and the dividend yields on utilities (recently 4.02% on average). As rates fell 110 basis points, from 4.98% in mid-October to 3.88% in late December, utility stocks rallied. Year to date, however, they're back to underperforming, as the 10-year Treasury yield has risen to 4.42%.

With this year's drop in utility share prices, 3- to 5-year total annual return potential for this group has risen to 10.5% from 8.6% three months ago. Although there is a generally reduced risk level in owning utilities, given that they're regulated monopolies, we like to see the prospect of at least 10%-11% total returns for a given equity before recommending it. That level is in line with historical returns for the broader market.

INDUSTRY TIMELINESS: 84 (of 93)

Utility Portfolio Considerations

While many equities within the Electric Utility (West) Industry remain depressed relative to their highs of a few years ago, we're not overly bullish on this industry. If interest rates fall, it's highly likely that well-positioned utility stocks will perform relatively well. But, we think it's doubtful that the overly favorable backdrop for interest-rate sensitive stocks, often witnessed over the past several years, is on its way back. In long-term historical terms, if interest rates on government bonds normalized to the mid- to high-single-digit range, utilities would be relatively overvalued.

Utility investors can help their cause by being disciplined buyers. New commitments should be made when the midpoint of the annual total return projections are no less than 11%. It would also be a good practice to emphasize utilities with above-average dividend growth prospects. We'd put the industry median at about 4.5% for that measure. Staying away from utilities in a poor regulatory climate is a good practice, as is keeping a well-diversified group of dividend-paying stocks.

Topical Considerations

Key challenges electrics are facing include higher interest rates and overall inflation. Due to how the regulatory mechanisms work, some costs can rapidly be passed on to consumers, such as natural gas prices. Others cannot and have to go through a filed rate-case process with regulators. The regulatory lag before recoupment may be as short as one year or less, but in some instances can drag on for a few years. Some companies are fortunate to have a very minimal lag on a reasonable percentage of outlays, owing to their approved use of near real-time pricing mechanisms.

Another recent problem for this industry is the level of authorized return on equity (ROE) that's being set by regulators. They're looking back to a time of historically low interest rates over the past several years and using that snap shot to price returns in the present. Note that the ROE applied to investments made in grid infrastructure (known as the rate base) is what drives profits in these regulated monopolies. Utilities recoup their investment plus a return on it through the regulatory-approved delivery rates they bill for.

High purchased power costs during peak load periods have been exacerbated by the shuttering of cheap and reliable coal generation in the West. We've also seen that under certain conditions, such as mild weather, the supply of "green" energy, including hydro, can get depressed. The impact is especially problematic because open-market power purchases are not necessarily an automatic and quick pass-through to consumers. This problem also represents an opportunity, as it increasingly makes sense for more generating capacity to be approved for utility ownership.

Lastly, with *PG&E Corp.* back within our coverage, and *Edison Int'l* embroiled in some new wildfire lawsuits, a discussion on business risk in California is always topical in the Electric Utility (West) Industry. Regarding the mounting lawsuits impacting *Hawaiian Electric* and to a lesser degree *Xcel Energy*, we'd refer subscribers to the respective company reviews.

The California Wildfire Fund, established in 2019, is a form of insurance for the state's three major electric utility holding corporations (*Sempra Energy* is the third), funded by the companies and their customer base up to $21 billion. Pre-2019 disasters are not covered and individual claims are paid after a $1 billion deductible is incurred. The fund covers catastrophic losses, but does not cover gross negligence. With this extra layer of protection above regular liability insurance, bankruptcy risk for the aforementioned California holding companies is very much reduced.

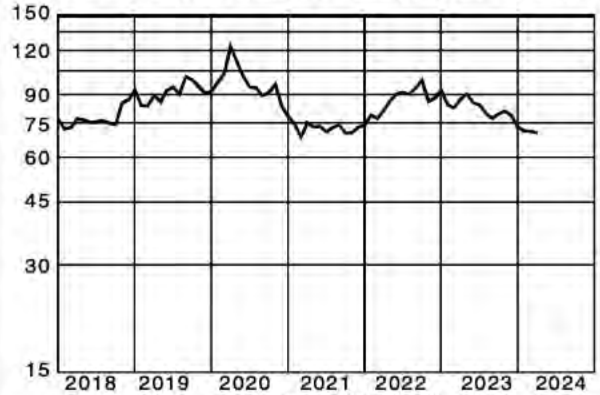
Conclusion

Individual utilities vary widely. Regulatory climate and the overall health of the underlying regional and local economies encompassed within a service area are impactful. And, states with progressive renewable-energy goals are providing solid growth prospects to utilities. As always, investors need to be selective.

Anthony J. Glennon

Electric Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

ALLETE NYSE-ALE

RECENT PRICE **62.92** | P/E RATIO **16.8** (Trailing: 15.1 Median: 19.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD **4.5%** | **VALUE LINE**

High:	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7	73.1	68.6	66.7	65.9
Low:	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2	56.8	47.8	49.3	55.9

TIMELINESS 3 Lowered 2/16/24
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 6/7/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$82	$68 (5%)

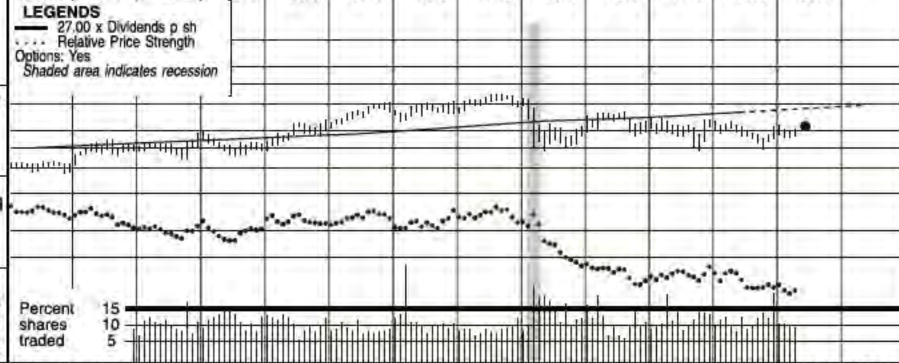
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+60%)	16%
Low	75	(+20%)	9%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	159	145	156
to Sell	123	141	153
Hld's(000)	43650	44027	44075

LEGENDS
— 27.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Percent shares traded 15 10 5

Target Price Range 2027 | 2028 | 2029
160 120 100 80 60 50 40 30 20 15

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.7	11.5
3 yr.	-5.5	5.5
5 yr.	-12.9	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	29.10	23.99	22.44	26.68	28.04	32.65	*29.50*	*30.50*	Revenues per sh	*32.80*
4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	7.37	7.24	7.52	7.54	7.70	8.67	*8.30*	*8.80*	"Cash Flow" per sh	*9.65*
2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	3.38	3.33	3.35	3.23	3.38	4.30	*3.75*	*4.10*	Earnings per sh A	*5.15*
1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	2.35	2.47	2.52	2.60	2.71	*2.82*	*2.93*	Div'd Decl'd per sh B ■ †	*3.25*
9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	6.07	11.55	13.78	8.90	3.64	4.92	*5.95*	*6.20*	Cap'l Spending per sh	*7.25*
25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	41.86	43.17	44.04	45.36	47.06	48.78	*51.25*	*52.55*	Book Value per sh C	*54.00*
32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	51.50	51.70	52.10	53.20	56.01	57.58	*59.00*	*59.00*	Common Shs Outst'g D	*61.00*
13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	22.2	24.7	18.3	20.6	18.1	13.8	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	.94	1.11	1.05	.79	*Value Line*		Relative P/E Ratio	*.95*
4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	3.0%	2.9%	4.0%	3.8%	4.4%	4.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $1797.3 mill. **Due in 5 Yrs** $390.7 mill.
LT Debt $1772.4 mill. **LT Interest** $65.9 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/22 $745.7 mill.
Oblig $911.7 mill.

Pfd Stock None

Common Stock 57,666,069 shs.

MARKET CAP: $3.6 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	1169.1	1419.2	1570.7	1879.8	*1740*	*1800*	Revenues ($mill)	*2000*
124.8	163.4	155.3	159.2	174.1	172.4	174.2	169.2	189.3	247.6	*220*	*240*	Net Profit ($mill)	*315*
22.6%	19.4%	11.3%	14.8%	--	--	--	NMF	NMF	NMF	*NMF*	*NMF*	Income Tax Rate	*NMF*
6.3%	2.0%	1.4%	.8%	.7%	1.3%	1.1%	1.5%	1.4%	1.3%	*2.0%*	*1.5%*	AFUDC % to Net Profit	*1.0%*
44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	41.0%	42.2%	40.8%	40.3%	*39.5%*	*40.0%*	Long-Term Debt Ratio	*40.5%*
55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	59.6%	53.8%	*60.5%*	*60.0%*	Common Equity Ratio	*59.5%*
2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	3887.8	4176.3	4457.5	4682.8	*4900*	*5150*	Total Capital ($mill)	*5550*
3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	4840.8	5100.2	5004.0	5013.0	*5450*	*5500*	Net Plant ($mill)	*5675*
5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	5.3%	4.8%	5.6%	6.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	7.5%	8.8%	*8.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	7.5%	8.8%	*8.0%*	*8.0%*	Return on Com Equity E	*9.0%*
2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	2.0%	1.5%	2.5%	3.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.5%*
67%	60%	66%	68%	66%	70%	74%	78%	76%	70%	*69%*	*69%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-12.0	+11.5	+4.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	1588	1557	1556
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	230	219	220

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	--	-3.0%	3.0%
"Cash Flow"	4.5%	2.0%	4.5%
Earnings	3.0%	.5%	6.0%
Dividends	3.5%	3.5%	3.5%
Book Value	4.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2021	339.2	335.6	345.4	399.0	1419.2
2022	383.5	373.1	388.3	425.8	1570.7
2023	564.9	533.4	378.8	402.7	1879.8
2024	403.3	*475*	*421.7*	*440*	*1740*
2025	*430*	*480*	*440*	*450*	*1800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2021	.99	.53	.53	1.18	3.23
2022	1.24	.67	.59	.90	3.38
2023	1.02	.90	1.49	.89	4.30
2024	.88	*.85*	*.80*	*1.22*	*3.75*
2025	*1.05*	*.90*	*.90*	*1.25*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6175	.6175	.6175	.6175	2.47
2021	.63	.63	.63	.63	2.52
2022	.65	.65	.65	.65	2.60
2023	.6775	.6775	.6775	.6775	2.71
2024	.7050	.7050			

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; wholesale, 14%; residential, 13%; commercial 13% paper/wood products, 9%; other industrial, 8%; other, 17%. ALLETE Clean Energy (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal, 28%; wind, 10%; other, 4%; purchased, 58%. Fuel costs: 40% of revs. '23 deprec. rate: 3.1%. Has 1,400 employees. Chairman, President & CEO: Bethany M. Owen. Inc.: Minnesota. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE agreed to be acquired by a combination of Canada Pension Plan Investment Board and Global Infrastructure Partners. ALE stockholders would receive $67 per share in a deal to be taken private at a total value of $6.2 billion. The stock price has risen nicely of late and the transaction currently represents a very slight premium to the present quotation. The deal is expected to close in mid-2025.

The company plans to spend $4.3 billion on renewable energy over the next five years. While utilities are well positioned to benefit from artificial intelligence innovations and data centers that boost power demand, the clean-energy transition requires raising significant investments, which is very challenging for small utilities in public markets. If approved, the buyout would allow ALLETE to take advantage of the biggest demand jump in its history, and provide the utility assistance in its long-term goals. Indeed, ALLETE's largest subsidiary, Minnesota Power, has a carbon-free mandate by 2040, among other initiatives that should be easier to obtain as a private company.

We think the deal makes sense. ALLETE is looking to grow at a significant rate to keep up with the elevated demand from tech innovations. The pending acquisition should set up the company nicely in the long term to meet the all-time high power demand. This would likely not be possible as a small-cap utility in the currently volatile markets. The purchase price of $67 per share is right near the midpoint of our 18-month Target Price Range, indicating a modest premium to our future projected stock price. ALLETE plans to retain its workforce and continue to operate locally in Minnesota.

The stock is inching closer to its buyout price. Investors seem enthused with the deal and the likelihood of it being completed, accounting for the recent run-up. If the transaction does not go through, capital appreciation potential for the 3- to 5-year time frame is above average in comparison to most of ALLETE's peers. We look for the stock to trade around $75-$100 by 2027-2029. ALLETE is also ranked Above Average (2) for Safety and holds a high score for Price Stability.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; '19 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '23: $9.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '21: 7.2%. Regul. Climate: Avg. (F) Summer peak in '21.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	90

ALLIANT ENERGY NDQ-LNT

RECENT PRICE 49.95 | P/E RATIO 16.4 (Trailing: 18.2 / Median: 21.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 5/3/24
SAFETY 2 Raised 9/28/07
TECHNICAL 4 Raised 5/31/24
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$43-$66	$55 (10%)

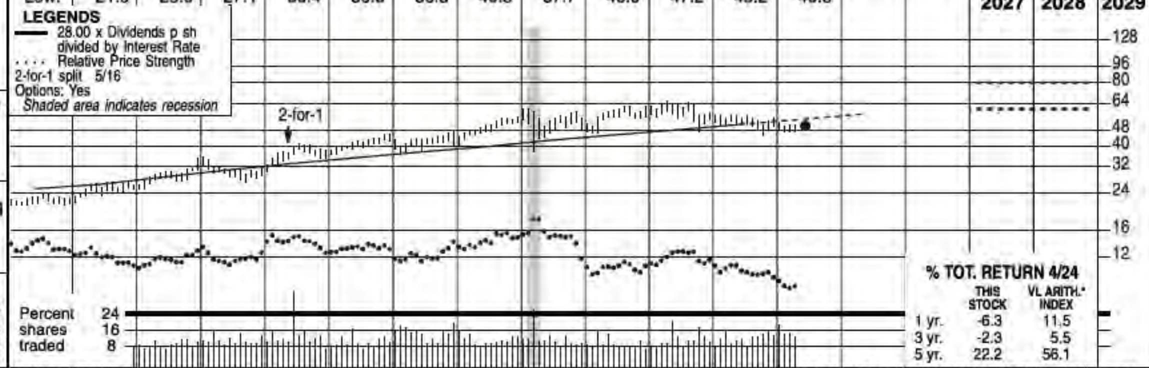
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+60%)	15%
Low	60	(+20%)	9%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	270	277	312
to Sell	267	282	279
Hld's(000)	196380	204187	209105

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3	65.4	56.3	52.4
Low:	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7	46.0	47.2	45.2	46.8



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	16.74	15.72	16.75	17.30	Revenues per sh	18.35
2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	5.40	5.38	5.65	5.85	"Cash Flow" per sh	6.50
1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	2.73	2.78	3.05	3.25	Earnings per sh A	3.90
.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	1.71	1.81	1.92	2.04	Div'd Decl'd per sh B ■ †	2.43
3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	5.91	7.24	5.80	5.60	Cap'l Spending per sh	5.40
12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	24.99	26.46	27.65	28.85	Book Value per sh C	31.90
220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	251.14	256.10	256.70	256.70	Common Shs Outst'g D	257.00
13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	21.4	18.8	Bold figures are		Avg Ann'l P/E Ratio	18.0
.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.15	1.24	1.05	Value Line		Relative P/E Ratio	1.00
4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%	2.9%	3.5%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $9667 mill. **Due in 5 Yrs** $2984 mill.
LT Debt $8524 mill. **LT Interest** $370 mill.
(LT interest earned: 2.8x)

Leases, Uncapitalized Annual rentals $3 mill.

Pension Assets-12/23 $732 mill. **Oblig** $876 mill.

Pfd Stock None

Common Stock 256,379,032 shs.

MARKET CAP: $12.8 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	4205.0	4027.0	4300	4440	Revenues ($mill)	4720
395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	686.0	703.0	780	835	Net Profit ($mill)	975
10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	- -	- -	3.1%	.6%	2.0%	2.0%	Income Tax Rate	2.0%
8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	8.7%	14.2%	6.0%	6.0%	AFUDC % to Net Profit	4.0%
49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	55.0%	54.8%	56.5%	55.0%	Long-Term Debt Ratio	52.0%
47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	45.0%	45.2%	43.5%	45.0%	Common Equity Ratio	48.0%
7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	13944	15002	16220	16530	Total Capital ($mill)	17070
6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	16247	17157	18300	18600	Net Plant ($mill)	19180
6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	6.1%	6.0%	6.0%	6.5%	Return on Total Cap'l	7.0%
10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	10.9%	10.4%	11.0%	11.5%	Return on Shr. Equity	12.0%
11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	10.9%	10.4%	11.0%	11.5%	Return on Com Equity E	12.0%
4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	4.1%	3.6%	4.0%	4.0%	Retained to Com Eq	4.5%
60%	66%	72%	64%	62%	61%	62%	62%	62%	65%	63%	63%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.7	-.7	
Avg. Indust. Use (MWH)	11696	11494	11435
Avg. Indust. Revs. per KWH (¢)	7.64	8.39	8.47
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5486	5629	5856
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.7	+.7
Fixed Charge Cov. (%)	259	NA	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	.5%	1.5%	2.5%
"Cash Flow"	6.0%	6.5%	2.0%
Earnings	6.0%	7.0%	6.0%
Dividends	6.5%	6.5%	6.0%
Book Value	6.0%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	901	817	1024	927	3669
2022	1068	943	1135	1059	4205
2023	1077	912	1077	961	4027
2024	1031	975	1150	1144	4300
2025	1065	1005	1185	1185	4440

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	.43	2.73
2023	.65	.64	1.02	.47	2.78
2024	.62	.66	1.10	.67	3.05
2025	.74	.69	1.14	.68	3.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	1.71
2023	.4525	.4525	.4525	.4525	1.81
2024	.48				

BUSINESS: Alliant Energy Corporation is the parent company of Interstate Power and Light Company (IPL) and Wisconsin Power and Light Company (WPL). Together, the utility subsidiaries serve approximately one million electric and 425,000 natural gas customers in Wisconsin and Iowa. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revenues. '23 reported depreciation rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, WI 53718-2148. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy kicked off 2024 on a fairly weak note. Indeed, earnings at the Wisconsin-based electric and gas utility fell nearly 5% in the March quarter, as unseasonably mild weather resulted in lower heating demand across the company's Midwest service area. Notably, the key markets of Cedar Rapids, Iowa and Madison, Wisconsin each had the warmest start to a year since 2012 and were 6%–9% less frigid, year over year, based on the total number of heating degree days through the first three months of 2024. On a consolidated basis, the incremental earnings hit due to the unseasonable weather was roughly $0.04 a share. Other, nonweather-related costs were a $0.02 drag.

Recent rate hikes are providing some support. Late last year, Alliant's Wisconsin Power & Light (WPL) subsidiary received regulatory authorization to raise electric and gas rates by $49 million and $13 million respectively, coinciding with capital investments in, among other things, solar power and battery storage. As we understand it, the recent quarterly benefit was roughly $0.03, net of associated increases in borrowing costs and depreciation expense.

Alliant remains a compelling long-term investment play on renewable energy. WPL was recently expected to complete the last of several projects that will increase the utility's overall solar-power capacity in the Badger State to 1.1 gigawatts. Meantime, Interstate Power & Light continues to target 400 megawatts of solar power generation by the end of this year. Importantly, these solar projects have zero fuel costs, thus reducing Alliant's susceptibility to swings in natural-gas prices and the like. Its investments in "green" power also yield significant tax credits that can be sold to regional manufacturers and other third parties looking to maintain compliance with restrictions on carbon emissions. In 2025 alone, Alliant could realize as much as $400 million from the sale of tax credits.

Alliant shares remain neutrally ranked for relative year-ahead price performance. Still, the utility company boasts both a fairly attractive dividend (current yield: 3.8%) and solid long-term total return potential.

Nils C. Van Liew *June 7, 2024*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. (D) In millions, adj. for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

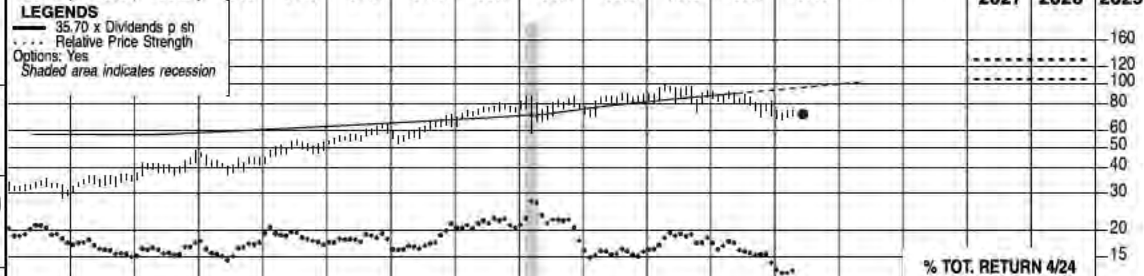
AMEREN NYSE-AEE

RECENT PRICE 71.34 | P/E RATIO 15.5 (Trailing: 16.4 Median: 20.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 12/29/23
SAFETY 1 Raised 9/10/21
TECHNICAL 3 Raised 6/7/24
BETA .90 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2	91.2	76.1
Low:	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3	69.7	67.0

LEGENDS
— 35.70 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High Midpoint (% to Mid)
$62-$110 $86 (20%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+80%)	19%
Low	105	(+45%)	13%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	269	280	283
to Sell	287	314	321
Hld's(000)	204708	210352	215268

Percent shares traded 30 20 10

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.2	11.5
3 yr.	-5.1	5.5
5 yr.	15.8	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	30.37	28.10	**29.00**	**30.35**	Revenues per sh	**34.05**
6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	9.59	9.99	**10.55**	**11.15**	"Cash Flow" per sh	**12.30**
2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	4.14	4.37	**4.60**	**4.90**	Earnings per sh A	**5.95**
2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	2.36	2.52	**2.68**	**2.86**	Div'd Decl'd per sh B ■	**3.30**
9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	12.79	12.87	**12.55**	**12.80**	Cap'l Spending per sh	**13.00**
32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	40.11	40.26	**42.90**	**45.95**	Book Value per sh C	**52.65**
212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	262.00	267.00	**269.00**	**272.00**	Common Shs Outst'g D	**285.00**
14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	21.5	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	**20.0**
.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.16	1.24	1.07	*Value Line*		Relative P/E Ratio	**1.10**
6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%	2.7%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**3.0%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $16316 mill. **Due in 5 Yrs** $2789 mill.
LT Debt $15167 mill. **LT Interest** $450 mill.
(LT interest earned: 3.8x)
Pension Assets-12/23 $5745 mill. **Oblig** $5457 mill.
Pfd Stock $129 mill. **Pfd Div'd** $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 266,670,374 shs. **as of 4/30/24**
MARKET CAP: $19.0 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	7957.0	7500.0	**7800**	**8250**	Revenues ($mill)	**9700**
593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	1074.0	1152.0	**1235**	**1330**	Net Profit ($mill)	**1700**
38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	14.0%	12.0%	**12.0%**	**12.0%**	Income Tax Rate	**12.0%**
5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	5.0%	6.0%	**5.0%**	**5.0%**	AFUDC % to Net Profit	**4.0%**
47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	56.6%	55.7%	**53.5%**	**52.5%**	Long-Term Debt Ratio	**51.0%**
51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	43.4%	43.8%	**46.0%**	**47.0%**	Common Equity Ratio	**48.5%**
12975	13968	13840	14420	15632	17116	20158	22391	24193	24847	**25750**	**26450**	Total Capital ($mill)	**29500**
17424	18799	20113	21466	22810	24376	26807	29261	31262	33776	**35000**	**36300**	Net Plant ($mill)	**38400**
5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	5.4%	5.5%	**5.0%**	**5.0%**	Return on Total Cap'l	**6.0%**
8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	10.2%	11.0%	**11.0%**	**11.0%**	Return on Shr. Equity	**10.0%**
8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	10.2%	11.0%	**11.0%**	**11.0%**	Return on Com Equity E	**10.0%**
2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	4.4%	5.0%	**5.0%**	**5.0%**	Retained to Com Eq	**4.0%**
67%	70%	64%	64%	56%	57%	57%	57%	57%	57%	**56%**	**56%**	All Div'ds to Net Prof	**60%**

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.5	-5.6	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	307	291	325

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	-1.5%	.5%	4.0%
"Cash Flow"	4.0%	6.5%	5.5%
Earnings	4.0%	8.0%	6.5%
Dividends	3.5%	5.0%	6.5%
Book Value	2.0%	5.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	2046	7957
2023	2062	1760	2060	1618	7500
2024	1816	*1830*	*2150*	*2004*	*7800*
2025	*2000*	*1900*	*2250*	*2100*	*8250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	.63	4.14
2023	1.00	.90	1.87	.60	4.37
2024	.98	*.95*	*2.00*	*.67*	*4.60*
2025	*1.20*	*.95*	*2.00*	*.75*	*4.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	2.36
2023	.63	.63	.63	.63	2.52
2024	.67	.67			

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. Has approximately 9,250 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren's profits should rise nicely in 2024. Higher earnings in its transmission segment from clean-energy investments, along with electric and gas rate increases, will probably be the main factors. The utility will likely also benefit from elevated power demand due to artificial intelligence innovations and data centers. Our earnings-per-share estimate remains at $4.60, which is within the company's updated outlook range of $4.52-$4.72. Management expects significant year-over-year operations and maintenance cost reductions in the second half of this year from several savings initiatives, which should prop up the bottom line.

We look for stronger bottom-line growth in 2025. Ameren will receive additional rate relief from its transmission and Illinois electric operations, which are currently under way. The utility recently updated its goal for annual earnings growth of 6%-8%, and our estimate of $4.90 a share represents an increase of 6% from our 2024 estimate. This target is supported by annual rate base growth of 8.2%.

Ameren is making progress in a number of regulatory matters in Illinois. In April, the utility filed an electric distribution annual rate request for $160 million of reconciliations for 2023 actual revenue costs. A decision is expected by the end of this year, and the full amount will likely be collected in 2025. And, in its multiyear grid plan, Ameren Illinois revised its request for an annual increase from 2023 rates of $321 million. The request is based on a return on equity of 8.72% and an equity ratio of 50%. A final order is expected by the end of 2024. Ameren Missouri is also active on the regulatory front, and recently filed a 60-day notice for its next rate review.

Risk-averse, income-oriented investors may want to take a closer look here. The dividend yield of this untimely but top-quality stock is about average by utility standards. And, long-term capital appreciation potential is attractive in comparison to most of its peers. Indeed, the midpoint of our 18-month Target Price Range indicates a 20% premium over the current quotation. And, we look for the stock to trade within $105-$130 by 2027-2029.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due early Aug.
(B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '21: $6.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '22: elec. & gas, none specified; in IL: electric, varies; in '21: gas, 9.67%; earned on avg. com. eq., '21: 10.6%.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	100

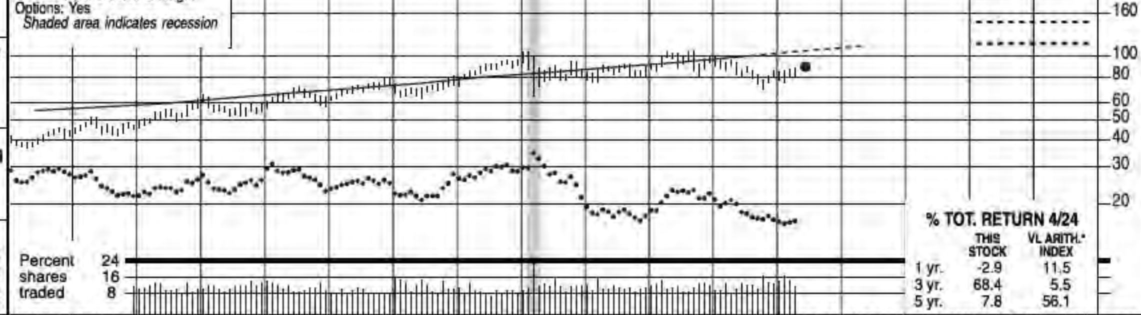
AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE 88.97 | P/E RATIO 15.9 (Trailing: 14.8, Median: 18.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 3/15/24
SAFETY 1 Raised 3/17/17
TECHNICAL 3 Raised 6/7/24
BETA .85 (1.00 = Market)

High:	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	105.6	98.3	93.4			Target Price Range 2027 | 2028 | 2029
Low:	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	80.3	69.4	75.2			

LEGENDS
— 29.40 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
\$77-\$126	\$102 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+65%)	16%
Low	115	(+30%)	10%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	596	599	628
to Sell	572	557	609
Hld's(000)	386016	391405	398265

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.9	11.5
3 yr.	68.4	5.5
5 yr.	7.8	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	38.20	36.08	**38.00**	**40.20**	Revenues per sh	**44.20**
6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	10.72	10.92	**11.65**	**12.35**	"Cash Flow" per sh	**15.20**
2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	5.09	5.24	**5.60**	**6.00**	Earnings per sh A	**7.20**
1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	3.17	3.37	**3.60**	**3.81**	Div'd Decl'd per sh B ■ †	**4.16**
9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	13.18	13.89	**14.15**	**14.10**	Cap'l Spending per sh	**14.00**
26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	46.60	48.46	**55.05**	**58.90**	Book Value per sh C	**62.55**
406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	513.87	526.18	**530.00**	**535.00**	Common Shs Outst'g D	**550.00**
13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	21.1	16.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**18.0**
.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.92	1.23	.93	*estimates*		Relative P/E Ratio	**1.00**
4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%	3.3%	4.5%			Avg Ann'l Div'd Yield	**3.3%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt \$42375 mill. **Due in 5 Yrs** \$12886 mill.
LT Debt \$38637 mill. **LT Interest** \$1400 mill.

Leases, Uncapitalized Annual rentals \$119.6 mill.

Pfd Stock None

Common Stock 527,121,759 shs.

MARKET CAP: \$46.9 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
17020	16453	16380	15425	16196	15561	14919	16792	19640	18982	**20150**	**21500**	Revenues (\$mill)	**24300**
1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2448.1	2307.2	2208.1	**2970**	**3210**	Net Profit (\$mill)	**3960**
37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	NMF	NMF	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	7.0%	7.0%	**7.0%**	**6.5%**	AFUDC % to Net Profit	**5.0%**
49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	58.5%	58.2%	**58.0%**	**58.0%**	Long-Term Debt Ratio	**57.5%**
51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	42.0%	42.0%	**42.0%**	**42.0%**	Common Equity Ratio	**42.5%**
33001	35633	34775	37707	40677	44759	49537	53734	57520	62837	**68900**	**70730**	Total Capital (\$mill)	**75900**
44117	46133	45639	50262	55099	60138	63902	66001	71283	76693	**78000**	**81250**	Net Plant (\$mill)	**87300**
6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	4.0%	3.6%	**4.5%**	**4.5%**	Return on Total Cap'l	**5.0%**
9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	8.7%	**10.0%**	**10.0%**	Return on Shr. Equity	**11.0%**
9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	9.7%	8.7%	**10.0%**	**10.0%**	Return on Com Equity	**11.0%**
3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	2.9%	2.4%	**4.0%**	**4.0%**	Retained to Com Eq	**4.5%**
61%	60%	54%	67%	65%	67%	65%	61%	70%	63%	**63%**	**63%**	All Div'ds to Net Prof	**61%**

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	--	+3.0	--
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	243	272	285

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	.5%	-.5%	3.0%
"Cash Flow"	5.0%	5.5%	5.5%
Earnings	5.0%	4.0%	6.5%
Dividends	5.0%	5.0%	5.5%
Book Value	3.5%	3.5%	6.0%

Cal-endar	QUARTERLY REVENUES (\$ mill.) E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	4881	19640
2023	4690	4373	5342	4577	18982
2024	5026	**4500**	**5350**	**5274**	**20150**
2025	**5250**	**4850**	**5800**	**5600**	**21500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.15	1.15	1.59	1.07	4.96
2022	1.22	1.20	1.62	1.05	5.09
2023	1.11	1.13	1.77	1.23	5.24
2024	1.27	**1.25**	**1.80**	**1.28**	**5.60**
2025	**1.50**	**1.40**	**1.80**	**1.30**	**6.00**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	3.17
2023	.83	.83	.83	.88	3.37
2024	.88	.88			

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '23 reported depreciation rates (utility): 2.6%-12.5%. Has approximately 16,700 employees. Interim Chief Executive Officer: Benjamin G.S. Fowke III. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power got off to a solid start in 2024. First-quarter earnings per share came in at \$1.27, ahead of Wall Street's expectations due to a number of rate hikes, clean-energy investment growth, and power demand increases. Accordingly, management maintained its 2024 bottom-line outlook of \$5.53 to \$5.73 and a long-term annual profit growth target of 6%-7%. Our 2024 and 2025 earnings estimates are staying put as the company should continue to benefit from rate relief, increased investments in its transmission business, and volume growth. What's more, AEP is well positioned to take advantage of the elevated demand from artificial intelligence innovations and new data centers, which we will discuss more below.

AEP filed a proposal with Ohio regulators to require data center developers to buy a majority of electricity they need upfront. Indeed, new large data centers would be required to make a 10-year commitment to pay for a minimum of 90% of the energy requested before AEP builds and invests billions on transmission. The boost in power demand from artificial intelligence innovations and data centers is set to rise exponentially through 2030. Indeed, data centers are expected to double the power demand in the utility's Ohio region within the next five years.

The company agreed to sell its AEP OnSite Partners distributed resources business to Basalt Infrastructure Partners for \$315 million in cash. OnSite Partners sells distributed energy resources to commercial and industrial customers. The deal is expected to close in the third quarter of this year, and will provide AEP with support in its transmission investments as power demand soars.

Risk-adverse, income-oriented investors may want to take a closer look here. The dividend yield of this top-quality stock stands above the utility average. Too, AEP is committed to its target payout ratio of 60%-70%. So, the dividend should continue growing nicely. Also, intermediate- and long-term return prospects are solid in comparison to most of its peers. Meanwhile, the Timeliness rank has been upgraded one notch to 3 (Average) since our March review.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted EPS. Excl. nonrec. gains (losses): '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, (\$2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢); '22, (58¢); '23, (34¢). Next earnings report due late July. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '23: \$52.5 million (D) In mill. (E) Rev. may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	95

AVANGRID, INC. NYSE-AGR

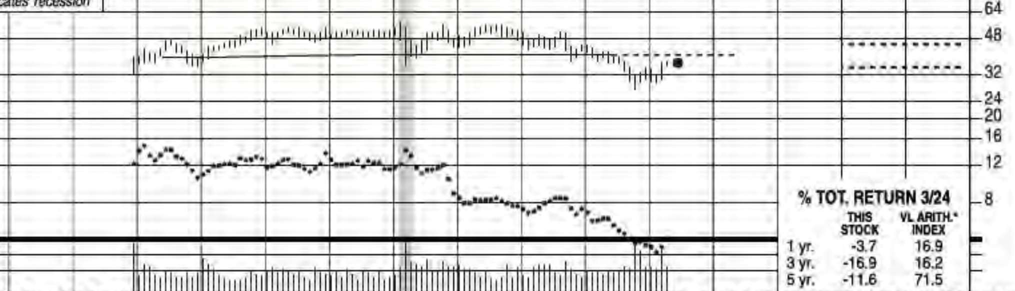
RECENT PRICE 36.63 | P/E RATIO 16.3 (Trailing: 15.7 / Median: NMF) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 4.8%

VALUE LINE

TIMELINESS — Suspended 3/22/24
SAFETY 2 Raised 5/10/24
TECHNICAL — Suspended 3/22/24
BETA .95 (1.00 = Market)

LEGENDS
— 22.7 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	38.9	46.7	53.5	54.6	52.9	57.2	55.6	51.7	44.8	37.3
Low:	32.4	35.4	37.4	45.2	47.4	35.6	44.0	37.6	27.5	29.7



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range
Low-High: $23-$43 Midpoint (% to Mid): $33 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(-5%)	4%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	146	166	142
to Sell	132	136	152
Hld's(000)	50434	51130	51016

Percent shares traded 9 6 3

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.7	16.9
3 yr.	-16.9	16.2
5 yr.	-11.6	71.5

Avangrid, Inc. was formed through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in December of 2015. Iberdrola S.A., a worldwide leader in the energy industry, owns 81.5% of Avangrid. The predecessor company was founded in 1852 and is headquartered in New Gloucester, Maine. It was incorporated in 1997 in New York under the name NGE Resources, Inc. Avangrid began trading on the NYSE on December 17, 2015.

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
--	14.14	19.48	19.30	20.96	20.51	20.45	18.04	20.49	21.48	*22.20*	*23.00*	Revenues per sh	*25.85*
--	3.44	4.74	4.49	4.89	5.41	5.22	4.64	5.14	5.08	*5.30*	*5.60*	"Cash Flow" per sh	*6.25*
--	1.05	1.98	1.67	1.92	2.17	2.02	2.18	2.32	2.09	*2.25*	*2.40*	Earnings per sh A	*2.70*
--	--	1.73	1.73	1.74	1.76	1.76	1.76	1.76	1.76	*1.76*	*1.76*	Div'd Decl'd per sh B ■	*1.76*
--	3.50	5.52	7.82	5.78	8.87	9.00	7.70	6.52	7.68	*7.50*	*7.60*	Cap'l Spending per sh	*8.00*
--	48.74	48.90	48.79	48.88	49.31	49.21	49.35	50.13	50.80	*51.25*	*51.90*	Book Value per sh C	*54.50*
--	308.86	308.99	309.01	309.01	309.01	309.08	386.57	386.63	386.77	*387.00*	*387.00*	Common Shs Outst'g D	*387.00*
--	33.5	20.5	27.3	26.1	23.1	23.6	23.2	19.6	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
--	1.69	1.08	1.37	1.41	1.23	1.21	1.25	1.13	.98	*Value Line*		Relative P/E Ratio	*.85*
--	--	4.3%	3.8%	3.5%	3.5%	3.7%	3.5%	3.9%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*
4594.0	4367.0	6018.0	5963.0	6478.0	6338.0	6320.0	6974.0	7923.0	8309.0	*8600*	*8900*	Revenues ($mill)	*10000*
424.0	267.0	611.0	516.0	595.0	673.0	625.0	780.0	901.0	808.0	*870*	*930*	Net Profit ($mill)	*1050*
39.9%	11.3%	37.4%	32.4%	22.1%	17.0%	7.2%	6.2%	3.2%	7.0%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
6.8%	12.7%	7.5%	12.4%	9.4%	15.0%	17.1%	15.5%	12.9%	17.9%	*18.0%*	*18.0%*	AFUDC % to Net Profit	*16.0%*
16.8%	23.1%	23.0%	25.6%	26.2%	30.6%	40.8%	29.3%	29.8%	33.7%	*36.5%*	*39.5%*	Long-Term Debt Ratio	*44.5%*
83.2%	76.9%	77.0%	74.4%	73.8%	69.4%	59.2%	70.7%	70.2%	66.3%	*63.5%*	*60.5%*	Common Equity Ratio	*55.5%*
14956	19583	19619	20273	20472	21953	25687	26998	27603	29632	*31375*	*33075*	Total Capital ($mill)	*38000*
17099	20711	21548	22669	23459	25218	26751	28866	30994	32857	*34575*	*36300*	Net Plant ($mill)	*41150*
3.7%	2.1%	3.8%	3.1%	3.5%	3.7%	3.0%	3.4%	3.8%	3.4%	*3.5%*	*3.5%*	Return on Total Cap'l	*3.5%*
3.4%	1.8%	4.0%	3.4%	3.9%	4.4%	4.1%	4.1%	4.6%	4.1%	*4.5%*	*4.5%*	Return on Shr. Equity	*5.0%*
3.4%	1.8%	4.0%	3.4%	3.9%	4.4%	4.1%	4.1%	4.6%	4.1%	*4.5%*	*4.5%*	Return on Com Equity E	*5.0%*
3.4%	1.8%	1.4%	NMF	.4%	.8%	.5%	.9%	1.1%	.6%	*1.0%*	*1.0%*	Retained to Com Eq	*2.0%*
--	--	66%	104%	90%	81%	87%	79%	76%	84%	*78%*	*73%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $12965 mill. **Due in 5 Yrs** $3579 mill.
LT Debt $9859 mill. **LT Interest** $409 mill.
Incl. $81 mill. finance leases.
(Total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $12 mill.

Pension Assets-12/23 $2159 mill. **Oblig.** $2500 mill.

Pfd Stock None

Common Stock 386,906,260 shs.
as of 4/23/24
MARKET CAP: $14.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (MWH)	+1.8	+.7	-3.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (MW)	NA	NA	NA
Peak Load, Summer (MW)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	+1.2	+.4
Fixed Charge Cov. (%)	300	247	203

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	--	--	*4.5%*
"Cash Flow"	--	1.0%	*4.0%*
Earnings	--	3.5%	*3.5%*
Dividends	--	0.5%	*Nil*
Book Value	--	0.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1966	1477	1598	1933	6974
2022	2133	1794	1838	2158	7923
2023	2466	1587	1974	2282	8309
2024	2417	*1733*	*2150*	*2300*	*8600*
2025	*2500*	*1800*	*2225*	*2375*	*8900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.14	.35	.34	.44	2.18
2022	1.16	.46	.31	.39	2.32
2023	.64	.21	.27	.97	2.09
2024	.88	*.37*	*.40*	*.60*	*2.25*
2025	*.90*	*.40*	*.45*	*.65*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.44	.44	.44	.44	1.76
2021	.44	.44	.44	.44	1.76
2022	.44	.44	.44	.44	1.76
2023	.44	.44	.44	.44	1.76
2024	.44	.44			

BUSINESS: Avangrid, Inc. (formerly Iberdrola USA, Inc.), is a diversified energy and utility company that serves 2.3 million electric customers in New York, Connecticut, and Maine and 1.0 million gas customers in New York, Connecticut, Massachusetts & Maine. Has a nonregulated generating subsidiary focused on wind and solar power generation, with 9.3 GW of capacity and 1.3 GW under construction. Renewables segment accounted for about 22% of net profits for trailing 12 months. Power/fuel costs: 29% of rev. '23 reported depr. rate: 2.5%. Iberdrola owns 81.6% of stock. Employs about 8,000. Board Chair: Ignacio Sanchez Galan. CEO: Pedro Azagra Blazquez. Inc.: New York. Address: 180 Marsh Hill Road, Orange, CT 06477. Tel.: 207-629-1200. Web: www.avangrid.com.

Avangrid's parent company, Iberdrola S.A., has made a $34.25-per-share cash offer for the public float. The Spanish multinational power company already owns about 81.6% of Avangrid's common stock. The non-binding proposal to purchase the remaining stake was made to Avangrid's board of directors on March 6th. The company's board stated that it will review, evaluate, negotiate, and approve or disapprove of the offer based on the recommendations of its legal and financial advisers. Consummation of the proposed transaction is conditional upon the independent board's approval and a vote by minority shareholders.

We see very little potential of a competing third-party offer coming for the whole of the company. This is because of Iberdrola's majority stake and the additional regulatory constraints involved in purchasing a utility holding company such as Avangrid. Approval from the utility regulatory agencies of each of the four states it does business in plus the green light from a host of federal agencies would be necessary. Following the parent company's proposal, Avangrid's stock price has managed to remain above the buyout price, trading within a tight range of $35.50-$37.00 per share. We think the recent price mainly reflects the presumption that the independent board of directors will be able to negotiate a better deal. Ironically, the last major buyout proposed for a utility holding company that can be used as a benchmark for valuation was Avangrid's long-standing offer to purchase PNM Resources. (The merger was never able to gain regulatory approval.) Using a comparable valuation on operating profits to the PNM deal, while taking into account the varied debt levels, would imply about a $39-per-share price for Avangrid. Hence, there is a bit of room for an improved offer from Iberdrola.

Most existing shareholders should exit their positions in the open market. This can be a lengthy process and the offer is nonbinding, so there's no guarantee a deal will get done. On the other hand, there may be $1-$3 per share of upside and a few more dividends to collect. The Timeliness rank for this equity is suspended due to the buyout proposal.

Anthony J. Glennon *May 10, 2024*

(A) Diluted egs. Excl. nonrecur. gain/(loss): '16, 6¢; '17, (44¢); '19, 9¢; '20, (14¢); '21, (21¢); '22, (5¢); '23, (6¢); 1Q '24, 3¢. Qtly. EPS may not sum to full-year due to rounding. Next egs. report due late July. (B) Div'ds paid in early Jan., Apr., July and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '23: $6,214 mill., $16.07/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in NY in '23: 9.2%; in CT in '23: 8.63% elec.; in CT in '19: 9.3% gas; in ME in '22: 9.25%. Regulatory Climate: Below Average.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	35
Earnings Predictability	80

AVISTA CORP. NYSE-AVA

RECENT PRICE	35.44	P/E RATIO	14.6 (Trailing: 15.9; Median: 19.0)	RELATIVE P/E RATIO	0.79	DIV'D YLD	5.4%	VALUE LINE

TIMELINESS 3 Lowered 2/9/24
SAFETY 3 Lowered 1/19/24
TECHNICAL 5 Lowered 4/19/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$28-$55	$42 (15%)

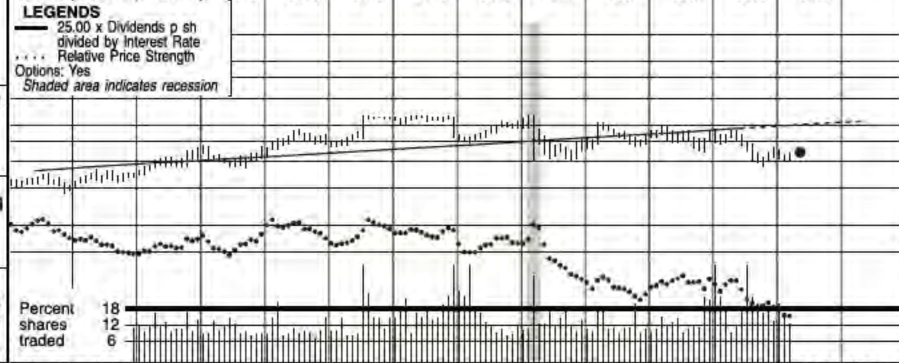
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+70%)	18%
Low	40	(+15%)	9%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	109	141	146
to Sell	133	115	121
Hld's(000)	67636	65779	66647

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	29.3	37.4	38.3	45.2	52.8	52.9	49.5	53.0	49.1	46.9	45.3	36.6
Low:	24.1	27.7	29.8	34.3	37.8	41.9	39.8	32.1	36.7	35.7	30.5	31.9



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-13.1	16.9
3 yr.	-16.1	16.2
5 yr.	5.7	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	21.27	20.03	19.09	20.13	22.82	22.43	21.50	22.00	Revenues per sh	23.50
3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	6.06	5.16	5.34	5.47	5.63	5.85	6.15	"Cash Flow" per sh	6.50
1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	2.07	2.97	1.90	2.10	2.12	2.24	2.40	2.60	Earnings per sh A	2.90
.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	1.49	1.55	1.62	1.69	1.76	1.84	1.92	2.00	Div'd Decl'd per sh B ■	2.25
4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	6.46	6.59	5.84	6.15	6.03	6.39	6.95	7.15	Cap'l Spending per sh	7.50
18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	26.99	28.87	29.31	30.14	31.15	31.83	32.85	33.50	Book Value per sh C	35.00
54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	65.69	67.18	69.24	71.50	74.95	78.08	79.00	81.00	Common Shs Outst'g D	85.00
15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	24.5	15.0	21.2	20.2	20.0	17.1	Bold figures are		Avg Ann'l P/E Ratio	17.0
.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	.80	1.09	1.09	1.16	.95	Value Line		Relative P/E Ratio	.95
3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%	2.9%	3.5%	4.0%	4.0%	4.2%	4.8%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 12/31/23
Total Debt $2621.0 mill. **Due in 5 Yrs** $40.0 mill.
LT Debt $2606.4 mill. **LT Interest** $150.0 mill.
Incl. $51.5 mill. debt to affiliated trusts; $39.9 mill. finance leases.
(LT interest earned: 2.1x)
Leases, Uncapitalized Annual rentals $10.4 mill.
Pension Assets-12/23 $589.3 mill. **Oblig** $585.3 mill.
Pfd Stock None

Common Stock 78,161,596 shs. **as of 1/31/24**
MARKET CAP: $2.8 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1472.6	1484.8	1442.5	1445.9	1396.9	1345.6	1321.9	1438.9	1710.2	1751.6	1700	1780	Revenues ($mill)	1995
114.2	118.1	137.2	126.1	136.4	197.0	129.5	147.3	155.2	171.2	190	210	Net Profit ($mill)	245
37.6%	36.3%	36.3%	36.5%	16.0%	13.8%	5.2%	7.5%	7.5%	NMF	15.0%	15.0%	Income Tax Rate	15.0%
11.1%	10.1%	8.1%	7.9%	7.7%	5.5%	8.5%	7.5%	2.4%	2.1%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
51.0%	50.0%	51.2%	47.2%	50.5%	49.4%	50.4%	47.5%	50.4%	51.2%	51.0%	51.0%	Long-Term Debt Ratio	50.5%
49.0%	50.0%	48.8%	52.8%	49.5%	50.6%	49.6%	52.5%	49.6%	48.8%	49.0%	49.0%	Common Equity Ratio	49.5%
3027.3	3060.3	3379.0	3273.2	3580.3	3834.6	4089.8	4104.7	4709.7	5091.3	5300	5500	Total Capital ($mill)	6000
3620.0	3898.6	4147.5	4398.8	4648.9	4797.0	4991.6	5225.5	5444.7	5700.1	5950	6250	Net Plant ($mill)	7000
4.9%	5.1%	5.3%	5.0%	4.8%	6.2%	4.2%	4.7%	4.6%	4.8%	4.5%	5.0%	Return on Total Cap'l	5.0%
7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.6%	6.9%	7.5%	7.5%	Return on Shr. Equity	8.5%
7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.6%	6.9%	7.5%	7.5%	Return on Com Equity E	8.5%
2.4%	2.3%	3.0%	1.9%	2.2%	4.9%	.9%	1.4%	1.1%	1.2%	1.5%	2.0%	Retained to Com Eq	2.0%
69%	70%	64%	73%	72%	52%	85%	80%	83%	82%	80%	77%	All Div'ds to Net Prof	77%

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+4.3	+3.1	-4.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.98	9.99	10.58
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1889	1860	1809
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	-1.0	+1.4
Fixed Charge Cov. (%)	216	175	200

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.0%	--	2.0%
"Cash Flow"	3.5%	1.5%	3.5%
Earnings	3.0%	1.0%	6.0%
Dividends	4.5%	4.5%	4.5%
Book Value	4.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	412.9	298.2	296.0	431.8	1438.9
2022	462.7	378.6	359.4	509.5	1710.2
2023	474.6	379.9	379.6	517.5	1751.6
2024	470	370	400	460	1700
2025	490	380	410	500	1780

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.98	.20	.20	.71	2.10
2022	.99	.16	d.08	1.05	2.12
2023	.73	.23	.19	1.08	2.24
2024	.95	.20	.20	1.05	2.40
2025	1.00	.25	.25	1.10	2.60

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.405	.405	.405	.405	1.62
2021	.4225	.4225	.4225	.4225	1.69
2022	.44	.44	.44	.44	1.76
2023	.46	.46	.46	.46	1.84
2024	.475				

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 416,000 electric, 381,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 36%; commercial, 29%; industrial, 9%; wholesale, 21%; other, 5%. Generating sources: gas & coal, 41%; hydro, 25%; purch., 42%. Fuel costs: 35% of revs. '23 reported depr. rate (Avista Utilities): 3.5%. Has 1,858 employees. Chairman: Scott L. Morris. Pres. & CEO: Dennis Vermillion. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista Utilities, a subsidiary of Avista Corporation, has pending electric and natural gas rate cases. In January, the utility filed multiyear electric and natural gas rate cases with the Washington Utilities and Transportation Commission (WUTC). These proposed adjustments aim to increase annual base electric revenues by $77.1 million (13.0%) in December 2024 and $53.7 million (11.7%) in December 2025. For natural gas, the proposed hikes are $17.3 million (13.6%) in December 2024 and $4.6 million (3.2%) in December 2025. These rate increases are based on a 10.4% return on equity with a common equity ratio of 48.5% and a rate of return on a rate base of 7.61%. Upon approval, the new rates are anticipated to take effect in December 2024 and 2025, remaining intact until 2026. The company is also seeking changes to the Energy Recovery Mechanism (ERM), intending to shift to a 95% customer and 5% company sharing of power supply costs above or below the authorized level. The decision period by WUTC for the filing is usually 11 months.

Share profits this year and next will likely advance at a mid- to high-single-digit pace. Although Avista anticipates some weakness in the bottom line due to the adverse effects of the ERM, the overall net outlook for the year and beyond appears promising. This optimism mostly stems from the continued support of results by the improved cost recovery thanks to the 2023 general rate cases. Nevertheless, power supply costs and interest rates are still on the higher side. All told, we remain cautiously optimistic.

Ongoing capital investments should pave the way for future rate cases. Avista plans to prioritize investments aimed at enhancing and expanding its infrastructure. It also remains committed to advancing clean energy goals. To mention briefly, during rate case negotiations, utilities usually present their ongoing or completed capital projects as evidence for the need for increased revenue to cover costs. All told, these efforts should justify upcoming rate increases.

Shares of Avista have good capital appreciation potential over the next 18 months. What's more, the dividend yield (5.4%) is higher than the sector's average.

Emma Jalees *April 19, 2024*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on discont. ops.: '14, $1.17; '15, 8¢. EPS may not sum due to rounding. Next earnings report due May 1st. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '23: $973.8 mill., $12.47/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in WA in '21: 9.4%; in ID in '21: 9.4%; in OR in '21: 9.4%; earned on avg. com. eq., '22: 7.1%. Regulatory Climate: WA, Below Avg.; ID, Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	70
Price Growth Persistence	30
Earnings Predictability	70

BLACK HILLS CORP. NYSE-BKH

RECENT PRICE 54.50 | P/E RATIO 14.2 (Trailing: 13.9, Median: 18.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Raised 12/1/23
SAFETY 3 Lowered 1/19/24
TECHNICAL 4 Lowered 3/22/24
BETA 1.05 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	55.1	62.1	53.4	64.6	72.0	68.2	82.0	87.1	72.8	80.9	74.0	56.1
Low:	36.9	47.1	36.8	44.7	57.0	50.5	60.8	48.1	58.2	59.1	46.4	49.3

LEGENDS
— 23.0 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

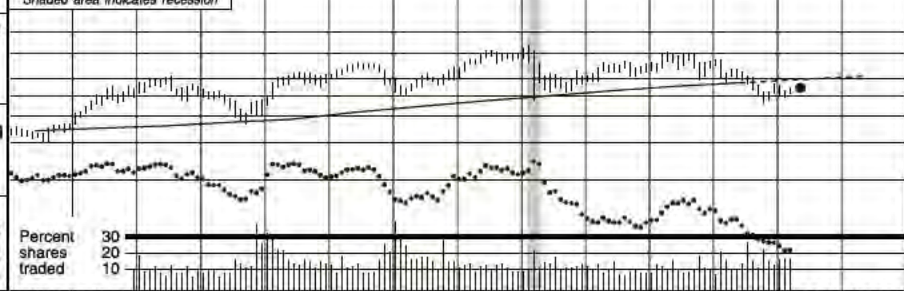
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$43-$85 $64 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+55%)	15%
Low	55	(Nil)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	164	162	200
to Sell	136	148	147
Hld's(000)	58479	58260	59277



Target Price Range 2027 | 2028 | 2029
200 160 100 80 60 50 40 30 20

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-9.4	16.9
3 yr.	-8.3	16.2
5 yr.	-12.5	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38	29.24	28.22	27.02	30.11	38.60	34.18	*35.70*	*36.10*	Revenues per sh	*38.95*
2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15	6.61	7.02	7.41	7.41	7.85	7.76	*7.95*	*8.30*	"Cash Flow" per sh	*9.65*
.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38	3.47	3.53	3.73	3.74	3.97	3.91	*3.90*	*4.10*	Earnings per sh A	*4.75*
1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	1.81	1.93	2.05	2.17	2.29	2.41	2.50	*2.60*	*2.70*	Div'd Decl'd per sh B ■	*3.00*
8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09	7.62	13.31	12.22	10.47	9.14	8.15	*11.70*	*11.10*	Cap'l Spending per sh	*11.25*
27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	31.92	36.36	38.42	40.79	43.05	45.31	47.15	*48.80*	*50.35*	Book Value per sh C	*55.75*
38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54	60.00	61.48	62.79	64.74	66.10	68.20	*70.00*	*72.00*	Common Shs Outst'g D	*75.00*
NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	19.5	16.8	21.2	17.0	17.7	18.1	15.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	1.13	.87	.96	1.05	.85	*Value Line*		Relative P/E Ratio	*.80*
4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	2.7%	3.3%	2.7%	3.4%	3.5%	3.4%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $4401.2 mill. **Due in 5 Yrs** $1660.0 mill.
LT Debt $3801.2 mill. **LT Interest** $170.0 mill.
(Total Interest Coverage: 2.6x)
Leases, Uncapitalized Annual rentals $2.2 mill.

Pension Assets-12/22 $308.6 mill. **Oblig** $348.1 mill.

Pfd Stock None

Common Stock 68,196,551 shs. as of 1/31/24

MARKET CAP: $3.7 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1393.6	1304.6	1573.0	1680.3	1754.3	1734.9	1696.9	1949.1	2551.8	2331.3	*2500*	*2600*	Revenues ($mill)	*2920*
128.8	128.3	140.3	186.5	192.5	214.5	232.9	236.7	258.4	262.2	*270*	*290*	Net Profit ($mill)	*355*
33.7%	35.8%	25.1%	28.7%	19.2%	13.0%	12.2%	2.8%	8.5%	8.5%	*8.5%*	*8.5%*	Income Tax Rate	*8.5%*
2.4%	2.7%	5.3%	2.7%	1.4%	3.3%	2.5%	2.0%	2.4%	2.4%	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
47.9%	56.0%	66.5%	64.5%	57.5%	57.1%	57.9%	59.7%	54.6%	54.2%	*54.5%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
52.1%	44.0%	33.5%	35.5%	42.5%	42.9%	42.1%	40.3%	45.4%	45.8%	*45.5%*	*45.0%*	Common Equity Ratio	*44.0%*
2643.6	3332.7	4825.8	4818.4	5132.4	5502.2	6089.5	6914.0	6602.3	7016.5	*7530*	*8030*	Total Capital ($mill)	*9525*
3239.4	3259.1	4469.0	4541.4	4854.9	5503.2	6019.7	6449.2	6797.9	7119.3	*7650*	*8150*	Net Plant ($mill)	*9775*
6.1%	4.9%	4.0%	5.2%	5.0%	4.9%	5.0%	4.5%	5.1%	4.9%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	8.6%	8.2%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	8.6%	8.2%	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
4.3%	3.8%	3.3%	5.3%	3.9%	3.8%	3.8%	3.3%	3.4%	2.9%	*2.5%*	*3.0%*	Retained to Com Eq	*3.0%*
54%	57%	62%	52%	55%	58%	58%	61%	61%	64%	*67%*	*66%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+1.5	+3.4	+1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1078	1107	1101
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	+.9
Fixed Charge Cov. (%)	259	281	254

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	2.5%	*2.5%*
"Cash Flow"	4.0%	3.0%	*4.0%*
Earnings	7.5%	4.0%	*3.5%*
Dividends	5.0%	6.0%	*4.0%*
Book Value	5.0%	6.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	633.4	372.6	380.6	562.5	1949.1
2022	823.6	474.2	462.6	791.4	2551.8
2023	921.2	411.3	407.1	591.7	2331.3
2024	*940*	*450*	*460*	*650*	*2500*
2025	*975*	*470*	*480*	*675*	*2600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.54	.40	.70	1.11	3.74
2022	1.82	.52	.54	1.11	3.97
2023	1.73	.35	.67	1.17	3.91
2024	*1.70*	*.40*	*.58*	*1.22*	*3.90*
2025	*1.75*	*.40*	*.65*	*1.30*	*4.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.535	.535	.535	.565	2.17
2021	.565	.565	.565	.595	2.29
2022	.595	.595	.595	.625	2.41
2023	.625	.625	.625	.625	2.50
2024	.65				

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 222,340 electric customers in CO, SD, WY and MT, and 1.12 million gas customers in NE, IA, KS, CO, WY, and AR. Has coal mining sub. Acq'd utility ops. from Aquila 7/08; SourceGas 2/16. Discontinued gas marketing in '11; gas & oil E&P in '17. Electric rev. breakdown: residential, 34%; commercial, 39%; industrial, 24%; other, 3%. Generating sources: coal, 35%; gas, 26%; wind, 9%; purchased, 30%. Fuel costs: 38% of revs. '23 deprec. rate: 2.9%-3.5%. Has 2,874 employees. Chairman: Steven R. Mills. President & CEO: Linden R. Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Telephone: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills will likely post flat per-share profits this year. With the fourth-quarter financial release, management provided bottom-line targets for the year ahead. The company expects to earn $3.80-$4.00 a share in 2024. This reflects a 4% increase at the midpoint from 2023's initial in-house targeted range of $3.65-$3.85 a share. Ultimately Black Hills earned $0.16 above plan last year ($3.91 versus $3.75 at the midpoint) as a result of some one-off, non-operating items that aren't expected to repeat again.

Share dilution and regulatory lag are problematic for earnings-per-share growth. We're actually forecasting a rise in net profits this year, but because the cost of borrowing has gone up so much in recent years, it's become increasingly difficult for regulated utilities to sustain their share-earnings growth rates. On the one hand, there's no lack of capital investment projects to go after, but the payoff for company's such as Black Hills is not what it was previously. Because most utilities, including this equity, are down significantly from their highs of a few years ago, they are receiving less funds and suffering more dilution when floating equity to keep the balance sheet viable. Meanwhile, regulators are looking backwards to what borrowing costs were over the past number of years and are in turn setting authorized return on equity (ROE) levels that aren't reflective of today's market. Seeing the reality of that situation, BKH management lowered its long-term expected growth rate for earnings per share, to 4%-6% from 5%-7%, last year.

The company is filing for rate relief in key service areas. Black Hills received incremental revenue increases through the regulatory process last year. They secured an additional $13.9 million annually from the Wyoming gas jurisdiction in May. They also have a $20.2 million settlement agreement in place for Colorado gas, that's expected to gain final approval this quarter. A $44 million Arkansas gas request has been submitted and BKH is preparing to file rate cases for Iowa gas and Colorado electric shortly.

The main draw here for long-term investors is reliable dividend growth and an above-average yield.

Anthony J. Glennon *April 19, 2024*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '15, ($3.54); '16, ($1.26); '17, 14¢; '18, $1.31; '19, (25¢); '20, (8¢); discont. ops.: '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢); '17, (31¢); '18, (12¢). Qtly. EPS may not sum to full year due to rounding. Next egs. report due early May. (B) Div'ds paid in early March, June, Sept., and Dec. ■ Div'd reinv. plan avail. (C) Incl. deferred chgs. and intagibles in '23: $23.64/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SD in '15: none specified; in CO in '17: 9.37%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	100

CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE **29.51** | P/E RATIO **20.4** (Trailing: 20.8; Median: 19.0) | RELATIVE P/E RATIO **1.14** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS 3 Lowered 5/24/24
SAFETY 3 Lowered 12/18/15
TECHNICAL 3 Raised 6/7/24
BETA 1.15 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$26-$37	$32 (5%)

2027-29 PROJECTIONS

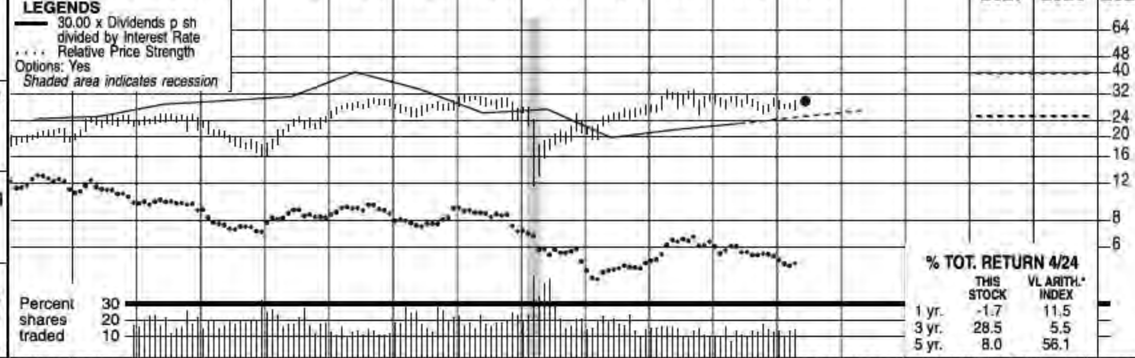
	Price	Gain	Ann'l Total Return
High	40	(+35%)	10%
Low	25	(-15%)	-1%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	257	258	300
to Sell	272	270	251
Hld's(000)	562002	579775	591989

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	25.7	25.8	23.7	25.0	30.5	29.6	31.4	27.5	28.4	33.5	31.5	30.4
Low:	19.3	21.1	16.0	16.4	24.5	24.8	24.3	11.6	19.3	25.0	25.4	26.9

LEGENDS
— 30.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range

2027	2028	2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.7	11.5
3 yr.	28.5	5.5
5 yr.	8.0	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	22.30	21.13	24.49	13.45	13.28	14.81	13.78	*13.75*	*14.20*	Revenues per sh	*17.00*
3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	4.03	3.24	4.12	3.46	3.00	3.65	3.67	*3.80*	*4.00*	"Cash Flow" per sh	*4.50*
1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	1.57	.74	1.49	1.29	.94	1.59	1.37	*1.45*	*1.55*	Earnings per sh A	*1.90*
.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	1.12	.86	.90	.66	.72	.77	*.83*	*.89*	Div'd Decl'd per sh B ■	*1.01*
2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	3.31	3.29	4.99	4.71	5.03	7.02	6.97	*6.85*	*5.95*	Cap'l Spending per sh	*6.50*
5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	10.88	12.53	13.10	10.78	13.70	14.68	15.31	*16.35*	*17.10*	Book Value per sh C	*20.00*
346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	431.04	501.20	502.24	551.36	628.92	629.54	631.23	*640.00*	*641.00*	Common Shs Outst'g D	*645.00*
11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	17.9	37.0	19.5	15.9	26.1	18.7	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	2.00	1.04	.82	1.41	1.08	1.18	*Value Line*		Relative P/E Ratio	*1.00*
5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%	4.8%	4.1%	3.0%	4.4%	2.7%	2.4%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $18295 mill. **Due in 5 Yrs** $7300 mill.
LT Debt $18117 mill. **LT Interest** $800 mill.
Incl. $320 mill. securitized transition & system restoration bonds.
(LT interest coverage: 2.5x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/23 $1204 mill. **Oblig** $1548 mill.
Pfd Stock None
Common Stock 639,724,143 shs. as of 4/22/24
MARKET CAP: $18.9 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
9226.0	7386.0	7528.0	9614.0	10589	12301	7418.0	8352.0	9321.0	8696.0	*8800*	*9100*	Revenues ($mill)	*11000*
611.0	465.0	432.0	679.0	368.0	871.0	863.0	668.0	1057.0	917.0	*980*	*1055*	Net Profit ($mill)	*1285*
31.0%	35.1%	37.0%	36.1%	28.4%	14.9%	13.4%	14.1%	25.4%	15.6%	*16.0%*	*16.0%*	Income Tax Rate	*16.0%*
4.1%	4.7%	3.5%	2.9%	5.4%	6.7%	6.0%	9.3%	9.3%	5.0%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
63.8%	69.5%	68.5%	63.6%	51.9%	63.0%	58.0%	62.3%	59.6%	64.5%	*63.5%*	*62.5%*	Long-Term Debt Ratio	*59.0%*
36.2%	30.5%	31.5%	36.4%	37.5%	29.1%	29.9%	34.5%	37.1%	35.5%	*36.5%*	*37.5%*	Common Equity Ratio	*41.0%*
12557	11362	10992	12883	16740	22603	19869	24973	24878	27226	*28550*	*29175*	Total Capital ($mill)	*31300*
10502	11537	12307	13057	14044	20945	22362	23484	27143	29853	*32750*	*35000*	Net Plant ($mill)	*41000*
6.7%	6.1%	5.8%	6.8%	3.4%	5.1%	5.6%	3.8%	5.3%	4.7%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
13.4%	13.4%	12.5%	14.5%	4.6%	10.4%	10.3%	7.1%	10.5%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
13.4%	13.4%	12.5%	14.5%	5.3%	11.5%	11.6%	6.7%	10.9%	9.5%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
4.5%	1.1%	NMF	4.7%	NMF	2.7%	5.0%	2.2%	6.1%	4.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
67%	92%	103%	68%	NMF	80%	66%	72%	46%	53%	*54%*	*54%*	All Div'ds to Net Prof	*51%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (GWH)	+1.8	+2.0	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+2.5	+2.0	+2.0%
Fixed Charge Cov. (%)	135	252	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-7.0%	3.5%
"Cash Flow"	-.5%	-1.0%	4.5%
Earnings	- -	3.5%	6.5%
Dividends	-1.0%	-9.5%	6.0%
Book Value	4.0%	7.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2021	2547	1742	1749	2314	8352
2022	2763	1944	1903	2711	9321
2023	2779	1875	1860	2182	8696
2024	2620	*1900*	*1950*	*2330*	*8800*
2025	*2250*	*2250*	*2300*	*2300*	*9100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2021	.41	.29	.21	.03	.94
2022	.82	.28	.30	.19	1.59
2023	.49	.17	.40	.30	1.37
2024	.55	*.20*	*.45*	*.25*	*1.45*
2025	*.50*	*.25*	*.50*	*.30*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.29	.15	.15	.15	.74
2021	.16	.16	.16	.17	.65
2022	.17	.17	.18	.18	.70
2023	.18	.19	.19	.20	.76
2024	.20	.20			

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves over 2.76 million customers in Houston and environs. Indiana Electric, which serves approximately 152,000 customers, and gas utilities with 4.31 million customers in Texas, Minnesota, Louisiana, Mississippi, Indiana, and Ohio. Acquired Vectren 2/19. Sold nonutility operations in '20. Sold its stake in Energy Transfer LP in '22 and '23. Electric revenue breakdown not available. Fuel costs: 25% of total revenues. Has 8,827 employees. Chairman: Martin H. Nesbitt. President & Chief executive officer: Jason P. Wells. Incorporated: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Telephone: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy registered mixed first-quarter results. The top line fell 6% year over year, to $2.6 billion, primarily due to soft utility revenues, particularly in natural gas. However, the bottom line increased 12%, to $0.55 per share, driven by rate recovery, favorable weather, and improved usage metrics.

The utility appears to be progressing as planned with its previously announced gas asset sales. CenterPoint filed approval applications with the regulator in April regarding the transaction involving the Louisiana and Mississippi Gas local distribution companies (LDCs). The divestiture is projected to yield approximately $1 billion in after-cash proceeds and is expected to conclude in the first quarter of 2025. The decision to sell these LDCs reflects the company's strategic focus on jurisdictions where it maintains a notable presence in electric and gas utilities. After the sale, CenterPoint estimates its utility mix to be 66% electric and 34% gas.

We look for near-term share earnings to proceed at a mid-single-digit pace. Benefits from rate relief and new customer wins should support the bottom line. Also, operations and maintenance cost controls have been ongoing, aimed at 1% to 2% annual cost reductions. All things considered, we expect 2024 and 2025 earnings per share to clock in at about $1.45 and $1.55, respectively.

CenterPoint has developed a comprehensive plan to enhance the resilience of the electric grid in Texas. The proposal includes upgrading transmission infrastructures, modernizing old transmission lines to meet current standards, and elevating substations to reduce flood risks. We believe this initiative represents a valuable capital investment, especially in light of recent power outages and restoration efforts in the region. The company anticipates making capital investments in the range of $2.2 billion to $2.7 billion through 2027.

Shares of CenterPoint have below average capital gains prospects over the next 18 months and the 2027-2029 time frame. The dividend yield is low for a utility, as well. Consequently, income-oriented investors may find better selections in the sector.

Emma Jalees *June 7, 2024*

(A) GAAP Dil. EPS 2022 & onwards. Excl. nonrecur. gains (losses): '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; '20, ($2.74); gain (loss) on disc. ops.: '20, (34¢); '21, $1.34. Next egs. report due late July. (B) Div'ds histor. paid in early Mar., June, Sept. & Dec. 5 declarations in '17 & '20, 3 in '19. ■ Div'd reinv. plan avail. (C) Incl. intang. In '23: $6.59/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. (elec.) in '20: 9.4%; (gas): 9.45%-11.25%; earned on avg. com. eq., '22: 8.27%. Regulatory Climate: TX, Avg.; IN, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	40
Earnings Predictability	55

CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 61.43 | P/E RATIO 18.6 (Trailing: 18.7 Median: 21.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 5/10/24
SAFETY 2 Raised 3/8/24
TECHNICAL 3 Raised 6/7/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$79	$66 (5%)

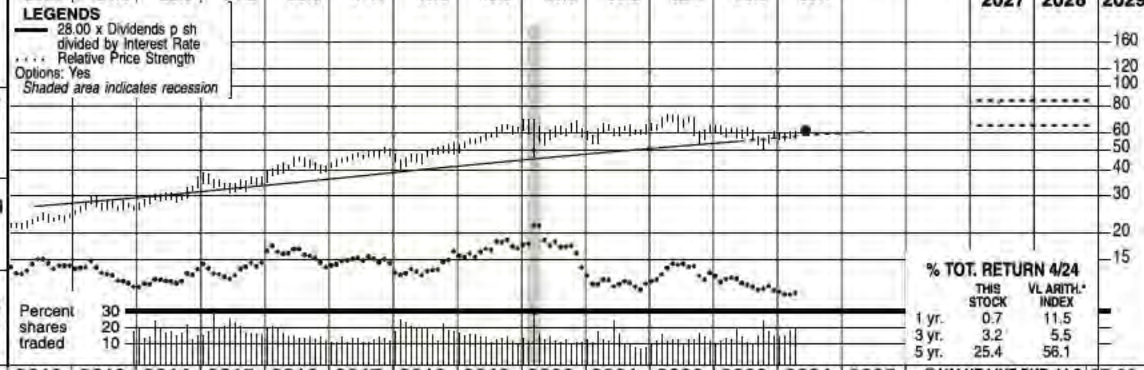
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+40%)	12%
Low	65	(+5%)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	297	272	293
to Sell	262	309	311
Hld's(000)	284222	280935	286313

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	30.0	36.9	38.7	46.3	50.8	53.8	65.3	69.2	65.8	73.8	65.7	63.7
Low:	24.6	26.0	31.2	35.0	41.1	40.5	48.0	46.0	53.2	52.4	49.9	55.1



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.7	11.5
3 yr.	3.2	5.5
5 yr.	25.4	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	23.37	24.25	24.11	23.12	25.29	29.51	25.35	26.35	26.95	Revenues per sh	31.05
3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	5.29	5.61	5.89	6.24	6.42	6.69	6.98	7.95	8.50	"Cash Flow" per sh	9.25
1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	2.17	2.32	2.39	2.64	2.58	2.84	3.01	3.30	3.50	Earnings per sh A	3.75
.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	1.33	1.43	1.53	1.63	1.74	1.84	1.95	2.08	2.16	Div'd Decl'd per sh B ■	2.30
3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	5.91	7.32	7.41	8.02	7.16	8.15	8.18	10.00	9.65	Cap'l Spending per sh	9.75
10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	15.77	16.78	17.68	19.02	22.11	23.32	24.86	26.15	27.85	Book Value per sh C	29.50
226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	281.65	283.37	283.86	288.94	289.76	291.27	294.40	300.00	300.50	Common Shs Outst'g D	301.00
10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	21.3	20.3	24.3	23.3	23.6	22.9	19.6	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	20.0
.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	1.29	1.20	1.28	1.32	1.10			Relative P/E Ratio	1.10
2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	2.9%	3.0%	2.6%	2.6%	2.9%	2.8%	3.3%			Avg Ann'l Div'd Yield	3.1%
						7179.0	6456.0	6399.0	6583.0	6873.0	6845.0	6680.0	7329.0	8596.0	7462.0	7900	8100	Revenues ($mill)	9350
						479.0	525.0	553.0	610.0	659.0	682.0	757.0	751.0	833.0	886.0	995	1065	Net Profit ($mill)	1140
						34.3%	34.0%	33.1%	31.2%	14.9%	17.7%	15.0%	11.5%	10.3%	15.4%	15.5%	15.5%	Income Tax Rate	15.5%
						2.3%	2.7%	3.1%	1.1%	1.4%	2.1%	1.1%	1.5%	1.4%	1.4%	1.5%	1.0%	AFUDC % to Net Profit	1.0%
						68.7%	68.3%	67.1%	67.3%	69.0%	70.4%	71.2%	64.5%	65.3%	65.9%	65.0%	65.0%	Long-Term Debt Ratio	63.0%
						31.0%	31.4%	32.6%	32.4%	30.7%	29.4%	28.6%	34.2%	33.6%	33.1%	35.0%	35.0%	Common Equity Ratio	37.0%
						11846	12534	13040	13692	15476	17082	19223	18760	20205	22114	23075	23800	Total Capital ($mill)	24500
						13412	14705	15715	16761	18126	18926	21039	22352	22713	25072	27450	28850	Net Plant ($mill)	31500
						5.7%	5.7%	5.8%	5.9%	5.6%	5.3%	5.2%	5.3%	5.4%	5.4%	5.5%	6.0%	Return on Total Cap'l	6.0%
						12.9%	13.2%	12.9%	13.6%	13.8%	13.5%	13.7%	11.3%	11.9%	11.7%	12.0%	12.5%	Return on Shr. Equity	12.5%
						13.0%	13.3%	13.0%	13.7%	13.8%	13.6%	13.7%	11.6%	12.1%	12.0%	12.5%	12.5%	Return on Com Equity E	12.5%
						5.0%	5.2%	4.8%	5.2%	5.3%	4.9%	5.3%	3.8%	4.3%	4.2%	4.5%	5.0%	Retained to Com Eq	5.0%
						62%	61%	63%	62%	62%	64%	62%	68%	65%	65%	63%	62%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $15806 mill. **Due in 5 Yrs** $2771 mill.
LT Debt $15034 mill. **LT Interest** $649 mill.
Incl. $61 mill. finance leases.
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/23 $3004 mill.
Oblig $2195 mill.
Pfd Stock $224 mill. **Pfd Div'd** $10 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00; 9,200,000 shs. 4.2%, $25 par, cum.
Common Stock 298,635,428 shs.
as of 4/8/24
MARKET CAP: $18.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+2.4	+3.0	-1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.46	8.78	8.90
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	7951	8061	8067
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	+1.0
Fixed Charge Cov. (%)	223	226	244

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	1.0%	2.5%	2.5%
"Cash Flow"	5.5%	5.0%	5.5%
Earnings	6.0%	5.5%	5.0%
Dividends	7.0%	6.5%	4.0%
Book Value	6.5%	8.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2013	1558	1725	2033	7329
2022	2374	1920	2024	2278	8596
2023	2284	1555	1673	1950	7462
2024	2176	1700	1875	2149	7900
2025	2200	1745	2000	2155	8100

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.09	.55	.54	.40	2.58
2022	1.20	.50	.56	.58	2.84
2023	.69	.67	.60	1.05	3.01
2024	.96	.65	.70	.99	3.30
2025	.80	.90	.80	1.00	3.50

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2020	.4075	.4075	.4075	.4075	1.63
2021	.435	.435	.435	.435	1.74
2022	.46	.46	.46	.46	1.84
2023	.4875	.4875	.4875	.4875	1.95
2024	.515	.515			

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.9 million electric, 1.8 million gas customers. Has 2,016 megawatts of nonregulated generating capacity. Sold EnerBank in '21. Electric revenue breakdown: residential, 47%; commercial, 33%; industrial, 14%; other, 6%. Generating sources: coal, 20%; gas, 33%; renewables, 6%; purchased, 43%. Fuel costs: 37% of revenues. '23 depreciation rates: 3.8% electric, 2.8% gas, 7.8% other. Has 8,350 full-time employees. Chairman: John G. Russell. President & CEO: Garrick Rochow. Inc.: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Telephone: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy reported mixed results for the March period. The top line declined 5% year over year, to nearly $2.2 billion. However, the bottom line jumped almost 40%, to $0.96 per share, compared to the year-ago period. This improvement was due to lower operating expenses and benefits from rate relief. For 2024, management has guided for annual adjusted earnings per share in the range of $3.29 to $3.35. Additionally, the company anticipates achieving adjusted earnings growth of 6% to 8% over the long term.

CMS Energy's subsidiary, Consumers Energy, received an electric rate order. The Michigan Public Service Commission authorized an annual rate increase of $92 million, with a 9.9% return on equity. The new rate took effect on March 15, 2024.

Near-term profit growth is probable. The company should benefit from rate relief and ongoing cost controls. Thus, we expect 2024 and 2025 share earnings to advance in the management-guided range of 6%- 8%.

The utility is actively expanding its infrastructure to enhance cost savings and increase profitability. The company anticipates investing $17 billion through 2028 to upgrade its infrastructure. Of this total, $6.3 billion will likely be allocated to gas networks, $7.3 billion to electric distribution, and $3.4 billion to clean energy projects. This investment strategy is projected to grow the rate base by 7.5% over the specified period, enabling the company to maintain affordable prices for its customers. To note, utility companies typically have incentives to invest in such capital projects.

Meanwhile, the company is advancing smart technology deployment through its subsidiary to enhance electric reliability. Consumers Energy intends to invest $24 million in smart technology initiatives aimed at fortifying its electric grid and mitigate power outages. This investment aligns with its ongoing Reliability Roadmap, designed to bolster the resilience of the electric infrastructure.

This untimely stock has a dividend yield that is below average for a utility. Also, these shares do not stand out for 18-month capital gains potential.

Emma Jalees *June 7, 2024*

(A) Diluted GAAP EPS. Excl. nonrec. gains (losses): '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢; '21, $2.08; '22, 1¢. Next earnings report due late July. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '23: $8.52/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '22: 9.9% elec.; in '19: 9.9% gas; earned on avg. com. eq., '21: 13.2%. Regulatory Climate: Above Average.

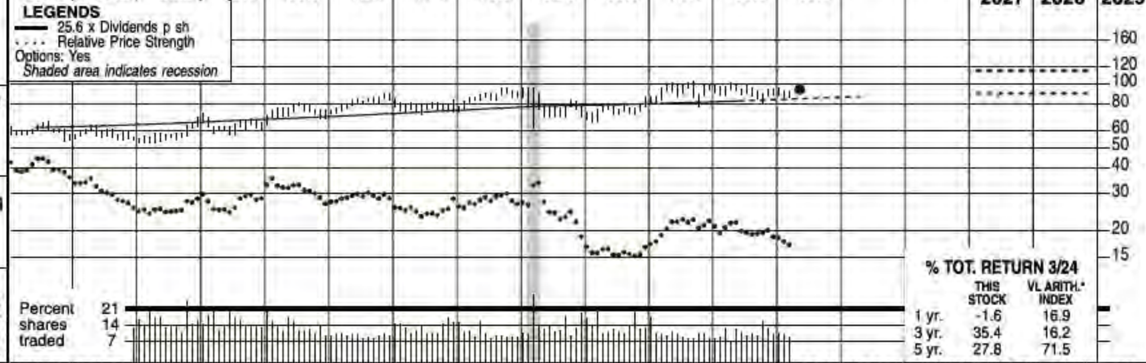
Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	90

CON. EDISON NYSE-ED

RECENT PRICE 93.97 | P/E RATIO 17.7 (Trailing: 18.6 Median: 18.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 2 Raised 5/3/24
SAFETY 1 New 7/27/90
TECHNICAL 5 Lowered 5/3/24
BETA .80 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	64.0	68.9	72.3	81.9	89.7	84.9	95.0	95.1	85.6	102.2	100.9	94.8
Low:	54.2	52.2	56.9	63.5	72.1	71.1	73.3	62.0	65.6	78.1	80.5	85.9



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$81-$121	$101 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+20%)	9%
Low	90	(-5%)	3%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	476	436	515
to Sell	461	483	450
Hld's(000)	224094	223737	230144

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.6	16.9
3 yr.	35.4	16.2
5 yr.	27.8	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	38.44	37.80	35.78	38.63	44.15	42.45	*44.80*	*46.85*	Revenues per sh	*53.50*
5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	8.92	9.39	9.70	10.06	10.36	10.98	*12.10*	*12.70*	"Cash Flow" per sh	*14.60*
3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	4.55	4.37	4.17	4.38	4.55	5.04	*5.30*	*5.60*	Earnings per sh A	*6.60*
2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	2.86	2.96	3.06	3.10	3.16	3.24	*3.32*	*3.40*	Div'd Decl'd per sh B ■	*3.95*
8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	10.90	10.48	11.42	11.17	11.74	13.01	*14.40*	*14.50*	Cap'l Spending per sh	*15.50*
35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	52.11	54.18	55.06	56.60	58.28	61.25	*63.50*	*65.75*	Book Value per sh C	*74.50*
273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	320.96	332.63	342.30	353.98	354.96	345.42	*346.00*	*347.00*	Common Shs Outst'g D	*355.00*
12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8	17.1	19.7	19.0	17.2	20.3	18.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	1.05	.98	.93	1.17	1.03	*Value Line*		Relative P/E Ratio	*.85*
5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%	3.7%	3.4%	3.9%	4.1%	3.4%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $24465 mill. **Due in 5 Yrs** $1730 mill.
LT Debt $21927 mill. **LT Interest** $962 mill.
(Total Interest Coverage: 3.0x)

Leases, Uncapitalized Annual rentals $70 mill.

Pension Assets-12/23 $15404 mill.
Oblig. $12712 mill.

Pfd Stock None

Common Stock 345,510,031 shs.
as of 1/31/24
MARKET CAP: $32.5 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
12919	12554	12075	12033	12337	12574	12246	13676	15670	14663	*15500*	*16250*	Revenues ($mill)	*19000*
1066.0	1193.0	1189.0	1266.0	1424.0	1438.0	1399.0	1528.0	1620.0	1762.0	*1835*	*1950*	Net Profit ($mill)	*2355*
34.0%	33.6%	35.3%	36.6%	20.1%	17.5%	12.9%	16.2%	15.4%	17.8%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
.3%	.7%	1.3%	1.5%	1.5%	1.9%	2.2%	2.1%	3.4%	4.4%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
48.0%	47.9%	50.8%	48.9%	51.1%	50.7%	52.0%	53.0%	49.3%	50.9%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
52.0%	52.1%	49.2%	51.1%	48.9%	49.3%	48.0%	47.0%	50.7%	49.1%	*49.0%*	*49.0%*	Common Equity Ratio	*48.0%*
24207	25058	29033	30149	34221	36549	39229	42641	40834	43085	*44200*	*46750*	Total Capital ($mill)	*55000*
29827	32209	35216	37600	41749	43889	46555	48596	46766	49608	*52300*	*54800*	Net Plant ($mill)	*63200*
5.6%	6.0%	5.3%	5.4%	5.3%	5.1%	4.7%	4.7%	5.2%	5.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
8.5%	9.1%	8.3%	8.2%	8.5%	8.0%	7.4%	7.6%	7.8%	8.3%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.5%	9.1%	8.3%	8.2%	8.5%	8.0%	7.4%	7.6%	7.8%	8.3%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
2.6%	3.5%	3.0%	3.0%	3.5%	2.9%	2.2%	2.5%	2.6%	3.1%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
69%	61%	64%	63%	59%	64%	70%	67%	67%	62%	*63%*	*60%*	All Div'ds to Net Prof	*60%*

CECONY ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Electric Sales (GWH)	-.5	+3.3	-1.4
Annual Residential Use (GWH)	11344	11875	11574
Annual Comm./Ind. Use (GWH)	9250	10522	10895
Annual Retail Choice (GWH)	21549	21116	20315
Annual Govt. & Other Use (GWH)	9185	9507	9472
% Change Customers (yr-end)	NA	NA	NA
Peak Load, Summer (MW)	13517	12424	11565
ConEd Fixed Charge Cov. (%)	352	240	217

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	- -	1.5%	*4.0%*
"Cash Flow"	4.0%	4.5%	*5.5%*
Earnings	2.0%	2.0%	*6.0%*
Dividends	2.5%	2.5%	*3.5%*
Book Value	4.0%	3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3677	2971	3613	3415	13676
2022	4060	3415	4165	4031	15670
2023	4403	2944	3872	3444	14663
2024	*4400*	*3125*	*4250*	*3725*	*15500*
2025	*4525*	*3275*	*4550*	*3900*	*16250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.44	.53	1.41	1.00	4.38
2022	1.47	.64	1.63	.81	4.55
2023	1.82	.61	1.61	1.00	5.04
2024	*1.85*	*.65*	*1.80*	*1.00*	*5.30*
2025	*1.90*	*.70*	*1.90*	*1.10*	*5.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.765	.765	.765	.765	3.06
2021	.775	.775	.775	.775	3.10
2022	.79	.79	.79	.79	3.16
2023	.81	.81	.81	.81	3.24
2024	.83				

BUSINESS: Consolidated Edison, Inc. (ConEd) is a holding company for Consolidated Edison Company of New York (CECONY), which sells electricity, gas, and steam in most of NY city and Westchester County. ConEd also owns Orange and Rockland utilities (O&R), which operates in southeastern NY and northern NJ. ConEd has 4.0 mill. electric and 1.3 mill. gas customers. Sold its portfolio of renewable power generation for $6.8 billion (3/23). Entered into midstream gas joint venture 6/16; sold it 7/21. Purchases most of its power. Fuel costs: 24% of revenues. '23 depreciation rate for CECONY: 3.6%. Employs about 14,600. Chairman, Pres., and CEO: Timothy Cawley. Inc.: NY. Addr.: 4 Irving Place, NY, NY 10003. Tel.: 212-460-4600. Internet.: www.conedison.com.

Consolidated Edison is enjoying a renaissance, driven by New York's clean energy goals. ConEd's earliest corporate entity, the New York Gas Light Company, received a state charter to install natural gas lines in lower Manhattan more than 200 years ago. Gas lanterns would light the city for a time, replacing the whale oil lamps that dated to the mid-18th century. The company was listed on the New York Stock Exchange in 1824 and is the longest continuously listed issue on the NYSE. In the early 20th century, it expanded into electricity and was renamed as Consolidated Edison Company of New York in 1936. To say that ConEd is a mature company would be an understatement. Earnings per share had slowed to about a 3% annual growth rate for the opening decade of the 21st century, and 1.8% in the second 10-year stretch, before starting to improve more recently. Most of its service area was fully built out decades ago, leaving very little new investments to be made in transmission and distribution work. That all changed when New York State decided to "go green" in a big way, and ConEd is reaping the rewards.

The company reaffirmed its 5%-7% bottom-line growth target through late decade. New York is a difficult regulatory environment, but in its latest rate case, which concluded last year, the utility held a solid bargaining position. ConEd needed a reasonable increase in its regulated return on equity (ROE), from the former 8.8%, before committing billions in modernization work, necessary to prepare the grid to receive renewable energy interfaces. As a result of last year's rate decision, the company is now at a 9.25% ROE, which translated into annualized price increases for electric and gas of $442 million and $217 million, respectively, from August of 2023. Additional increases of $518 million for electric and $173 million for gas take effect this summer, followed by another hike in August, 2025 of $382 million and $122 million, respectively. ConEd is now in the upper tier of its industry in terms of earnings growth prospects.

This equity is timely. However, investors with a longer-term bent should wait for a decent pullback, as total return potential is subpar at the recent quote.

Anthony J. Glennon *May 10, 2024*

(A) Diluted EPS. Excl. nonrec. gains/losses: '13, d32¢; '14, 9¢; '16, 18¢; '17, 84¢; '18, d13¢; '19, d29¢; '20, d89¢; '21, d53¢; '22, 11¢; '23, $2.17. Excl. gain on disc. ops.: '08, $1.01. Next egs. report due early August. Quarterly figures may not sum to full year due to rounding.
(B) Div'ds paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available.
(C) Incl. intang. In '23: $14.52/sh. (D) In mill.
(E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '23: 9.25%; O&R in '22: 9.2%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	100

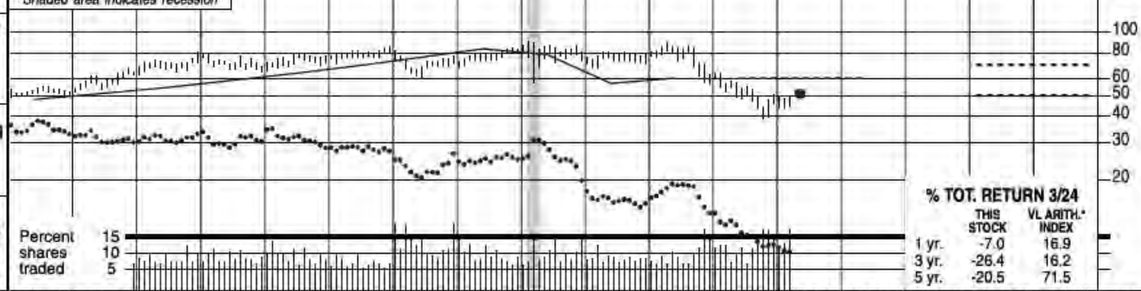
DOMINION ENERGY NYSE-D

RECENT PRICE 51.14 | P/E RATIO 18.3 (Trailing: 25.8; Median: 21.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 3 Raised 3/29/24
SAFETY 3 Lowered 9/29/23
TECHNICAL 5 Lowered 4/26/24
BETA .90 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	68.0	80.9	79.9	79.0	85.3	81.7	83.9	90.9	81.1	88.8	63.9	51.4
Low:	51.9	63.1	64.5	66.3	70.9	61.5	67.4	57.8	67.9	57.2	39.2	43.5

LEGENDS
— 22.7 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$60	$47 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+35%)	12%
Low	50	(Nil)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	562	485	467
to Sell	625	658	681
Hld's(000)	595361	609936	611917

Percent shares traded 15 10 5

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.0	16.9
3 yr.	-26.4	16.2
5 yr.	-20.5	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
27.94	25.26	26.16	25.23	22.73	22.58	21.26	19.60	18.69	19.51	19.63	19.78	17.58	17.24	20.57	17.18	*18.15*	*18.60*	Revenues per sh	*20.45*
5.07	4.82	5.10	5.04	5.24	5.47	5.71	5.99	6.32	6.89	7.24	7.65	7.17	7.27	7.81	5.58	*6.50*	*7.20*	"Cash Flow" per sh	*7.95*
3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	4.05	4.24	3.54	3.86	4.11	1.99	*2.80*	*3.35*	Earnings per sh A	*4.00*
1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	3.34	3.67	3.45	2.52	2.67	2.67	*2.67*	*2.67*	Div'd Decl'd per sh B ■	*2.67*
6.10	6.41	5.89	6.41	7.20	7.06	9.14	9.35	9.69	8.53	6.25	5.94	7.47	7.36	9.09	12.19	*12.70*	*12.45*	Cap'l Spending per sh	*9.00*
17.28	18.67	20.65	20.08	18.35	20.04	19.75	21.25	23.26	26.58	29.53	35.33	29.44	31.51	31.26	30.72	*31.00*	*31.90*	Book Value per sh C	*36.35*
583.00	599.00	581.00	570.00	576.00	581.00	585.00	596.00	628.00	645.00	681.00	838.00	806.00	810.00	835.00	838.00	*843.00*	*850.00*	Common Shs Outst'g D	*880.00*
13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	22.2	17.5	18.2	22.6	19.5	18.7	26.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	.95	.97	1.16	1.05	1.08	1.46	*Value Line*		Relative P/E Ratio	*.85*
3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	3.9%	4.7%	4.8%	4.3%	3.3%	3.5%	5.1%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $44243 mill. **Due in 5 Yrs** $13361 mill.
LT Debt $33248 mill. **LT Interest** $1674 mill.
(Total interest coverage: 2.2x)
Leases, Uncapitalized Annual rentals $60 mill.

Pension Assets-12/23 $9087 mill. **Oblig.** $8431 mill.

Pfd Stock $1783 mill. **Pfd Divd** $81 mill.

Common Stock 837,443,257 shs. as of 2/19/24

MARKET CAP: $42.8 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
12436	11683	11737	12586	13366	16572	14172	13964	17174	14393	*15300*	*15800*	Revenues ($mill)	*18000*
1793.0	1899.0	2123.0	2244.0	2651.0	3447.0	3006.0	3191.0	3505.0	1743.0	*2455*	*2940*	Net Profit ($mill)	*3620*
28.1%	32.0%	22.8%	27.2%	17.3%	20.3%	12.2%	13.7%	16.3%	18.9%	*17.0%*	*17.0%*	Income Tax Rate	*17.0%*
4.5%	5.3%	7.5%	10.5%	5.1%	2.6%	3.4%	3.7%	3.2%	9.1%	*6.5%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
65.4%	65.1%	67.4%	64.4%	60.8%	51.4%	56.5%	56.4%	58.3%	54.7%	*53.0%*	*54.5%*	Long-Term Debt Ratio	*56.0%*
34.6%	34.9%	32.6%	35.6%	39.2%	45.0%	39.5%	38.5%	39.1%	42.4%	*44.0%*	*42.5%*	Common Equity Ratio	*41.5%*
33360	36280	44836	48090	51251	65818	60074	66344	66795	60777	*59400*	*63750*	Total Capital ($mill)	*77100*
36270	41554	49964	53758	54560	69082	57848	59774	63460	58780	*61700*	*67550*	Net Plant ($mill)	*80400*
6.6%	6.5%	6.0%	5.9%	6.5%	6.4%	6.2%	5.9%	6.0%	4.2%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
15.5%	15.0%	14.5%	13.1%	13.2%	10.8%	11.5%	11.0%	12.6%	6.3%	*9.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
15.4%	15.0%	14.5%	13.1%	13.2%	11.6%	12.4%	12.2%	13.1%	6.5%	*9.0%*	*10.5%*	Return on Com Equity E	*11.0%*
3.3%	2.9%	2.7%	1.8%	2.3%	1.5%	.3%	4.3%	4.6%	NMF	*.5%*	*2.0%*	Retained to Com Eq	*3.5%*
79%	81%	81%	86%	82%	87%	98%	66%	66%	NMF	*95%*	*80%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (MWH)	+2.1	+5.0	-1.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.1	+1.2
Fixed Charge Cov. (%)	227	272	201

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.5%	-1.0%	*2.0%*
"Cash Flow"	2.5%	--	*2.5%*
Earnings	1.5%	-2.0%	*3.0%*
Dividends	2.0%	-3.0%	*.5%*
Book Value	5.0%	3.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3870	3038	3176	3880	13964
2022	4279	3596	4386	4913	17174
2023	3883	3166	3810	3534	14393
2024	*3700*	*3600*	*4225*	*3775*	*15300*
2025	*3850*	*3725*	*4350*	*3875*	*15800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.09	.76	1.11	.90	3.86
2022	1.18	.77	1.11	1.06	4.11
2023	.59	.35	.75	.29	1.99
2024	*.55*	*.60*	*.90*	*.75*	*2.80*
2025	*.80*	*.80*	*.95*	*.80*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.94	.94	.94	.63	3.45
2021	.63	.63	.63	.63	2.52
2022	.6675	.6675	.6675	.6675	2.67
2023	.6675	.6675	.6675	.6675	2.67
2024	.6675				

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources) is a holding company for Virginia Power, North Carolina Power, & South Carolina E&G, which serve 3.5 mill. customers in VA, SC, & NC. Serves 3.5 mill. gas customers in OH, WV, UT, SC, & NC. Other ops. incl. independent power production. Acq'd Questar 9/16; SCANA 1/19. Elec. rev. breakdown: residential, 44%; commercial, 39%; industrial, 7%; other, 10%. Generating sources: gas, 36%; nuclear, 29%; coal, 5%; renewable, 5%; purchased, 25%. Power/fuel costs: 31% of revs. '23 reported deprec. rates: 2.3%-4.2%. Employs 17,700. Chair, Pres. & CEO: Robert M. Blue. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dominionenergy.com.

Dominion Energy has nearly completed its restructuring. Announced 18 months ago, it was described by management as a full analysis, including a look at alternatives to the business mix and capital allocation. One solace for existing shareholders is that Dominion is maintaining the current dividend level. It plans to grow its way out of the constraints of a high payout ratio. This means that it will take years before the company is in a position to resume dividend growth. There are a number of nonstrategic assets being divested, which will take time to receive regulatory approval and close. Hence, the company's income statement for both 2023 and this year are transitory. Revenue comes off the books right away, but it takes time to see the benefits from more than $16 billion in debt relief that mostly arrives later. Our 2025 share-earnings estimate may not fully reflect where the company is at in terms of earnings power, post restructuring.

The stock price has begun to recover of late, as the financial picture has become clearer. A good portion of the year-long nose dive in the equity's value was attributable to weakness among utilities in general, responding to higher interest rates. Most of the decline was from uncertainty and the loss of near- to intermediate-term earnings power. What the company has done is basically a financial reset. Dominion gave up income from its divestitures to improve the balance sheet and position itself for a more sustainable 5%-7% annual profit growth over the longer term (from 2025's base year). In September, the 50% stake in the Cove Point liquefied natural gas operation in Maryland was sold to Berkshire Hathaway for $3.3 billion. That same month, the company agreed to sell three natural gas utilities for $9.4 billion in cash and $4.6 billion in assumed debt to Enbridge. Dominion is also in the process of bringing on an equity partner to help fund and reduce its considerable business risk from offshore wind generation.

The stout dividend yield is the main draw here. And investors will be giving up dividend growth for the above-average income. We don't see a lot of recovery potential for D stock from the recent price.

Anthony J. Glennon *May 10, 2024*

(A) Dil. egs. Excl. nonrec. gain/(loss): '08, 12¢; '09, (47¢); '10, $2.13; '11, (31¢); '12, ($2.18); '14, (81¢); '17, $1.19; '18, (31¢); '19, ($2.62); '20, ($1.72); '21, (67¢); '22, ($3.03); '23, 49¢; gain/(losses) from disc. ops.: '10, (26¢); '12, (4¢); '13, (16¢); '20, ($2.39); '21, 79¢; '22, 1¢; '23, (19¢). Next egs. report due early August.
(B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '23: $16.04/sh. (D) In mill. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in VA in '22: 9.35%; in SC in '21: 9.5%. Regul'y. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	80

DTE ENERGY CO. NYSE-DTE

RECENT PRICE **112.96** | P/E RATIO **16.9** (Trailing: 19.0, Median: 18.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS 4 Lowered 6/7/24
SAFETY 2 Raised 12/21/12
TECHNICAL 3 Raised 6/7/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$98-$158	$128 (15%)

2027-29 PROJECTIONS

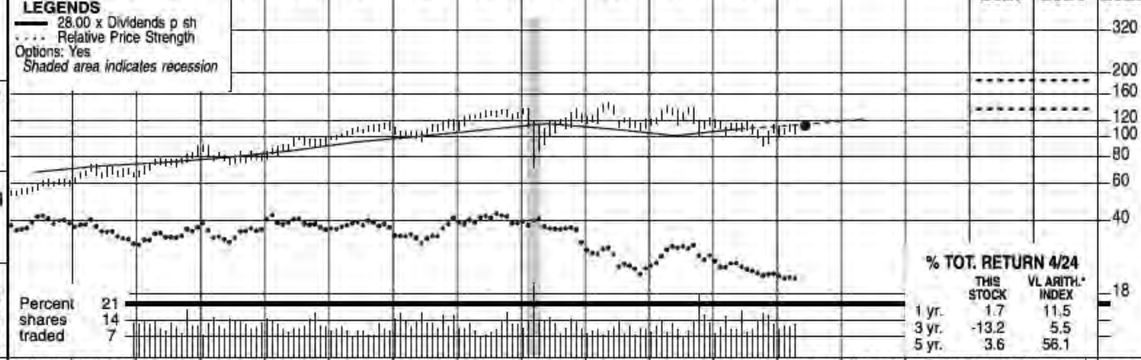
	Price	Gain	Ann'l Total Return
High	185	(+65%)	16%
Low	135	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	334	317	354
to Sell	284	324	300
Hld's(000)	154545	158915	160452

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7	145.4	140.2	121.3	117.4
Low:	60.3	64.8	73.2	78.0	96.6	94.3	107.3	71.2	108.2	100.6	90.1	102.2

LEGENDS
— 28.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	78.12	65.91	62.84	77.23	93.48	61.76	*61.30*	*63.25*	Revenues per sh	*80.10*
8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	12.58	12.97	14.70	11.94	12.66	14.54	*15.20*	*15.95*	"Cash Flow" per sh	*17.85*
2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	6.17	6.31	7.08	4.10	5.52	6.76	*6.70*	*7.20*	Earnings per sh A	*8.85*
2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	3.59	3.85	4.12	3.88	3.54	3.88	*4.08*	*4.34*	Div'd Decl'd per sh B ■	*4.83*
8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	14.91	15.59	19.91	19.47	16.42	17.02	*17.50*	*17.75*	Cap'l Spending per sh	*18.50*
36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	56.27	60.73	64.12	44.93	46.35	53.55	*55.95*	*58.40*	Book Value per sh C	*63.10*
163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	181.93	192.21	193.77	193.75	205.69	206.36	*205.50*	*205.50*	Common Shs Outst'g D	*206.00*
14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	17.4	19.9	16.3	30.0	22.4	16.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	.84	1.62	1.30	.92			Relative P/E Ratio	*1.00*
5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%	3.3%	3.1%	3.6%	3.2%	3.4%	3.8%			Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $21657 mill. **Due in 5 Yrs** $6481 mill.
LT Debt $19248 mill. **LT Interest** $514 mill.
Incl. $209 mill. securitization bonds. Incl. $19 mill. finance leases.
(LT interest earned: 1.7x)
Leases, Uncapitalized Annual rentals $16 mill.

Pension Assets-12/22 $5507 mill.
Oblig $5857 mill.

Pfd Stock None
Common Stock 206,937,244 shs.

MARKET CAP: $23.4 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
12301	10337	10630	12607	14212	12669	12177	14964	19228	12745	*12600*	*13000*	Revenues ($mill)	*16500*
905.0	796.0	868.0	1029.0	1120.0	1169.0	1368.0	796.0	1135.4	1395.0	*1375*	*1480*	Net Profit ($mill)	*1825*
28.5%	25.6%	24.5%	21.8%	8.1%	11.5%	10.9%	--	2.6%	4.8%	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	3.4%	4.9%	4.0%	3.2%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	60.5%	62.5%	63.0%	61.2%	*61.5%*	*61.5%*	Long-Term Debt Ratio	*61.0%*
50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	39.5%	37.5%	37.0%	38.0%	*38.5%*	*38.5%*	Common Equity Ratio	*39.0%*
16670	17607	20280	21697	22371	27607	31426	23236	25158	26282	*29000*	*30000*	Total Capital ($mill)	*32200*
16820	18034	19730	20721	21650	25317	27969	26944	28767	28169	*31500*	*32250*	Net Plant ($mill)	*36600*
6.6%	5.7%	5.3%	5.9%	6.1%	5.3%	5.4%	4.7%	4.4%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	13.0%	11.0%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.5%*
10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	13.0%	11.0%	*11.5%*	*11.5%*	Return on Com Equity E	*12.5%*
5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	4.9%	.1%	2.0%	4.0%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
52%	63%	61%	58%	55%	59%	56%	99%	76%	60%	*60%*	*60%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.4	+2.1	-1.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	268	233	264

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.0%	2.5%	*5.0%*
"Cash Flow"	3.0%	4.5%	*4.5%*
Earnings	4.0%	2.5%	*4.5%*
Dividends	5.5%	5.5%	*3.0%*
Book Value	3.0%	1.5%	*1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3581	3021	3715	4647	14964
2022	4577	4924	5251	4476	19228
2023	3779	2684	2888	3394	12745
2024	3240	*2400*	*2850*	*4110*	*12600*
2025	*3400*	*2500*	*2900*	*4200*	*13000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.65	.60	.30	1.55	4.10
2022	2.03	.19	1.99	1.31	5.52
2023	2.16	.97	1.61	2.02	6.76
2024	1.51	*1.20*	*1.90*	*2.09*	*6.70*
2025	*2.40*	*1.30*	*2.00*	*1.50*	*7.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	1.0125	1.0125	1.0125	1.0125	4.05
2021	.9225	.9225	.9225	.825	3.59
2022	.885	.885	.885	.885	3.54
2023	.9525	.9525	.9525	1.02	3.88
2024	1.02				

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.2 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 50%; commercial, 33%; industrial, 11%; other, 6%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 62% of revenues. '22 reported deprec. rates: 4.2% electric, 2.9% gas. Has 10,600 employees. Chairman, President & CEO: Jerry Norcia. Incorporated: Michigan. Address: One Energy Plaza, Detroit, Michigan 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary has filed another general rate case. The utility is seeking an increase of $456 million to improve reliability. Note, DTE received a $368.1 million electricity rate increase in December, compared to its initial request of $620 million. As a result of this and past decisions, we think the Michigan Public Service Commission will likely give the utility an unfavorable, but reasonable, ruling. This shouldn't have too much of an effect on the company's results this year, but will probably boost profits nicely in 2025.

We have slightly lowered our 2024 earnings-per-share estimate. The first-quarter performance was negatively impacted by inflationary pressures and the interest rate environment, which led to higher rate base costs. And, these challenges should persist throughout this year, before the utility is able to pass on higher costs to consumers. Our earnings estimate is now right near the midpoint of DTE Energy's targeted range of $6.54-$6.83 a share, and within the company's 6%-8% long-term profit growth forecast based off original 2023 guidance.

DTE Energy is well positioned for the long term. The utility's grid investments to improve maintenance and infrastructure, reduce outages, and enhance tree trimming should come to fruition over that interim and benefit operations. DTE plans to fully automate the grid within five to six years, and we think it's in a great position to take advantage of elevated power demand from data centers and tech innovations. Too, the utility should be able to pass on the aforementioned higher costs associated with the challenging macroeconomic climate to the consumer. Our 2025 bottom-line estimate is staying put at $7.20 per share.

Conservative, income-oriented, long-term investors may be attracted to this issue. Indeed, the dividend yield is in line with the high-paying industry average, and has a decent annual dividend growth rate of 3.0%. Too, 18-month and 3- to 5-year appreciation potential is solid in comparison to most of its peers. These shares also hold a high mark for Price Stability (90), and are ranked Above Average (2) for Safety.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted EPS. Excl. nonrec. gains (loss): '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on discontinued operations: '08, 13¢; '12, (33¢); '21, 57¢. Next earnings report due late July. (B) Div'ds paid mid-Jan., Apr., July & Oct. ■ Div'd reinvestment plan available. (C) Incl. intang. In '22: $29.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on common equity in '20: 9.9% elec.; in '22: 9.9% gas; earned on avg. com. eq., '21: 7.6%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

DUKE ENERGY NYSE-DUK

RECENT PRICE **98.73** | P/E RATIO **16.5** (Trailing: 17.8; Median: 18.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **4.2%** | VALUE LINE

TIMELINESS **3** Raised 11/24/23
SAFETY **2** New 6/1/07
TECHNICAL **4** Lowered 3/29/24
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$87-$133	$110 (10%)

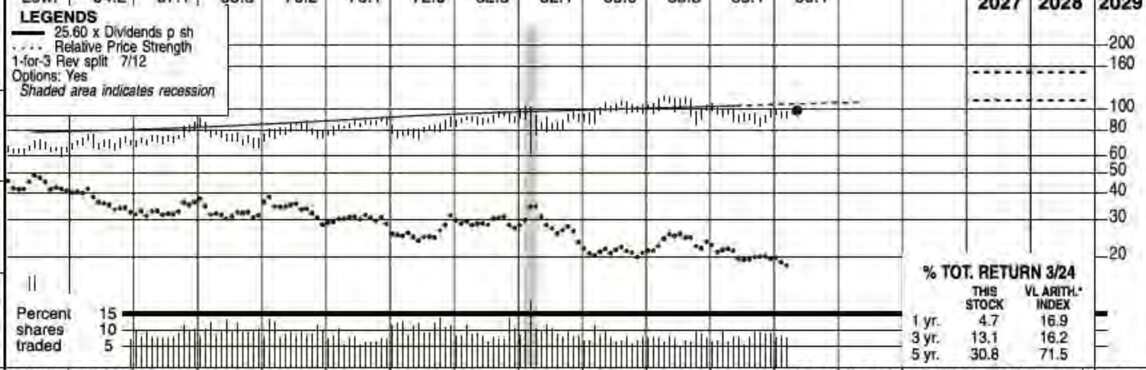
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+50%)	14%
Low	110	(+10%)	7%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	852	830	838
to Sell	753	745	864
Hld's(000)	495714	500344	505574

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3	106.4	99.9	
Low:	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8	83.1	90.1	



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.7	16.9
3 yr.	13.1	16.2
5 yr.	30.8	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	37.36	37.69	**38.85**	**40.25**	Revenues per sh	**42.40**
7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	12.91	13.22	**13.55**	**13.90**	"Cash Flow" per sh	**15.05**
3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	5.27	5.56	**6.00**	**6.35**	Earnings per sh A	**7.60**
2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	3.98	4.06	**4.14**	**4.22**	Div'd Decl'd per sh B ■	**4.30**
10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	14.76	16.35	**17.60**	**17.75**	Cap'l Spending per sh	**16.75**
49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	61.51	63.70	**66.25**	**68.65**	Book Value per sh C	**70.00**
423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	770.00	771.00	**772.00**	**773.00**	Common Shs Outst'g D	**775.00**
17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	19.6	16.9	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	1.14	.94	*Value Line*		Relative P/E Ratio	**.95**
5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%	3.9%	4.3%	*estimates*		Avg Ann'l Div'd Yield	**3.9%**

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
23925	23459	22743	23565	24521	25079	23868	25097	28768	29060	**30000**	**31100**	Revenues ($mill)	**32850**
2934.0	2854.0	2560.0	2963.0	3339.0	3748.0	1377.0	3908.0	2550.0	2841.0	**3350**	**3825**	Net Profit ($mill)	**4775**
30.6%	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	7.4%	9.2%	**9.0%**	**9.0%**	Income Tax Rate	**9.0%**
7.2%	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	8.1%	7.1%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	56.1%	59.6%	**58.5%**	**58.5%**	Long-Term Debt Ratio	**61.0%**
52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	42.5%	40.4%	**41.0%**	**40.5%**	Common Equity Ratio	**37.5%**
78088	77222	86609	90774	94940	101807	103589	109744	115235	121564	**124525**	**125500**	Total Capital ($mill)	**144100**
70046	75709	82520	86391	91694	102127	106782	111408	111748	115315	**124375**	**132500**	Net Plant ($mill)	**141100**
4.8%	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	2.0%	2.3%	**4.5%**	**4.5%**	Return on Total Cap'l	**4.5%**
7.2%	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	5.2%	5.8%	**9.0%**	**9.0%**	Return on Shr. Equity	**9.0%**
7.2%	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	5.2%	5.8%	**9.0%**	**9.0%**	Return on Com Equity E	**9.0%**
1.7%	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	1.5%	1.8%	**2.5%**	**2.5%**	Retained to Com Eq	**3.0%**
76%	79%	91%	83%	74%	71%	73%	78%	76%	73%	**73%**	**73%**	All Div'ds to Net Prof	**68%**

CAPITAL STRUCTURE as of 12/31/23
Total Debt $75252 mill. **Due in 5 Yrs** $19536 mill.
LT Debt $72452 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $225 mill.
Pension Assets-12/23 $6993 mill.
Oblig $8207 mill.
Pfd Stock $1962 mill. **Pfd Div'd** $107 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 770,811,446 shs. **as of 1/31/24**
MARKET CAP: $76.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+2.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	209	285	NA

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	.5%	-.5%	2.5%
"Cash Flow"	4.0%	5.0%	5.0%
Earnings	3.0%	4.5%	5.0%
Dividends	3.0%	3.5%	2.0%
Book Value	2.0%	1.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	6150	5758	6951	6238	25097
2022	7132	6685	7968	6983	28768
2023	7276	6578	7994	7212	29060
2024	*7350*	*6650*	*8250*	*7750*	*30000*
2025	*7700*	*6850*	*8450*	*8100*	*31100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.26	1.15	1.88	.94	5.24
2022	1.30	1.14	1.78	1.11	5.27
2023	1.20	.91	1.94	1.51	5.56
2024	*1.40*	*1.05*	*2.05*	*1.50*	*6.00*
2025	*1.40*	*1.35*	*2.10*	*1.50*	*6.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005	1.005	3.98
2023	1.005	1.005	1.025	1.025	4.06
2024	1.025				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, and KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '22 reported deprec. rate: 3.6%. Has 27,600 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy recently filed some rate cases. In Indiana, the utility filed for a hike of $492 million (16%) over 2026 for its investments in improving the electric grid. In North Carolina, Piedmont Gas is seeking recovery for its infrastructure investments to improve reliability, an overall 11.7% increase. And, Duke Energy Florida requested an increase of approximately $820 million between 2025-2027 to increase efficiency, reduce outages, and add 14 new solar sites.

We are sticking with our 2024 earnings-per-share estimate of $6.00. This is around the midpoint of the company's targeted range of $5.85-$6.10 per share. Management also reaffirmed its long-term profit growth target of 5%-7% annually through 2028. We think rate relief and growing power demand will produce a 8% rise in earnings this year, and a 6% increase in 2025. Duke Energy expects its power demand to grow by 1.5%-2% annually in the near-term and looks for a sharper rise of 2.5% a year over the next decade or so. The adoption of electric vehicles should make up about 40% of this increase. Meanwhile, the company's earnings over the next few years should benefit from the aforementioned pending rate cases and energy-efficiency programs.

Duke remains focused on improving the electricity grid and providing solar investments. The utility recently completed its Bad Creek upgrade, which added 320 MWh of energy to support electricity demand. The upgrades took four years to complete and the total capacity of the station is now 1,680 MWh, enough to power over a million homes. The company is looking to extend its license of the Bad Creek facility and potentially add a second powerhouse at the site.

This issue is tailor made for income-oriented accounts. Duke stock has an above-average dividend yield for a utility. And, the company has proven to be one of the better-managed and best-performing utilities in the industry. We also slightly increased our 3- to 5-year Target Price Range, and now look for these shares to trade around $110-$150 over that interim. At the current quotation, however, long-term capital appreciation potential is nothing to write home about.

Zachary J. Hodgkinson *May 10, 2024*

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; net nonrec gain: '17, 14¢. 2021 EPS may not sum to annual due to rounding. Next egs. due early Aug. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '22: $41.34/sh. (D) In mill., (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. in '19 in SC:9.5%; Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 70.68 | P/E RATIO 14.3 (Trailing: 14.8; Median: 14.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 3 Raised 3/1/24
SAFETY 3 Lowered 11/23/18
TECHNICAL 3 Lowered 3/22/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range
Low-High: $55-$90 | Midpoint (% to Mid): $73 (5%)

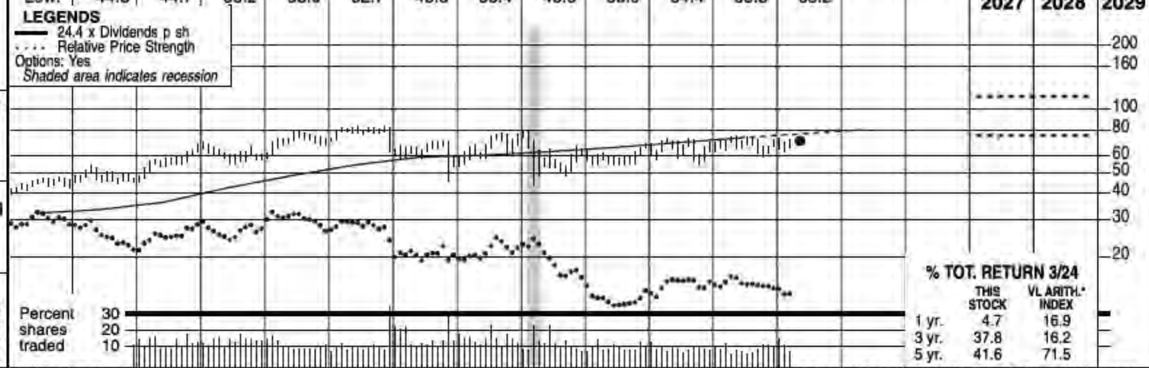
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+65%)	16%
Low	75	(+5%)	6%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	369	361	356
to Sell	304	299	362
Hld's(000)	340122	336919	342030

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3	74.9	73.3
Low:	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	54.4	58.8	63.2



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	35.83	39.18	45.05	42.56	44.95	47.40	Revenues per sh	53.85
8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.39	9.80	10.59	11.51	11.80	12.85	13.60	"Cash Flow" per sh	15.00
3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	4.70	4.52	4.59	4.63	4.76	4.95	5.50	Earnings per sh A	6.55
1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	2.84	2.99	3.14	3.29	Div'd Decl'd per sh B ■	3.86
8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	15.12	14.19	15.75	16.25	Cap'l Spending per sh	17.00
29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	35.70	36.02	38.00	40.40	Book Value per sh C	48.25
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	382.21	383.93	386.00	388.00	Common Shs Outst'g D	390.00
12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	--	14.1	13.3	12.9	14.0	14.4	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.5
.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.75	.68	.70	.81	.80			Relative P/E Ratio	.80
2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%	4.4%	4.4%			Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 12/31/23
Total Debt $34090 mill. **Due in 5 Yrs** $10489 mill.
LT Debt $30316 mill. **LT Interest** $1565 mill.
(Total Interest Coverage: 2.4x)
Leases, Uncapitalized Annual rentals $166 mill.

Pension Assets-12/22 $3609 mill. **Oblig** $3647 mill.

Pfd Stock $4116 mill. **Pfd Div'd** $225 mill.

Common Stock 384,524,276 shs. **as of 2/15/24**
MARKET CAP: $27.2 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
13413	11524	11869	12320	12657	12347	13578	14905	17220	16338	17350	18400	Revenues ($mill)	21000
1539.0	1480.0	1422.0	1603.0	d290.0	1716.0	1818.0	1907.0	1977.0	2035.0	2120	2345	Net Profit ($mill)	2770
22.4%	6.6%	11.1%	5.0%	--	1.2%	5.0%	18.0%	12.5%	14.9%	13.0%	13.0%	Income Tax Rate	13.0%
5.8%	8.0%	6.8%	7.2%	--	9.6%	9.6%	8.8%	9.6%	11.4%	11.0%	10.5%	AFUDC % to Net Profit	10.0%
44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	60.7%	62.8%	64.0%	64.0%	Long-Term Debt Ratio	65.0%
47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	30.6%	28.7%	28.0%	28.5%	Common Equity Ratio	28.5%
23216	24352	24362	25506	27284	33360	35581	41959	44547	48260	52150	55350	Total Capital ($mill)	65650
32981	35085	37000	39050	41348	44285	47839	50700	53486	56084	59100	62250	Net Plant ($mill)	72200
7.7%	7.1%	6.9%	7.3%	.1%	6.4%	6.3%	5.6%	5.7%	5.8%	5.0%	5.5%	Return on Total Cap'l	5.5%
11.9%	11.1%	10.0%	11.6%	NMF	11.1%	11.4%	10.7%	11.3%	11.3%	11.5%	12.0%	Return on Shr. Equity	12.0%
13.0%	12.0%	10.8%	12.7%	NMF	12.0%	12.0%	12.5%	12.9%	13.1%	13.0%	13.5%	Return on Com Equity E	13.5%
8.8%	7.2%	5.6%	6.6%	NMF	5.9%	5.4%	5.4%	5.2%	5.0%	5.0%	5.5%	Retained to Com Eq	5.5%
37%	44%	53%	52%	NMF	54%	58%	61%	64%	66%	67%	63%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-3.9	+.9	-6.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21190	24345	21254
Annual Load Factor (%)	52.7	45.8	49.7
% Change Customers (yr-end)	+.3	+.8	+.7
Fixed Charge Cov. (%)	113	135	166

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	1.0%	2.5%	4.0%
"Cash Flow"	2.0%	5.5%	5.0%
Earnings	2.0%	14.0%	6.0%
Dividends	8.0%	5.0%	5.5%
Book Value	2.0%	0.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2960	3315	5299	3331	14905
2022	3968	4008	5228	4016	17220
2023	3966	3964	4702	3706	16338
2024	4250	4300	4950	3850	17350
2025	4500	4550	5250	4100	18400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.79	.94	1.69	1.16	4.59
2022	1.07	.94	1.48	1.15	4.63
2023	1.09	1.01	1.38	1.28	4.76
2024	1.15	1.05	1.45	1.30	4.95
2025	1.30	1.15	1.60	1.45	5.50

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6375	.6375	.6375	.6375	2.55
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70	.70	2.80
2023	.7375	.7375	.7375	.7375	2.95
2024	.78				

BUSINESS: Edison International is a holding company for Southern California Edison Company (SoCal Edison), which supplies electricity to 5.28 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 40%; commercial, 43%; industrial, 3%; other, 14%. Generating sources: nuclear, 9%; gas, 5%; hydroelectric, 6%; purchased, 80%. Power costs: 34% of revs. '23 reported depr. rate: 4.1%. Employs 14,316. Board Chair: Peter J. Taylor. President & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International should see decent earnings gains in 2024. This year's weather comparisons are not particularly difficult. And, the utility ought to continue to prosper from the escalation mechanism set forth in the 2021 General Rate Case (GRC) decision that allows it to bill for certain types of expenses, alleviating regulatory lag to a large degree. Load growth in California is healthy, at about 3% due to trends in electrification for vehicles and heavy equipment. This leads to plenty of transmission and distribution work that pays off rapidly in terms of return on investment for regulated utilities in California. Fire mitigation work also keeps the rate base growing. Edison's current authorized return on equity (ROE) is 10.3%, which is fairly generous relative to the rates that peers have been receiving in other states. That said, the company may get a further lift next year in that regard.

Edison has a general rate case decision coming its way in 2025. State peer, PG&E, received favorable terms from the California Public Utilities Commission, with a recent boost to its authorized ROE to 10.7% without too much public backlash. There's a reasonable chance that Edison will get a lift in its investment returns, as well. As such, we're projecting a 6% gain in earning per share next year.

Wildfire headline risk comes with the territory here. In October, Orange County filed a lawsuit alleging EIX's equipment caused forest fires in 2020 and 2022. Dollar amounts sought weren't given. In February, the company agreed to pay an $80 million settlement to the federal government for forestland burned in the 2017 Thomson fire. In recent years, EIX has paid out billions of dollars in lawsuit settlements associated with the role its power lines played in 2017 and 2018 forest fires. Notably, management recently said the settlement payout process has nearly run its course. The company also believes it has reduced its risk of causing a blaze by 88% as a result of its ongoing mitigation work.

This neutrally ranked equity (Timeliness: 3, Average) doesn't stand out from the crowd at the recent quotation. On a total-return basis, EIX is right at the utility industry median.

Anthony J. Glennon *April 19, 2024*

(A) Adjusted (non-GAAP) EPS from 2019 on. Excl. gains/(losses): nonrecur's ; '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (14¢); '19, (92¢); '20, ($2.54); '21, ($2.59); '22, ($3.02); '23, ($1.34); disc. ops.: '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. Qtly. EPS may not sum to full yr. due to rounding. Next egs. report due early May. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '23: $4.36/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

RECENT PRICE 109.14 | P/E RATIO 20.6 (Trailing: 10.9, Median: 14.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 3/8/24
SAFETY 2 Raised 12/13/19
TECHNICAL 3 Raised 5/31/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range
Low-High: $80-$125 | Midpoint (% to Mid): $103 (-5%)

2027-29 PROJECTIONS

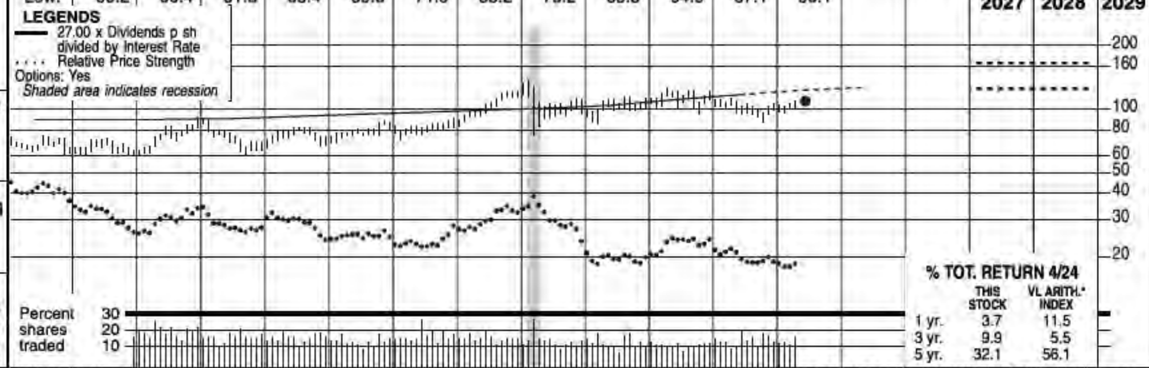
	Price	Gain	Ann'l Total Return
High	165	(+50%)	15%
Low	125	(+15%)	7%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	405	402	429
to Sell	270	304	319
Hld's(000)	181973	184676	191523

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8	111.9	114.3	
Low:	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	94.9	87.1	96.1	

LEGENDS
— 27.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Percent shares traded 30 / 20 / 10

Target Price Range 2027 | 2028 | 2029: 200, 160, 100, 80, 60, 50, 40, 30, 20

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.7	11.5
3 yr.	9.9	5.5
5 yr.	32.1	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	65.18	57.07	**56.40**	**59.00**	Revenues per sh	**69.90**
12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	15.51	21.53	**17.05**	**18.05**	"Cash Flow" per sh	**21.35**
6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	5.37	11.10	**5.30**	**6.85**	Earnings per sh A	**8.05**
3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	4.10	4.34	**4.56**	**4.70**	Div'd Decl'd per sh B ■ †	**5.00**
13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	25.04	20.86	**21.00**	**22.00**	Cap'l Spending per sh	**19.75**
42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	61.40	68.70	**70.65**	**73.65**	Book Value per sh C	**84.65**
189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	211.18	212.85	**218.00**	**222.00**	Common Shs Outst'g D	**230.00**
16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	21.1	9.1	*Bold figures are*		Avg Ann'l P/E Ratio	**18.0**
1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.81	1.22	.51	*Value Line*		Relative P/E Ratio	**1.00**
2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	3.6%	4.3%	*estimates*		Avg Ann'l Div'd Yield	**3.7%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $28400 mill. **Due in 5 Yrs** $11117 mill.
LT Debt $24309 mill. **LT Interest** $1046.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $67.4 mill.
Pension Assets-12/23 $5469.6 mill. **Oblig** $5915.4 mill.
Pfd Stock $219.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 213,536,936 shs. **as of 4/30/24**
MARKET CAP: $23.3 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
12495	11513	10846	11074	11009	10879	10114	11743	13764	12147	**12300**	**13100**	Revenues ($mill)	**16070**
1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	1103.2	2356.5	**1155**	**1520**	Net Profit ($mill)	**1850**
37.8%	2.2%	11.3%	1.8%	--	--	--	16.1%	16.1%	16.1%	**23.0%**	**23.0%**	Income Tax Rate	**23.0%**
9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	2.5%	1.7%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	64.2%	60.8%	**61.0%**	**61.0%**	Long-Term Debt Ratio	**61.0%**
43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	35.2%	38.6%	**39.0%**	**39.0%**	Common Equity Ratio	**39.0%**
22842	22714	22777	22528	24602	27557	32386	36733	36810	37851	**39995**	**42400**	Total Capital ($mill)	**50555**
28723	27824	27921	29664	31974	35183	38853	42244	42477	43834	**46465**	**49255**	Net Plant ($mill)	**58660**
6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.9%	4.3%	7.6%	**4.0%**	**4.5%**	Return on Total Cap'l	**6.0%**
10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.8%	8.4%	15.9%	**7.5%**	**9.0%**	Return on Shr. Equity	**9.5%**
10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	8.4%	16.0%	**1.0%**	**9.0%**	Return on Com Equity E	**9.5%**
4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	1.9%	9.7%	**.5%**	**3.0%**	Retained to Com Eq	**3.5%**
58%	58%	50%	68%	61%	58%	55%	57%	78%	40%	**86%**	**69%**	All Div'ds to Net Prof	**62%**

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.2	+1.1	+4.5
Total Indust. Use (GWH)	49819	52501	52807
Avg. Indust. Revs. per KWH(¢)	5.91	7.08	6.00
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.0	+.4
Fixed Charge Cov. (%)	243	209	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-.5%	--	2.5%
"Cash Flow"	1.0%	1.0%	2.5%
Earnings	2.5%	5.5%	.5%
Dividends	2.0%	3.0%	3.5%
Book Value	2.0%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	3273	13764
2023	2981	2846	3596	2725	12147
2024	2795	**3200**	**3200**	**3105**	**12300**
2025	**3000**	**3500**	**3400**	**3200**	**13100**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	.78	2.74	.51	5.37
2023	1.47	1.84	3.14	4.66	11.10
2024	.35	**1.05**	**2.95**	**.95**	**5.30**
2025	**1.60**	**1.15**	**3.05**	**1.05**	**6.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	4.10
2023	1.07	1.07	1.07	1.13	4.34
2024	1.13	1.13			

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 68%; nuclear, 22%; coal, 9%; hydro and solar, 1%. Fuel costs: 32% of revenues. '23 reported depreciation rate: 2.7%. Has 11,707 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy recorded disappointing first-quarter results. Revenues fell to just under $2.8 billion, as the company faced lower industrial sales, while warmer weather caused less energy to be used across its coverage areas. The company signed an additional eight electric service agreements with industrial customers, including a data center in Mississippi, which represents 1.1 gigawatts of loads. The power provider had much higher maintenance costs as a few planned plant refurbishments occurred in the quarter, and Entergy had some downtime at a few of its plants. The company achieved much higher interest income, but it faced some negative regulatory charges, such as one in Arkansas, while another was based on an old audit resolution. These factors caused earnings to drop sharply to $0.35 per share during the March period.

The company ought to have better results over the rest of the year. Revenues should increase thanks to projects going into service to supply multiple new industrial clients. Several areas that Entergy supplies power to are seeing population growth, leading to incremental supply gains. Some rate cases have reached conclusions recently, including one in New Orleans, which should have better operations and fewer legal costs. Still, costs will likely rise to provide more power, and we think less of higher fuel prices will be passed along to industrial customers. Overall, we estimate that earnings will tumble to $5.30 per share this year.

We expect solid expansion over the long haul. Several projects have been approved to enhance resilience and improve the grid, including 2,100 capital expansions in the company's Louisiana coverage area totaling $1.9 billion over the next five years. Moreover, we think other renewable energy projects should help operations expand. Entergy ought to also benefit from continued growth in the Texas region as more operations occur there. Overall, we project earnings will recover to $6.85 per share in 2025 and $8.05 by 2027-2029.

Shares of Entergy are neutrally ranked for Timeliness. The stock has below average appreciation potential but the dividend yield is appealing, making this equity best suited for income-seekers.

John E. Seibert III *June 7, 2024*

(A) Diluted EPS. GAAP starting in 2022. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33. Next earnings report due early August. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '23: $26.66/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.71%; earned on avg. com. eq., '23: 16.0%. Regulatory Climate: Average.

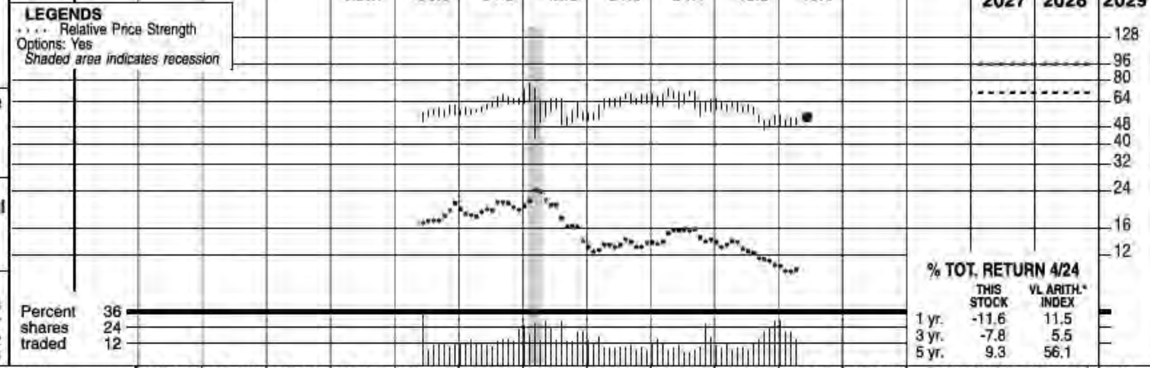
Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

EVERGY, INC. NYSE-EVRG

RECENT PRICE 53.43 | P/E RATIO 14.8 (Trailing: 18.8; Median: NMF) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 3 Raised 6/7/24
SAFETY 2 New 9/14/18
TECHNICAL 4 Raised 6/7/24
BETA .95 (1.00 = Market)

	2018	2019	2020	2021	2022	2023	2024
High:	61.1	67.8	76.6	69.4	73.1	65.4	56.3
Low:	50.9	54.6	42.0	51.9	54.1	46.9	48.0



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$75	$61 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+80%)	19%
Low	70	(+30%)	11%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	298	320	357
to Sell	272	273	292
Hld's(000)	192350	196134	203440

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.6	11.5
3 yr.	-7.8	5.5
5 yr.	9.3	56.1

Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
--	--	--	--	16.75	22.71	21.66	24.36	25.49	23.98	*25.20*	*26.10*	Revenues per sh	*29.80*
--	--	--	--	4.89	7.18	7.06	8.18	7.34	8.33	*7.95*	*8.50*	"Cash Flow" per sh	*9.20*
--	--	--	--	2.50	2.79	2.72	3.83	3.26	3.17	*3.60*	*4.00*	Earnings per sh A	*4.60*
--	--	--	--	1.74	1.93	2.05	2.18	2.33	2.48	*2.61*	*2.74*	Div'd Decl'd per sh B ■	*3.05*
--	--	--	--	4.19	5.34	6.88	8.60	9.41	9.23	*9.25*	*9.30*	Cap'l Spending per sh	*9.50*
--	--	--	--	39.28	37.82	38.50	40.32	41.86	42.06	*44.10*	*45.65*	Book Value per sh C	*47.50*
--	--	--	--	255.33	226.64	226.84	229.30	229.90	229.73	*230.00*	*230.00*	Common Shs Outst'g D	*230.00*
--	--	--	--	22.7	21.8	21.7	16.2	19.9	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
--	--	--	--	1.23	1.16	1.11	.88	1.15	1.01	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	3.1%	3.2%	3.5%	3.5%	4.0%	5.1%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
--	--	--	--	4275.9	5147.8	4913.4	5586.7	5859.1	5508.2	*5800*	*6000*	Revenues ($mill)	*6850*
--	--	--	--	535.8	669.9	618.3	879.7	752.7	731.3	*830*	*920*	Net Profit ($mill)	*1060*
--	--	--	--	9.8%	12.6%	14.1%	11.7%	5.8%	2.1%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
--	--	--	--	2.5%	2.5%	5.5%	5.0%	5.1%	5.4%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
--	--	--	--	40.0%	50.6%	51.3%	50.1%	50.0%	51.5%	*51.5%*	*52.0%*	Long-Term Debt Ratio	*53.5%*
--	--	--	--	60.0%	49.4%	48.7%	49.9%	48.0%	48.0%	*48.5%*	*48.0%*	Common Equity Ratio	*46.5%*
--	--	--	--	16716	17337	17924	18542	19668	20019	*21250*	*22500*	Total Capital ($mill)	*23400*
--	--	--	--	18952	19346	20106	21150	22277	23729	*24200*	*25300*	Net Plant ($mill)	*26300*
--	--	--	--	4.0%	4.8%	4.5%	5.7%	6.9%	6.4%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	7.6%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.1%	7.6%	*9.0%*	*9.0%*	Return on Com Equity E	*10.0%*
--	--	--	--	.6%	2.4%	1.8%	4.1%	3.1%	2.5%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
--	--	--	--	89%	69%	75%	57%	73%	69%	*68%*	*68%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $12470 mill. **Due in 5 Yrs** $4388 mill.
LT Debt $11658 mill. **LT Interest** $306 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/22 $1714.7 mill. **Oblig** $2561.7 mill.

Pfd Stock None

Common Stock 229,929,116 shs.
MARKET CAP: $12.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.9	+3.1	+6.7
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.14	6.94	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	286	350	382

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	--	--	2.5%
"Cash Flow"	--	--	5.0%
Earnings	--	--	7.5%
Dividends	--	--	7.0%
Book Value	--	--	3.5%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1611.4	1236.7	1616.5	1122.1	5586.7
2022	1223.9	1446.5	1909.1	1279.6	5859.1
2023	1296.8	1354.2	1669.3	1187.9	5508.2
2024	1331.0	*1400*	*1750*	*1319*	*5800*
2025	*1350*	*1450*	*1850*	*1350*	*6000*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	.03	3.26
2023	.62	.78	1.53	.24	3.17
2024	.53	*.85*	*1.75*	*.47*	*3.60*
2025	*.70*	*.85*	*2.00*	*.45*	*4.00*

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.5725	.6125	2.33
2023	.6125	.6125	.6125	.6425	2.48
2024	.6425	.6425			

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 32%; commercial, 27%; industrial, 15%; wholesale, 13%; other, 13%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '23 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy's Missouri West subsidiary has a rate case pending. As a reminder, Missouri West filed for an increase of $104 million (13.4%), excluding fuel. The utility is looking to recover grid modernization investments and new rates will go into effect in January 2025, if approved. In Kansas, the utility filed its 2024 integrated resource plan (IRP), which will add 360 MW over the next 10 years compared to the 2023 update. Note, Evergy's $12.5 billion capital investment plan does not yet include the changes in its 2024 IRP.

Our 2024 bottom-line target is staying put at $3.60 per share. The company should continue to benefit from investments in its transmission system, and rate relief through this year and beyond. What's more, elevated power demand due to artificial intelligence innovations and data centers will likely rise exponentially and prop up profits nicely. Evergy remains committed to its earnings-per-share growth target of 4%-6% annually through 2026 based on management's original 2023 outlook midpoint. And, it expects annual rate base growth of 6% through 2028. We look for earnings to improve in 2025 to $4.00 per share. The aforementioned Missouri West rate case should provide a full year of rate relief, along with other regulatory matters over that time period. And, borrowing costs should improve if interest rates start to decline, which is important as Evergy generally has low return rates on total capital and relies heavily on high debt levels.

Evergy's stock price has risen nicely of late. The stock is up almost 10% since our early March report, erasing year-to-date losses. Indeed, these shares are now up slightly so far this year, after struggling in the early months.

Income-oriented investors may want to take a look here. The dividend yield of this stock stands far above the utility average, and prospective annual dividend increases of 7% add to the appeal. Meanwhile, intermediate- and long-term capital appreciation potential is decent in comparison to most of its peers. Indeed, our 18-month Target Price Range indicates a 15% premium to the current quotation. And, we look for the stock to trade between $70-$95 by 2027-2029.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted earnings. Next earnings report due early Aug. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%; earned on average common equity, '22: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	85

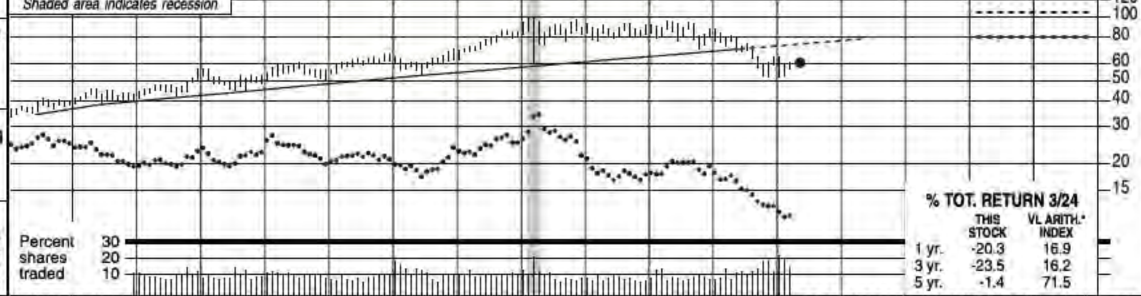
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 60.46 | P/E RATIO 13.1 (Trailing: 14.0; Median: 19.0) | RELATIVE P/E RATIO 0.75 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 5 Lowered 2/23/24
SAFETY 2 Lowered 5/12/23
TECHNICAL 5 Lowered 5/10/24
BETA .95 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	92.7	94.6	86.8	64.6				
Low:	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	76.6	70.5	52.0	52.1				

LEGENDS
— 26.0 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$49-$82	$66 (10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+75%)	18%
Low	80	(+30%)	12%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	379	371	366
to Sell	375	374	417
Hld's(000)	283976	281272	282086

Percent shares traded 30 20 10

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-20.3	16.9
3 yr.	-23.5	16.2
5 yr.	-1.4	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	25.85	25.96	28.64	35.27	34.08	37.25	38.70	Revenues per sh	41.80
6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	6.65	6.99	7.74	8.79	6.68	9.40	9.75	"Cash Flow" per sh	10.45
1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	3.45	3.64	3.86	4.09	4.34	4.60	4.85	Earnings per sh A	5.80
.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	2.14	2.27	2.41	2.55	2.70	2.86	3.03	Div'd Decl'd per sh B ■	3.60
8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	8.83	8.58	9.22	9.88	12.41	12.40	12.40	Cap'l Spending per sh	13.00
19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	38.29	41.01	42.39	44.41	40.55	42.35	44.25	Book Value per sh C	51.75
155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	329.88	342.95	344.40	348.44	349.54	350.50	351.50	Common Shs Outst'g D	365.00
13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	22.1	23.7	22.2	20.9	16.0	Bold figures are		Avg Ann'l P/E Ratio	16.0
.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.22	1.20	1.21	.89	Value Line		Relative P/E Ratio	.90
3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	2.8%	2.6%	2.8%	3.0%	3.9%	estimates		Avg Ann'l Div'd Yield	3.9%

CAPITAL STRUCTURE as of 12/31/23
Total Debt $26754 mill. **Due in 5 Yrs** $9258.1 mill.
LT Debt $23956 mill. **LT Interest** $793.7 mill.
(Total interest coverage: 3.1x)

Leases, Uncapitalized Annual rentals $80.6 mill.

Pension Assets-12/23 $5775.0 mill. **Oblig.** $5238.4 mill.

Pfd Stock $155.6 mill. **Pfd Div'd** $7.52 mill.

Common Stock 349,687,183 shs. as of 1/31/24

MARKET CAP: $21.1 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	9863.1	12289	11911	13050	13600	Revenues ($mill)	15250
827.1	886.0	949.8	995.5	1040.5	1121.0	1244.8	1337.7	1427.4	1525.2	1620	1715	Net Profit ($mill)	2130
36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	21.9%	24.3%	19.8%	24.0%	24.0%	Income Tax Rate	24.0%
2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.3%	4.2%	4.8%	8.0%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	54.2%	56.3%	62.6%	62.5%	62.5%	Long-Term Debt Ratio	59.0%
53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	45.3%	43.3%	37.0%	37.0%	37.0%	Common Equity Ratio	40.5%
18738	19313	19697	23018	24474	27097	29842	32233	35763	38285	39800	41700	Total Capital ($mill)	46600
18647	19892	21351	23617	25610	27585	30883	33378	36113	39499	41700	44050	Net Plant ($mill)	51000
5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.1%	5.1%	5.0%	5.0%	5.5%	5.5%	Return on Total Cap'l	6.0%
8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.8%	9.1%	9.1%	10.6%	11.0%	11.0%	Return on Shr. Equity	11.0%
8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.8%	9.1%	9.2%	10.7%	11.0%	11.0%	Return on Com Equity E	11.0%
3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.5%	3.6%	3.6%	4.2%	4.0%	4.0%	Retained to Com Eq	4.5%
58%	61%	60%	61%	62%	60%	60%	61%	61%	61%	62%	62%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (GWH)	+1.6	+.5	-3.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+.7
Fixed Charge Cov. (%)	347	310	263

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.5%	5.5%	4.0%
"Cash Flow"	5.0%	5.5%	5.0%
Earnings	6.5%	5.5%	6.0%
Dividends	7.0%	6.0%	6.0%
Book Value	4.5%	4.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2826	2123	2433	2482	9863
2022	3471	2573	3216	3030	12289
2023	3796	2629	2792	2694	11911
2024	3900	2700	3250	3200	13050
2025	4075	2825	3375	3325	13600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.15	.79	1.02	.91	3.86
2022	1.30	.86	1.01	.92	4.09
2023	1.41	1.00	.97	.95	4.34
2024	1.45	1.03	1.07	1.05	4.60
2025	1.50	1.10	1.15	1.10	4.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022	.6375	.6375	.6375	.6375	2.55
2023	.675	.675	.675	.675	2.70
2024	.715				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of 12 regulated utilities with 4.45 million electric, natural gas, and water customers. Supplies power to most of Connecticut and gas to part of CT; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern MA & gas to central & eastern MA; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17; Columbia Gas 10/20. Electric rev. breakdown: residential, 56%; commercial/indus'l/other, 43.4%. Fuel costs: 41% of revs. '23 reported depr. rate: 3.1%. Employs about 10,200. Chairman, President & CEO: Joseph R. Nolan, Jr. Inc.: MA. Addr.: 300 Cadwell Drive, Springfield, MA 01104. Telephone: 413-785-5871. Internet: www.eversource.com.

Eversource Energy has largely divested its offshore wind generation assets, lifting most of the uncertainty that had been weighing on the stock. The rapid rise in financing and development costs over the past few years caused these assets to drop in value. The company ultimately had to take a $1.95 billion nonrecurring impairment charge in 2023. Eversource was able to recoup some of its initial investment. In September, the company sold its stake in undeveloped offshore leased areas to its joint-venture partner, Orsted, for $625 million. And in February, Eversource reached an agreement to sell its 50% stake in the South Fork Wind and Revolution Wind projects to Global Infrastructure Partners for $1.1 billion. All that remains is a 50% interest in the Sunrise Wind venture, where a conditional sales agreement is in place with Orsted. The finances of that deal were not disclosed, as they are contingent on what New York State bids for the annual power.

To further shore up its finances, the company is exploring the sale of its water utility. Aquarion water, which was purchased in 2017 for $1.67 billion, has been deemed a nonstrategic asset by Eversource. The business distributes water to 72 towns and cities in Connecticut, Massachusetts, and New Hampshire.

Eversource remains poised for solid intermediate-term profit gains. In Massachusetts, $64 million of higher electric rates were phased in during 2023. This year, additional increases will go into effect based on inflation, maintenance, and transmission & distribution project spending. Rate increases are tied to nearly real-time formulaic pricing adjustments based on a 9.8% return on equity in the company's most important state territory. The company is targeting earnings of $4.50-$4.67 per share this year. Management has affirmed its 5%-7% annual profit growth expectation through late decade.

Longer-term utility investors should consider a commitment here. Eversource recently upped its dividend by 5.9%, and looks poised to regain its stride among utilities prized for their above-average dividend growth prospects. The equity trades at a deep discount to its peer group's average P/E multiple of 16.1.

Anthony J. Glennon *May 10, 2024*

(A) Diluted EPS excl. nonrecur. gain/(losses): '08, (19¢); '10, 9¢; '19, (64¢); '20, (9¢); '21, (32¢); '22, (4¢); '23, ($3.45). Next egs. report due early Aug. Quarterly figures may not sum to full year due to rounding. (B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '23: $26.45/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '22, 9.8%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; Regulatory Climate: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	50
Earnings Predictability	100

EXELON CORP. NDQ-EXC

RECENT PRICE **37.72** | P/E RATIO **15.4** (Trailing: 15.7 Median: 14.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS — Suspended 2/4/22 F
SAFETY 2 Raised 8/13/21
TECHNICAL — Suspended 2/4/22
BETA NMF (1.00 = Market)

18-Month Target Price Range
Low-High: $26-$44 | Midpoint (% to Mid): $35 (-5%)

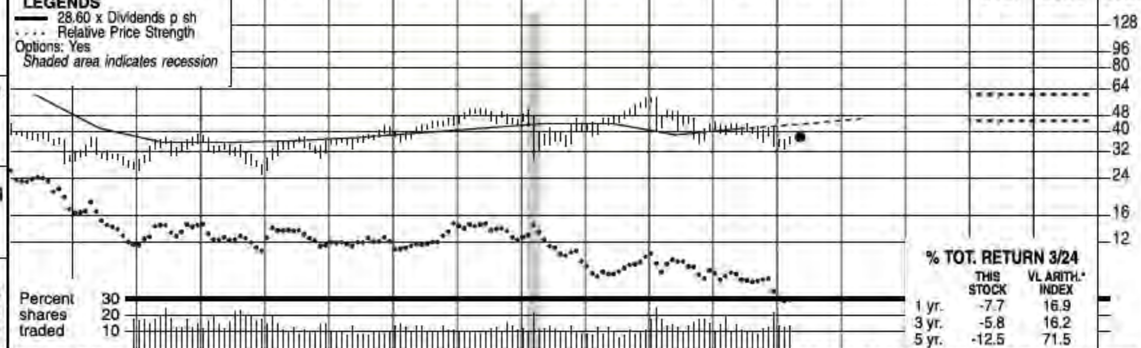
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+60%)	15%
Low	45	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	438	453	458
to Sell	411	400	475
Hld's(000)	812887	816650	820814

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5	58.0	58.2	44.4	38.0	
Low:	26.6	26.5	25.1	26.3	33.3	35.6	43.4	29.3	38.4	35.2	34.1	33.3	



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.7	16.9
3 yr.	-5.8	16.2
5 yr.	-12.5	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	37.17	35.39	33.85	37.13	19.19	21.75	*21.50*	*22.00*	Revenues per sh	*24.65*
7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.88	8.37	9.29	9.17	9.65	10.56	6.07	6.12	*6.25*	*6.55*	"Cash Flow" per sh	*7.50*
4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	2.68	2.78	3.12	3.22	3.22	2.82	2.26	2.38	*2.45*	*2.60*	Earnings per sh A	*3.10*
2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	1.38	1.45	1.53	1.53	1.35	1.44	*1.52*	*1.62*	Div'd Decl'd per sh B ■	*1.95*
4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	7.87	7.84	7.45	8.25	8.15	7.19	7.42	*7.80*	*7.80*	Cap'l Spending per sh	*8.00*
16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	31.77	33.12	33.39	35.13	24.89	25.78	*26.35*	*27.25*	Book Value per sh C	*29.75*
658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	963.34	968.19	973.00	976.00	979.00	994.00	999.00	*1000.0*	*1000.0*	Common Shs Outst'g D	*1005.0*
18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	12.5	13.4	13.3	14.7	12.4	16.6	19.9	17.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
1.08	.77	.70	.71	1.22	.75	.84	.63	.66	.67	.72	.78	.64	.90	1.15	.95			Relative P/E Ratio	*.95*
2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%	3.3%	3.1%	3.8%	3.3%	3.2%	4.3%			Avg Ann'l Div'd Yield	*3.5%*

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
27429	29447	31360	33531	35985	34438	33039	36347	19078	21727	*21500*	*22000*	Revenues ($mill)	*24750*
1826.0	2282.0	2488.0	2636.0	3026.0	3139.0	3149.0	2764.0	2170.0	2328.0	*2450*	*2600*	Net Profit ($mill)	*3000*
27.2%	32.2%	38.5%	34.2%	11.1%	19.4%	17.4%	16.1%	14.5%	13.8%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
5.5%	5.4%	8.3%	6.5%	4.6%	5.0%	5.5%	7.4%	7.0%	7.4%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	52.1%	50.9%	59.9%	60.3%	*61.0%*	*61.0%*	Long-Term Debt Ratio	*64.5%*
52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	47.9%	49.1%	40.2%	39.1%	*39.0%*	*39.0%*	Common Equity Ratio	*35.5%*
42811	50272	58053	62422	65229	63943	68068	70107	58836	65837	*65250*	*70300*	Total Capital ($mill)	*81000*
52087	57439	71555	74202	76707	80233	82584	84219	69076	73593	*69750*	*70100*	Net Plant ($mill)	*77600*
5.3%	5.5%	5.5%	5.3%	5.7%	6.0%	5.7%	5.0%	5.0%	3.6%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.0%	8.8%	9.6%	8.8%	9.8%	9.7%	9.7%	8.0%	9.5%	9.0%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.0%	8.8%	9.6%	8.8%	9.8%	9.7%	9.7%	8.0%	9.5%	9.0%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
3.3%	4.5%	5.1%	4.7%	5.5%	5.4%	5.1%	3.7%	4.0%	3.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
59%	49%	47%	47%	44%	45%	47%	54%	60%	60%	*60%*	*60%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $42577 mill. **Due in 5 Yrs** $12334 mill.
LT Debt $39692 mill. **LT Interest** $1450 mill.
Includes $390 mill. nonrecourse transition bonds.
(Interest coverage: 2.7x)
Leases, Uncapitalized Annual rentals $156 mill.

Pension Assets-12/23 $20827 mill. **Oblig** $23846 mill.
Pfd Stock None

Common Stock 999,538,542 shs.
as of 1/31/24
MARKET CAP: $37.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	NA	NA
Fixed Charge Cov. (%)	237	325	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.5%	1.0%	NMF
"Cash Flow"	3.0%	5.5%	NMF
Earnings	-.5%	2.5%	NMF
Dividends	-3.0%	4.0%	NMF
Book Value	4.5%	3.5%	NMF

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	9890	7915	8910	9632	36347
2022	5327	4239	4845	4667	19078
2023	5562	4818	5980	5367	21727
2024	*5600*	*4850*	*6100*	*4950*	*21500*
2025	*5750*	*5000*	*6250*	*5000*	*22000*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	d.06	.89	1.09	.90	2.82
2022	.64	.44	.75	.43	2.26
2023	.70	.41	.67	.60	2.38
2024	*.70*	*.45*	*.80*	*.50*	*2.45*
2025	*.75*	*.45*	*.85*	*.55*	*2.60*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3825	.3825	.3825	.3825	1.53
2021	.3825	.3825	.3825	.3825	1.53
2022	.3375	.3375	.3375	.3375	1.35
2023	.360	.360	.360	.360	1.44
2024	.380				

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison (ComEd), PECO Energy, Baltimore Gas and Electric (BGE), Pepco, Delmarva Power (DPL), & Atlantic City Electric (ACE). Has 9.1 mill. elec., 1.3 mill. gas customers. Spun off Constellation Energy (nonregulated generating & energy-marketing ops.) 2/22. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: residntl., 54%; small commercl. & indstrl., 16%; large commercl. & indstrl., 17%; other, 13%. Fuel costs: 48% of revs. '22 deprec. rates: 2.8%-8.7% elec., 2.1% gas. Has 18,700 empls. Chrmn.: John F. Young. CEO: Calvin Butler. Inc.: PA. Address: 10 S.Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Telephone: 312-394-7398. Internet: www.exeloncorp.com.

Exelon Corporation continues to look more stable and predictable as an entirely regulated utility. Indeed, the company delivered a better-than-expected fourth-quarter performance, while also raising its quarterly dividend and capital spending plan. Management now looks for $35 billion of capital expenditures through 2027, a 10% increase from its previous outlook, and expects annual profit growth of 5%-7% over that interim. Investors were enthused with the strong final stanza and the stock has risen nearly 10% in value since our early February review, outperforming most electric utility equities. Exelon was set to release first-quarter financial results shortly after this report went to press. We look for earnings of $0.70 a share on revenues of $5.6 billion.

Our full-year 2024 profit estimate is staying put at $2.45 per share. This is the midpoint of management's initial target range of $2.40-$2.50 a share, which was released in late February. Exelon's earnings continue to be much less volatile as an entirely regulated utility, and results are benefiting from additional revenues from regulatory mechanisms and higher distribution rates. Along with rate relief, volume growth and growing power demand should contribute to higher profits. Regarding 2025, we estimate that the bottom line will advance 6%, to $2.60 a share, within managements aforementioned growth target.

The Illinois rate case rejection and higher power bills are challenging long-term energy goals. Remember, Exelon's Commonwealth Edison (COMED) unit had its $1.5 billion integrated grid plans rejected by the Illinois Commerce Commission in December, 2023. Since then, the transition toward renewable power has slowed as the utility has cut $1.4 billion in capital spending in Illinois and laid off 900 direct contractors, which impacted more than 2,000 indirect jobs. As of now, the company remains committed to reducing emissions by 50% by 2030 and achieving net-zero by 2050.

Income-oriented accounts may want to take a look at this issue. Exelon holds an above-average dividend yield and is generally considered to be a solid addition to a well-rounded portfolio.

Zachary J. Hodgkinson *May 10, 2024*

(A) Dil. egs. Excl. nonrec. gain (loss): '09, (20¢); '12, (50¢); '13, (31¢); '14, (22¢); '16, ($1.46); '17, $1.19; '18, ($1.05); '19, (21¢); '20, ($1.21); '21, ($1.08); Next egs. report: Aug. (B) Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '22: $15.20/sh. (D) In mill. (E) Rate allowed on common equity in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; Regulatory Climate: PA, NJ: Average; IL, MD: Below Avg. (F) Timeliness rank suspended due to Constellation Energy spinoff.

Company's Financial Strength	B++
Stock's Price Stability	NMF
Price Growth Persistence	NMF
Earnings Predictability	NMF

FIRSTENERGY NYSE-FE

RECENT PRICE 38.78 | P/E RATIO 14.4 (Trailing: 15.4, Median: 14.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Lowered 5/10/24
SAFETY 3 Lowered 7/31/20
TECHNICAL 4 Raised 4/5/24
BETA .90 (1.00 = Market)

High:	46.8	40.8	41.7	36.6	35.2	39.9	49.1	52.5	41.8	48.8	43.3	38.9
Low:	31.3	30.0	28.9	29.3	27.9	29.3	36.3	22.9	29.2	35.3	32.2	35.4

Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

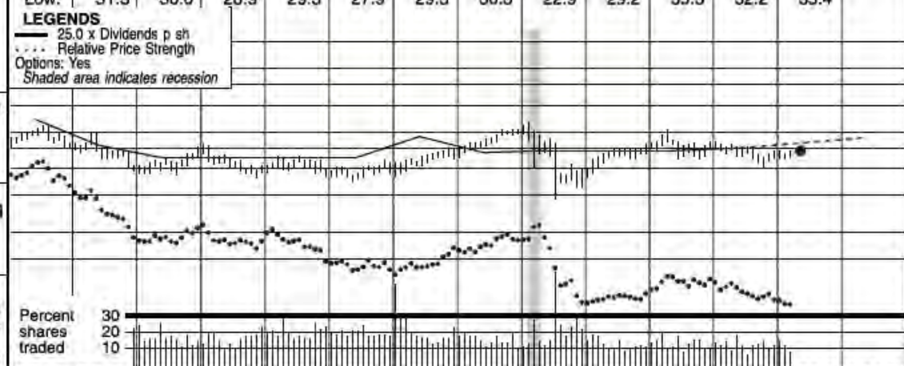
Low-High	Midpoint (% to Mid)
$33-$49	$41 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+70%)	17%
Low	40	(+5%)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	301	258	306
to Sell	334	356	311
Hld's(000)	472563	471442	477876



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.7	16.9
3 yr.	25.8	16.2
5 yr.	13.0	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	20.41	19.87	19.52	21.78	22.41	**23.40**	**24.50**	Revenues per sh	**27.40**
9.04	8.80	8.50	5.75	6.05	6.30	6.26	7.04	7.04	6.54	5.19	4.80	4.59	5.41	4.71	4.78	**4.95**	**5.20**	"Cash Flow" per sh	**6.20**
4.38	3.32	3.25	1.88	2.13	2.97	2.56	2.71	2.63	2.73	2.59	2.56	2.39	2.60	2.41	2.56	**2.70**	**2.85**	Earnings per sh A	**3.40**
2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.82	1.53	1.56	1.56	1.56	1.60	**1.70**	**1.80**	Div'd Decl'd per sh B ■	**2.14**
9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	5.23	4.93	4.89	4.29	4.82	5.84	**6.05**	**6.20**	Cap'l Spending per sh	**6.50**
27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	13.17	12.90	13.33	15.21	17.77	18.17	**18.95**	**19.85**	Book Value per sh C	**24.00**
304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	511.92	540.65	543.12	570.26	572.13	574.34	**577.00**	**580.00**	Common Shs Outst'g D	**595.00**
15.6	13.0	11.7	22.4	21.1	13.1	13.2	12.6	12.7	11.4	13.6	17.1	15.7	14.1	17.0	14.9	*Bold figures are*		Avg Ann'l P/E Ratio	**15.5**
.94	.87	.74	1.41	1.34	.74	.69	.63	.67	.57	.73	.91	.81	.76	.98	.83	*Value Line*		Relative P/E Ratio	**.85**
3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%	5.2%	3.5%	4.2%	4.3%	3.8%	4.2%	*estimates*		Avg Ann'l Div'd Yield	**4.1%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $24515 mill. **Due in 5 Yrs** $10605 mill.
LT Debt $21652 mill. **LT Interest** $955 mill.
Incl. $14 mill. finance leases.
(Total interest coverage: 2.6x)
Leases, Uncapitalized Annual rentals $56 mill.

Pension Assets-12/23 $6879 mill.
Oblig. $8363 mill.
Pfd Stock None

Common Stock 575,516,472 shs.

MARKET CAP: $22.3 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
15049	15029	14562	14022	11261	11035	10790	11132	12459	12870	**13500**	**14200**	Revenues ($mill)	**16300**
1074.0	1144.0	1118.0	1213.0	1346.0	1380.0	1296.0	1419.0	1377.0	1468.0	**1560**	**1655**	Net Profit ($mill)	**2035**
28.4%	35.8%	37.4%	37.2%	28.5%	19.8%	13.6%	20.6%	48.1%	16.2%	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
11.0%	10.2%	9.2%	6.5%	4.8%	5.1%	5.9%	5.3%	6.1%	6.6%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
60.7%	60.7%	74.5%	84.3%	72.3%	73.8%	75.4%	71.9%	67.6%	68.7%	**65.5%**	**66.0%**	Long-Term Debt Ratio	**63.0%**
39.3%	39.3%	25.5%	15.7%	27.4%	26.2%	24.6%	28.1%	32.4%	31.3%	**34.5%**	**34.0%**	Common Equity Ratio	**37.0%**
31596	31613	24433	25040	24565	26593	29368	30923	31369	33322	**31950**	**34000**	Total Capital ($mill)	**38500**
35783	37214	29387	28879	29911	31650	33294	34744	36285	38412	**39300**	**41500**	Net Plant ($mill)	**48300**
5.0%	5.3%	6.6%	7.0%	7.4%	6.8%	6.0%	6.2%	5.9%	5.8%	**6.5%**	**6.5%**	Return on Total Cap'l	**6.5%**
8.6%	9.2%	17.9%	30.9%	19.8%	19.8%	17.9%	16.4%	13.5%	14.1%	**14.5%**	**14.5%**	Return on Shr. Equity E	**14.5%**
8.6%	9.2%	17.9%	30.9%	18.9%	19.7%	17.9%	16.4%	13.5%	14.1%	**14.5%**	**14.5%**	Return on Com Equity E	**14.5%**
3.8%	4.3%	8.1%	14.6%	8.4%	8.1%	6.2%	6.6%	4.8%	5.4%	**5.5%**	**5.5%**	Retained to Com Eq	**5.5%**
56%	53%	55%	53%	58%	59%	65%	60%	65%	62%	**63%**	**63%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (MWH)	+2.4	+1.5	-3.3
Residential Use (MWH)	55624	55995	52216
Commercial Use (MWH)	35599	36317	34891
Industrial Use (MWH)	54027	55169	55541
Tot. Electric Deliv'd (MWH)	145250	147481	142648
Peak Load Summer (Mw)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.4	+.5
Fixed Charge Cov. (%)	171	290	225

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-5.5%	-6.0%	4.5%
"Cash Flow"	-2.0%	-4.5%	4.5%
Earnings	1.0%	-1.0%	5.5%
Dividends	-2.5%	--	5.5%
Book Value	-6.0%	7.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2726	2622	3124	2660	11132
2022	2989	2818	3475	3177	12459
2023	3231	3006	3487	3146	12870
2024	3287	**3163**	**3650**	**3400**	**13500**
2025	**3480**	**3300**	**3850**	**3570**	**14200**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.69	.59	.82	.51	2.60
2022	.60	.53	.79	.50	2.41
2023	.60	.47	.88	.62	2.56
2024	.55	**.55**	**.90**	**.70**	**2.70**
2025	**.60**	**.55**	**.95**	**.75**	**2.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.39	.39	.39	.39	1.56
2021	.39	.39	.39	.39	1.56
2022	.39	.39	.39	.39	1.56
2023	.39	.39	.39	.41	1.58
2024	.41	.425			

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to 6.24 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 59.6%; commercial, industrial & other, 40.4%. Purchases most of its power. Power costs: 36.1% of revenues. 2023 reported depreciation rate: 2.8%. Employs about 12,000. Chair: John W. Somerhalder II. President and CEO: Brian X. Tierney. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy is off to a decent start to 2024. Despite mild winter weather in its service area, the company bettered its own earnings-per-share target by $0.02 during the first quarter. Management reaffirmed its bottom-line target of $2.61-$2.81 per share for the full year, representing 6% growth at the midpoint of its range. We expect FirstEnergy will continue to leverage the flexibility of its vast Mid-Atlantic to Midwest network by prioritizing transmission and distribution projects. This type of investment provides a relatively quick regulated return on capital employed. Meanwhile, rate relief should add to the bottom line, as well. In October, a favorable outcome was concluded in the Maryland rate case and constructive settlements just concluded in West Virginia and New Jersey. Recently, cases were filed in Pennsylvania and Ohio.

Finances are improving. In 2021, FirstEnergy settled its bribery charges with federal prosecutors and Ohio regulators. After this year's payment of $45 million, just a $25 million disbursement remains. New leadership continues to cooperate with federal prosecutors as the DPA (deferred prosecution agreement) concludes this July. To recap, equity injections of $1 billion were received in late 2021, followed by the mid-2022 sale of a minority interest in the company's long-range transmission assets for $2.4 billion. Fitch restored FirstEnergy's credit rating to investment grade in 2022. Upgrades from the other major credit rating agencies recently took place, as the DPA is concluding soon and the company is set to receive $3.5 billion in proceeds this year from the sale of a second minority interest.

FirstEnergy raised its dividend. Last year, the board lifted the payout target to 60%-70% of adjusted profits. The recent hike in the quarterly rate, to $0.425 per share, represents over 6% annual growth relative to 2023's level. We think 5%-7% increases per annum are likely to follow, commensurate with earnings growth.

Utility investors with a longer-term slant should keep this stock on their watch list. An entry point that provides more worthwhile upside to the midpoint of our 18-month Target Price Range should be sought.

Anthony J. Glennon *May 10, 2024*

(A) Diluted egs. excl. nonrc. loss: '13, $2.07; '14, $2.05; '15, $1.34; '16, $17.12; '17, $6.61; '18, $1.26; '19, 89¢; '20, 54¢; '21, 33¢; '22, $1.70; '23, 60¢; gain/loss from disc. ops.: '18, 66¢; '20, 14¢; '21, 8¢; '23, d4¢. Qtly. EPS don't sum due to rnd'g. Next egs. report in Jul. (B) Div. pd. Mar., June, Sept., & Dec. 3 div. in '13, 5 in '18. ■ Div'd reinv. avail. (C) Incl. intang. in '23: $10.42/sh. (D) In mill. (E) High ROE from large writeoffs. Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.6-11.7%; Reg.: OH Above Avg.; PA/NJ Avg.; MD/WV Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	35
Earnings Predictability	100

FORTIS INC. TSE-FTS.TO [A]

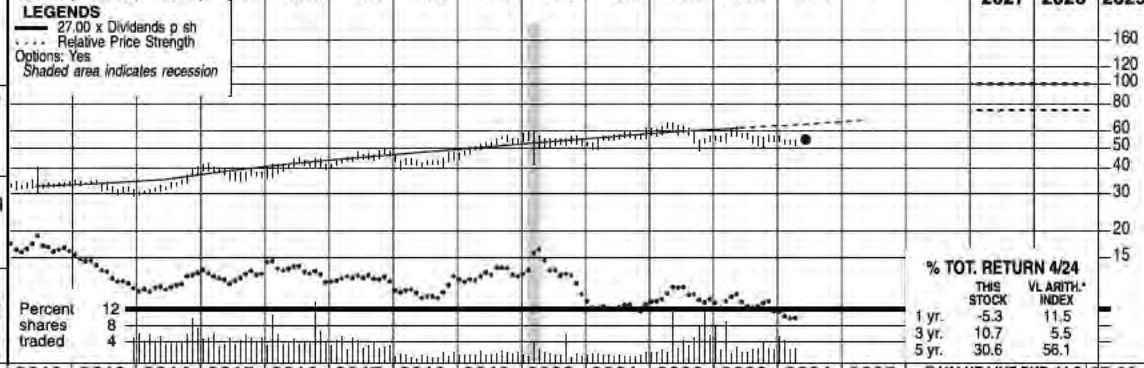
RECENT PRICE 54.53 | P/E RATIO 17.0 (Trailing: 17.4, Median: 20.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Lowered 3/8/24
SAFETY 1 Raised 6/7/24
TECHNICAL 5 Lowered 5/10/24
BETA .75 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	35.1	40.5	42.1	45.1	48.7	47.4	56.9	59.3	61.6	65.4	62.1	56.7				
Low:	29.6	29.8	34.5	36.0	40.6	39.4	44.0	41.6	48.7	48.2	49.8	51.0				

Target Price Range 2027 | 2028 | 2029

LEGENDS
— 27.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$49-$72	$61 (10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+85%)	19%
Low	75	(+40%)	12%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	120	112	127
to Sell	107	108	109
Hld's(000)	244100	245793	255450

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.3	11.5
3 yr.	10.7	5.5
5 yr.	30.6	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
23.07	21.24	21.01	19.84	19.07	18.99	19.57	23.89	17.03	19.71	19.58	18.96	19.14	19.90	22.90	23.48	*24.55*	*25.30*	Revenues per sh	*27.45*
3.51	3.66	3.99	3.90	4.10	4.10	3.62	5.21	3.91	5.43	5.40	5.44	5.65	5.76	6.24	6.71	*7.00*	*7.30*	"Cash Flow" per sh	*8.00*
1.52	1.51	1.62	1.74	1.65	1.63	1.38	2.11	1.89	2.66	2.52	2.68	2.60	2.61	2.78	3.10	*3.20*	*3.35*	Earnings per sh [B]	*4.00*
1.00	1.04	1.12	1.17	1.21	1.25	1.30	1.43	1.55	1.65	1.75	1.86	1.97	2.08	2.17	2.29	*2.38*	*2.49*	Div'd Decl'd per sh [C] ■	*2.85*
5.34	5.79	5.89	5.91	5.68	5.32	6.00	7.97	5.13	7.18	7.51	8.03	8.65	7.13	7.02	7.18	*8.25*	*8.25*	Cap'l Spending per sh	*8.25*
18.00	18.57	18.95	20.53	20.84	22.39	24.90	28.63	32.32	31.77	34.80	36.49	36.58	37.21	36.44	39.24	*41.40*	*43.50*	Book Value per sh [D]	*47.05*
169.19	171.26	174.39	188.83	191.57	213.17	276.00	281.56	401.49	421.10	428.50	463.30	466.80	474.80	482.15	490.60	*495.00*	*500.00*	Common Shs Outst'g [E]	*510.00*
17.5	16.4	18.2	18.8	20.1	20.0	24.3	18.0	21.6	16.8	17.1	19.2	20.6	21.2	21.1	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	*21.5*
1.05	1.09	1.16	1.18	1.28	1.12	1.28	.91	1.13	.84	.92	1.02	1.06	1.15	1.22	1.03	*Value Line*		Relative P/E Ratio	*1.20*
3.8%	4.2%	3.8%	3.6%	3.6%	3.8%	3.9%	3.8%	3.8%	3.7%	4.1%	3.6%	3.7%	3.8%	4.1%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $30653 mill. **Due in 5 Yrs** $7732 mill.
LT Debt $27363 mill. **LT Interest** $945 mill.
Incl. $340 mill. finance leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $8 mill.

Pension Assets-12/23 $3722 mill. **Oblig** $3922 mill.
Pfd Stock $1623 mill. **Pfd Div'd** $65 mill.

Common Stock 491,600,000 shs.

MARKET CAP: $26.8 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
5401.0	6727.0	6838.0	8301.0	8390.0	8783.0	8935.0	9448.0	11043.0	11517.0	*12150*	*12650*	Revenues ($mill)	*14000*
374.0	672.0	660.0	1174.0	1136.0	1238.0	1274.0	1294.0	1340.4	1520.9	*1585*	*1675*	Net Profit ($mill)	*2040*
14.6%	21.3%	16.9%	25.8%	13.4%	12.5%	14.3%	14.3%	16.0%	14.6%	*14.5%*	*14.5%*	Income Tax Rate	*14.5%*
7.2%	7.4%	10.0%	9.5%	8.4%	9.2%	9.3%	9.0%	9.0%	8.0%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
54.8%	53.3%	59.3%	58.4%	58.8%	54.2%	55.6%	55.5%	55.0%	54.2%	*53%*	*53%*	Long-Term Debt Ratio	*51.5%*
35.7%	38.1%	36.2%	37.1%	37.2%	41.8%	40.5%	40.8%	41.5%	42.5%	*43.5%*	*43.5%*	Common Equity Ratio	*45.0%*
19235	21151	35874	36108	40082	40445	42141	43328	44922	46282	*48050*	*49225*	Total Capital ($mill)	*51900*
17816	19595	29337	29668	32654	33988	35998	37816	41663	14938	*43500*	*44750*	Net Plant ($mill)	*48600*
3.4%	4.5%	2.8%	4.5%	4.1%	4.4%	4.3%	4.2%	2.4%	4.5%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
4.3%	6.8%	4.5%	7.8%	6.9%	6.7%	6.8%	6.7%	4.4%	7.0%	*7.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
4.5%	7.4%	4.5%	8.3%	7.2%	6.9%	7.1%	7.0%	4.4%	7.0%	*7.0%*	*7.0%*	Return on Com Equity [F]	*7.5%*
1.7%	4.5%	2.1%	5.2%	4.1%	4.0%	2.5%	3.5%	3.5%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
68%	46%	59%	41%	46%	45%	67%	52%	78%	81%	*82%*	*82%*	All Div'ds to Net Prof [G]	*75%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	207	211	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	--	-.5%	3.5%
"Cash Flow"	3.5%	3.5%	5.0%
Earnings	4.5%	3.5%	5.0%
Dividends	5.5%	5.5%	6.0%
Book Value	6.5%	3.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2539	2130	2196	2583	9448
2022	2835	2487	2553	3168	11043
2023	3319	2594	2719	2885	11517
2024	3118	*2700*	*2770*	*3562*	*12150*
2025	*3400*	*2750*	*2850*	*3650*	*12650*

Cal-endar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.76	.54	.62	.69	2.61
2022	.74	.59	.68	.77	2.78
2023	.90	.61	.81	.78	3.10
2024	.93	*.65*	*.80*	*.82*	*3.20*
2025	*.95*	*.75*	*.80*	*.85*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.505	1.94
2021	.505	.505	.505	.535	2.05
2022	.535	.535	.535	.565	2.17
2023	.565	.565	.565	.590	2.29
2024	.590				

BUSINESS: Fortis Inc.'s main focus is electricity, hydroelectric, and gas utility operations (both regulated and nonregulated) in the United States, Canada, and the Caribbean. Has 2 mill. electric, 1.3 mill. gas customers. Owns UNS Energy (Arizona), Central Hudson (New York), FortisBC Energy (British Columbia), FortisAlberta (Central Alberta), and Eastern Canada (Newfoundland). Sold commercial real estate and hotel property assets in 2015. Acquired ITC Holdings 10/16. Fuel costs: 31% of revs. '23 reported deprec. rate: 2.6%. Has 9,100 employees. Chairman: Jo Mark Zurel. President & CEO: David G. Hutchens. Inc.: Canada. Address: Fortis Place, Suite 1100, 5 Springdale St., PO Box 8837, St. John's, NL, Canada, A1B 3T2. Tel.: 709-737-2800. Internet: www.fortisinc.com.

We continue to look for Fortis to post steady earnings growth over the next couple years. Rate relief should remain a main driver of growth and help improve upon low allowed returns seen in many of the company's utilities. There are currently ongoing cases in New York and British Columbia, with decisions in both expected by the end of this year. And, in Arizona, a full-year of new rates will likely benefit profits. Too, Fortis' ITC transmission subsidiary should increase its yearly income due to a forward-looking regulatory mechanism that enables the utility to earn a return on its capital spending and recover most operating expenses. Our 2024 bottom-line estimate is staying put at $3.20 per share.

We are also sticking with our 2025 earnings target of $3.35 per share. We look for investments in the transition to clean energy and rate relief to remain prevalent next year. Indeed, the company's $25-billion five-year capital plan is expected to rise to over $49 billion in 2028 due to rate-base increases. This is within management's five-year annual rate-base growth of 6.3%. We feel confident with our profit estimate as Fortis has a high Earnings Predictability score, along with a stretch of respectable financial performances of late.

We look for a dividend increase at the third-quarter meeting in September. The company has raised its distribution in 49 consecutive years, and remains committed to its target of a 4%-6% annual dividend growth rate through 2028. We expect a hike of approximately $0.15 a share (6%) this time around in the annual payment.

These shares are best suited for income-oriented accounts with a long-term investment horizon. The dividend yield of 4.4% stands comfortably above the high-paying utility average, and remains this issue's most notable feature. Too, capital appreciation potential for the 3- to 5-year time frame stands out in comparison to its peers. Short-term prospects are not as exciting. Indeed, capital gains potential for the next 18 months is not enticing, and the stock is ranked to trail the broader market averages over the coming six to 12 months.

Zachary J. Hodgkinson *June 7, 2024*

(A) Also trades on NYSE (FTS). All data in Canadian $. (B) Dil. egs. Excl. nonrecur. gains (loss): '14, 2¢; '15, 48¢; '17, (35¢); '18, 7¢. '19, $1.12. Next egs. report due early July. (C) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (2% disc.). (D) Incl. intang. In '23: $34.05/sh. (E) In mill. (F) Rates all'd on com. eq.: 8.3%-10.32%; earn. on avg. com. eq., '21: 7.1%. Reg. Clim.: FERC, Above Avg.; AZ, Below Avg.; NY, Below Avg. (G) Excl. div'ds pd. via reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 11.07 | P/E RATIO 6.0 (Trailing: 6.1; Median: 19.0) | RELATIVE P/E RATIO 0.33 | DIV'D YLD Nil | VALUE LINE

TIMELINESS – Suspended 8/25/23
SAFETY 5 Lowered 9/15/23
TECHNICAL – Suspended 8/25/23
BETA 1.00 (1.00 = Market)

18-Month Target Price Range
Low-High: $10-$38 | Midpoint (% to Mid): $24 (115%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	16	(+45%)	10%
Low	8	(-30%)	-7%

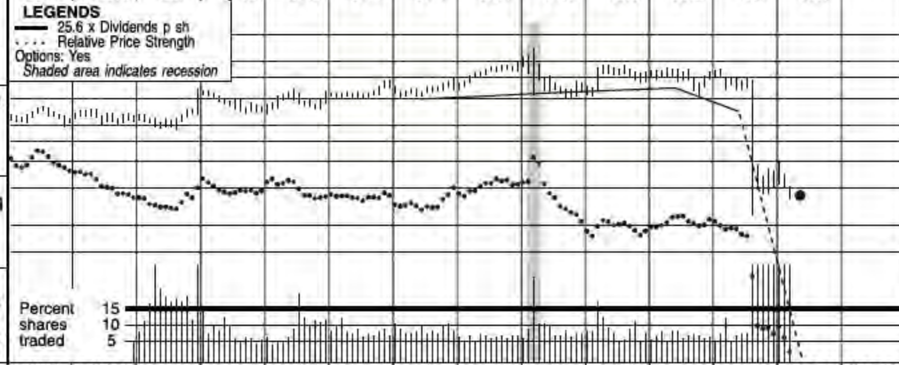
Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	130	161	151
to Sell	151	196	142
Hld's(000)	58926	63814	66270

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	28.3	35.0	34.9	35.0	38.7	39.3	47.6	55.2	46.0	44.7	43.7
Low:	23.8	22.7	27.0	27.3	31.7	31.7	35.1	31.8	33.0	33.2	9.1

High/Low (2024): 16.0 / 10.7

LEGENDS
— 25.6 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-69.5	16.9
3 yr.	-71.8	16.2
5 yr.	-67.4	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49	26.28	26.38	23.63	26.08	34.18	33.43	*34.40*	*35.15*	Revenues per sh	*37.15*
2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.68	4.20	4.55	4.48	4.80	4.90	4.63	*4.80*	*4.00*	"Cash Flow" per sh	*4.35*
1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.64	1.85	1.99	1.81	2.25	2.20	1.81	*1.90*	*1.00*	Earnings per sh A	*1.00*
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.28	1.32	1.36	1.40	1.08	*Nil*	*Nil*	Div'd Decl'd per sh B	*Nil*
3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	4.55	4.94	4.20	3.52	2.88	3.14	4.07	*4.00*	*4.00*	Cap'l Spending per sh	*4.00*
15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	19.28	19.86	20.93	21.41	21.87	20.12	21.29	*23.10*	*24.00*	Book Value per sh C	*25.30*
90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	108.79	108.88	108.97	109.18	109.31	109.47	110.15	*110.50*	*111.00*	Common Shs Outst'g D	*113.00*
23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6	20.7	18.9	21.3	21.5	18.2	18.5	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*12.0*
1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	1.04	1.02	1.13	1.10	.98	1.07	.89	*Value Line*		Relative P/E Ratio	*.65*
5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%	3.7%	3.5%	3.0%	3.4%	3.3%	3.4%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*Nil*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $3931.5 mill. **Due in 5 Yrs** $1023 mill.
LT Debt $3913.5 mill. **LT Interest** $120.0 mill.
Incl. $339.0 mill. finance leases.
(Total Interest Coverage: 3.0x)
Leases, Uncapitalized Annual rentals $27.3 mill.

Pension Assets-12/23 $1973.5 mill. **Oblig** $2033.0 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $1.9 mill.

Common Stock 110,151,798 shs. as of 2/15/24
MARKET CAP: $1.2 billion (Small Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3239.5	2603.0	2380.7	2555.6	2860.8	2874.6	2579.8	2850.4	3742.0	3682.2	*3800*	*3900*	Revenues ($mill)	*4200*
170.2	161.8	250.1	180.6	203.7	219.8	199.7	248.1	243.0	201.1	*210*	*110*	Net Profit ($mill)	*115*
35.0%	36.5%	33.1%	34.7%	20.0%	19.0%	17.0%	20.2%	20.1%	18.1%	*18.0%*	*19.0%*	Income Tax Rate	*19.0%*
5.5%	5.8%	4.6%	9.6%	7.7%	7.5%	5.9%	5.2%	5.8%	10.1%	*9.5%*	*18.0%*	AFUDC % to Net Profit	*18.0%*
45.2%	43.5%	41.6%	43.4%	47.5%	44.6%	46.5%	46.4%	50.3%	62.2%	*60.0%*	*59.0%*	Long-Term Debt Ratio	*57.5%*
53.8%	55.5%	57.5%	55.7%	51.7%	54.6%	52.7%	52.8%	49.0%	37.3%	*39.5%*	*40.5%*	Common Equity Ratio	*42.0%*
3332.3	3473.5	3595.1	3765.5	4182.3	4176.9	4435.9	4524.1	4498.5	6292.6	*6500*	*6600*	Total Capital ($mill)	*6800*
4148.8	4377.7	4603.5	5025.9	4830.1	5109.6	5265.7	5392.1	5687.0	6150.1	*6275*	*6375*	Net Plant ($mill)	*6600*
6.2%	5.7%	7.9%	5.8%	5.9%	6.3%	5.5%	6.4%	6.4%	4.1%	*4.5%*	*3.0%*	Return on Total Cap'l	*3.0%*
9.3%	8.2%	11.9%	8.5%	9.3%	9.5%	8.4%	10.2%	10.9%	8.5%	*8.0%*	*4.0%*	Return on Shr. Equity	*4.0%*
9.4%	8.3%	12.0%	8.5%	9.3%	9.6%	8.5%	10.3%	10.9%	8.5%	*8.0%*	*4.0%*	Return on Com Equity E	*4.0%*
2.3%	1.5%	6.3%	2.1%	3.1%	3.4%	2.3%	4.1%	4.0%	3.7%	*8.0%*	*4.0%*	Retained to Com Eq	*4.0%*
75%	83%	48%	76%	67%	64%	73%	61%	64%	57%	*1%*	*2%*	All Div'ds to Net Prof F	*2%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (MWH)	+1.7	+1.1	-1.5
Avg. Indust. Use (MWH)	3174	3296	3273
Avg. Indust. Revs. per KWH (¢)	26.88	36.75	35.34
Capacity at Yearend (Mw)	2278	2100	2101
Peak Load/Demand (Mw)	1471	1467	1447
Annual Load Factor (%)	67.2	68.2	68.0
% Change Customers (yr-end)	+.5	-.2	+.4
Fixed Charge Cov. (%)	393	356	273

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-0.5%	5.5%	*2.5%*
"Cash Flow"	4.0%	3.5%	*-1.5%*
Earnings	3.0%	1.5%	*-11.5%*
Dividends	0.5%	0.5%	*NMF*
Book Value	2.5%	1.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	642.9	680.3	756.9	770.3	2850.4
2022	785.1	895.6	1042.2	1019.1	3742.0
2023	928.2	895.7	896.9	961.4	3682.2
2024	*940*	*910*	*975*	*975*	*3800*
2025	*965*	*935*	*1000*	*1000*	*3900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.59	.58	.58	.50	2.25
2022	.63	.48	.57	.52	2.20
2023	.50	.50	.37	.44	1.81
2024	*.45*	*.45*	*.50*	*.50*	*1.90*
2025	*.40*	*.30*	*.20*	*.10*	*1.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.33	.33	.33	.33	1.32
2021	.34	.34	.34	.34	1.36
2022	.35	.35	.35	.35	1.40
2023	.36	.36	.36	--	1.08
2024	--				

BUSINESS: Hawaiian Electric Industries (HEI) is the parent company of Hawaiian Electric Company, Inc. (HECO), American Savings Bank (ASB), and Pacific Current. HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 416,177 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 32%; commercial, 36%; industrial, 32%; other, less than 1%. Generating sources: oil, 52%; purchased, 48%. Fuel costs: 50%+ of revs. '23 reported deprec. rate: 3.2%. Has about 3,600 employees. Chairman: Tom Fargo. Pres. & CEO: Scott Seu. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Telephone: 808-543-5662. Internet: www.hei.com.

Hawaiian Electric Industries faces a mounting number of lawsuits related to its role in the Maui wildfires. To recap, on August 8th, winds associated with Hurricane Dora knocked down power lines that started an early morning fire near the town of Lahaina. According to HEI, that blaze was extinguished by firefighters. HEI contends that the fires that began hours later, resulting in over 100 deaths and massive property damage (estimated to be more than $1.5 billion), were not from its equipment, since the utility deenergized its system following the initial downed wires. Maui County filed a lawsuit against the company, claiming the utility acted negligently by not preemptively cutting power, given the forecast for extreme winds. HEI has been named as a defendant in more than 100 lawsuits for local damages (up from 60 in November). The company has also been hit with a class action suit on behalf of shareholders and subrogation claims on the part of about 150 different insurers. The dividend was suspended to preserve cash and the company fully exhausted its $375 million revolving credit facility.

Hawaiian Electric was unsuccessful in its bid to move wildfire cases from state to federal court. In March, a U.S. district judge ruled that the lawsuits filed against the company will be remanded back to state court on the island of Maui. Plaintiffs' lawyers considered it a victory because these cases will be heard by a local jury beginning this October.

Our estimates assume hefty legal settlements. Thus far, HEI has agreed to contribute up to $75 million of a $175 million fund for victims as part of the state's response. Payouts are expected to be in the $1.5 million range per claim. HEI's share will be paid by insurance, leaving $90 million of additional coverage. While the fund may alleviate some of the court cases, we think substantial legal costs are inevitable and have priced in settlement figures of $125 million to $250 million annually starting in 2025. It's an amount the company can stay viable at in terms of maintaining the power grid. This outcome results in poor total return prospects for shareholders. The Timeliness rank is suspended due to the vagaries ahead.

Anthony J. Glennon *April 19, 2024*

(A) Diluted EPS. Excl. nonrec. losses: '12, 25¢; '17, 12¢. Qtrly. EPS may not sum to full year due to rounding. Next egs. report due early May. (B) Quarterly dividends not declared prior to 8/21/23 have been suspended. (C) Incl. deferred charges. In '23: $294.8 mill., $2.68/sh. (D) In mill. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '18: HECO, 9.5%; in '18: HELCO, 9.5%; in '18: MECO, 9.5%; Regulatory Climate: Below Average. (F) Includes preferred dividends.

Company's Financial Strength	C+
Stock's Price Stability	5
Price Growth Persistence	35
Earnings Predictability	90

IDACORP, INC. NYSE-IDA

RECENT PRICE 93.19 | P/E RATIO 18.1 (Trailing: 18.1 Median: 20.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 5 Lowered 3/1/24

SAFETY 1 Raised 4/19/24

TECHNICAL 5 Lowered 3/29/24

BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$78-$132	$105 (15%)

2027-29 PROJECTIONS

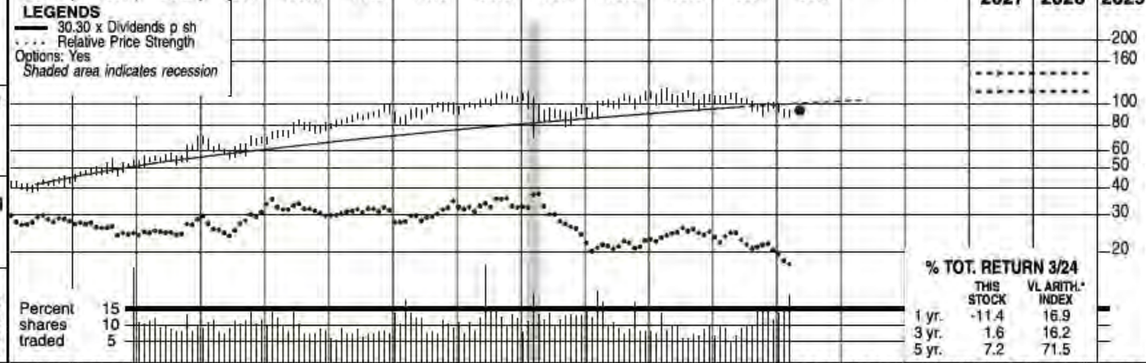
	Price	Gain	Ann'l Total Return
High	140	(+50%)	14%
Low	115	(+25%)	9%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	168	160	192
to Sell	170	177	168
Hld's(000)	42011	43079	45178

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9	113.0	99.8
Low:	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	93.5	88.1	86.4

LEGENDS
— 30.30 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.4	16.9
3 yr.	1.6	16.2
5 yr.	7.2	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	32.51	34.90	*34.30*	*35.90*	Revenues per sh	*39.60*
4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	8.55	9.11	*9.50*	*10.10*	"Cash Flow" per sh	*11.40*
2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	5.11	5.14	*5.40*	*5.75*	Earnings per sh A	*6.65*
1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	3.04	3.20	*3.34*	*3.46*	Div'd Decl'd per sh B ■ †	*4.25*
5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	8.56	12.07	*17.00*	*14.00*	Cap'l Spending per sh	*12.00*
27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	55.52	57.44	*59.30*	*63.10*	Book Value per sh C	*69.80*
46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	50.56	50.62	*51.00*	*51.50*	Common Shs Outst'g D	*53.00*
13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	21.0	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.12	1.21	1.11	*Value Line*		Relative P/E Ratio	*1.05*
4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	2.8%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $2825.6 mill. **Due in 5 Yrs** $186.0 mill.
LT Debt $2775.8 mill. **LT Interest** $96.4 mill.
(Total Interest Coverage: 2.6x)

Pension Assets-12/23 $917.5 mill.
Oblig $1028.0 mill.

Pfd Stock None

Common Stock 50,628,079 shs.
as of 2/9/24

MARKET CAP: $4.7 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	1644.0	1766.4	*1750*	*1850*	Revenues ($mill)	*2100*
193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	259.0	261.2	*275*	*295*	Net Profit ($mill)	*355*
8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	12.7%	9.4%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	19.8%	8.8%	*15.0%*	*15.0%*	AFUDC % to Net Profit	*16.0%*
45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	43.9%	48.8%	*49.0%*	*49.5%*	Long-Term Debt Ratio	*49.5%*
54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	56.1%	51.2%	*51.0%*	*50.5%*	Common Equity Ratio	*50.5%*
3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	5001.4	5683.4	*6000*	*6325*	Total Capital ($mill)	*7300*
3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	5173.0	5745.2	*6100*	*6425*	Net Plant ($mill)	*7400*
6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	6.1%	5.4%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	9.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	9.2%	9.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	3.7%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
46%	50%	53%	53%	54%	56%	58%	60%	60%	63%	*62%*	*60%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.9	+9.6	+7.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3751	3568	3615
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.8	+2.4	+2.4
Fixed Charge Cov. (%)	390	395	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.5%	4.0%	*3.5%*
"Cash Flow"	3.5%	3.5%	*4.5%*
Earnings	4.0%	3.5%	*5.0%*
Dividends	8.0%	6.5%	*5.5%*
Book Value	4.5%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	518.0	422.9	1644.0
2023	429.7	413.8	510.9	412.0	1766.4
2024	*365*	*415*	*560*	*410*	*1750*
2025	*390*	*440*	*585*	*435*	*1850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	2.10	.83	5.11
2023	1.11	1.35	2.07	.61	5.14
2024	*1.10*	*1.35*	*2.10*	*.85*	*5.40*
2025	*1.15*	*1.45*	*2.25*	*.90*	*5.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75	.79	3.04
2023	.79	.79	.79	.83	3.20
2024	.83				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 633,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.4 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 39%; commercial, 21%; industrial, 14%; irrigation, 10%; other, 16%. Generating sources: hydro, 35%; coal, 13%; gas, 15%; purchased, 37%. Fuel costs: 40% of revenues. '23 reported depreciation rate: 3.1%. Has 2,112 employees. Chairman: Richard J. Dahl. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's management has set its earnings target for 2024 in a range of $5.25 to $5.45 a share. The company extended its streak of 15 years when it comes to annual earnings growth in 2023, but not by a whole lot. Our 2024 estimate is being placed at $5.40, which assumes a 5% annual gain, which is in line with the company's in-house goal. Most utilities strive for something in the 4%-6% or 5%-7% spread. Digging deeper, our estimate assumes Idaho Power will use between $35 million and $60 million of additional tax credits available under its regulatory mechanism. A good portion of this figure is tied to battery storage projects approved by the Idaho Public Utilities Commission in the general rate case last December.

A rate case in Oregon is now on the table. IDACORP has filed with the Oregon Public Utilities Commission for a rate increase to go into effect in October of this year. The company is requesting an ROE of 10.4%, and a 7.8% rate of return with a capital structure comprised of 51% equity and 49% debt. Infrastructure investments have been made in this service area and the last general rate case was filed in 2011. Since then, there has been an 8% increase in the number of customers. We expect the parties to mutually agree on a pact that is fair to both IDA and its constituents.

Capital expenditures are expected to peak this year at above $900 million. New capacity resources are pushing the spending up, but management has cast a wide net ($20 million to $200 million), so the total could be somewhat lower. Still, the average over the next five years is apt to come in around the $800 million threshold. Distribution and transmission will be areas of heavy outlays, as will high voltage transmission, one of the driving forces behind IDA's heavier spending coming off an average of about $400 million in the previous five-year window.

These untimely shares lack real investment appeal at this juncture. Even with the quotation down 7% in value since our January review, capital appreciation potential three to five years out is below average. Yes, the yield is handsomely above the *Value Line* median, but does not stand out for a utility.

Erik M. Manning *April 19, 2024*

(A) Diluted EPS. Earnings may not sum due to rounding. Next earnings report due early May. (B) Dividends historically paid in late February, May, August, and November. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '23: $882.7 mill., $17.44/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

MGE ENERGY, INC. NDQ-MGEE

RECENT PRICE 78.22 | P/E RATIO 21.1 (Trailing: 23.6, Median: 25.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 3 Lowered 2/23/24
SAFETY 3 Lowered 6/7/24
TECHNICAL 3 Raised 5/24/24
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$62-$111	$87 (10%)

2027-29 PROJECTIONS

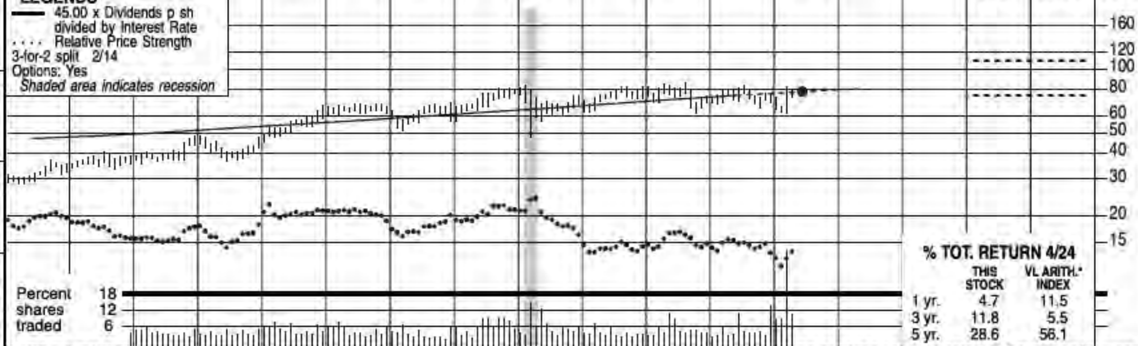
	Price	Gain	Ann'l Total Return
High	110	(+40%)	11%
Low	75	(-5%)	2%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	82	84	120
to Sell	82	84	78
Hld's(000)	19530	19172	19078

High:	40.5	48.0	48.0	66.9	68.7	68.9	80.8	83.3	82.9	86.3	83.3	82.5		
Low:	33.4	35.7	36.5	44.8	60.3	51.1	56.7	47.2	63.0	61.7	65.1	61.9		

Target Price Range 2027 2028 2029



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.7	11.5
3 yr.	11.8	5.5
5 yr.	28.6	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
17.35	15.40	15.36	15.76	15.61	17.04	17.88	16.27	15.71	16.24	16.15	16.41	14.89	16.77	19.76	19.09	**19.50**	**20.20**	Revenues per sh	**24.00**
2.68	2.66	2.76	2.94	2.98	3.28	3.49	3.33	3.47	3.73	4.06	4.57	4.61	5.05	5.43	6.03	**6.75**	**7.30**	"Cash Flow" per sh	**8.25**
1.59	1.47	1.67	1.76	1.86	2.16	2.32	2.06	2.18	2.20	2.43	2.51	2.60	2.92	3.07	3.25	**3.70**	**4.00**	Earnings per sh A	**4.65**
.96	.97	.99	1.01	1.04	1.07	1.11	1.16	1.21	1.26	1.32	1.38	1.45	1.52	1.59	1.67	**1.73**	**1.80**	Div'd Decl'd per sh B ■	**1.95**
3.08	2.35	1.76	1.88	2.84	3.43	2.67	2.08	2.41	3.12	6.12	4.73	5.62	4.24	4.84	6.14	**6.15**	**6.20**	Cap'l Spending per sh	**7.00**
13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	22.45	23.56	24.68	26.99	28.41	29.91	31.53	**33.20**	**34.55**	Book Value per sh C	**38.75**
34.36	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	36.16	36.16	36.16	36.16	**36.16**	**36.16**	Common Shs Outst'g D	**36.16**
14.2	15.1	15.0	15.8	17.2	17.0	17.2	20.3	24.9	29.4	25.1	28.4	26.4	25.5	24.7	22.9	*Bold figures are*		Avg Ann'l P/E Ratio	**19.5**
.85	1.01	.95	.99	1.09	.96	.91	1.02	1.31	1.48	1.36	1.51	1.36	1.38	1.43	1.28	*Value Line*		Relative P/E Ratio	**1.10**
4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%	2.8%	2.2%	2.0%	2.2%	1.9%	2.1%	2.0%	2.1%	2.2%	*estimates*		Avg Ann'l Div'd Yield	**2.2%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $722.8 mill. **Due in 5 Yrs** $110.0 mill.
LT Debt $717.6 mill. **LT Interest** $30.4 mill.

(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $2.0 mill.
Pension Assets-12/23 $404 mill. **Oblig** $65.0 mill.
Pfd Stock None

Common Stock 36,175,888 shs. as of 4/30/24
MARKET CAP: $2.8 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
619.9	564.0	544.7	563.1	559.8	568.9	538.6	606.6	714.5	690.4	**705**	**730**	Revenues ($mill)	**865**
80.3	71.3	75.6	76.1	84.2	86.9	92.4	105.8	111.0	117.7	**135**	**145**	Net Profit ($mill)	**170**
37.5%	36.7%	36.0%	36.4%	24.6%	18.5%	17.4%	3.7%	19.1%	19.1%	**19.0%**	**19.0%**	Income Tax Rate	**19.0%**
5.7%	1.3%	2.1%	2.1%	5.2%	3.6%	8.7%	6.3%	6.3%	4.0%	**4.0%**	**3.0%**	AFUDC % to Net Profit	**3.0%**
37.5%	36.2%	34.6%	33.8%	37.7%	38.0%	35.5%	38.1%	35.8%	39.3%	**37.0%**	**36.0%**	Long-Term Debt Ratio	**33.5%**
62.5%	63.8%	65.4%	66.2%	62.3%	62.0%	64.5%	61.9%	64.2%	60.7%	**63.0%**	**64.0%**	Common Equity Ratio	**66.5%**
1054.7	1081.5	1106.9	1176.3	1310.0	1379.4	1512.8	1659.0	1684.0	1876.9	**1950**	**1950**	Total Capital ($mill)	**2100**
1208.1	1243.4	1282.1	1341.4	1509.4	1642.7	1769.4	1878.8	1971.1	2128.2	**2250**	**2350**	Net Plant ($mill)	**2600**
8.6%	7.5%	7.7%	7.3%	7.2%	7.1%	6.8%	7.1%	7.4%	7.1%	**7.0%**	**7.5%**	Return on Total Cap'l	**8.0%**
12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	9.5%	10.3%	10.3%	10.3%	**11.0%**	**11.5%**	Return on Shr. Equity	**12.0%**
12.2%	10.3%	10.4%	9.8%	10.3%	10.2%	9.5%	10.3%	10.3%	10.3%	**11.0%**	**11.5%**	Return on Com Equity E	**12.0%**
6.4%	4.5%	4.7%	4.2%	4.7%	4.6%	4.2%	5.0%	4.9%	5.0%	**6.0%**	**6.5%**	Retained to Com Eq	**7.0%**
48%	56%	55%	57%	54%	55%	56%	52%	52%	51%	**47%**	**45%**	All Div'ds to Net Prof	**42%**

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.2	-.3	-1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.69	8.71	9.09
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	486	517	525

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	1.5%	3.0%	4.5%
"Cash Flow"	6.0%	8.0%	7.0%
Earnings	5.0%	6.5%	7.0%
Dividends	4.5%	4.5%	3.5%
Book Value	6.0%	6.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	167.9	130.7	145.9	162.1	606.6
2022	209.0	152.3	163.4	189.8	714.5
2023	217.3	148.0	160.5	164.6	690.4
2024	191.3	*150*	*165*	*198.7*	*705*
2025	*190*	*180*	*180*	*180*	*730*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.96	.63	.97	.36	2.92
2022	.96	.60	.93	.58	3.07
2023	.86	.79	1.05	.55	3.25
2024	.93	*.95*	*1.15*	*.67*	*3.70*
2025	*1.00*	*1.00*	*1.00*	*1.00*	*4.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2020	.352	.352	.37	.37	1.45
2021	.37	.37	.388	.388	1.52
2022	.388	.388	.408	.408	1.59
2023	.408	.408	.4275	.4275	1.67
2024	.4275				

BUSINESS: MGE Energy, Inc. is a holding company for Madison Gas and Electric Company (MGE), which provides electric service to 163,000 customers in Dane County and gas service to 176,000 customers in seven counties in Wisconsin. Electric revenue breakdown: residential, 35%; commercial, 51%; industrial, 3%; other, 11%. Generating sources: coal, 40%; gas, 17%; renewables, 21%; purchased power, 22%. Fuel costs: 30% of revenues. '23 reported depreciation rates: electric, 3.8%; gas, 2.1%; nonregulated, 2.3%. Has about 700 employees. Chairman, President & CEO: Jeffrey M. Keebler. Incorporated: Wisconsin. Address: 133 South Blair Street, P.O. Box 1231, Madison, Wisconsin 53701-1231. Telephone: 608-252-7000. Internet: www.mgeenergy.com.

MGE Energy reported mixed first-quarter results. Revenues decreased 12% year over year, to $191.3 million. The company experienced a slight decline in electric revenues and a double-digit fall in gas revenues due to warmer-than-normal weather. However, GAAP earnings per share increased by 8% compared to the previous year, reaching $0.93. This growth was thanks to favorable rates and lower fuel costs, boosting electric utility earnings.

The company is investing in assets to support the expansion of renewable energy generation. The utility has several solar and battery projects that are either proposed or under construction. Notable investments include a 20-megawatt solar project, Paris, which is also being developed as a battery storage infrastructure, scheduled for completion in 2024 and 2025, respectively. Another significant solar project, dubbed Darien, is anticipated to be operational by the end of this year. Ongoing investments in capital infrastructure are important for negotiating rate cases and should make a solid ground for future rate cases. We note that rate cases for 2024 and 2025 were approved in December 2023 by the Public Service Commission of Wisconsin.

A combination of rate relief and better cost controls should keep the near-term bottom line healthy. MGE will probably remain active on the investment front to make a case for next rate negotiations. Plus, we also expect it to attract new customers to bolster the top line. All things considered, we estimate a 14% increase in per-share profit for 2024. In all, we project an 8% gain in 2025 earnings per share, bringing the figures to approximately $3.70 and $4.00, respectively.

Shares of MGE Energy are ranked to track the broader market averages in the year ahead. Looking over the 3- to 5-year time frame, the stock has subpar capital appreciation potential. Over the next 18 months, the capital upside prospects are also uninspiring, and the dividend yield is below average for a utility. We think patient, income-oriented investors looking to diversify portfolio risk and earn a high dividend yield may find better options elsewhere in the sector.

Emma Jalees *June 7, 2024*

(A) GAAP Diluted earnings. Excludes nonrecurring gain: '17, 62¢. Quarterly earnings may not sum to full year due to rounding or share count change. Next earnings report due early Aug. (B) Div'ds historically paid in mid-March, June, September, and December ■ Div'd reinvestment plan avail. (C) Includes regulatory assets. In '23: $102.3 mill., $2.83/sh. (D) In millions, adj for split. (E) Rate allowed on common equity in '23: 9.7%; Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	55
Earnings Predictability	100

NEXTERA ENERGY NYSE-NEE

RECENT PRICE 67.42 | P/E RATIO 19.8 (Trailing: 20.7 Median: 24.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Raised 5/3/24
SAFETY 3 Lowered 5/10/24
TECHNICAL 5 Lowered 4/5/24
BETA 1.05 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$52-$101	$77 (15%)

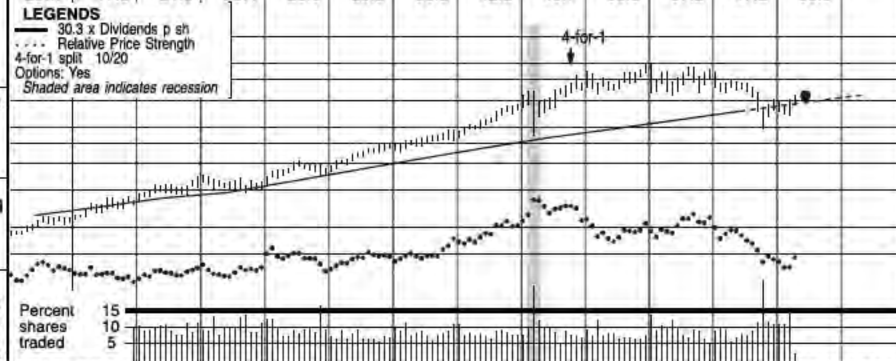
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+55%)	14%
Low	70	(+5%)	4%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	1166	1138	1164
to Sell	974	1080	1119
Hld's(000)	1563720	1591503	1622643

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	22.4	27.7	28.2	33.0	39.8	46.1	61.3	83.3	93.7	93.6	86.5	67.9	
Low:	17.5	21.0	23.4	25.5	29.3	36.3	42.2	43.7	68.3	67.2	47.2	53.9	



Target Price Range 2027 2028 2029

128 96 80 64 48 40 32 24 16 12

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.5	16.9
3 yr.	-9.1	16.2
5 yr.	48.4	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
10.03	9.45	9.10	9.22	8.41	8.70	9.61	9.48	8.63	9.13	8.75	9.82	9.18	8.70	10.55	13.70	**13.35**	**14.65**	Revenues per sh	**17.25**
2.01	2.19	2.41	2.32	2.17	2.63	3.03	3.23	3.24	3.03	3.84	4.22	4.52	4.70	5.30	6.14	**6.45**	**6.70**	"Cash Flow" per sh	**7.75**
1.02	.99	1.19	1.21	1.14	1.21	1.40	1.52	1.45	1.63	1.67	1.94	2.31	2.55	2.90	3.17	**3.40**	**3.65**	Earnings per sh A	**4.55**
.45	.47	.50	.55	.60	.66	.73	.77	.87	.98	1.11	1.25	1.40	1.54	1.70	1.87	**2.06**	**2.25**	Div'd Decl'd per sh B ■ †	**2.85**
3.20	3.63	3.47	3.98	5.58	3.84	3.96	4.54	5.15	5.70	6.80	6.29	7.45	8.19	9.70	12.24	**11.00**	**11.00**	Cap'l Spending per sh	**12.00**
7.14	7.84	8.59	8.98	9.47	10.37	11.24	12.24	13.00	14.97	17.86	18.92	18.63	18.95	19.74	23.13	**24.55**	**26.15**	Book Value per sh C	**34.50**
1635.7	1654.5	1683.4	1664.0	1696.0	1740.0	1772.0	1844.0	1872.0	1884.0	1912.0	1956.0	1960.0	1963.0	1987.0	2052.0	**2055.0**	**2065.0**	Common Shs Outst'g D	**2150.0**
14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	21.6	24.8	26.8	28.9	31.3	27.8	22.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**19.0**
.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.43	1.48	1.69	1.61	1.23	*estimates*		Relative P/E Ratio	**1.05**
3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	2.8%	2.7%	2.4%	2.1%	1.9%	2.1%	2.7%			Avg Ann'l Div'd Yield	**3.3%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $79937 mill. **Due in 5 Yrs** $32228 mill.
LT Debt $65868 mill. **LT Interest** $2880 mill.

(Total Interest coverage: 3.2x)

Pension Assets-12/23 $4897 mill. **Oblig.** $2785 mill.

Pfd Stock None

Common Stock 2,054,532,552 shs.

MARKET CAP: $138 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
17021	17486	16155	17195	16727	19204	17997	17069	20956	28114	**27400**	**30300**	Revenues ($mill)	**37000**
2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	4552.0	5021.0	5742.0	6441.0	**6995**	**7525**	Net Profit ($mill)	**9800**
32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	13.0%	15.0%	18.2%	12.5%	**18.0%**	**18.0%**	Income Tax Rate	**18.0%**
6.7%	6.9%	8.2%	6.7%	6.6%	4.1%	4.6%	6.3%	4.3%	5.4%	**5.0%**	**5.0%**	AFUDC % to Net Profit	**5.0%**
55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	53.5%	57.8%	58.5%	56.4%	**58.5%**	**59.5%**	Long-Term Debt Ratio	**58.0%**
45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	42.2%	41.5%	43.6%	**41.5%**	**40.5%**	Common Equity Ratio	**42.0%**
44283	49255	52159	59671	60926	74548	78457	88162	94485	108873	**121300**	**133900**	Total Capital ($mill)	**176200**
55705	61386	66912	72416	70334	82010	91803	99348	111059	125776	**139600**	**153200**	Net Plant ($mill)	**196400**
7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	6.8%	6.6%	6.9%	7.2%	**7.0%**	**6.5%**	Return on Total Cap'l	**6.5%**
12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	14.6%	13.6%	**14.0%**	**14.0%**	Return on Shr. Equity	**13.0%**
12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	14.6%	13.6%	**14.0%**	**14.0%**	Return on Com Equity E	**13.0%**
6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	5.0%	5.4%	6.1%	5.6%	**5.5%**	**5.5%**	Retained to Com Eq	**5.0%**
51%	50%	60%	60%	66%	64%	60%	60%	58%	59%	**60%**	**62%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-1.0%	+3.0	+.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+1.5	+1.2
Fixed Charge Cov. (%)	284	370	341

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.5%	4.5%	8.0%
"Cash Flow"	8.5%	10.0%	6.5%
Earnings	9.5%	12.5%	8.0%
Dividends	11.0%	11.5%	9.0%
Book Value	8.0%	6.0%	9.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3726	3927	4370	5046	17069
2022	2890	5183	6719	6164	20956
2023	6716	7349	7172	6877	28114
2024	5731	**7220**	**7975**	**6474**	**27400**
2025	**7175**	**7700**	**8500**	**6925**	**30300**

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.67	.71	.75	.41	2.55
2022	.74	.81	.85	.51	2.90
2023	.84	.88	.94	.52	3.17
2024	.91	**.93**	**.99**	**.57**	**3.40**
2025	**.97**	**1.00**	**1.06**	**.62**	**3.65**

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.35	.35	.35	.35	1.40
2021	.385	.385	.385	.385	1.54
2022	.425	.425	.425	.425	1.70
2023	.4675	.4675	.4675	.4675	1.87
2024	.515				

BUSINESS: NextEra Energy, Inc. is a holding company for Florida Power & Light Co. (FP&L), which provides electricity to roughly 5.9 million customers in eastern, southern, & northwestern Florida. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & renewables. Has 51.4% stake in NextEra Energy Partners. Acquired Gulf Power 1/19; Florida City Gas 7/18. Revenue: residential, about 55%; commercial/industrial/other, 45%. Generating sources: gas, 73%; nuclear, 20%; solar, 6%; other, 1%. Fuel costs: 19.4% of revenues. '23 depreciation rate: 3.4%. Employs about 16,800. Chairman, President and CEO: John W. Ketchum. Inc.: Florida. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy is off to an excellent start in 2024. First-quarter earnings exceeded the Wall Street consensus estimate by $0.11 per share and our call by $0.03. Getting off on the right foot makes it more probable the company will reach the high end of its full-year earnings target range of $3.23-$3.43 a share. The company's utility subsidiary, Florida Power & Light, saw strong growth driven by investment in the business. Regulatory capital employed increased by approximately 11.5% on a year-over-year basis, and the utility had its strongest quarter of customer growth in over 15 years with the count up by about 100,000 from the first quarter of 2023. The company's renewable energy subsidiary was also off to a strong start, with the second-best quarter in its history in terms of power and storage origination. The company grew its backlog of projects from year-end 2023 by 2,765 megawatts (MW) to 21,500 MW. The updated backlog level is net of 1,165 MW of projects placed in service during the first three months of the year.

The stock has continued to recover nicely from last year's washout low. Utilities as a whole were under intense pressure as interest rates climbed rapidly, with the benchmark 10-year Treasury bond yield reaching 5% in mid-October before backing off. Because interest bearing notes are an alternative investment vehicle to utility stocks, there tends to be a strong negative correlation between rates and this group of equities. Another way to think of it is the stock prices have to drop so that the dividend yields are competitive relative to low-risk bond rates. NEE stock did worse than the average utility as it was among the richest valuations within its peer group entering 2023, owing to its strong historical earnings growth. Rising borrowing costs for a company that regularly visits the capital markets brought into question how sustainable its above-industry-level growth is. The high end of leadership's long-term target of 6%-8% should be achievable due to the healthy regional economy it serves and NextEra's position as one of the nation's foremost renewable energy providers.

This equity is timely and offers worthwhile 18-month total returns.

Anthony J. Glennon *May 10, 2024*

(A) Diluted EPS. Excl. nonrecurring gains/(losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, $1.22¢; '18, $1.80; '20, (83¢); '21, (74¢); '22, (80¢); '23, 43¢; 1Q '23, 19¢; disc. ops.: '13, 11¢. EPS may not some to full yr. due to rounding. Next egs. report due late July. (B) Div'ds paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Includes intagibles. In '23: $5.85/sh. (D) In mill., adj. for stock split. (E) Rate allowed on common eq. in '22 (FPL): 9.8%-11.8%; Regult'y Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	55
Price Growth Persistence	80
Earnings Predictability	95

NORTHWESTERN NDQ-NWE

RECENT PRICE **50.25** | P/E RATIO **13.7** (Trailing: 15.6, Median: 17.0) | RELATIVE P/E RATIO **0.74** | DIV'D YLD **5.2%** | VALUE LINE

TIMELINESS **2** Raised 4/12/24
SAFETY **3** Lowered 1/19/24
TECHNICAL **5** Lowered 4/12/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$41-$70	$56 (10%)

2027-29 PROJECTIONS

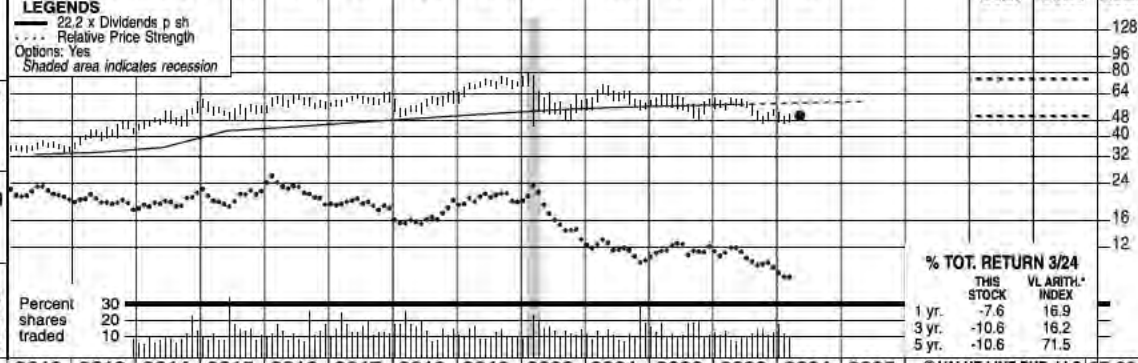
	Price	Gain	Ann'l Total Return
High	75	(+50%)	14%
Low	50	(Nil)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	157	123	144
to Sell	113	151	130
Hld's(000)	58238	59029	59945

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.8	63.1	61.2	51.8
Low:	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	48.7	46.0	46.2

LEGENDS
— 22.2 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.6	16.9
3 yr.	-10.6	16.2
5 yr.	-10.6	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	24.74	23.22	*25.60*	*26.60*	Revenues per sh	*28.90*
4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.86	6.92	6.46	6.69	*7.10*	*7.45*	"Cash Flow" per sh	*8.55*
1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.21	3.50	3.29	3.22	*3.50*	*3.70*	Earnings per sh A	*4.25*
1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.48	2.52	2.56	*2.60*	*2.64*	Div'd Decl'd per sh B ■ †	*2.76*
3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	8.02	8.03	8.62	9.26	*8.15*	*8.15*	Cap'l Spending per sh	*8.25*
21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	44.61	45.48	*46.40*	*47.50*	Book Value per sh C	*51.85*
35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	59.74	61.25	*61.50*	*62.00*	Common Shs Outst'g D	*64.00*
13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	18.6	17.4	17.3	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94	1.00	.95	*Value Line*		Relative P/E Ratio	*.80*
5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%	4.4%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	1477.8	1422.1	*1575*	*1650*	Revenues ($mill)	*1850*
120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	185.5	194.1	*215*	*230*	Net Profit ($mill)	*270*
--	13.7%	--	7.6%	--	1.6%	--	.9%	.9%	3.7%	*6.0%*	*9.0%*	Income Tax Rate	*12.0%*
8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	18.5%	21.6%	*20.0%*	*20.0%*	AFUDC % to Net Profit	*20.0%*
53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	48.2%	49.1%	*50.0%*	*51.0%*	Long-Term Debt Ratio	*50.5%*
46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	51.8%	50.9%	*50.0%*	*49.0%*	Common Equity Ratio	*49.5%*
3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	5148.3	5475.4	*5725*	*5975*	Total Capital ($mill)	*6700*
3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	5657.5	6039.8	*6300*	*6600*	Net Plant ($mill)	*7300*
4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	4.5%	4.5%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.0%	7.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*8.0%*
8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.0%	7.0%	*7.5%*	*8.0%*	Return on Com Equity E	*8.0%*
3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	1.7%	1.4%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
54%	65%	58%	62%	64%	64%	74%	71%	76%	79%	*74%*	*71%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $2820.8 mill. **Due in 5 Yrs** $1011.5 mill.
LT Debt $2690.5 mill. **LT Interest** $109.0 mill.
Incl. $5.5 mill. finance leases.
(Total Interest Coverage: 2.4x)

Pension Assets-12/23 $402.7 mill.
Oblig $477.0 mill.

Pfd Stock None

Common Stock 61,256,549 shs.
as of 2/9/24

MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+.7	+3.7	-.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2000	2073	1992
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.6	+1.5	+1.6
Fixed Charge Cov. (%)	245	219	216

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.0%	-1.0%	*2.5%*
"Cash Flow"	2.5%	-.5%	*3.5%*
Earnings	3.5%	--	*4.0%*
Dividends	5.5%	3.5%	*2.0%*
Book Value	6.0%	4.0%	*3.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	335.1	425.2	1477.8
2023	454.5	290.5	321.1	356.0	1422.1
2024	*475*	*325*	*370*	*405*	*1575*
2025	*500*	*340*	*385*	*425*	*1650*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	.47	1.16	3.29
2023	1.10	.32	.48	1.32	3.22
2024	*1.25*	*.50*	*.60*	*1.15*	*3.50*
2025	*1.30*	*.55*	*.65*	*1.20*	*3.70*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63	.63	2.52
2023	.64	.64	.64	.64	2.56
2024	.65				

BUSINESS: NorthWestern Energy Group, Inc. supplies electricity & gas in the Upper Midwest and Northwest, serving 467,700 electric customers in Montana and South Dakota and 307,600 gas customers in Montana, South Dakota, and Nebraska. Electric revenue breakdown for 2023: residential, 44%; commercial, 50%; industrial, 4%; and other, 2%. Generating sources: coal, 18%; hydro, 37%; wind, 4%; natural gas, 12%; purchased power, 29%. Fuel costs: 30% of revenues. 2023 reported depreciation rate: 2.8%. Had 1,573 employees as of 12/31/23. Chair of the board of directors: Dana J. Dykhouse. President and CEO: Brian B. Bird. Incorporated: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern Energy's profits should be on the rise this year from higher electric and natural gas delivery rates. In October, Montana regulators approved the settlement agreement the utility had negotiated with key members of the state's business community. The new prices lift annual electric and natural gas revenues by $67.4 million and $14.1 million, respectively. Those levels are based on an authorized return on equity (ROE) of 9.65% for electric and 9.55% for gas. The utility also received pricing mechanisms that allow for the expedient pass through of changes in both fuel/purchased power costs and property taxes. Those will reduce regulatory lag. In January, South Dakota officials came to terms with the company on electric rates that will raise annual revenue by $21.5 million based on a 6.81% rate of return. Management is targeting a range of $3.42 to $3.62 for 2024 earnings per share. The company raised the quarterly dividend to an annualized rate of $2.60 a share from $2.56.

Leadership affirmed its 4% to 6% annual earnings growth expectation. It provided an updated five-year capital investment plan that calls for average expenditures of $500 million per year from 2024 through 2028. The $2.5 billion total investment should grow the company's rate base (the dollar value of assets for which a utility is allowed to earn a regulated return on) by about 4% to 6% per annum. That, in turn, should translate to 4% to 6% yearly earnings-per-share gains. The fairly conservative plan assumes no equity needs are necessary unless there are opportunities to expand generation build beyond the $143 million budgeted for that category. We're projecting there will be some on both fronts. The plan also calls for $1.8 billion to be spent on the expansion and modernization of electric and gas transmission and distribution systems across its territories, with the remainder on infrastructure maintenance.

This equity is timely. Longer term, however, it doesn't really stand out relative to its peer group on an annual total-return basis. This is partially because it's growth prospects are about average and dividend hikes will likely remain limited until the payout ratio returns to the mid-60% area.

Anthony J. Glennon *April 19, 2024*

(A) Diluted egs. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; '22, (4¢). Qtly EPS may not sum to full yr. due to rounding. Next egs. report due early May. (B) Div'ds paid late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. (C) Incl. def'd charges and intag. '23: $17.90/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '22 (elec.): 9.65%; in '22 (gas): 9.55%; in SD in '24: 6.81%; in NE in '07: 10.4%. Reg. Climate: Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	95

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE **35.65** | P/E RATIO **17.0** (Trailing: 18.1 Median: 18.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **4.7%** | VALUE LINE

TIMELINESS 4 Raised 5/31/24
SAFETY 3 Lowered 3/8/24
TECHNICAL 5 Lowered 5/3/24
BETA 1.05 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$31-$46	$39 (10%)

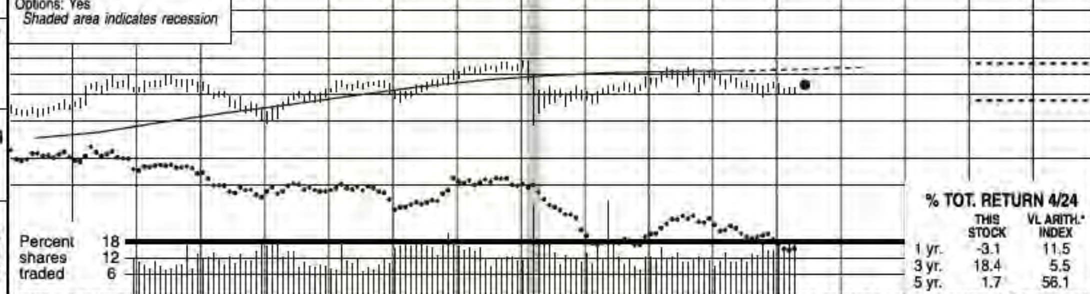
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	10%
Low	30	(-15%)	1%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	174	197	210
to Sell	216	199	206
Hld's(000)	134247	138173	144477

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.9	40.4	37.3
Low:	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	33.3	31.3	32.1



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.1	11.5
3 yr.	18.4	5.5
5 yr.	1.7	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	16.86	13.36	14.50	15.00	Revenues per sh	17.50
2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	5.63	4.61	4.70	5.05	"Cash Flow" per sh	5.85
1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	2.25	2.07	2.10	2.30	Earnings per sh A	2.70
.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	1.64	1.66	1.69	1.73	Div'd Decl'd per sh B ■	1.85
4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	5.25	4.49	4.75	4.75	Cap'l Spending per sh	4.75
10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	22.52	22.17	23.10	23.75	Book Value per sh C	26.25
187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	200.20	200.30	200.20	200.20	Common Shs Outst'g D	200.20
12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	17.2	17.4	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	14.0
.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.77	1.00	.96	*estimates*		Relative P/E Ratio	.80
4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%	4.5%	5.1%			Avg Ann'l Div'd Yield	4.4%

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	3375.7	2674.3	2900	3000	Revenues ($mill)	3500
395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	665.7	416.8	420	460	Net Profit ($mill)	540
30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	12.0%	12.0%	12.0%	12.0%	Income Tax Rate	12.0%
1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	2.0%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	49.8%	51.2%	52.0%	51.5%	Long-Term Debt Ratio	50.0%
54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	52.4%	49.6%	48.0%	48.5%	Common Equity Ratio	50.0%
5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	8962.0	9238.2	9750	9935	Total Capital ($mill)	10400
6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	10546.8	11301.0	11000	11250	Net Plant ($mill)	12075
7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	5.9%	6.3%	7.0%	7.0%	Return on Total Cap'l	7.5%
12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	12.5%	12.5%	Return on Shr. Equity	13.0%
12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	11.0%	12.0%	12.5%	12.5%	Return on Com Equity E	13.0%
6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	3.0%	3.5%	4.5%	4.5%	Retained to Com Eq	5.5%
47%	61%	67%	64%	64%	67%	76%	69%	73%	81%	75%	75%	All Div'ds to Net Prof	57%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $4341.3 mill. **Due in 5 Yrs** $1731.5 mill.
LT Debt $4261.9 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/22 $486.0 mill. **Oblig** $502.9 mill.

Pfd Stock None

Common Stock 200,547,842 shs.

MARKET CAP: $7.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-4.9	+2.6	+8.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.40	7.68	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6437	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.4	NA
Fixed Charge Cov. (%)	326	336	335

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	-3.0%	5.0%	5.5%
"Cash Flow"	2.5%	5.0%	7.0%
Earnings	3.0%	4.5%	6.5%
Dividends	7.5%	6.5%	3.0%
Book Value	4.0%	1.5%	5.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1630.0	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270.0	711.9	3375.7
2023	557.2	605.0	945.4	566.7	2674.3
2024	596.8	750	920	633.2	2900
2025	620	780	950	650	3000

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.26	.56	1.26	.28	2.36
2022	.33	.36	1.31	.25	2.25
2023	.19	.44	1.20	.24	2.07
2024	.09	.45	1.30	.26	2.10
2025	.40	.35	1.30	.25	2.30

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	1.64
2023	.4141	.4141	.4141	.4182	1.66
2024	.4182	.4182			

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '23 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary is awaiting a rate order in Oklahoma. Oklahoma Gas and Electric is seeking an increase of $332 million, based on a return on equity of 10.5% and a common-equity ratio of 53.5%. The utility needs to recover its additional capital investment in grid enhancements to improve reliability since its last rate case. OGE is making progress and testimony is under way, with new rates expected to be implemented sometime this summer. Meanwhile, the utility recently lowered Oklahoma customers' bills by $25 a month due to a reduction in fuel costs. The cost of fuel to produce electricity is reviewed by federal regulators twice a year, and fluctuates greatly.

We have lowered our 2024 earnings-per-share estimate by a dime. The first-quarter performance was negatively impacted by higher depreciation and interest expense, along with regulatory lag due to the pending Oklahoma rate case. Our profit estimate is now just below the midpoint of OGE Energy's targeted range of $2.06-$2.18, and within the company's long-term growth rate target of 5%-7% annually. We think the utility will have sharper earnings growth next year. Prospects over that interim should benefit from investments in the grid, as well as being a pure-play electric utility. A decision in Oklahoma will likely also bolster top- and bottom-line growth and help the utility pass on higher costs to the consumer. Accordingly, our 2025 earnings estimate is staying put at $2.30 a share.

OGE shares have risen nicely of late. Indeed, the stock has jumped around 10% in value since our early March report. And, the stock price is now up slightly over the past year, after reaching its new 12-month high recently.

The stock is untimely, but appealing for income-oriented investors. Indeed, the dividend yield of 4.7% stands comfortably above the high-paying utility average, and remains this issue's most notable feature. On the other hand, these shares are ranked 4 (Below Average) for Timeliness. Too, intermediate- and long-term return prospects are not attractive, as the current quotation is already trading within our Target Price Range for the 18-month and 3- to 5-year time frames.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '19 & '21 EPS don't sum due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '22: $6.15/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 90.90 | P/E RATIO 14.3 (Trailing: 12.5; Median: 20.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 2.1% | VALUE LINE

TIMELINESS 2 Raised 5/31/24
SAFETY 2 Raised 6/7/24
TECHNICAL 3 Raised 6/7/24
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High: $48-$113 — Midpoint (% to Mid): $81 (-10%)

2027-29 PROJECTIONS

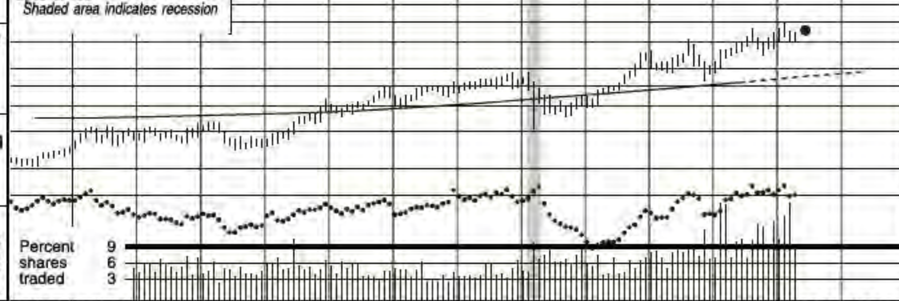
	Price	Gain	Ann'l Total Return
High	90	(Nil)	2%
Low	60	(-35%)	-7%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	108	111	132
to Sell	115	128	117
Hld's(000)	25238	24880	25634

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9	71.7	82.5	92.7	99.5
Low:	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0	39.4	52.6	57.3	80.0

LEGENDS
— 29.40 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029
160 120 100 80 60 50 40 30 20 15

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.6	11.5
3 yr.	93.9	5.5
5 yr.	89.2	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	23.10	22.90	21.46	28.80	35.08	32.35	***34.50***	***36.90***	Revenues per sh	***37.65***
2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	4.11	4.29	6.45	8.77	9.35	***8.75***	***7.05***	"Cash Flow" per sh	***6.80***
1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	2.17	2.34	4.23	6.78	7.00	***6.35***	***4.65***	Earnings per sh A	***4.25***
1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	1.40	1.48	1.56	1.65	1.75	***1.87***	***1.97***	Div'd Decl'd per sh B ■	***2.20***
7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	5.16	8.96	4.14	4.11	4.72	***6.00***	***6.00***	Cap'l Spending per sh	***6.25***
19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	19.46	21.00	23.84	29.24	29.42	***31.15***	***32.25***	Book Value per sh C	***34.25***
35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	40.16	41.47	41.55	41.63	41.71	***42.00***	***42.00***	Common Shs Outst'g D	***42.50***
30.1	31.2	NMF	47.5	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	18.3	12.3	9.5	10.7	***Bold figures are***		Avg Ann'l P/E Ratio	***17.5***
1.81	2.08	NMF	2.98	1.38	1.19	.99	.92	1.06	1.11	1.20	1.25	.94	.66	.55	.61	***Value Line***		Relative P/E Ratio	***.95***
3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	2.7%	3.5%	3.0%	2.5%	2.3%	***estimates***		Avg Ann'l Div'd Yield	***3.4%***

CAPITAL STRUCTURE as of 3/31/24
Total Debt $943.5 mill. **Due in 5 Yrs** $207.8 mill.
LT Debt $943.5 mill. **LT Interest** $31.6 mill.
(LT interest earned: 9.7x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/23 $313.8 mill. **Oblig** $416.7 mill.

Pfd Stock None

Common Stock 41,814,425 shs.
as of 4/30/24

MARKET CAP: $3.8 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
799.3	779.8	803.5	849.4	916.4	919.5	890.1	1196.8	1460.2	1349.2	***1450***	***1550***	Revenues ($mill)	***1600***
56.9	58.6	62.0	73.9	82.3	86.8	95.9	176.8	282.3	292.0	***265***	***195***	Net Profit ($mill)	***180***
22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	17.4%	16.9%	20.5%	20.2%	***20.0%***	***20.0%***	Income Tax Rate	***20.0%***
3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	6.4%	.8%	.9%	1.4%	***2.0%***	***2.5%***	AFUDC % to Net Profit	***4.0%***
46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	41.8%	42.6%	40.0%	41.0%	***41.0%***	***41.5%***	Long-Term Debt Ratio	***42.5%***
53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	58.3%	58.5%	***58.5%***	***58.5%***	Common Equity Ratio	***57.5%***
1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	1495.4	1724.8	2041.1	2148.2	***2250***	***2375***	Total Capital ($mill)	***2525***
1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	2049.3	2124.6	2212.7	2418.4	***2475***	***2550***	Net Plant ($mill)	***2700***
6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	7.4%	11.1%	12.0%	9.0%	***8.5%***	***8.0%***	Return on Total Cap'l	***7.5%***
9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	18.0%	13.5%	***13.0%***	***12.5%***	Return on Shr. Equity	***11.5%***
9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	18.0%	13.5%	***13.0%***	***12.5%***	Return on Com Equity E	***11.5%***
2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	4.1%	11.3%	12.4%	7.5%	***7.0%***	***7.0%***	Retained to Com Eq	***5.0%***
78%	79%	78%	69%	65%	64%	63%	37%	24%	44%	***52%***	***52%***	All Div'ds to Net Prof	***60%***

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-3.9	+.3	+16.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	405	651	653

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.0%	*5.0%*
"Cash Flow"	7.5%	9.5%	*5.5%*
Earnings	18.0%	14.5%	*4.5%*
Dividends	2.5%	4.0%	*7.0%*
Book Value	3.5%	6.0%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	261.7	285.6	316.3	333.2	1196.8
2022	374.9	400.0	383.9	301.4	1460.2
2023	339.1	337.7	358.1	314.3	1349.2
2024	347.1	***365***	***390***	***347.9***	***1450***
2025	***375***	***395***	***395***	***385***	***1550***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.73	1.01	1.26	1.23	4.23
2022	1.72	2.05	2.01	1.00	6.78
2023	1.49	1.95	2.19	1.37	7.00
2024	1.77	***1.70***	***1.75***	***1.13***	***6.35***
2025	***1.10***	***1.15***	***1.20***	***1.20***	***4.65***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.37	.37	.37	.37	1.48
2021	.39	.39	.39	.39	1.56
2022	.4125	.4125	.4125	.4125	1.65
2023	.4375	.4375	.4375	.4375	1.75
2024	.4675				

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 133,000 customers in Minnesota (52% of retail electric revenues), North Dakota (38%), and South Dakota (10%). Electric rev. breakdown: residential, 32%; commercial & farms, 36%; industrial, 30%; other, 2%. Generating sources: coal, 38%; wind & other, 18%; purchased, 44%. Fuel costs: 10% of revenues. Also has operations in manufacturing and plastics (67% of '23 operating income). '23 deprec. rate: 3.0%. Has 2,500 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Inc.: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

Otter Tail Corporation raised its earnings target for 2024 upon reporting March-period results. Management now looks for profits this year to end up in a range of $6.23-$6.53 per share, from the previous target range of $5.13-$5.43 a share. The Plastics segment continues to outperform expectations due to higher sales driven by growth in customer volumes and strong distributor and end market demand. Indeed, earnings in the Plastics division rose 39% from the first quarter of 2023, and PVC pipe is expected to recede at a much slower rate than previously anticipated, which is largely responsible for Otter Tail's updated guidance range. Meanwhile, the manufacturing segment's profit target was cut due to lower-than-expected sales volumes and margins. Too, the Electric division is projected to make up just 34% of the bottom line, versus the long-term goal of 65% electric and 35% non-electric.

We have raised our 2025 earnings estimate by $0.65, to $4.65 per share. Otter Tail should benefit from rate relief in Minnesota and North Dakota over that interim. Furthermore, the utility's updated expectations for the Plastics segment will likely pour into next year, lifting profits higher than previously projected. The company is also well positioned to take advantage of its clean-energy transmission investments, which include $1.3 billion of capital spending over the next five years, and is expected to produce 7.7% rate base growth.

Otter Tail shares have risen slightly in value since our March report, and are now up nearly 20% over the past year. Investors are enthused by better-than-expected earnings and elevated power demand from tech innovations and data centers. At the recent quotation, upside potential here in the 18-month and 3- to 5-year time frames is negative.

The dividend yield is below average by utility standards. Even after the payout was raised in the March quarter, the current yield of 2.1% sits below the high-paying industry median. Too, long-term prospects are unattractive. On the other hand, these shares are ranked to outpace the broader-market averages over the coming six to 12 months.

Zachary J. Hodgkinson *June 7, 2024*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS may not sum due to rounding. Next earnings report due early Aug. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '23: $4.72/sh. (D) In mill. (E) Rate allowed on com. eq. in MN in '22: 9.48%; in ND in '18: 9.77%; in SD in '19: 8.75%; earned on avg. com. eq., '21: 19.2%.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	80
Earnings Predictability	70

PG&E CORP. NYSE-PCG

RECENT PRICE **16.81** | P/E RATIO **12.3** (Trailing: 13.7 / Median: 20.0) | RELATIVE P/E RATIO **0.67** | DIV'D YLD **0.2%** | VALUE LINE

TIMELINESS **3** Raised 3/8/24
SAFETY **3** New 10/20/23
TECHNICAL **3** Lowered 4/12/24
BETA 1.10 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$14-$22	$18 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+110%)	21%
Low	20	(+20%)	5%

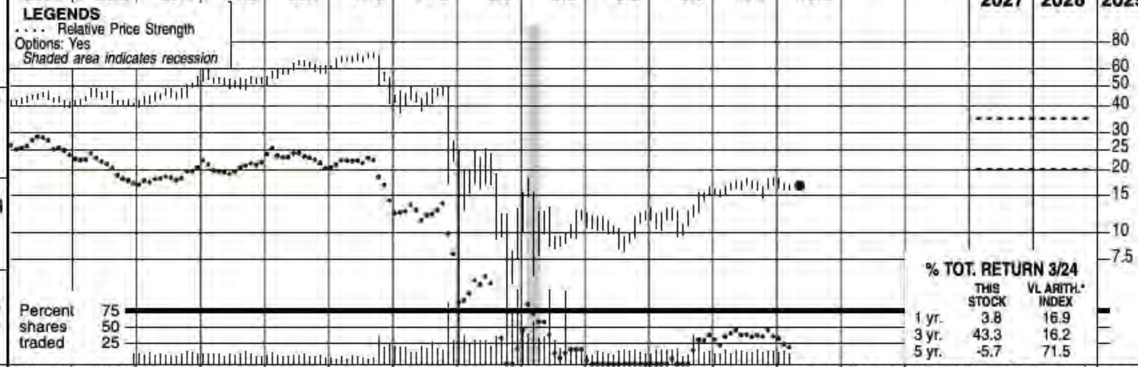
Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	309	347	350
to Sell	189	183	241
Hld's(000)	1847867	1994472	2066891

High:	48.5	55.2	60.2	65.4	71.6	49.4	25.2	18.3	12.7	16.5	18.3	18.2	
Low:	39.9	39.4	47.3	50.7	41.6	17.3	3.6	6.3	8.2	9.6	14.7	15.9	

Target Price Range 2027 | 2028 | 2029

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.8	16.9
3 yr.	43.3	16.2
5 yr.	-5.7	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
40.51	36.15	35.02	36.28	34.92	34.16	35.91	34.21	34.85	33.29	32.21	32.37	9.31	10.40	10.91	11.45	11.75	11.65	Revenues per sh	12.20
8.44	8.37	8.22	8.08	7.32	6.33	8.13	7.29	8.23	9.03	d7.30	d8.36	1.08	2.79	3.12	2.98	3.30	3.45	"Cash Flow" per sh	4.40
3.22	3.03	2.82	2.78	2.07	1.83	3.06	2.00	2.83	3.50	d13.25	d14.50	d1.05	1.00	1.10	1.23	1.35	1.45	Earnings per sh A	1.90
1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	1.93	1.55	--	--	--	--	--	.01	.04	.08	Div'd Decl'd per sh B ■	.20
10.05	10.68	9.62	9.79	10.74	11.40	10.16	10.51	11.26	10.96	12.52	11.93	3.87	3.87	4.82	4.55	5.00	5.20	Cap'l Spending per sh	5.80
25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.69	35.39	37.34	24.31	9.59	10.58	10.56	11.48	11.74	13.30	14.95	Book Value per sh C	20.65
361.06	370.60	395.23	412.26	430.72	456.67	475.91	492.03	506.89	514.76	520.34	529.24	1984.7	1985.4	1987.8	2133.6	2200.00	2300.00	Common Shs Outst'g D	2500.00
12.1	13.0	15.8	15.5	20.7	23.7	15.0	26.4	21.1	18.3	--	--	--	10.9	11.4	13.6	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.5
.73	.87	1.01	.97	1.32	1.33	.79	1.33	1.11	.92	--	--	--	.59	.66	.76			Relative P/E Ratio	.80
4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%	3.4%	3.2%	2.4%	--	--	--	--	--	.1%			Avg Ann'l Div'd Yield	.7%

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
17090	16833	17666	17135	16760	17129	18469	20642	21680	24428	25800	26800	Revenues ($mill)	30500
1450.0	988.0	1431.0	1807.0	d6818	d7642	d1304	2152.0	2357.0	2644.0	3110	3455	Net Profit ($mill)	4925
19.2%	--	3.7%	16.8%	--	--	--	44.2%	3.3%	6.6%	6.0%	8.0%	Income Tax Rate	11.0%
10.0%	15.7%	11.4%	7.0%	--	--	--	8.8%	11.2%	9.9%	9.0%	9.0%	AFUDC % to Net Profit	9.0%
48.5%	48.8%	47.1%	47.7%	--	--	63.7%	64.3%	67.4%	67.1%	64.0%	61.5%	Long-Term Debt Ratio	56.5%
50.7%	50.4%	52.1%	51.6%	98.0%	95.2%	35.9%	35.3%	32.2%	32.6%	35.5%	38.0%	Common Equity Ratio	43.0%
31050	32858	34412	37225	12903	5335.0	58541	59448	70817	76821	81925	90175	Total Capital ($mill)	120000
43941	46723	50581	53789	58557	61635	66136	69826	76208	82321	89175	96625	Net Plant ($mill)	122000
5.8%	4.1%	5.2%	5.9%	NMF	NMF	NMF	4.8%	4.6%	5.3%	5.0%	5.0%	Return on Total Cap'l	5.5%
9.1%	5.9%	7.9%	9.3%	NMF	NMF	NMF	10.1%	10.2%	10.5%	10.5%	10.0%	Return on Shr. Equity	9.5%
9.1%	5.9%	7.9%	9.3%	NMF	NMF	NMF	10.2%	10.3%	10.5%	10.5%	10.0%	Return on Com Equity E	9.5%
3.9%	.7%	2.8%	4.0%	NMF	NMF	NMF	10.2%	10.3%	10.5%	10.5%	9.5%	Retained to Com Eq	8.5%
58%	88%	65%	57%	NMF	NMF	NMF	1%	1%	1%	3%	6%	All Div'ds to Net Prof	10%

CAPITAL STRUCTURE as of 12/31/23
Total Debt $57135 mill. **Due in 5 Yrs** $17586 mill.
LT Debt $51529 mill. **LT Interest** $2850 mill.
(Incl. $554 mill. of noncurrent finance leases)
(Total Interest Coverage: 2.0x)
Leases, Uncapitalized Annual rentals $116 mill.

Pension Assets-12/23 $17211 mill. **Oblig** $17697 mill.

Pfd Stock $252 mill. **Pfd Div'd** $14 mill.
Common Stock 2,133,623,076 shs.
as of 2/14/24
MARKET CAP: $35.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (GWH)	+.1	-.9	-6.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.4	+.4
Fixed Charge Cov. (%)	296	188	162

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-11.0%	-20.0%	2.5%
"Cash Flow"	-8.5%	-2.0%	7.5%
Earnings	-6.5%	--	9.0%
Dividends	--	--	NMF
Book Value	-9.5%	-19.0%	10.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	4716	5215	5465	5246	20642
2022	5798	5118	5394	5370	21680
2023	6209	5290	5888	7041	24428
2024	6660	6030	6590	6520	25800
2025	6925	6275	6850	6750	26800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.23	.27	.24	.28	1.00
2022	.30	.25	.29	.26	1.10
2023	.29	.23	.24	.47	1.23
2024	.33	.28	.29	.45	1.35
2025	.35	.30	.32	.48	1.45

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	--	--	--	--	--
2021	--	--	--	--	--
2022	--	--	--	--	--
2023	--	--	--	--	--
2024	.01				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and natural gas to most of northern and central California (population 16 million). Has 5.6 million electric and 4.6 million natural gas customers. Electric revenue breakdown: residential, 40%; commercial, 37%; industrial, 12%; agricultural, 9%; other, about 2%. Power generating sources: nuclear, 40%; renewable, 24%; large hydro, 10%; fossil fuel, 26%. Power and Fuel costs: 17% of revenues. '23 reported depr. rate: 3.56% (utility). Has 28,000 employees. Chair of the Board: Robert C. Flexon. CEO: Patricia K. Poppe. Incorporated: California. Address: 300 Lakeside Drive, Oakland, California 94612. Tel.: 415-973-7000. Int.: www.pgecorp.com.

PG&E raised its profit targets for 2024 and subsequent years through late decade. The utility received a favorable outcome on its general rate case with the authorized return on equity moving up to 10.7% from 10.0%. Management initially projected core earnings of $1.31-$1.35 a share this year but upon further review has lifted its outlook to $1.33-$1.37 a share. PG&E also extended its expectation of at least 9% share-earnings growth through 2028. (Previously, management was only willing to project that level of growth through 2026.) The company now sees the potential to increase its capital plan by as much as 20% through late decade, which should keep the rate base growing at a very healthy 9%-10% level.

Wildfire mitigation work remains the key emphasis here. PG&E is using high-tech solutions coupled with regular maintenance and labor to lower the chance of a repeat of the massive wildfires that put the company in bankruptcy court years ago. Automated shutoff switching systems, drones, vegetation management, and, where possible, burying power lines are all being deployed. The California Wildfire Fund makes the odds of a bankruptcy far lower, as well. (It's like a large self-funded insurance policy for the state's utilities.) But, a utility can still rack up significant losses if its equipment is found to have caused a fire. There is essentially a $1 billion deductible per incident. Gross negligence is not covered.

The company reinstated its dividend. At a penny per share, quarterly, PG&E has the opportunity to keep the disbursement growing at a high rate. With well over two billion shares outstanding, the "growth from a small base" strategy does make sense, as a high payout ratio would be a large cash drain. We've projected that the quarterly dividend will be raised by a penny a share, once a year. But investors should know that the dividend policy is a work in progress and no payout target ratio has been set. The company could decide to make increases in fractional cents.

This stock is neutrally ranked (Timeliness: 3, Average). PG&E has decent upside potential. Still, we think most utility investors will prefer a more conventional dividend policy with a higher yield.

Anthony J. Glennon *April 19, 2024*

(A) Diluted EPS. Adjusted (non-GAAP) egs. from 2021 on. Excl. nonrecur. gains/(losses): '09, 17¢; '11, (68¢); '12, (15¢); '15, (21¢); '16, (5¢); '17, (29¢); '21, ($1.05); '22, (26¢); '23 (18¢); gain from disc. ops.: '08, 41¢. Qtly. EPS may not sum to full year due to rounding and/or changes in share count. Next egs. report due early May. (B) Div'ds suspended 12/17, reinstated 11/23. (C) Incl. def'd chgs. In '23: $8.06/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '23: 10.7%; Regulatory Climate: Average.

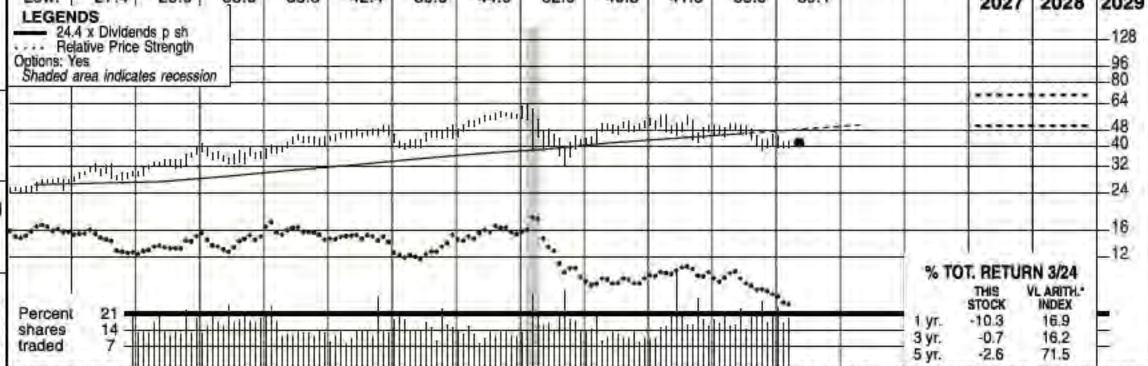
Company's Financial Strength	B++
Stock's Price Stability	15
Price Growth Persistence	15
Earnings Predictability	5

PORTLAND GENERAL NYSE-POR

RECENT PRICE **41.66** | P/E RATIO **14.3** (Trailing: 17.6, Median: 18.0) | RELATIVE P/E RATIO **0.78** | DIV'D YLD **4.8%** | VALUE LINE

TIMELINESS **5** Lowered 8/11/23
SAFETY **3** Lowered 1/19/24
TECHNICAL **4** Lowered 3/8/24
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0	51.6	44.8	
Low:	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	41.6	38.0	39.1	



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$35-$62 $49 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+70%)	17%
Low	50	(+20%)	9%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	169	173	213
to Sell	170	186	164
Hld's(000)	103597	100907	103294

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.3	16.9
3 yr.	-0.7	16.2
5 yr.	-2.6	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	29.65	28.90	*30.30*	*31.55*	Revenues per sh	*34.90*
4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	7.41	6.83	*8.00*	*8.55*	"Cash Flow" per sh	*10.20*
1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	2.74	2.38	*3.05*	*3.25*	Earnings per sh A	*3.85*
.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	1.79	1.88	*1.98*	*2.08*	Div'd Decl'd per sh B ■ †	*2.46*
6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	8.58	13.42	*12.90*	*11.75*	Cap'l Spending per sh	*11.00*
21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	31.13	32.81	*34.00*	*35.25*	Book Value per sh C	*39.75*
62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	89.28	101.16	*101.50*	*102.00*	Common Shs Outst'g D	*106.00*
16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	18.2	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.96	1.05	1.08	*Value Line*		Relative P/E Ratio	*.85*
4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	3.6%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $4440 mill. **Due in 5 Yrs** $467 mill.
LT Debt $4194 mill. **LT Interest** $166 mill.
Incl. $289 mill. finance leases.
(Total Interest Coverage: 2.5x)
Leases, Uncapitalized Annual rentals $3 mill.
Pension Assets-12/23 $530 mill. **Oblig** $690 mill.
Pfd Stock None

Common Stock 101,162,366 shs. **as of 2/8/24**

MARKET CAP: $4.2 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2647.0	2923.0	*3075*	*3220*	Revenues ($mill)	*3700*
175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	245.0	233.0	*310*	*330*	Net Profit ($mill)	*405*
26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	15.2%	16.8%	*17.5%*	*17.5%*	Income Tax Rate	*17.5%*
33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	8.6%	13.7%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*11.0%*
52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	57.0%	55.8%	*58.5%*	*60.0%*	Long-Term Debt Ratio	*60.0%*
47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	43.0%	44.2%	*41.5%*	*40.0%*	Common Equity Ratio	*40.0%*
4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	6459.0	7513.0	*8325*	*8975*	Total Capital ($mill)	*10500*
5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8465.0	9546.0	*10350*	*11000*	Net Plant ($mill)	*12600*
5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	4.9%	4.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	7.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	8.8%	7.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	3.1%	1.6%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
50%	56%	57%	58%	59%	63%	57%	61%	64%	77%	*65%*	*64%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+5.1	+3.4	+.9
Avg. Indust. Use (MWH)	20002	22097	23052
Avg. Indust. Revs. per KWH (¢)	5.22	5.23	5.85
Capacity at Peak (MW)	NA	NA	NA
Peak Load, Summer (MW)	4453	4255	4498
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+1.1	+.7
Fixed Charge Cov. (%)	261	254	217

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	5.0%	*3.5%*
"Cash Flow"	3.5%	3.0%	*6.0%*
Earnings	3.5%	3.0%	*6.0%*
Dividends	5.0%	6.0%	*5.5%*
Book Value	3.5%	3.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	609	537	642	608	2396
2022	626	591	743	687	2647
2023	748	648	802	725	2923
2024	*750*	*700*	*850*	*775*	*3075*
2025	*785*	*735*	*890*	*810*	*3220*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	.65	.70	2.74
2023	.80	.44	.46	.67	2.38
2024	*.95*	*.60*	*.70*	*.80*	*3.05*
2025	*1.00*	*.65*	*.75*	*.85*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	1.77
2023	.4525	.4525	.475	.475	1.86
2024	.475	.475			

BUSINESS: Portland General Electric Company provides electricity to 934,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which was closed in 1993. Electric revenue breakdown: residential, 52%; commercial, 33%; industrial, 15%; other, less than 1%. Generating sources: gas, 40%; wind, 7%; coal, 8%; hydro, 4%; purchased, 41%. Fuel costs: 40% of revenues. '23 reported depreciation rate: 3.4%. Has 2,842 full-time employees. Chair: James P. Torgerson. President and CEO: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric's per-share profits should bounce back this year and next. In 2023, the company suffered from weather that was exceedingly mild, resulting in less than 1% volume growth for a service area that is accustomed to 2% or better. On top of that, purchased-power costs were excessively high, as mild weather is not ideal for hydroelectric and wind power production in the Pacific Northwest. This resulted in a tight supply situation that drove up pricing. Management expects the utility will earn $2.98-$3.18 a share in 2024. To a large extent, the recovery is based on normalized weather conditions, as well as utility rate relief, to address last year's rise in costs and investments made in the electric grid. In 2025, a general rate case decision is due. Portland General is seeking $225 million in additional annual revenues for recoupment of investments made, plus timely recovery mechanisms via customer billing pass-throughs. The company appears to have a reasonably good partnership with the state of Oregon in terms of addressing the state's "green" energy commitments. We think that will translate to a constructive rate-case outcome.

Longer term, the utility's 5%-7% earnings and dividend growth targets seem achievable. Over time, Portland General's bottom line should be less volatile, as the company reduces its reliance on open market power purchases, which have a tendency to spike in price. The company has the green light from regulators to add at least 375-500 megawatts of nonemitting annual power generation in the intermediate term, plus significant battery storage capacity. Projects committed to appear to have solid partnerships in place with lengthy annual purchased-power agreements on portions of generating capacity the company does not directly own. There should be several years of 8%-plus rate base growth, as the general outline of the projects described above are replicated six-fold into the 2030s. On the demand front, 2% annual load growth is supported by a healthy high-tech industrial segment in Portland General's service area.

Though untimely, patient utility investors can do well here, as the stock offers good total return prospects.

Anthony J. Glennon *April 19, 2024*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢); '23, (5¢). Quarterly EPS many not sum to full year due to rounding. Next earnings report due early May. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '23: $492 mill., $4.86/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	95

PINNACLE WEST NYSE-PNW

RECENT PRICE **74.08** | P/E RATIO **15.8** (Trailing: 16.8 / Median: 17.0) | RELATIVE P/E RATIO **0.86** | DIV'D YLD **4.8%** | VALUE LINE

TIMELINESS	4	Lowered 3/22/24	
SAFETY	3	Lowered 1/19/24	
TECHNICAL	5	Lowered 3/22/24	
BETA .95 (1.00 = Market)			

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$97	$78 (5%)

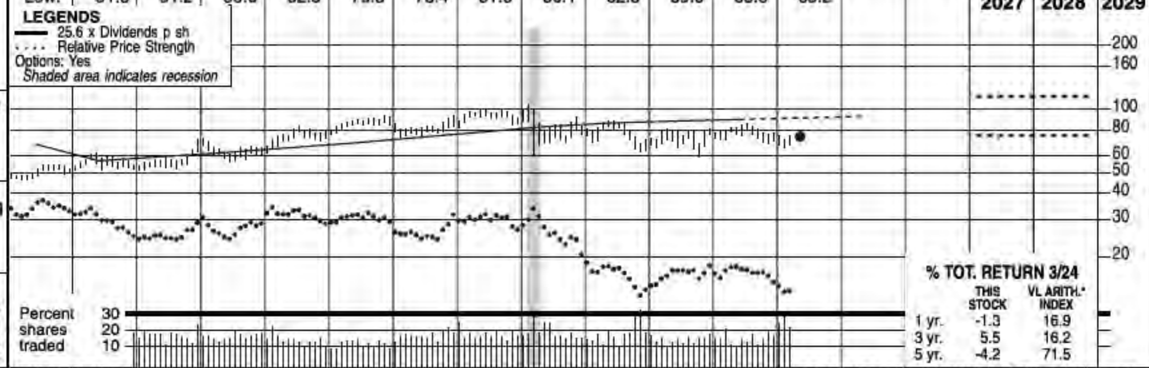
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+55%)	15%
Low	75	(Nil)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	201	225	240
to Sell	237	250	253
Hld's(000)	97185	97254	97685

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5	88.5	80.6	86.0	75.2
Low:	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1	62.8	59.0	68.6	65.2



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	30.87	31.81	33.66	38.21	41.40	41.70	42.45	Revenues per sh	46.00
8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.92	10.37	10.69	10.97	11.84	11.50	11.95	12.50	13.10	"Cash Flow" per sh	15.35
2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.77	4.87	5.47	4.26	4.41	4.70	5.00	Earnings per sh A	6.00
2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	3.23	3.36	3.43	3.49	3.55	3.61	Div'd Decl'd per sh B ■	3.79
9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	10.76	11.93	13.04	15.09	16.28	16.80	16.80	Cap'l Spending per sh	17.20
34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.30	49.96	52.26	53.45	54.47	59.85	60.55	Book Value per sh C	70.15
100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.44	112.76	113.01	113.17	113.42	116.00	119.00	Common Shs Outst'g D	125.00
16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	19.4	16.7	14.1	17.1	17.4	Bold figures are		Avg Ann'l P/E Ratio	16.0
.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.03	.86	.76	.99	.97	Value Line		Relative P/E Ratio	.90
6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	3.3%	4.0%	4.3%	4.7%	4.5%	estimates		Avg Ann'l Div'd Yield	3.9%
						3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	4324.4	4696.0	4840	5050	Revenues ($mill)	5750
						397.6	437.3	442.0	497.8	511.0	538.3	550.6	618.7	483.6	501.6	540	590	Net Profit ($mill)	750
						34.2%	34.3%	33.9%	32.5%	20.2%	--	12.1%	14.8%	13.0%	12.9%	14.0%	14.0%	Income Tax Rate	14.0%
						11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	15.2%	19.3%	19.0%	19.0%	AFUDC % to Net Profit	19.0%
						41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	56.1%	55.0%	52.5%	54.0%	Long-Term Debt Ratio	52.0%
						59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	43.9%	45.0%	47.5%	46.0%	Common Equity Ratio	48.0%
						7398.7	8046.3	8825.4	9796.4	9861.1	10263	11948	12820	13790	13718	14625	15625	Total Capital ($mill)	18350
						11194	11809	12714	13445	14030	14523	15159	15987	16854	17980	19025	20050	Net Plant ($mill)	23050
						6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	4.5%	5.0%	5.0%	5.0%	Return on Total Cap'l	5.5%
						9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.1%	8.0%	8.0%	Return on Shr. Equity	8.5%
						9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.1%	8.0%	8.0%	Return on Com Equity E	8.5%
						3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	1.7%	1.9%	2.0%	2.5%	Retained to Com Eq	3.0%
						62%	59%	62%	58%	60%	61%	64%	60%	78%	77%	75%	72%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 12/31/23
Total Debt $9025.1 mill. **Due in 5 Yrs** $2225.0 mill.
LT Debt $7540.6 mill. **LT Interest** $355.0 mill.
(Total Interest Coverage: 2.6x)

Leases, Uncapitalized Annual rentals $19.2 mill.

Pension Assets-12/22 $2835.5 mill. **Oblig** $2908.1 mill.

Pfd Stock None

Common Stock 113,427,367 shs. **as of 2/21/24**
MARKET CAP: $8.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-.1	+4.4	+2.8
Avg. Indust. Use (MWH)	808	849	874
Avg. Indust. Revs. per KWH (¢)	8.11	9.20	10.38
Capacity at Peak (Mw)	8726	8612	9629
Peak Load, Summer (Mw)	7580	7587	8159
Annual Load Factor (%)	45.1	48.1	45.7
% Change Customers (yr-end)	+2.2	+2.1	+1.8
Fixed Charge Cov. (%)	317	226	220

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	3.5%	4.0%
"Cash Flow"	4.0%	3.5%	3.5%
Earnings	3.5%	2.0%	4.5%
Dividends	4.0%	5.0%	1.5%
Book Value	4.0%	3.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	696.5	1000.2	1308.2	798.9	3803.8
2022	783.5	1061.7	1469.9	1009.3	4324.4
2023	945.0	1121.7	1637.8	991.5	4696.0
2024	1000	1190	1640	1010	4840
2025	1045	1240	1710	1055	5050

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.32	1.91	3.00	.24	5.47
2022	.15	1.45	2.88	d.21	4.26
2023	d.03	.94	3.50	Nil	4.41
2024	.05	1.25	3.40	Nil	4.70
2025	.05	1.33	3.62	Nil	5.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.783	.783	.783	.83	3.18
2021	.83	.83	.83	.85	3.34
2022	.85	.85	.85	.865	3.42
2023	.865	.865	.865	.88	3.48
2024	.88				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.4 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 49%; commercial/industrial, 44%; other, 7%. Generating sources: gas, 25%; nuclear, 25%; coal, 18%; renewables, 2%; purchased, 30%. Fuel costs: 38% of revenues. '23 reported deprec. rate: 2.98%. Has 6,133 employees. Chairman, President & CEO: Jeffrey B. Guldner. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

In late February, Pinnacle West received a constructive general rate case (GRC) decision. Investors may recall that from early 2022, the utility had been operating under revised regulatory parameters that cut its authorized return on equity (ROE) from 10% to 8.7% (one of the lowest levels for a major market at that time). The change effectively reduced Pinnacle's annual earnings power by over $1.00 per share. A revamped state regulatory commission, which has some new members and a different chairperson (due to term limits), heeded the recommendation of a state administrative law judge who consulted on the case. The newly established ROE of 9.55% plus an additional fair value increment (FVI) of .25% passed by a 4-1 vote. According to Pinnacle's CEO, assuming certain criteria are met for the FVI to kick in, the company's effective ROE will be 9.85%. The net effect of the GRC lifts the company's earning power by $1.33 per share. We're raising our rating on the Arizona regulatory climate back to "average." The 2021 GRC decision landed it in the below-average camp.

We've raised our 2024 share-earnings estimate. It's only going up by a dime, but that's because we expected a favorable GRC outcome from PNW's perspective. Notably, the additional earnings power is substantial, though not readily apparent in our estimates because the company benefited by $0.48 a share last year from an extreme heat wave. Moreover, there are a number of factors this year that are likely to offset the additional revenue from the increased ROE. The utility had been tightening its belt on operating and maintenance expense and that's set to rise, as are depreciation/amortization and interest expense. On the positive side of the ledger, weather-normalized retail sales growth in Arizona comes to about $0.25 a share annually on average. Pinnacle has a premium service area in terms of growth from interstate migration and rising energy demand from a thriving economy. There's no lack of capital investment prospects to drive rate-base growth there.

Though untimely, we think long-term utility investors should keep this stock on their watch list and target a pullback as an entry point.

Anthony J. Glennon *April 19, 2024*

(A) Diluted EPS. Excl. nonrec. gain/(loss): '09, ($1.45); '17, 8¢; gains/(losses) from discont. ops.: '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). Qtly. EPS may not sum to full year due to rounding. Next egs. report due early May. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges/other intangibles. In '23: $27.22/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on common equity in '23: 9.55%-9.85%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	90

PNM RESOURCES NYSE-PNM

RECENT PRICE 37.45 | P/E RATIO 14.2 (Trailing: 13.3; Median: 19.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Lowered 2/2/24

SAFETY 3 Lowered 1/19/24

TECHNICAL 4 Lowered 3/1/24

BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$34-$56	$45 (20%)

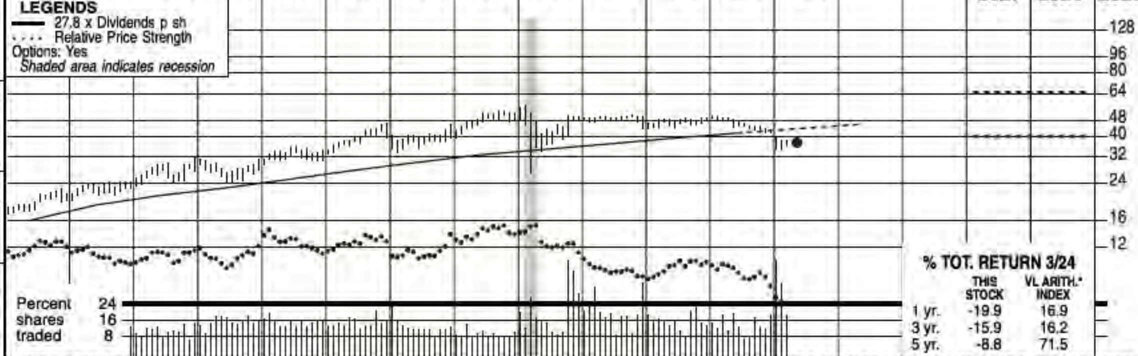
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+75%)	18%
Low	40	(+5%)	6%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	134	140	151
to Sell	146	139	144
Hld's(000)	78139	81263	82439

High:	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1	50.1	49.3	49.6	39.7
Low:	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1	43.8	43.4	41.4	34.6



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-19.9	16.9
3 yr.	-15.9	16.2
5 yr.	-8.8	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	18.04	18.30	17.74	20.74	26.21	21.50	**23.90**	**25.25**	Revenues per sh	**29.45**
1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.47	5.95	5.80	6.19	6.67	6.62	**6.80**	**7.25**	"Cash Flow" per sh	**8.70**
.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	2.00	2.16	2.28	2.45	2.69	2.82	**2.70**	**2.85**	Earnings per sh A	**3.40**
.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	1.25	1.33	1.41	1.49	**1.57**	**1.65**	Div'd Decl'd per sh B ■ †	**1.89**
3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	7.74	7.91	10.89	10.63	11.93	**12.90**	**13.85**	Cap'l Spending per sh	**13.50**
18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	21.08	23.88	25.25	25.54	26.04	**27.40**	**28.80**	Book Value per sh C	**33.60**
86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	85.83	85.83	85.83	90.20	**91.00**	**92.00**	Common Shs Outst'g D	**95.00**
NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	19.4	22.2	19.6	19.9	17.4	16.3	*Bold figures are*		Avg Ann'l P/E Ratio	**15.5**
NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.05	1.18	1.01	1.08	1.01	.91	*Value Line*		Relative P/E Ratio	**.85**
4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.8%	2.5%	2.8%	2.7%	3.0%	3.2%	*estimates*		Avg Ann'l Div'd Yield	**3.6%**
						1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	1523.0	1779.9	2249.6	1939.2	**2175**	**2325**	Revenues ($mill)	**2800**
						116.8	118.8	117.4	154.4	160.6	173.1	183.4	211.6	232.0	244.1	**245**	**265**	Net Profit ($mill)	**325**
						34.8%	36.9%	32.4%	33.0%	12.9%	8.1%	9.5%	13.4%	14.6%	13.6%	**14.5%**	**15.0%**	Income Tax Rate	**16.0%**
						10.7%	17.0%	11.0%	11.9%	12.1%	9.8%	8.9%	8.6%	9.0%	12.3%	**12.0%**	**13.0%**	AFUDC % to Net Profit	**13.0%**
						47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	56.9%	61.8%	63.9%	64.2%	**66.0%**	**67.5%**	Long-Term Debt Ratio	**69.0%**
						51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.9%	38.0%	36.0%	35.6%	**33.5%**	**32.0%**	Common Equity Ratio	**30.5%**
						3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	4780.6	5698.6	6096.1	6602.3	**7400**	**8250**	Total Capital ($mill)	**10400**
						4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	5965.1	6752.9	6972.8	7609.9	**8400**	**9300**	Net Plant ($mill)	**11500**
						5.1%	4.8%	4.7%	5.3%	5.0%	5.5%	4.9%	4.6%	4.9%	5.0%	**4.5%**	**4.5%**	Return on Total Cap'l	**4.5%**
						6.5%	7.1%	7.0%	9.0%	9.4%	10.2%	8.9%	9.7%	10.5%	10.3%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.0%**
						6.5%	7.1%	7.0%	9.1%	9.5%	10.3%	8.9%	9.7%	10.6%	10.4%	**10.0%**	**10.0%**	Return on Com Equity E	**10.0%**
						3.2%	3.3%	2.8%	4.5%	4.5%	4.8%	4.1%	4.6%	5.1%	5.0%	**4.0%**	**4.0%**	Retained to Com Eq	**4.5%**
						51%	54%	61%	51%	53%	54%	54%	53%	52%	52%	**58%**	**58%**	All Div'ds to Net Prof	**55%**

CAPITAL STRUCTURE as of 12/31/23
Total Debt $4783.7 mill. **Due in 5 Yrs** $2177.6 mill.
LT Debt $4241.6 mill. **LT Interest** $169.0 mill.
(Total Interest Coverage: 2.4x)

Leases, Uncapitalized Annual rentals $12.0 mill.

Pension Assets-12/22 $448.6 mill. **Oblig** $461.2 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.

Common Stock 90,200,384 shs.
as of 2/16/24
MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	1.0	5.2	1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1968	2139	2162
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	1.2	1.0	1.0
Fixed Charge Cov. (%)	317	289	230

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	5.0%	4.5%
"Cash Flow"	7.0%	5.0%	5.0%
Earnings	7.5%	8.0%	5.0%
Dividends	9.0%	7.0%	5.0%
Book Value	2.5%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	364.7	426.5	554.6	434.1	1779.9
2022	444.1	499.7	729.9	575.9	2249.6
2023	544.1	477.2	505.9	412.0	1939.2
2024	**560**	**525**	**580**	**510**	**2175**
2025	**595**	**560**	**630**	**540**	**2325**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.32	.55	1.37	.21	2.45
2022	.50	.57	1.46	.15	2.69
2023	.55	.55	1.54	.18	2.82
2024	**.45**	**.55**	**1.45**	**.25**	**2.70**
2025	**.50**	**.60**	**1.50**	**.25**	**2.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3075	.3075	.3075	.3075	1.23
2021	.3275	.3275	.3275	.3275	1.31
2022	.3475	.3475	.3475	.3475	1.39
2023	.3675	.3675	.3675	.3675	1.47
2024	.3875				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 548,000 customers in north central New Mexico, including Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 272,000 consumers in Texas. Electric revenue breakdown: residential, 32%; commercial, 28%; industrial, 7%; other, 33%. Generating sources not available. Fuel costs: 46% of revenues. '23 reported depreciation rates: 2.67%-7.64%. Has 1,600 employees. Chairman and CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' stock has been reeling after the company was left at the alter by its former merger partner. Investors may recall that PNM stockholders were to receive $50.30 per share in an all-cash deal from Northeast utility, Avangrid, Inc. (NYSE: AGR). At various stages of a lengthy courtship it looked as if the marriage would eventually be consummated despite regulators standing in the way. Ultimately, it was Avangrid's parent company, Iberdrola of Spain, who nixed the deal. The Spanish energy giant decided that buying the 18.4% minority stake in Avangrid itself for $34.25 a share is a better use of funds, as that deal is now on the table for AGR shareholders. Year to date, PNM stock is down 11%.

New Mexico regulators' early January rate decision didn't help matters. The New Mexico Public Regulation Commission ruled against the company on every front, making good on the state's reputation for being a difficult regulatory environment. Instead of the rise in its return on equity (ROE) that PNM was seeking, the company instead received a cut from 9.575% to 9.26%. Overall, $64 million in additional revenue was sought, much of that to recoup various investments made in the past to extend the lives of a coal-fired generating facility and a nuclear power plant. Regulators ruled that those investments were "imprudent" and disallowed them. The poor rate-base outcome and increased interest expense on an expanding debt load will likely weigh on this year's bottom line.

Even so, this equity may appeal to utility investors. The New Mexico operation is an average business of this sort, as it has reasonable long-term growth prospects, but is in a tough regulatory climate. Meanwhile, PNM's smaller, interstate long-range transmission & distribution (T&D) businesses, which serve around 300,000 consumers in Texas and New Mexico, are engines of growth for the company and suffer little regulatory lag. Beyond 2024, the recoupment of substantial T&D investments, via regulatory pricing mechanisms, can drive 5%-6% annual earnings and dividend gains. That should translate to worthwhile total return prospects out to late decade.

Anthony J. Glennon *April 19, 2024*

(A) Dil. EPS. Excl. nonrec. gain/(loss): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (93¢); '19, ($1.19); '20, (13¢); '21, (18¢); '22, (72¢); '23, ($1.80). Excl. disc. op. gains: '08, 42¢; '09, 78¢. Next egs. report due early May. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. def. charges/other intang. In '23: $15.45/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in NM in '23: 9.26%; in TX in '18: 9.65%; Regulatory Climate: NM, Below Average.; TX, Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	95

PPL CORPORATION NYSE-PPL

RECENT PRICE 27.53 | P/E RATIO 16.2 (Trailing: 17.2 Median: 14.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Raised 3/8/24
SAFETY 3 Lowered 3/18/22
TECHNICAL 4 Lowered 3/8/24
BETA 1.15 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$24-$41	$33 (20%)

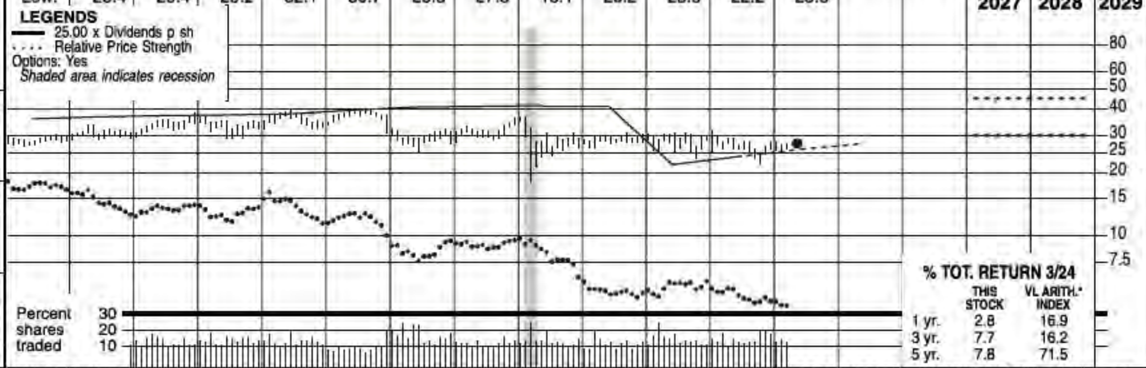
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+65%)	15%
Low	30	(+10%)	6%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	321	298	314
to Sell	385	412	396
Hld's(000)	541827	541856	569058

High:	33.6	38.1	36.7	39.9	40.2	32.5	36.3	36.8	30.7	31.0	31.7	28.0
Low:	28.4	29.4	29.2	32.1	30.7	25.3	27.8	18.1	26.2	23.5	22.2	25.3



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.8	16.9
3 yr.	7.7	16.2
5 yr.	7.8	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
21.47	20.03	17.63	22.02	21.11	18.82	17.27	11.38	11.06	10.74	10.81	10.13	9.89	7.87	10.73	11.28	11.00	11.30	Revenues per sh	11.80
4.71	3.47	3.66	4.59	4.84	4.64	4.58	3.78	4.28	3.68	4.16	3.94	3.81	2.07	3.09	3.44	3.55	3.65	"Cash Flow" per sh	4.10
2.45	1.19	2.29	2.61	2.61	2.38	2.38	2.37	2.79	2.11	2.58	2.37	2.04	.53	1.41	1.60	1.70	1.80	Earnings per sh A	2.25
1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	1.58	1.64	1.65	1.66	1.66	.88	.95	1.03	1.10	Div'd Decl'd per sh B ■	1.35
3.79	3.25	3.30	4.30	5.34	6.68	6.14	5.24	4.30	4.52	4.50	4.02	4.23	2.68	2.93	3.24	3.65	3.70	Cap'l Spending per sh	4.00
13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	15.52	16.18	16.93	17.39	18.67	18.89	18.90	19.85	20.55	Book Value per sh C	23.45
374.58	377.18	483.39	578.41	581.94	630.32	665.85	673.86	679.73	693.40	720.32	767.23	768.91	735.11	736.49	737.13	737.20	737.40	Common Shs Outst'g D	738.00
17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8	17.6	11.3	13.3	13.9	54.1	20.0	16.8	Bold figures are		Avg Ann'l P/E Ratio	17.0
1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.89	.61	.71	.71	2.92	1.16	.93	Value Line		Relative P/E Ratio	.95
3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	4.4%	4.5%	4.2%	4.2%	5.6%	5.2%	5.8%	5.8%	3.1%	3.5%	estimates		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 12/31/23
Total Debt $15604 mill. **Due in 5 Yrs** $3613 mill.
LT Debt $14611 mill. **LT Interest** $427 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $24 mill.
Pension Assets-12/23 $3175 mill. **Oblig** $3333 mill.

Pfd Stock None
Common Stock 737,603,408 shs. **as of 1/31/24**
MARKET CAP: $20.3 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
11499	7669.0	7517.0	7447.0	7785.0	7769.0	7607.0	5783.0	7902.0	8312.0	8100	8350	Revenues ($mill)	8700
1583.0	1603.0	1902.0	1449.0	1827.0	1746.0	1571.0	401.0	756.0	740.0	1255	1325	Net Profit ($mill)	1660
33.0%	22.5%	25.4%	24.2%	20.0%	19.0%	20.3%	23.0%	22.0%	19.9%	21.0%	21.0%	Income Tax Rate	21.0%
2.8%	1.6%	1.6%	1.9%	2.0%	1.9%	1.8%	6.0%	.7%	1.6%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
58.0%	65.2%	64.3%	64.8%	63.3%	61.5%	61.7%	43.7%	48.1%	51.1%	51.0%	51.0%	Long-Term Debt Ratio	49.5%
42.0%	34.8%	35.7%	35.2%	36.7%	38.5%	38.3%	56.3%	51.9%	48.8%	49.0%	49.0%	Common Equity Ratio	50.5%
32484	28482	27707	30608	31726	33712	34926	24389	26804	28544	29875	30925	Total Capital ($mill)	34280
34597	30382	30074	33092	34458	36482	38892	25470	30238	31418	31900	32700	Net Plant ($mill)	34900
6.5%	7.1%	8.4%	6.2%	7.2%	6.6%	5.9%	2.6%	2.8%	2.6%	5.5%	5.5%	Return on Total Cap'l	6.5%
11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	5.4%	5.3%	8.5%	8.5%	Return on Shr. Equity	9.5%
11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	5.4%	5.3%	8.5%	8.5%	Return on Com Equity E	9.5%
4.5%	6.0%	8.8%	3.5%	6.0%	4.3%	2.2%	NMF	1.8%	1.6%	3.5%	3.5%	Retained to Com Eq	3.5%
61%	63%	54%	74%	62%	68%	81%	NMF	76%	67%	61%	61%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+3.0	+1.5	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	154	348	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-7.5%	-3.0%	5.0%
"Cash Flow"	-6.0%	-8.5%	3.0%
Earnings	-9.0%	-17.0%	7.5%
Dividends	-1.0%	-4.5%	-.5%
Book Value	- -	4.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1498	1288	1512	1485	5783
2022	1782	1696	2134	2290	7902
2023	2415	1823	2043	2031	8312
2024	2060	1675	2130	2235	8100
2025	2245	1700	2155	2250	8350

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.26	d.20	.27	.19	.53
2022	.41	.30	.41	.28	1.41
2023	.48	.29	.43	.40	1.60
2024	.50	.30	.45	.45	1.70
2025	.50	.35	.50	.45	1.80

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4125	.415	.415	.415	1.66
2021	.415	.415	.415	.415	1.66
2022	.415	.20	.225	.225	1.07
2023	.225	.24	.24	.24	.95
2024	.24	.258			

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities, which distributes electricity to 1.4 mill. customers in eastern & central Pennsylvania. Acquired Kentucky Utilities and Louisville Gas and Electric (1.3 mill. customers) 11/10. Acq'd Narragansett Electric (770,000 customers, renamed Rhode Island Energy) 5/22. Spun off power-generating sub. in '15. Sold electric distribution sub. in U.K. in '21. Electric rev. breakdown: res'l, 48%; comm'l, 22%; ind'l, 10%; other, 20%. Fuel costs: 29% of revs. '23 reported deprec. rate: 3.2%. Has 6,527 employees. Chairman: William H. Spence. President & CEO: Vincent Sorgi. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

We look for PPL Corp. to deliver solid 2024 results. The company finished the 2023 final stanza on a good note with better-than-expected financial results, while also raising the quarterly dividend and capital expenditure plan. Too, management reaffirmed its long-term annual earnings growth target of 6%-8% through 2028 and released its 2024 earnings forecast range of $1.63-$1.75 per share. At $1.70 per share, our profit call is right near PPL's midpoint and represents an increase of 6% over the $1.60 that the Pennsylvania-based electric utility tallied last year. The company was set to release first-quarter financial results as this report went to press. We expect earnings of $0.50 a share on revenues of $2.06 billion.

Our full-year 2025 earnings estimate is staying put at $1.80 per share. This represents a 6% increase from our 2024 target, and is within PPL's long-term annual profit growth estimate. Additional revenues from regulatory mechanisms and lower operating and maintenance expenses should benefit prospects over that interim. Indeed, a full year of rate relief in Kentucky, Rhode Island, and Pennsylvania will likely benefit the company's bottom line. Too, the utility hopes to save $150 million in cost savings through the end of 2025, largely due to infrastructure improvements.

The board of directors recently raised the dividend. The increase was $0.018 a share (7.3%), making the quarterly distribution $0.2575 per share. The dividend yield of 3.8% sits just above the utility median.

Shares of PPL are now ranked 3 (Average) for relative year-ahead price performance, having been raised a notch on our Timeliness scale since February. The major draw here remains the dividend, especially after the aforementioned hike. The stock's prospects for the 18-month period are solid by utility standards. And, the total return potential for the 3- to 5-year time frame is respectable, given the strong yield and reduced risk of this equity. We recommend that conservative buy-and-hold investors seeking utility exposure take a closer look at this equity.

Zachary J. Hodgkinson *May 10, 2024*

(A) Dil. EPS. Excl. nonrec. gain (losses): '10, (8¢); '11, 8¢; '13, (62¢); '20, (13¢); '21, (50¢); gains (losses) on disc. ops.: '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 23¢; '15, ($1.36); '21, ($1.94). '20 & '21 EPS don't sum due to rounding. Next egs. rept. due early Aug. (B) Div'ds paid in early Jan., April, July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '23: $3.10/sh. (D) In mill. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '16: none spec.; in KY in '19: 9.725%; earned on avg. com. eq., '21: 2.8%. Reg. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	15
Earnings Predictability	45

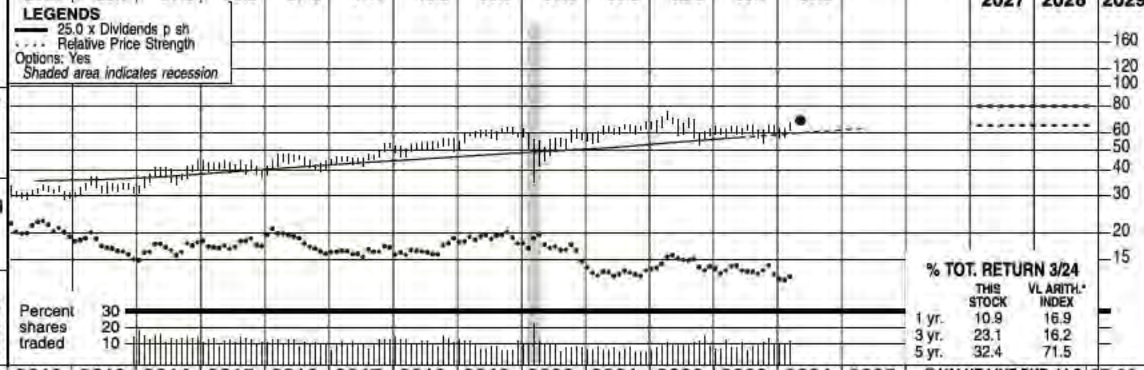
P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE	68.64	P/E RATIO	18.8 (Trailing: 19.7; Median: 16.0)	RELATIVE P/E RATIO	1.08	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS **4** Lowered 2/9/24
SAFETY **1** Raised 11/23/12
TECHNICAL **3** Raised 5/10/24
BETA .95 (1.00 = Market)

High:	37.0	43.8	44.4	47.4	53.3	56.7	63.9	62.2	67.1	75.6	65.5	68.9		
Low:	29.7	31.3	36.8	37.8	41.7	46.2	50.0	34.8	53.8	52.5	53.7	56.8		

LEGENDS
— 25.0 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$85	$72 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+15%)	7%
Low	65	(-5%)	3%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	395	412	493
to Sell	396	399	385
Hld's(000)	362902	368948	370095

Percent shares traded 30 20 10

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.9	16.9
3 yr.	23.1	16.2
5 yr.	32.4	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	18.22	18.14	19.24	19.99	19.05	19.29	19.72	22.56	*22.25*	*24.40*	Revenues per sh	*27.75*
4.68	4.98	5.27	5.36	4.87	5.17	5.82	5.75	5.07	5.30	5.81	6.14	6.37	6.46	6.08	6.16	*6.50*	*6.90*	"Cash Flow" per sh	*8.10*
2.90	3.08	3.07	3.11	2.44	2.45	2.99	2.91	2.83	2.82	3.12	3.28	3.43	3.65	3.47	3.48	*3.65*	*3.90*	Earnings per sh A	*4.65*
1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.16	2.28	*2.40*	*2.52*	Div'd Decl'd per sh B ■	*2.90*
3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	8.32	8.30	7.76	6.28	5.80	5.39	5.81	6.68	*7.20*	*7.30*	Cap'l Spending per sh	*9.00*
15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.86	26.01	27.42	28.53	29.94	31.71	28.65	27.62	31.08	*32.40*	*33.85*	Book Value per sh C	*39.00*
506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	504.87	505.00	504.00	504.00	504.00	504.00	497.00	498.00	*499.00*	*500.00*	Common Shs Outst'g D	*505.00*
13.6	10.0	10.4	10.4	12.8	13.5	12.6	14.1	15.3	16.3	16.6	18.0	15.7	16.8	18.5	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.82	.67	.66	.65	.81	.76	.66	.71	.80	.82	.90	.96	.81	.91	1.07	.99	*Value Line*		Relative P/E Ratio	*.85*
3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	3.7%	3.5%	3.2%	3.6%	3.3%	3.4%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $21789 mill. **Due in 5 Yrs** $6950 mill.
LT Debt $18764 mill. **LT Interest** $765 mill.
(Total Interest coverage: 3.1x)

Leases, Uncapitalized Annual rentals $35 mill.

Pension Assets-12/23 $4140 mill. **Oblig.** $4758 mill.

Pfd Stock None

Common Stock 498,080,467 shs.
as of 4/16/24
MARKET CAP: $34.2 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
10886	10415	9198.0	9161.0	9696.0	10076	9603.0	9722.0	9800.0	11237	*11100*	*12200*	Revenues ($mill)	*14500*
1518.0	1476.0	1436.0	1431.0	1582.0	1666.0	1741.0	1853.0	1739.0	1742.0	*1830*	*1960*	Net Profit ($mill)	*2350*
38.2%	37.4%	31.7%	37.3%	23.7%	32.2%	14.3%	19.5%	13.7%	10.1%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
4.5%	6.2%	8.4%	10.6%	8.7%	6.5%	7.0%	5.5%	5.1%	5.3%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
40.4%	40.3%	45.3%	46.6%	47.8%	47.7%	47.6%	51.3%	54.6%	53.5%	*54.5%*	*55.5%*	Long-Term Debt Ratio	*58.5%*
59.6%	59.7%	54.7%	53.4%	52.2%	52.3%	52.4%	48.7%	45.4%	46.5%	*45.5%*	*44.5%*	Common Equity Ratio	*41.5%*
20446	21900	24025	25915	27545	28832	30480	29657	30224	33261	*35600*	*37900*	Total Capital ($mill)	*47500*
23589	26539	29286	31797	34363	35844	37585	34366	35942	38031	*40250*	*42400*	Net Plant ($mill)	*51400*
8.4%	7.6%	6.8%	6.4%	6.7%	6.7%	6.6%	7.1%	6.7%	6.4%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.0%*
12.5%	11.3%	10.9%	10.3%	11.0%	11.0%	10.9%	12.8%	12.7%	11.3%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.0%*
12.5%	11.3%	10.9%	10.3%	11.0%	11.0%	10.9%	12.8%	12.7%	11.3%	*11.5%*	*11.5%*	Return on Com Equity E	*12.0%*
6.3%	5.3%	4.6%	4.1%	4.7%	4.7%	4.7%	5.7%	4.8%	3.9%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
49%	53%	58%	61%	58%	57%	57%	56%	62%	65%	*65%*	*64%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+1.3	+1.6	-4.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.9	+.9	+.9
Fixed Charge Cov. (%)	403	297	285

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	--	2.0%	4.5%
"Cash Flow"	2.0%	3.0%	4.5%
Earnings	3.0%	4.0%	5.0%
Dividends	4.5%	4.5%	5.0%
Book Value	3.0%	1.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2889	1874	1903	3056	9722
2022	2313	2076	2272	3139	9800
2023	3755	2421	2456	2605	11237
2024	2760	*2590*	*2750*	*3000*	*11100*
2025	*3500*	*2650*	*2900*	*3150*	*12200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.28	.70	.98	.69	3.65
2022	1.33	.64	.86	.64	3.47
2023	1.39	.70	.85	.54	3.48
2024	1.31	*.77*	*.95*	*.62*	*3.65*
2025	*1.41*	*.82*	*1.01*	*.66*	*3.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.49	.49	.49	.49	1.96
2021	.51	.51	.51	.51	2.04
2022	.54	.54	.54	.54	2.16
2023	.57	.57	.57	.57	2.28
2024	.60				

BUSINESS: Public Service Enterprise Group Inc. (PSEG) is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.4 million electric and 1.9 million gas customers in NJ, and PSEG Power LLC, a nonregulated power generator with 5 nuclear plants in the Northeast (sold fossil-fuel generation, 2/22). Divested offshore wind assets (5/23). Percentange of electric sales: Commercial (58%); Residential (33%); Industrial (9%). Fuel costs: 41% of revenues. '23 reported depreciation rates (utility): 1.84%-2.54%. Employs approximately 12,500. Chair of the Board, President and CEO: Ralph A. LaRossa. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Tel.: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group has been one of the top-performing electric utilities, of late. The equity held up better than most peers last year in a weak overall period for the group, which has a high negative correlation with rising interest rates. PSEG shares are up 28% from their October low and 12% year to date, outperforming the *Value Line Utility Index* by 18 percentage points (PPs) and 13 PPs, respectively. Investors apparently appreciate the lower risk of a nearly pure-play utility. The only significant business held outside of the regulatory pricing umbrella is the company's nuclear power generators, which provide a steady stream of cash flow to the company. PSEG's balance sheet is in good shape, interest expense is well covered by profits, and a relatively low amount of debt comes due in the next five years. There is also no intermediate-term need to do a major equity offering, which dilutes existing shareholders. The dividend was recently raised by 5.3% and the payout ratio is near the industry median. Longer-term growth prospects for both earnings and dividends are slightly above the peer-group average.

Profits should be up this year. Utility revenue is rising due to regulatory pricing mechanisms that allow for nearly real-time returns on capital deployed for electric grid improvements. Relatively mild weather in the second half of 2023 provides a somewhat easy comparison, while interest expense and pension contributions are likely to moderate. Management recently affirmed its earnings target of $3.60-$3.70 per share for 2024 and its 5%-7% annual growth expectation through late decade (supported by New Jersey's clean energy goals).

PSEG wants to extend the life of its nuclear power plants. The company hopes to receive federal approval to keep its units operational for 20 additional years, extending the average life to 2061.

The valuation has gotten a little rich as a result of the stock's outperformance. The P/E multiple, at 18.8 times 2024 expected earnings, compares unfavorably to PSEG's electric utility peer median of 16.1. Total return prospects look somewhat limited over the longer term and the stock is untimely.

Anthony J. Glennon *May 10, 2024*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '15, 39¢; '16, ($1.08); '17, 28¢ (net); '18, (29¢); '19, 5¢; '20, 33¢; '21, ($4.94); '22, ($1.41); '23, $1.65; disc. ops.: '08, 40¢; '10, 1¢; '11, 19¢. Next egs. report due late July.
(B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail.
(C) Incl. intangibles. In '23: $13.36/sh.
(D) In mill., adj. for '08 split. (E) Rate base: Net original cost. Rate allowed on common equity in '21: 9.9%-10.4%; Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

SEMPRA ENERGY NYSE-SRE

RECENT PRICE **70.77** | P/E RATIO **15.0** (Trailing: 15.4 / Median: 20.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 4 Raised 12/1/23
SAFETY 2 Raised 7/29/16
TECHNICAL 4 Lowered 3/29/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range
Low-High: $61-$105 | Midpoint (% to Mid): $83 (15%)

2027-29 PROJECTIONS

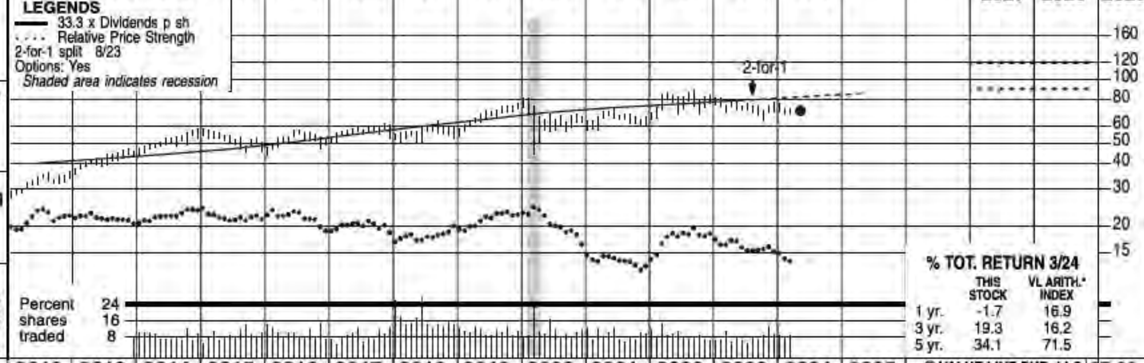
	Price	Gain	Ann'l Total Return
High	120	(+70%)	17%
Low	90	(+25%)	10%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	446	915	502
to Sell	389	115	427
Hld's(000)	539812	531380	566873

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	46.5	58.2	58.1	57.3	61.5	63.6	77.2	80.9	72.5	88.2	81.8	77.1
Low:	35.3	43.4	44.7	43.4	49.9	50.2	53.0	44.0	57.3	64.8	63.8	68.4

LEGENDS
— 33.3 x Dividends p sh
.... Relative Price Strength
2-for-1 split 8/23
Options: Yes
Shaded area indicates recession



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.7	16.9
3 yr.	19.3	16.2
5 yr.	34.1	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
22.11	16.44	18.72	20.91	19.90	21.59	22.40	20.60	20.35	22.29	21.34	18.56	19.71	20.28	22.97	26.48	*24.75*	*26.25*	Revenues per sh	*29.30*
3.70	3.97	3.88	4.29	4.46	4.43	4.70	5.16	4.75	5.29	5.53	5.57	6.61	7.09	7.85	8.15	*8.35*	*9.00*	"Cash Flow" per sh	*10.75*
2.22	2.39	2.01	2.24	2.18	2.11	2.32	2.62	2.12	2.32	2.74	2.99	3.69	4.22	4.61	4.61	*4.80*	*5.15*	Earnings per sh A	*6.30*
.69	.78	.78	.96	1.20	1.26	1.32	1.40	1.51	1.65	1.79	1.94	2.09	2.20	2.29	2.38	*2.48*	*2.58*	Div'd Decl'd per sh B ■	*3.08*
4.24	3.88	4.29	5.93	6.10	5.26	6.34	6.36	8.42	7.86	6.91	6.36	8.10	7.91	8.52	13.30	*13.25*	*14.00*	Cap'l Spending per sh	*15.75*
16.38	18.27	18.77	20.50	21.21	22.51	22.99	23.78	25.89	25.20	27.18	30.29	35.06	39.59	41.72	44.00	*46.90*	*49.55*	Book Value per sh C	*59.65*
486.65	493.02	480.89	479.87	484.74	488.92	492.66	496.60	500.31	502.72	547.54	583.43	576.94	633.84	628.67	631.43	*646.00*	*648.00*	Common Shs Outst'g D	*665.00*
11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3	20.4	22.5	17.5	15.4	16.8	16.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.20	.90	.83	.97	.90	*Value Line*		Relative P/E Ratio	*.90*
2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%	3.2%	2.9%	3.2%	3.4%	3.0%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*
						11035	10231	10183	11207	11687	10829	11370	12857	14439	16720	*16000*	*17000*	Revenues ($mill)	*19500*
						1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2316.0	2701.0	2960.0	2965.0	*3115*	*3380*	Net Profit ($mill)	*4240*
						19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	18.0%	25.5%	20.1%	18.7%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
						14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	8.7%	8.0%	8.6%	15.1%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*11.0%*
						51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.2%	44.8%	47.5%	49.2%	*50.0%*	*52.5%*	Long-Term Debt Ratio	*55.0%*
						48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	44.8%	53.3%	50.7%	49.2%	*48.5%*	*46.5%*	Common Equity Ratio	*44.0%*
						23513	24963	27400	29135	38769	40734	45174	47069	51683	56454	*62550*	*69175*	Total Capital ($mill)	*90400*
						25902	28039	32931	36503	36796	36452	40003	43894	47782	54960	*61100*	*67600*	Net Plant ($mill)	*89200*
						6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	6.1%	6.6%	6.8%	6.4%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	9.9%	10.4%	10.9%	10.3%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.5%*
						10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	10.6%	10.5%	11.1%	10.5%	*10.0%*	*10.5%*	Return on Com Equity E	*10.5%*
						5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	4.8%	5.2%	5.7%	5.2%	*5.0%*	*5.0%*	Retained to Com Eq	*5.5%*
						52%	48%	65%	65%	62%	62%	58%	52%	50%	52%	*52%*	*51%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $31076 mill. **Due in 5 Yrs** $8283 mill.
LT Debt $27759 mill. **LT Interest** $1309 mill.
Incl. $1276 mill. finance leases.
(Total Interest Coverage: 2.9x)

Leases, Uncapitalized Annual rentals $85 mill.
Pension Assets-12/23 $2664 mill. **Oblig** $3107 mill.
Pfd Stock $889 mill. **Pfd Div'd** $44 mill.
900,000 shs. 4.875%, cumulative.
Common Stock 632,149,916 shs.
as of 2/20/24
MARKET CAP: $44.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (kWh)	-3.7	+2.8	-4.8
Avg. Indust. Use (MWh)	NA	NA	NA
Avg. Indust. Revs. per kWh (¢)	NA	NA	NA
Capacity at Peak (MW)	NMF	NMF	NMF
Peak Load, Summer (MW)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.8	+.5	+.9
Fixed Charge Cov. (%)	207	232	194

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	1.0%	1.5%	*4.5%*
"Cash Flow"	6.0%	8.0%	*6.0%*
Earnings	7.5%	13.5%	*7.0%*
Dividends	7.0%	7.0%	*5.0%*
Book Value	7.0%	10.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3259	2741	3013	3844	12857
2022	3820	3547	3617	3455	14439
2023	6560	3335	3334	3491	16720
2024	*5325*	*3375*	*3550*	*3750*	*16000*
2025	*5650*	*3575*	*3775*	*4000*	*17000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.48	.82	.85	1.08	4.22
2022	1.46	.99	.99	1.18	4.61
2023	1.46	.94	1.08	1.13	4.61
2024	*1.46*	*.99*	*1.13*	*1.22*	*4.80*
2025	*1.55*	*1.05*	*1.22*	*1.33*	*5.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.484	.523	.523	.523	2.05
2021	.523	.55	.55	.55	2.17
2022	.55	.573	.573	.573	2.27
2023	.573	.595	.595	.595	2.36
2024	.595	.620			

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric (SDG&E), which sells electricity & gas mainly in San Diego County, and Southern California Gas (SoCalGas), which distributes gas to most of Southern CA. Owns 80% of Oncor (acquired 3/18), which distributes electricity in TX. Serves nearly 40 mill. consumers, mainly in CA, TX, and MX. Electric rev. breakdown: N/A. Purchases about 3/4ths of its power; rest is mainly gas. Sempra Infrastrucure (SI) subsidiary is active in LNG exportation and other energy endeavors. Sold S.A. utilities in '20. Power costs: 25% of revenue. '23 reported deprec. rates: 2.6%-7.1%. Employs 16,835. Chr., Pres. & CEO: Jeffrey W. Martin. Inc.: CA. Addr.: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Int: www.sempra.com.

Sempra Energy's per-share profits should be up this year and next, after a flat 2023 result. Retail electricity sales, in terms of millions of kilowatt-hours, were down 4.8% last year as compared to 2022's level, which benefited from a protracted heat wave in southern California. Higher interest expense and regulatory lag also weighed on last year's bottom line. Leadership is projecting earnings of $4.60 to $4.90 per share for this year, which is up a nickel on the bottom end of the range from where the in-house target was previously. In mid-2023, the company's Texas subsidiary, Oncor, received a favorable regulatory outcome, which should have beneficial knock-on effects for this year's bottom line. Meanwhile, in California, rate relief should be forthcoming. A regulatory decision is expected by mid-year for San Diego Gas & Electric and SoCalGas. Higher rates ought to be retroactive to January 1st. Sempra's preliminary bottom-line target for 2025 is $4.90 to $5.25 per share.

The company recently affirmed its projected long-term earnings-per-share growth rate of 6%-8%. With the fourth-quarter financial release, Sempra announced a 20% increase in its capital plan to $48 billion for the 2024 to 2028 time frame, with more than 90% of the investments focused on the regulated utilities. Oncor's rate base (assets for which a regulated utility is allowed to recoup an economic rate of return) is now projected to increase from $23 billion in 2023 to $39 billion in 2028, an 11% expansion per annum. The Texas service area is benefiting from residential growth that's more than twice the national average, as well as from healthy demand from the continued increase in large commercial & industrial customers. Meanwhile, the rate base in California is projected to increase from $27 billion in 2023 to $38 billion in 2028, for a 7% yearly expansion. Mitigating natural disaster risks and the state's aggressive renewable energy goals are driving investment. The 9% growth across the companywide rate base should translate to at least 7% share-earnings gains to 2027-29.

Though untimely, Sempra stock offers reasonably good annual total return potential out to late decade.

Anthony J. Glennon *April 19, 2024*

(A) Diluted egs. Excl. nonrec. gains/(losses): '09, (13¢); '10, (52¢); '11, 58¢; '12, (44¢); '13, (11¢); '15, 7¢; '16, 61¢; '17, ($1.81); '18, ($1.03); '19, 8¢; '20, (40¢); '21, ($2.21); '22, ($1.30); '23, 18¢. Disc. ops.: '19, 58¢; '20, $3.15. Qtly. EPS may not sum due to rounding. Next egs. report due early May. (B) Div'ds paid Jan., Apr., July, Oct. ■ Div. reinv. avail. (C) Incl. intang. In '22: $7.21/sh. (D) In mill., adj. for 8/23 stk. split. (E) Rate allowed on com. eq.: SDG&E '22: 9.95%; SoCalGas '22: 9.8%; Oncor '23: 9.7%. Reg. Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	95

SOUTHERN COMPANY NYSE-SO

RECENT PRICE **74.39** | P/E RATIO **18.6** (Trailing: 20.4 / Median: 17.0) | RELATIVE P/E RATIO **1.07** | DIV'D YLD **3.8%** | VALUE LINE

TIMELINESS 3 Raised 3/1/24
SAFETY 2 Lowered 2/21/14
TECHNICAL 4 Raised 4/19/24
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High $64-$101 Midpoint (% to Mid) $83 (10%)

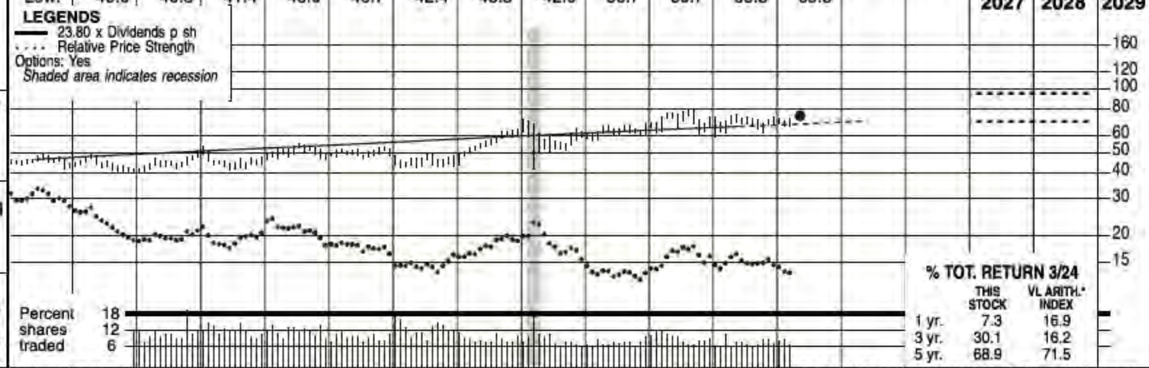
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+30%)	10%
Low	70	(-5%)	3%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	773	753	841
to Sell	703	757	776
Hld's(000)	688021	689919	708610

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1	68.9	80.6	75.8	74.9
Low:	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0	56.7	60.7	58.8	65.8



% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.3	16.9
3 yr.	30.1	16.2
5 yr.	68.9	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	19.29	21.80	26.89	23.15	*24.66*	*25.85*	Revenues per sh	*29.20*
4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	6.98	7.20	7.34	7.79	*8.00*	*8.30*	"Cash Flow" per sh	*9.25*
2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	3.25	3.42	3.61	3.64	*4.00*	*4.30*	Earnings per sh A	*5.10*
1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	2.54	2.62	2.70	2.78	*2.86*	*2.96*	Div'd Decl'd per sh B ■	*3.10*
5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	7.04	6.83	7.87	8.88	*8.85*	*8.75*	Cap'l Spending per sh	*8.50*
17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	26.48	26.30	27.93	28.82	*29.90*	*31.75*	Book Value per sh C	*32.25*
777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	1056.5	1060.0	1089.0	1091.0	*1095.0*	*1095.0*	Common Shs Outst'g D	*1095.0*
16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	17.9	18.4	19.6	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	1.14	1.06	*Value Line*		Relative P/E Ratio	*.90*
4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	4.4%	4.2%	4.1%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
18467	17489	19896	23031	23495	21419	20375	23113	29279	25253	*27000*	*28300*	Revenues ($mill)	*32000*
2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	3931.3	3976.0	*4280*	*4600*	Net Profit ($mill)	*5510*
33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	18.9%	11.4%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	8.0%	7.9%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	63.0%	65.6%	*64.0%*	*64.0%*	Long-Term Debt Ratio	*63.0%*
47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	36.5%	37.6%	*36.0%*	*36.0%*	Common Equity Ratio	*37.0%*
42142	46788	69359	68953	65750	69594	73336	78285	80558	83654	*85000*	*87500*	Total Capital ($mill)	*93500*
54868	61114	78446	79872	80797	83080	87634	91108	94570	99844	*100000*	*100500*	Net Plant ($mill)	*110000*
7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	5.5%	4.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	12.5%	12.6%	*13.0%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	12.5%	12.6%	*13.0%*	*13.0%*	Return on Com Equity E	*14.5%*
3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	3.0%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
75%	76%	78%	72%	79%	77%	78%	76%	78%	77%	*77%*	*77%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $57210 mill. **Due in 5 Yrs** $15427 mill.
LT Debt $54745 mill. **LT Interest** $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/23 $14218 mill. **Oblig** $16382 mill.
Pfd Stock $242 mill. **Pfd Div'd** $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).
Common Stock 1,091,015,113 shs.
MARKET CAP: $81.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	-5.3	+2.0	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.5	NA
Fixed Charge Cov. (%)	270	275	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	--	.5%	6.0%
"Cash Flow"	4.0%	4.5%	5.0%
Earnings	3.0%	3.0%	6.5%
Dividends	3.5%	3.5%	3.5%
Book Value	3.0%	2.5%	3.5%

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	5910	5198	6238	5767	23113
2022	6648	7206	8378	7047	29279
2023	6480	5748	6980	6045	25253
2024	*6550*	*6100*	*7300*	*7050*	*27000*
2025	*6800*	*6500*	*7600*	*7400*	*28300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.09	.67	1.22	.44	3.42
2022	.97	1.07	1.31	.26	3.61
2023	.79	.79	1.42	.64	3.64
2024	*.90*	*1.00*	*1.45*	*.65*	*4.00*
2025	*1.00*	*1.10*	*1.50*	*.70*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.62	.64	.64	.64	2.54
2021	.64	.66	.66	.66	2.62
2022	.66	.68	.68	.68	2.70
2023	.68	.70	.70	.70	2.78
2024	.70	.72			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.4 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric revenue breakdown: residential, 43%; commercial, 35%; industrial, 21%; other, 1%. Generating sources: gas, 51%; coal, 19%; nuclear, 10%; other, 11%; purchased, 9%. Fuel costs: 26% of revenues. '23 reported deprec. rates (utility): 2.7%-3.4%. Has 27,300 employees. President and CEO: Chris Womack. Incorporated.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Telephone: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary has completed its nuclear construction project. In late April, unit 4 entered commercial operation, and plant Vogtle became the largest generator of clean energy in the U.S. Units 3 and 4 will combine to produce enough electricity to power approximately 1 million homes for at least 60-80 years. The construction project faced significant delays and reached completion seven years later than Southern's initial forecast, while costing more than $20 billion over original budget estimates. We look for the Vogtle station to greatly improve earnings prospects moving forward, as the project will provide clean, reliable, cost-effective energy amid greater demand for energy and growing power volumes. The transition to cleaner energy should also begin to accelerate with earnings and dividend growth as units 3 and 4 start to pick up steam this year.

We look for full-year 2024 earnings of $4.00 a share. This is the midpoint of management's initial profit target range of $3.95-$4.05 per share, which was released in February. Too, Southern reaffirmed its long-term EPS growth estimate of 5%-7%. We expect even greater growth of 10% this year due to an almost full year of operations from Vogtle units 3 and 4, as well as rate relief and an improved macroeconomic environment. As a result, we project earnings of $4.30 per share on revenues of $28.3 billion for full-year 2025.

The board of directors recently raised the dividend. The increase was $0.02 a share, making the quarterly distribution $0.72 per share. The dividend has now been raised in 23 consecutive years, and the yield of 3.8% sits above the utility average.

This issue is best-suited to conservative, income-oriented accounts. Indeed, the consistently raised dividend remains Southern's most notable feature. These shares also hold a strong financial strength rating (A), and an Above Average (2) Safety rank. Plus, risks from the nuclear construction project have concluded and prospects ahead for the Vogtle station are bright. On the other hand, the current quotation is already trading on the low-end of our 3- to 5-year Target Price range, as long-term prospects are weak.

Zachary J. Hodgkinson *May 10, 2024*

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due in mid-May. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '23: $17.35/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common eq. (blended): 12.5%; earned on avg. com. eq., '21: 12.8%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	95

WEC ENERGY GROUP NYSE-WEC

RECENT PRICE **80.70** | P/E RATIO **16.5** (Trailing: 16.2 Median: 21.0) | RELATIVE P/E RATIO **0.92** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 4 Raised 4/26/24
SAFETY 1 Raised 3/23/12
TECHNICAL 3 Raised 6/7/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$70-$116	$93 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+80%)	18%
Low	120	(+50%)	13%

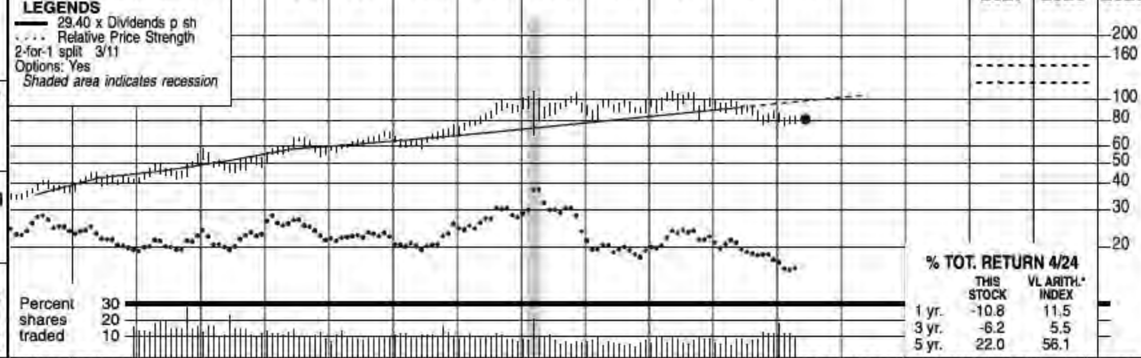
Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	428	415	450
to Sell	426	457	443
Hld's(000)	239348	243133	247998

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	45.0	55.4	58.0	66.1	70.1	75.5	98.2	109.5	99.9	108.4	99.3	86.9
Low:	37.0	40.2	44.9	50.4	56.1	58.5	67.2	68.0	80.6	80.8	75.5	75.1

LEGENDS
— 29.40 x Dividends p sh
.... Relative Price Strength
2-for-1 split 3/11
Options: Yes
Shaded area indicates recession

Target Price Range 2027 | 2028 | 2029



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.8	11.5
3 yr.	-6.2	5.5
5 yr.	22.0	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.24	24.34	23.85	22.96	26.36	30.43	28.19	*29.00*	*30.30*	Revenues per sh	*35.50*
2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.69	6.04	6.53	6.90	7.53	8.01	8.64	*9.35*	*10.15*	"Cash Flow" per sh	*11.95*
1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.14	3.34	3.58	3.79	4.11	4.46	4.63	*4.90*	*5.25*	Earnings per sh A	*6.40*
.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	2.21	2.36	2.53	2.71	2.91	3.12	*3.34*	*3.57*	Div'd Decl'd per sh B ■	*3.83*
4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	6.21	6.71	7.17	7.10	7.14	7.34	9.14	*9.30*	*9.30*	Cap'l Spending per sh	*9.25*
14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.98	31.02	32.06	33.19	34.60	36.76	37.25	*37.90*	*38.70*	Book Value per sh C	*42.00*
233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.57	315.52	315.43	315.43	315.43	315.43	315.43	*315.43*	*315.43*	Common Shs Outst'g D	*315.43*
14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	20.0	19.6	23.5	24.9	22.3	21.9	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	1.25	1.28	1.21	1.27	1.09	*Value Line*		Relative P/E Ratio	*1.15*
2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	3.3%	3.4%	2.8%	2.7%	3.0%	3.4%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $16016.3 mill. **Due in 5 Yrs** $4611 mill.
LT Debt $15375.8 mill. **LT Interest** $452.7 mill.
Incl. $12.1 mill. finance leases.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $6.8 mill.
Oblig $3136.6 mill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable $101;
44,498 shs. 6%, $100 par.
Common Stock 315,822,587 shs.

MARKET CAP: $25.5 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
4997.1	5926.1	7472.3	7648.5	7679.5	7523.1	7241.7	8316.0	9597.4	8893.0	*9150*	*9550*	Revenues ($mill)	*11200*
589.5	640.3	940.2	998.2	1060.5	1134.2	1201.1	1301.5	1406.8	1460.4	*1545*	*1655*	Net Profit ($mill)	*2020*
38.0%	40.4%	37.6%	37.2%	13.8%	9.9%	15.9%	13.4%	18.6%	18.8%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
1.3%	4.5%	3.8%	1.6%	2.1%	1.8%	2.4%	1.9%	2.1%	2.1%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
48.5%	51.2%	50.5%	48.0%	50.4%	52.5%	52.8%	55.3%	54.7%	54.9%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*55.5%*
51.2%	48.6%	49.3%	51.9%	49.4%	47.4%	47.1%	44.6%	44.4%	44.5%	*44.5%*	*44.5%*	Common Equity Ratio	*44.5%*
8636.5	17809	18118	18238	19813	21355	22228	24467	25368	26279	*27000*	*28120*	Total Capital ($mill)	*29800*
11258	19190	19916	21347	22001	23620	25707	26982	29114	31582	*31000*	*32750*	Net Plant ($mill)	*35100*
8.1%	4.5%	6.3%	6.6%	6.5%	6.5%	6.5%	6.3%	6.4%	6.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
13.2%	7.4%	10.5%	10.5%	10.8%	11.2%	11.4%	11.9%	12.0%	12.5%	*12.5%*	*12.5%*	Return on Shr. Equity	*13.0%*
13.3%	7.4%	10.5%	10.5%	10.8%	11.2%	11.5%	11.9%	12.5%	12.5%	*12.5%*	*12.5%*	Return on Com Equity E	*13.0%*
5.3%	2.1%	3.5%	3.6%	3.7%	3.8%	3.8%	4.1%	4.0%	4.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
60%	71%	67%	66%	66%	66%	67%	66%	65%	68%	*68%*	*68%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-2.5	-2.6	+3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I Revs. per KWH (¢)	7.25	6.61	7.51
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+.2
Fixed Charge Cov. (%)	300	338	357

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.0%	2.0%	5.0%
"Cash Flow"	7.0%	7.5%	6.5%
Earnings	6.5%	7.0%	6.0%
Dividends	10.0%	6.5%	7.0%
Book Value	7.0%	3.5%	4.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2691	1676	1746	2201	8316.0
2022	2908	2127	2003	2558	9597.4
2023	2888	1830	1957	2218	8893.0
2024	2680	*1870*	*2000*	*2600*	*9150*
2025	*2750*	*2000*	*2150*	*2650*	*9550*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.61	.87	.92	.71	4.11
2022	1.79	.91	.96	.80	4.46
2023	1.61	.92	1.00	1.10	4.63
2024	1.97	*.75*	*1.05*	*1.13*	*4.90*
2025	*2.00*	*1.00*	*1.10*	*1.15*	*5.25*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6325	.6325	.6325	.6325	2.53
2021	.6775	.6775	.6775	.6775	2.71
2022	.7275	.7275	.7275	.7275	2.91
2023	.7800	.7800	.7800	.7800	3.12
2024	.8350				

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.9 mill. gas. Acq'd Integrys Energy 6/15. Electric revenue breakdown: residential, 39%; small commercial & industrial, 32%; large commercial & industrial, 21%; other, 8%. Generating sources: coal, 36%; gas, 28%; renewables, 5%; purchased, 31%. Fuel costs: 40% of revenues. '23 reported deprec. rates: 2.4%-3.1%. Has 6,900 employees. Chairman: Gale E. Klappa. President & CEO: Scott J. Lauber. Incorporated.: Wisconsin. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Telephone.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy's utilities in Wisconsin have filed general rate cases. The utilities are seeking approximately $800 million in rate increases over the next two years to improve reliability, reduce outages, and assist the transition from coal to renewables. An order is expected by the end of this year, and new tariffs are subject to take effect at the start of 2025. In Illinois, there is a rehearing underway regarding the request to restore $145 million for its safety program. Remember, the Illinois Commerce Commission disallowed $236.2 million of capital costs related to the construction of Peoples Gas & Light service centers, causing WEC to pause the multi billion-dollar pipeline replacement program.

We look for 2024 profits to advance 6%, to $4.90 a share. We are sticking with our estimate, even though it is on the high-end of WEC Energy's targeted range of $4.80-$4.90 per share. The company has a strong track record of exceeding its guidance, and management typically winds up raising it as the year progresses. The utility will likely continue to benefit from electric and gas volume increases due to elevated power demand, construction initiatives and positive developments in the infrastructure and transmission segments. Profit growth should also be driven by rate relief in Wisconsin. WEC reaffirmed its goal for annual earnings growth of 6.5%-7%. We are maintaining our 2025 profit estimate of $5.25 per share, which is within management's updated target range. Indeed, this would provide an increase of 7% above our 2024 estimate.

WEC Energy agreed to acquire a 90% ownership interest in a Texas solar project for $459 million. The Delilah 1 center in North Texas is one of the largest solar facilities under construction, and will generate renewable energy. Commercial operation of the project is set to start by the end of this month, and will likely be eligible for production tax credits.

This issue is best suited for conservative, income-oriented investors with a long-term investment horizon. The dividend yield of 4.1% stands above the utility average, and total return potential for the next 18-months and 3- to 5-years is attractive versus most of its peers.

Zachary J. Hodgkinson *June 7, 2024*

(A) Diluted EPS. Excl. gain on discontinued ops.: '11, 6¢; nonrecurring gain: '17, 65¢. Next earnings report due early July. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '23: $20.05/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.2%; in IL in '21: 9.67%; in MN in '19: 9.7%; in MI in '23: 9.85%; earned on avg. com. eq., '21: 12.2%. Regulatory Climate: WI, Above Average; IL, Below Average; MN & MI, Average.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	100

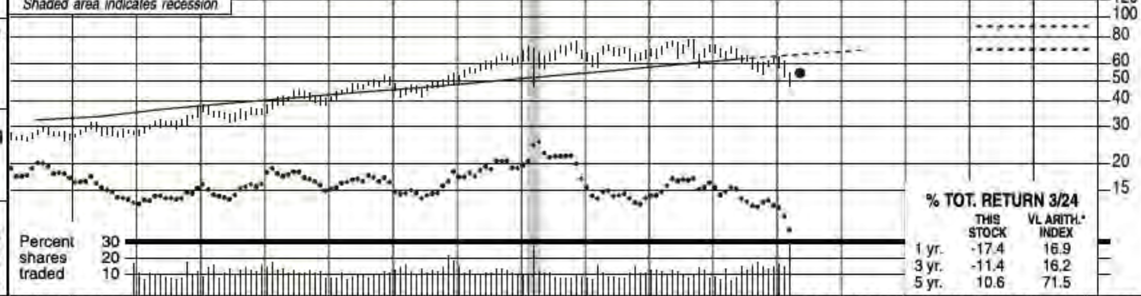
XCEL ENERGY NDQ-XEL

RECENT PRICE **54.08** | P/E RATIO **15.3** (Trailing: 16.2; Median: 20.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **4.2%** | VALUE LINE

TIMELINESS **4** Lowered 12/1/23
SAFETY **2** Lowered 1/19/24
TECHNICAL **4** Lowered 4/12/24
BETA .85 (1.00 = Market)

High:	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	77.7	73.0	64.2
Low:	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	56.9	53.7	46.8

LEGENDS
— 30.3 x Dividends p sh
···· Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$51-$91	$71 (30%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+65%)	17%
Low	70	(+30%)	10%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	426	448	514
to Sell	422	404	387
Hld's(000)	432509	434495	438235

% TOT. RETURN 3/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-17.4	16.9
3 yr.	-11.4	16.2
5 yr.	10.6	71.5

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	27.86	25.60	*27.70*	*28.65*	Revenues per sh	*32.05*
3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	7.81	7.96	*8.60*	*9.25*	"Cash Flow" per sh	*11.25*
1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	3.17	3.35	*3.55*	*3.80*	Earnings per sh A	*4.70*
.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	1.95	2.08	*2.19*	*2.30*	Div'd Decl'd per sh B ■ †	*2.67*
4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	8.44	10.55	*13.25*	*16.40*	Cap'l Spending per sh	*11.65*
15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	30.34	31.74	*33.30*	*35.00*	Book Value per sh C	*41.35*
453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	549.58	554.94	*560.00*	*565.00*	Common Shs Outst'g D	*580.00*
13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	22.2	19.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.22	1.28	1.06			Relative P/E Ratio	*.95*
4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%	2.8%	3.3%			Avg Ann'l Div'd Yield	*3.3%*
						11686	11024	11107	11404	11537	11529	11526	13431	15310	14206	*15500*	*16200*	Revenues ($mill)	*18600*
						1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	1736.0	1851.0	*1985*	*2140*	Net Profit ($mill)	*2725*
						33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	--	--	--	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
						12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	5.9%	7.7%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
						53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	57.8%	58.6%	*60.5%*	*62.5%*	Long-Term Debt Ratio	*62.5%*
						47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	42.2%	41.4%	*39.5%*	*37.5%*	Common Equity Ratio	*37.5%*
						21714	23092	25216	25975	28025	30646	34220	37391	39488	42529	*46975*	*53000*	Total Capital ($mill)	*64200*
						28757	31206	32842	34329	36944	39483	42950	45457	48253	51642	*56225*	*62450*	Net Plant ($mill)	*74000*
						6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	5.5%	5.4%	*5.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
						10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	10.5%	*10.5%*	*11.0%*	Return on Shr. Equity	*11.5%*
						10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.4%	10.5%	*10.5%*	*11.0%*	Return on Com Equity E	*11.5%*
						4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	4.3%	4.3%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
						55%	57%	61%	62%	58%	58%	58%	59%	58%	59%	*61%*	*60%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $26250 mill. **Due in 5 Yrs** $3790 mill.
LT Debt $24913 mill. **LT Interest** $904 mill.
Incl. $218 mill. finance leases.
(Total Interest Coverage: 2.8x)

Leases, Uncapitalized Annual rentals $277 mill.
Pension Assets-12/23 $2690 mill. **Oblig** $2943 mill.
Pfd Stock None

Common Stock 555,155,770 shs.
as of 2/15/24
MARKET CAP: $30.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2021	2022	2023
% Change Retail Sales (KWH)	+1.4	+1.2	-1.6
Resid'l Revs. per KWH (¢)	12.94	13.41	13.80
C & I Revs. per KWH (¢)	8.73	9.02	8.82
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19849	20346	20512
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	262	255	245

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	2.0%	3.0%	*3.5%*
"Cash Flow"	7.0%	7.0%	*7.0%*
Earnings	5.5%	6.5%	*7.0%*
Dividends	6.0%	6.5%	*5.5%*
Book Value	5.0%	6.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	3541	3068	3467	3355	13431
2022	3751	3424	4082	4053	15310
2023	4080	3022	3662	3442	14206
2024	*4100*	*3325*	*4050*	*4025*	*15500*
2025	*4275*	*3475*	*4230*	*4220*	*16200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	1.18	.69	3.17
2023	.76	.52	1.23	.83	3.35
2024	*.80*	*.60*	*1.30*	*.85*	*3.55*
2025	*.85*	*.65*	*1.40*	*.90*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	1.92
2023	.4875	.52	.52	.52	2.05
2024	.52	.5475			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.8 mill. electric, 2.2 mill. gas. Electric revenues: resid'l, 31%; comm'l & ind'l, 50%; other, 19%. Purchases 34% of power, owns 66%. Total electric mix: wind, 29%; gas, 23%; coal, 13%, nuclear, 24%, solar/other, 11%. Fuel cost: 40% of revenues. '23 deprec. rate: 3.6%. Employs 11,311. Chrmn., President, and CEO: Robert Frenzel. Inc.: MN. Addr.: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Int.: www.xcelenergy.com.

Xcel Energy stock is down sharply this year due to the company's role in the recent Texas Panhandle wildfires. There are multiple ongoing blazes in this region under various names with different levels of containment. The utility holding company disputes it's subsidiary acted negligently, but has acknowledged that its equipment had a part in igniting what's being called the Smokehouse Creek fire. That blaze has scorched more than one million acres, destroyed about 80 homes, and caused at least two deaths. Xcel does not believe that its equipment had a part in other contiguous wildfires, such as the Windy Deuce blaze. At one point, the equity was down nearly 25% in value on a year-to-date basis. As the fires have become contained and liabilities reasonably assessed Xcel shares have started to recover, but are still down 13% year to date. These drops are off of what were already discount levels late last year from the pressure higher interest rates unleashed on the rate-sensitive utility sector. We doubt that this unfortunate disaster will result in claims that exceed Xcel's $560 million of liability insurance.

Meanwhile, little has changed on the Marshall Wildfire litigation scene in Colorado. There, Xcel faces 14 complaints with 675 plaintiffs, which have been consolidated into a single case. There were two deaths and nearly 1,100 structures were either damaged or fully destroyed in the December, 2021 fire. The state of Colorado estimated the damages to be over $2 billion. Xcel has $560 million of liability coverage associated with that incident. The company expects to get a litigation calender some time this year with a trial most likely taking place in 2025. Management strongly disputes the findings of Colorado officials regarding Xcel's equipment being a source of ignition.

On an operating basis, this company has been a model of consistency few utilities can match. It almost always delivers solid annual earnings and dividend increases to shareholders. We think the valuation hit the company has taken recently is likely overdone. Although ranked to underperform over the near term, the shares offer significant recovery potential in the 18-month timeframe.

Anthony J. Glennon *April 19, 2024*

(A) Diluted EPS. Excl. nonrec. gain/(losses): '10, 5¢; '15, (16¢); '17, (5¢); '23, (14¢); gain/(loss) on discontinued ops.: '09, (1¢); '10, 1¢. Qtly. EPS may not sum to full yr. due to rounding. Next egs. report due April 25th. (B) Div'ds typically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '23: $2798 mill., $5.04/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	100

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2409

ROE:
Other GDP Growth Rates

August 16, 2024

Congressional Budget Office
Nonpartisan Analysis for the U.S. Congress

The Long-Term Budget Outlook: 2024 to 2054

[The Long-Term Budget Outlook: 2024 to 2054 (cbo.gov)](https://www.cbo.gov)
accessed by Staff June 22, 2024.

Average Annual Values for Key Economic Variables That Underlie CBO's Extended Baseline Projections

Percent

	1994–2023	2024–2034	2035–2044	2045–2054	Overall, 2024–2054
Growth of GDP					
Real potential GDP[a]	2.4	2.1	1.6	1.6	1.8
Potential labor force[b]	0.8	0.7	0.3	0.2	0.4
Potential labor force productivity[c]	1.6	1.4	1.4	1.3	1.4
Real GDP	2.5	2.0	1.6	1.6	1.7
Real GDP per person	1.6	1.4	1.3	1.3	1.3
Nominal GDP (fiscal year)	4.7	4.0	3.7	3.6	3.8
Labor force participation rate[d]	64.8	62.0	61.1	60.8	61.3
Labor force growth	0.9	0.6	0.3	0.2	0.4
Inflation					
Growth of the PCE price index	2.1	2.0	1.9	1.9	1.9
Growth of the CPI-U	2.5	2.3	2.2	2.2	2.3
Growth of the GDP price index	2.2	2.0	2.0	2.0	2.0
Interest rates					
On 10-year Treasury notes					
Nominal rate	3.8	4.1	4.2	4.3	4.2
Real rate	1.3	1.8	1.9	2.1	1.9
On all federal debt held by the public[e]	3.7	3.2	3.5	3.7	3.5

Source: Table 3-1, pg. 24 – Congressional Budget Office (CBO) Long-Term (LT) Budget Outlook (BO) 2024-2054 dated March 1, 2024.

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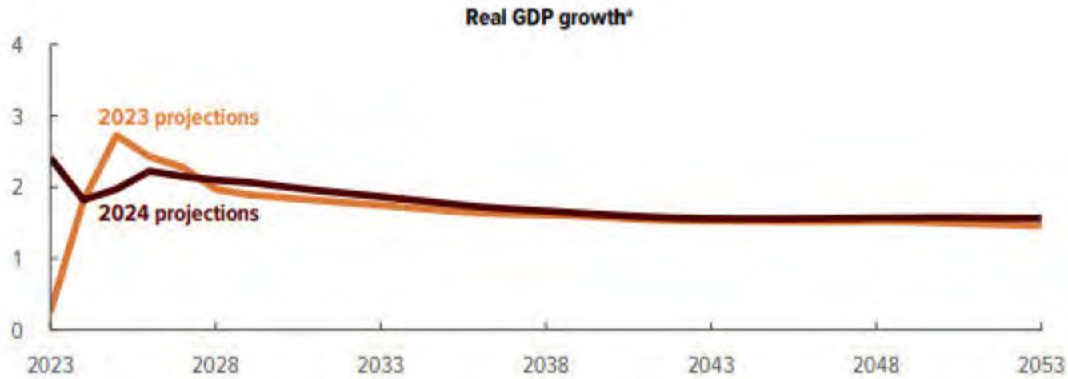

Source: Figure B-1, pg.44 – CBO LT BO 2024-2054 published March1, 2024.

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Average Annual Values for Additional Economic Variables That Underlie CBO's Extended Baseline Projections

Percent

	1994–2023	2024–2034	2035–2044	2045–2054	Overall, 2024–2054
Unemployment					
Unemployment rate[a]	5.6	4.4	4.3	4.1	4.3
Noncyclical rate of unemployment[b]	4.9	4.3	4.1	3.9	4.1
Growth of average weekly hours worked	-0.1	*	*	*	*
Growth of total hours worked	0.9	0.6	0.3	0.2	0.4
Earnings as a share of compensation	81.4	82.4	81.5	80.8	81.6
Growth of real earnings per worker	1.1	1.2	1.0	1.0	1.1
Growth of total factor productivity[c]	1.2	1.1	1.1	1.1	1.1
Growth of labor productivity (real GDP per hour worked)	1.6	1.4	1.4	1.3	1.4

Source: Table C-1, pg.48 – Congressional Budget Office (CBO) Long-Term (LT) Budget Outlook (BO) 2024-2054 dated March 1, 2024.

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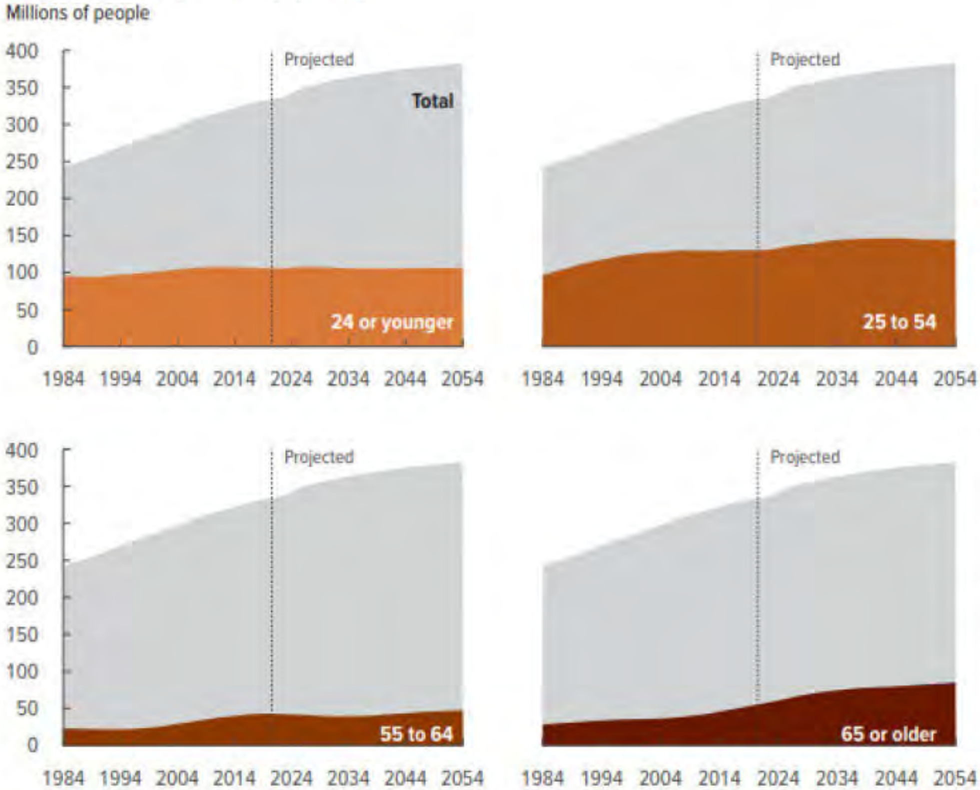
Population, by Age Group



The number of people ages 25 to 54, which particularly affects the number of people employed, is projected to grow more slowly than the number of people age 65 or older, who are less likely to work and who are generally eligible for Social Security and Medicare.

Data source: Congressional Budget Office. See www.cbo.gov/publication/59711#data.

The population referred to in this figure is the Social Security area population, which includes all residents of the 50 U.S. states and the District of Columbia, as well as civilian residents of U.S. territories. It also includes federal civilian employees and members of the U.S. armed forces living abroad and their dependents, U.S. citizens living abroad, and noncitizens living abroad who are eligible for Social Security benefits on the basis of their earnings while in the United States.

Source: Table 3-1, pg.24 – CBO LT BO 2024-2054 dated March 1, 2024.

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Annual Energy Outlook 2023

Release Date: March 16, 2023 – **Next Release Date:** 2025

Narrative 2023 - U.S. Energy Information Administration (EIA)

High and Low Economic Growth cases

The High Economic Growth case and Low Economic Growth case address the effects of economic assumptions on energy consumption modeled in the AEO2023. From 2022 to 2050, the **High** Economic Growth case assumes the compound **annual growth rate for U.S. GDP** is **2.3%,** and the **Low** Economic Growth case assumes a **1.4%** rate. By contrast, the **Reference** case assumes the U.S. GDP annual growth rate is **1.9%** over the projection period.

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2023 Annual Report of the Boards of Trustees of the Federal Hospital Insurance and Federal Supplementary Medical Insurance Trust Funds,
Washington, D.C., March 31, 2023

2023 Medicare Trustees Report (cms.gov)

Table II.F2. – PG 40

Table II.F2.—Average Annual Rates of Growth in SMI and the Economy
[In percent]

Calendar years	SMI: Beneficiary population	SMI: Per capita expenditures	SMI: Total expenditures	U.S. Economy: Total population	U.S. Economy: Per capita GDP	U.S. Economy: Total GDP	Growth differential[1]
Historical data:							
1968–2002	2.2%	11.0%	13.4%	1.0%	6.5%	7.5%	5.4%
2003–2012	2.0	8.4[2]	10.6[2]	0.8	3.2	4.0	6.3[2]
2013–2022	2.5	3.7	6.3	0.5	4.0	4.6	1.7
Intermediate estimates:							
2023–2032	2.0	5.9	8.0	0.6	3.6	4.2	3.6
2033–2047	0.6	4.7	5.3	0.5	3.5	4.0	1.2
2048–2072	0.7	3.7	4.4	0.4	3.6	4.1	0.3
2073–2097	0.4	3.7	4.1	0.4	3.7	4.1	0.0

[1]Excess of total SMI expenditure growth above total GDP growth, calculated as a multiplicative differential.
[2]Includes the addition of the prescription drug benefit to the SMI program in 2006. Excluding 2006, the average annual per capita expenditure increase is 5.6 percent, the total expenditure increase is 7.8 percent, and the growth differential is 3.8 percent.

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2024 **Report** OASDI **Trustees – tr.book (ssa.gov)** **May 7, 2024**

THE 2024 ANNUAL REPORT OF THE BOARD OF TRUSTEES OF THE FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS – https://www.ssa.gov/OACT/TR/2024/tr2024.pdf

Table II.C1.—Key Assumptions and Summary Measures for Long-Range (75-Year) Projections[a]

Assumption	Intermediate	Low-cost	High-cost
Demographic:			
Total fertility rate (children per woman) for years 2040 and later	1.9	2.1	1.6
Annual percentage reduction in total age-sex-adjusted death rates	.73	.28	1.23
Annual net lawful permanent resident (LPR) immigration (in thousands)	788	1,000	595
Average annual net other-than-LPR immigration (in thousands)	457	683	234
Economic:			
Annual percentage change in productivity (total U.S. economy)	1.63	1.93	1.33
Annual percentage change in Consumer Price Index (CPI-W)	2.4	3.0	1.8
Average annual percentage change in average OASDI covered wage (nominal)	3.56	4.79	2.34
Average annual percentage change in average OASDI covered wage (real)	1.14	1.74	.53
Age-sex-adjusted unemployment rate (percent)	4.5	3.5	5.5
Annual trust fund new-issue real interest rate (percent) for years 2041 and later	2.3	2.8	1.8
Programmatic:			
Age-sex-adjusted disability incidence rate (per thousand exposed)	4.5	3.6	5.4
Age-sex-adjusted disability recovery rate (per thousand beneficiaries)	10.8	13.0	8.6

[a] Measures shown in this table are applicable for the last 65 years of the 75-year projection period (years 2034-98), unless otherwise specified. See chapter V for additional details, including historical and projected values.

Table VI.G4.—OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calendar Years 2024-2100

	Percentage of GDP									GDP in dollars (billions)
	OASDI			HI			Combined			
Calendar year	Income[a]	Cost[b]	Balance[b]	Income[a]	Cost	Balance	Income[a]	Cost[b]	Balance[b]	
Intermediate:										
2024	4.59	5.18	-0.59	1.51	1.46	0.06	6.11	6.64	-0.53	$28,599
2025	4.56	5.30	-.75	1.53	1.46	.06	6.08	6.76	-.68	29,710
2026	4.63	5.38	-.75	1.56	1.49	.06	6.19	6.88	-.69	30,942
2027	4.65	5.45	-.80	1.58	1.55	.03	6.23	7.00	-.77	32,271
2028	4.68	5.50	-.81	1.60	1.59	[c]	6.28	7.09	-.81	33,709
2029	4.71	5.54	-.83	1.61	1.65	-.03	6.33	7.19	-.86	35,143
2030	4.75	5.59	-.85	1.63	1.69	-.06	6.38	7.28	-.90	36,589
2031	4.78	5.64	-.86	1.65	1.74	-.08	6.43	7.38	-.94	38,095
2032	4.81	5.68	-.87	1.68	1.78	-.11	6.49	7.46	-.97	39,666
2033	4.84	5.71	-.87	1.69	1.85	-.15	6.53	7.56	-1.03	41,286
2035	4.83	5.78	-.95	1.71	1.91	-.20	6.54	7.69	-1.15	44,714
2040	4.80	5.88	-1.08	1.73	1.99	-.26	6.54	7.87	-1.34	54,472
2045	4.77	5.92	-1.15	1.75	2.02	-.27	6.52	7.93	-1.41	66,240
2050	4.74	5.94	-1.20	1.77	2.01	-.24	6.51	7.96	-1.45	80,633
2055	4.71	6.01	-1.30	1.79	1.99	-.21	6.50	8.01	-1.50	98,265
2060	4.69	6.12	-1.43	1.81	1.99	-.17	6.51	8.10	-1.60	119,677
2065	4.67	6.20	-1.53	1.83	1.99	-.16	6.51	8.19	-1.68	145,501
2070	4.65	6.28	-1.62	1.86	2.01	-.15	6.51	8.28	-1.78	176,496
2075	4.64	6.35	-1.71	1.87	2.01	-.14	6.51	8.36	-1.85	213,925
2080	4.62	6.35	-1.74	1.89	2.01	-.12	6.50	8.36	-1.86	259,673
2085	4.59	6.28	-1.69	1.90	1.99	-.09	6.49	8.27	-1.78	316,061
2090	4.57	6.16	-1.59	1.90	1.96	-.06	6.47	8.12	-1.65	385,337
2095	4.55	6.09	-1.55	1.90	1.93	-.02	6.45	8.02	-1.57	469,420
2100	4.53	6.11	-1.58	1.91	1.89	.02	6.44	8.00	-1.56	570,610

Gross Domestic Product Projections:

The value of real GDP is equal to the product of three components: (1) productivity (i.e., output per hour worked), (2) average weekly total employment,[2] and (3) average hours worked per week, times 52.

Consequently, the growth rate in real GDP is equal to the combined growth rates for productivity, total employment, and average hours worked. For the period from 1969 to 2019, which covers the last six complete economic cycles, the average annual growth in real GDP was 2.76 percent, combining average growth rates of 1.59 percent for productivity, 1.35 percent for total employment, and -0.20 percent for average hours worked.

The real GDP growth rate was -2.2 percent for 2020, 5.8 percent for 2021, 1.9 percent for 2022, and is estimated to be 2.4 percent for 2023 under the intermediate assumptions.

For the intermediate assumptions, the average annual growth in real GDP is 2.0 percent from 2023 to 2033, combining the average growth rates of 1.54 percent for productivity, 0.50 percent for total employment, and -0.02 percent for average hours worked. The projected average annual growth in real GDP of 2.0 percent from 2023 to 2033 is slightly lower than the underlying sustainable trend rate of 2.1 percent over the same period, because the economy is estimated to be slightly above the sustainable trend in 2023.

After 2033, the **annual growth in real GDP** follows the sustainable trend rate and averages **1.9 percent**, which combines the projected ultimate annual growth rate of 1.63 percent for productivity, average annual growth rate of 0.32 percent for total employment, and the ultimate annual growth rate of -0.05 percent for average hours worked per week. The projected growth rate of real GDP is lower than the past average growth rate mainly because the **working-age population is expected to grow more slowly than in the past**.

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OECD English

United States Economic Snapshot – June 2024
United States Economic Snapshot | OECD

Note: OECD GDP per Capita & Productivity Growth still references the 2023 Edition. Staff does not update OECD GDP Growth Rates in its Rebuttal Testimony.

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 2410

ROE: Financial News that Investors in Electric Utilities Are Seeing

August 16, 2024

After Years of Raising Prices, Food Companies Hit Consumers' Limits

by Jesse Newman and Heather Haddon – WSJ – Aug. 1, 2024

Left: Companies dangle $5 burger meals, flakier biscuits to encourage consumer spending and keep profits steady.

Food companies are working on fixes for **consumers fed up with high prices**, while trying to protect some of the biggest profits earned in years.

Restaurant chains this summer are promoting a flurry of deals to keep registers ringing. Food manufacturers are hiking prices at a slower pace, rolling out more discounts and introducing new products, such as "Star Wars"-themed Oreos and Super Mario-shaped mac and cheese.

The companies' moves aim to lure people back to brands that consumers have ditched as prices skyrocketed.

"**We had 3% inflation this year**," **said** Kraft **Heinz** Chief Executive Carlos Abrams-Rivera on Wednesday. "**We're only pricing 1%.**"

Americans in the **past two years spent more of their income on food than** they have **in three decades**. Food prices have become a hot-button issue on the campaign trail as U.S. presidential candidates and other politicians debate economic issues ahead of November elections.

Domino's Pizza CEO Russell Weiner **said restaurants ultimately didn't have** the ability to **increase prices as much as they thought they could**.

"In retrospect the pricing power wasn't there," Weiner said in a recent interview. Domino's, he said, raised prices less than competitors and slower than the overall rate of restaurant inflation.

Food Company Fortunes

Last fiscal year, each of the 10 largest U.S. restaurant chains by market value posted a **profit** that met or surpassed 2019 levels, according to a Wall Street Journal analysis of company filings. For a number of chains including Chipotle Mexican Grill and Darden Restaurants' Olive Garden, restaurant-level profit margins reflecting operating costs as a percentage of sales matched or exceeded 2019 levels, filings show.

Domino's Pizza says it raised prices less than competitors and slower than the overall rate of restaurant inflation.

Big food manufacturers booked similar results. Between 2019 and 2023, annual net profit for the snack giants Hershey and Mondelez International rose 62% and 28%, respectively. General Mills and Kraft Heinz posted 48% increases. Gross margins for many food makers are at or near pre-pandemic levels.

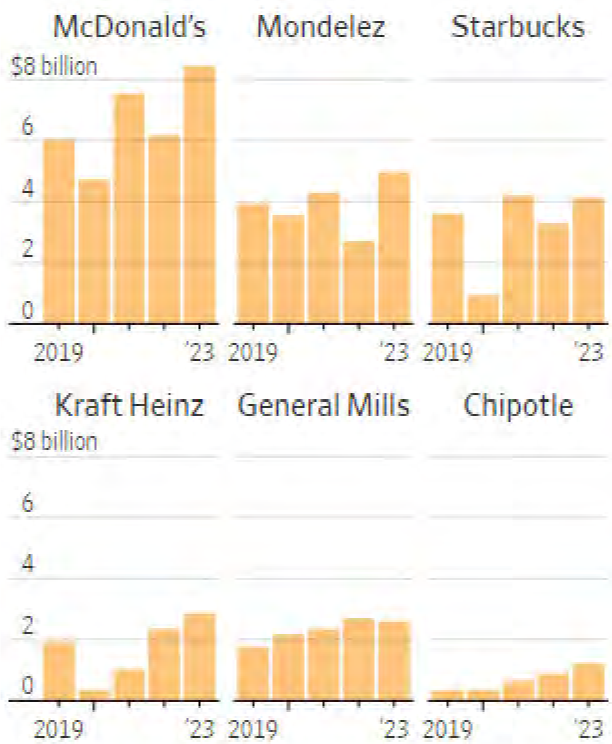
Food companies' earnings have grown in tandem with the broader economy, with quarterly profits last year hitting records, according to Commerce Department data.

"We are coming off a period where companies have enjoyed incredible **pricing power**," said Lydia Boussour, senior economist at the consulting firm EY-Parthenon.

Food executives in recent years have said they increased prices to cover their rapidly escalating costs for labor, ingredients and transportation. Over time, those prices helped offset the companies' higher expenses.

More recently, food companies have benefited from declines in some of those costs as well as from efforts to become more efficient. Many restaurant chains have made gains through technology including kiosks that help process orders without a human at a register.

Annual net profit for major restaurant chains and food manufacturers



Note: The fiscal year for Starbucks ends in late September or early October; General Mills, in late May.
Source: S&P Capital IQ

Food makers have scaled back costly measures they took to keep shelves stocked during the pandemic, such as relying on emergency suppliers and third-party manufacturers. They are also stepping up delayed programs to improve plant operations, investing for instance in automation, said Robert Moskow, a TD Cowen analyst.

Food price politics

Many consumers and politicians have said they are angry about growing corporate profits while household budgets don't go as far as they used to.

Moderators opened June's presidential debate with a question about sharply higher costs for groceries and housing. The Biden administration has criticized tactics including **shrinkflation**, through which companies reduce the size of products but not prices.

Food executives have **said** they **haven't gouged consumers** and are working to keep prices as low as possible. They have said that they need to maintain their profit margins to fund new products and that a number of expenses, such as those for labor and cocoa, surged in recent years and have remained high. Some chains, such as Olive Garden, stress that they are raising their prices below inflation. **Consumers will eventually adjust to higher prices, executives said**.

Still, **more than 70% of consumers believe** that restaurants, supermarkets and food manufacturers are **overcharging**, according to a survey this year conducted by economists at the University of Illinois and Purdue University.

“No doubt they all took advantage of the situation to widen margins,” said Rick Dunphy, a retired bond salesman from Duxbury, Mass. Dunphy said he and his wife are **cutting back** on going to restaurants and **opting** more often **for lower-cost store-brand** condiments, cereal, cookies and crackers.

Top Right: Hershey’s annual net profit climbed between 2019 and 2023.

Value, Value, Value

Restaurant Brands International’s Burger King and McDonald’s kicked off limited-time $5 meal deals in June, and Inspire Brands’ Sonic sought to one-up its burger competitors by launching a permanent $1.99 menu in July.

McDonald’s said Monday that the $5 meal was starting to woo back customers, but that it needed to do more to make its meals affordable. Joe Erlinger, McDonald’s U.S. president, said franchisees’ gross margins were at a 20-year high and could afford to invest in value now. In an internal message Monday, he urged them to do more to back affordable options.

“In order to do better for our customers, we must acknowledge where we are falling short,” Erlinger said in the email, a copy which was viewed by the Journal.

McDonald's said this week that the $5 meal was starting to woo back customers.

Starbucks on Tuesday said it would pump up promotions to try to get lapsed customers to return to its cafes and pay for them through more-efficient operations.

Big food makers are leaning into lower prices to help lift stubborn sales volumes. The snack giant Mondelez said Tuesday that it plans to offer discounts and smaller, less-expensive packs of goods including Oreo, Chips Ahoy and Ritz crackers.

Today, 60% to 70% of Mondelez's products cost more than $4 each, said CEO Dirk Van de Put in June. Three years ago the same portion of products cost less than $3 each.

General Mills said in June that it plans to increase its investment in coupons by more than 20% in the first half of its current fiscal year. The company is also working to improve the taste of some of its biggest brands – making Pillsbury biscuits flakier, Annie's mac and cheese cheesier and Betty Crocker fudge brownies fudgier.

Some food executives and analysts have warned that wooing consumers back will be a slow process or require more investments than companies anticipate.

"It's not one of these events where we sprinkle a little money on the consumer, and they forget that they ever experienced runaway inflation," Conagra Brands CEO Sean Connolly said in July.

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Allete Files Petitions in Minnesota, Wisconsin Seeking Private Buyout Approval

by Dan Lowrey,
Standard and Poor's Global Market Intelligence – Jul. 23, 2024

Allete Inc. tendered its formal **request** for approval by the **Minnesota P**ublic **U**tilities **C**ommission **and** the **Public S**ervice **C**ommission of **Wisconsin** of a transaction in which the **Canada Pension Plan Investment Board and Global Infrastructure Management** LLC will **acquire Allete for $67 per share in cash**, **taking** the Duluth, Minn.-headquartered **company private** in a deal valued at about **$6.2 billion**, **including debt**.

- While other approvals are necessary before the proposed transaction can close, the one that will likely receive the most scrutiny is approval by the Minnesota Public Utilities Commission (PUC). Allete's regulated utility service territory extends into Wisconsin, but its **largest footprint** is in **Minnesota**. The **PUC has discretion over utility mergers**, and the commission's merger review **standard** is **not particularly restrictive**. Pursuant to state statutes, when reviewing proposed **mergers and acquisitions**, the **PUC must consider whether** the **transaction** is "**consistent with** the **public interest**."
- Neither Wisconsin nor Minnesota has evaluated a utility merger of this size in at least five years, but Regulatory Research Associates does not anticipate the proposed transaction is likely to face onerous regulatory hurdles based on each state's merger evaluation criteria and the outcomes of prior merger-related proceedings.
- The commitments outlined in the July 19 application by Allete appear to be largely consistent with those agreed upon in past mergers that have come before utility commissions, including management retention and protections for utility employees.
- RRA considers the utility regulatory framework in Minnesota to be balanced and stable from an investor viewpoint, as recently authorized equity returns typically have approximated industry averages. Wisconsin regulation remains constructive from an investor perspective, in RRA's view. Energy utilities are regulated under a traditional framework, and the most recently authorized equity returns have been above the prevailing national averages when established.

In addition to approval by Minnesota and Wisconsin regulators, the company will also need approval from the Federal Energy Regulatory Commission. The company is requesting public hearings be scheduled in October and November and is **targeting** a **deal closing date** of **mid-2025**, subject to, among other things, the aforementioned state and federal approvals and approval from Allete shareholders.

Transaction overview

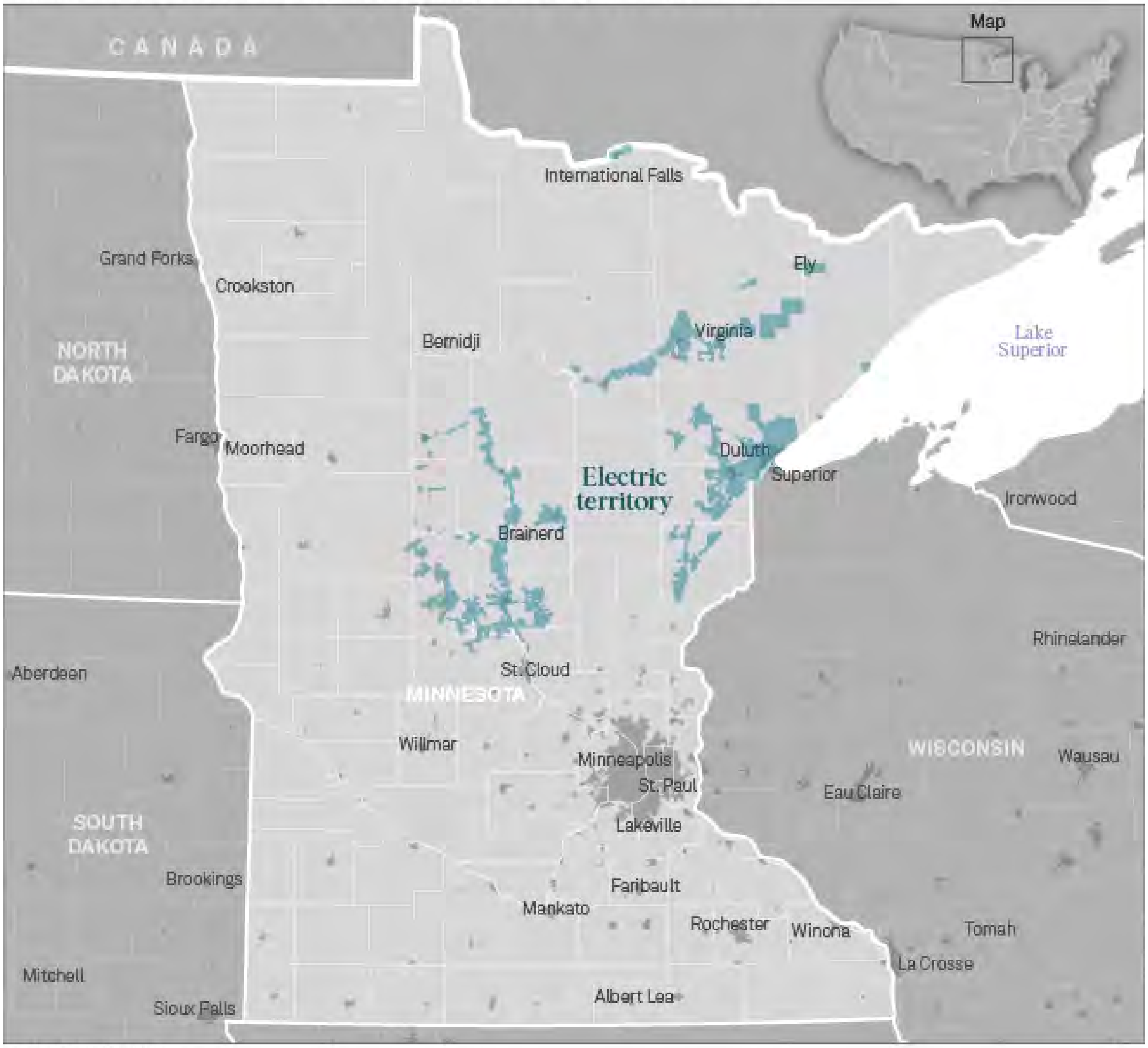
On May 6, Canada Pension Plan Investment Board (CPP) and Global Infrastructure Management (GIP) agreed to acquire Allete for $67 per share in cash. Allete indicated that through the transaction, it will have access to the capital needed to invest in the clean-energy transition and ensure it has access to the significant capital needed for planned investments over the long term.

Allete provides regulated utility electric services in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers, as well as regulated utility electric services in northeastern Minnesota to approximately 150,000 retail customers and 14 non-affiliated municipal customers. Regulated operations include regulated utilities, Minnesota Power Inc. (MP) and Superior Water Light and Power Co. (SWL&P), as well as an investment in American Transmission Co. LLC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois.

Through the acquisition, **Allete will transition to** a **private company wholly owned** by a **new partner-created company** known as **Alloy Parent** LLC, providing Allete with improved access to capital and partner resources that can support Allete's investment in the clean energy transition while continuing the safe, reliable, and affordable electric service to Minnesota Power's customers. Except for a new tax-sharing agreement between the partners, Allete, and MP, commission approval of which will be sought in a separate proceeding after consummation of the acquisition, there will be no changes to the affiliated interest relationships between the Allete entities as a result of the acquisition. **Allete** will **remain** a **stand-alone company** and will have the same relationship with MP and the PUC that it has now.

Allete will **continue** to have its **own board** of **directors** with fiduciary obligations and oversight responsibilities. Further, at least **one member** the **Allete's board** of directors **must be from Minnesota**, **one member** must be **from Wisconsin**, **and** the **board must have at least two independent directors**.

Minnesota Power electric operating territory in Minnesota



As of May 6, 2024.
Map credit: Joe Felizadio.
Source: S&P Global Market Intelligence.

Petition focuses on need to fund company's future investments

"The primary goal of transitioning to a private company is to enable Minnesota Power to obtain the significant additional capital it needs to continue and expand its investment in clean energy technology and systems, including changing transmission and generation needs, and to further its commitment to provide safe, reliable, and affordable energy to its customers," Allete indicated in its July 19 petition with the PUC.

According to its latest annual report, Allete is the largest investor in renewable energy, relative to market capitalization, of all publicly traded utilities in the US.

As a private company, Allete explained that the partners can exercise more patience with respect to quarterly earnings and dividends due to a focus on long-term investments. In another example, well-financed private investors can provide more readily available capital than can be accessed reliably in the public markets. "To these ends, the Company made its own choice to seek out private infrastructure investors, particularly those with expertise in the energy industry, and chose CPP Investments and GIP specifically. The Partners are highly regarded infrastructure investors with deep industry expertise, resources, and strong long-term outlooks," the company indicated.

Allete argued that the acquisition is consistent with the public interest, readily meets the PUC's corresponding public interest standard and will not adversely impact customers, service cost or quality, employees, or communities. The partners do not seek to change the operation of the MP or the regulatory construct in Minnesota. Nor is this a transaction about cutting costs or fundamentally changing cost structures or long-term plans for the MP utility; rather, it is about finding a better way to support the company's ongoing sustainability efforts and achievement of state policy goals, Allete said.

Conditions upon approval

The filing also outlines a list of commitments to ensure that these assertions are met. These are summarized below.

* Company employees: For the two-year period following the acquisition, each Allete nonunion employee who continues employment with Allete as of the effective time of the acquisition will retain extensive protections, including the same or better employment position in the same location and wages, incentive, benefits and employee protections no less favorable than those available to the employee immediately prior to the acquisition.
* Unions: Allete will also continue to honor its union contracts. This includes terms of compensation, benefits and work conditions, among other portions of any applicable union contract. Allete will satisfy all notice, information, consultation, bargaining or consent obligations owed to any labor union, labor organization or employee representative of any union employee in connection with the transactions contemplated by the acquisition.
* Maintaining current management: The company will maintain the current senior management team, subject to changes to account for voluntary departures or terminations in the ordinary course. The company and the partners expect that the current Allete management team, including the managing team of MP, will continue to operate the utility in the normal course, consistent with current management functions.

- * Headquarters: Allete will continue to maintain the MP **headquarters** in Duluth, Minn. SWL&P will continue to be headquartered in Superior, Wis.
- * Community commitments: After the closing, Allete will maintain certain historic levels of economic development and charitable contributions in service territories of Allete and subsidiaries, including MP and the State of Minnesota.
- * **Ring-fencing**: Allete will maintain certain corporate separateness (i.e., 'ring-fencing') commitments with respect to Parent and other upstream entities, including **Allete, and Parent will maintain separate books and records**, agree to prohibition**s against loans or pledges of assets of Allete without regulatory approval**, and **generally hold Allete harmless** from any **business and financial risk exposures**.
- * **No acquisition premium**: MP will not attempt to recover the acquisition premium of the transactions contemplated by the acquisition from its utility customers.
- * **Transaction costs**: MP will not attempt to recover from its utility customers the costs of executing the transactions contemplated by the acquisition. This includes legal fees, goodwill, regulatory filing costs and other costs historically recognized as transaction costs.

Minnesota PUC has approved similar conditions in past utility mergers

The PUC has authority over utility M&A in the state, and the commission's merger review standard is not particularly restrictive. Pursuant to state statutes, when reviewing proposed mergers and acquisitions, the PUC must consider whether the transaction is "**consistent with** the **public interest**." The commission has ruled that this public interest standard **does not require** an **affirmative finding** of **public benefit**, simply that the transaction is compatible with the public interest. There is **no statutory time frame** for the **PUC to act on** a **merger application**.

The most recent major merger of an investor-owned utility in Minnesota occurred in 2019, when the PUC approved a stipulation necessitated by the merger of CenterPoint Energy Inc. and Vectren Corp. Centerpoint Energy Minnesota Gas, a subsidiary of CenterPoint Energy, agreed to refrain from seeking recovery from Minnesota ratepayers of certain transaction costs including costs incurred to structure, negotiate and execute the transaction. The company also agreed to forgo recovery of other costs, including reorganization costs, bonuses paid as a result of the transaction, and the cost of moving employees unless it could demonstrate the costs were prudent and reasonable. The transaction was expected to result in net cost savings over time, with a goal of net cost savings of 2% or more in non-fuel operations and maintenance and corporate costs allocated to Minnesota within five years after the close of the transaction.

Minnesota Public Utilities Commission

Commissioners	Political party	Date began	Term expires	Method of commissioner selection	Commissioner confirmation	Commissioner term	Chairman selection	Chairman term	Minority party rep. required
Katie Sieben*	Democrat	January 2017	January 2029	Governor appointment[2,3]	Senate	6-year staggered terms [4,5]	Designated by governor	Concurrent with governor's term	Yes
Joseph Sullivan**	Democrat	April 2020	January 2026						
John Tuma	Republican	February 2015	January 2027						
Valerie Means	Democrat	April 2019	January 2025						
Hwikwon Ham[1]	Independent	January 2024	January 2028						

As of July 22, 2024.
* Chair; ** vice chairman.
[1] On Oct. 12, 2023, Commissioner Matthew Schuerger announced he would resign from the commission at the end of 2023. Gov. Tim Walz (D), on Jan. 3, 2024, announced the appointment of Hwikwon Ham to serve the remainder of Schuerger's term. Ham's appointment is subject to Senate confirmation.
[2] At least one commissioner must be from outside the Minneapolis/St. Paul area.
[3] According to state statute, the governor is to consider potential commissioners who have experience in law, engineering, public accounting, property and utility valuation, finance, physical or natural sciences, production agriculture or natural resources.
[4] A commissioner may continue to serve beyond the end of this term until a successor is appointed and confirmed.
[5] Any vacancy shall be filled by appointment for the unexpired portion of the term.

Wis. merger authority

The **PSC** has authority over mergers involving Wisconsin utilities and must determine that the merger is in the "**best interests**" of **shareholders**, **ratepayers and** the **public**, that **ratepayers** are **not rendered worse off in any way by** the **merger** and that the **transaction does not diminish** the **commission's authority over** the **utility**.

Under **Wisconsin law**, no person may take, hold or acquire, directly or indirectly, more than **10%** of the outstanding voting securities of a public utility holding company, with the unconditional power to vote those securities, unless the PSC has determined, after investigation and an opportunity for hearing, that the taking, holding or acquiring is in the best interests of utility consumers, investors and the public. This, however, does not apply to the taking, holding or acquiring of the voting securities of any holding company existing before Nov. 28, 1985, if such a holding company provides public utility service.

Wisconsin Energy's acquisition of Integrys Energy Group an instructive comparison

In 2015, the Minnesota PUC and Wisconsin PSC conditionally approved Wisconsin Energy's acquisition of Integrys Energy Group. Regulators in Illinois and Michigan also reviewed and approved the transaction. The $9.1 billion transaction was completed in June 2015, and WEC Energy Group was formed.

Wisconsin Energy was the parent of electric and natural gas utilities Wisconsin Electric Power Co. and Wisconsin Gas LLC. Integrys was the parent of electric and gas utilities Wisconsin Public Service and the gas utility Minnesota Energy Resources. It also owned the gas distribution utilities Peoples Gas Light and Coke and North Shore Gas, which the Illinois Commerce Commission regulated, and electric utility Upper Peninsula Power and Michigan Gas Utilities, which the Michigan PSC regulated.

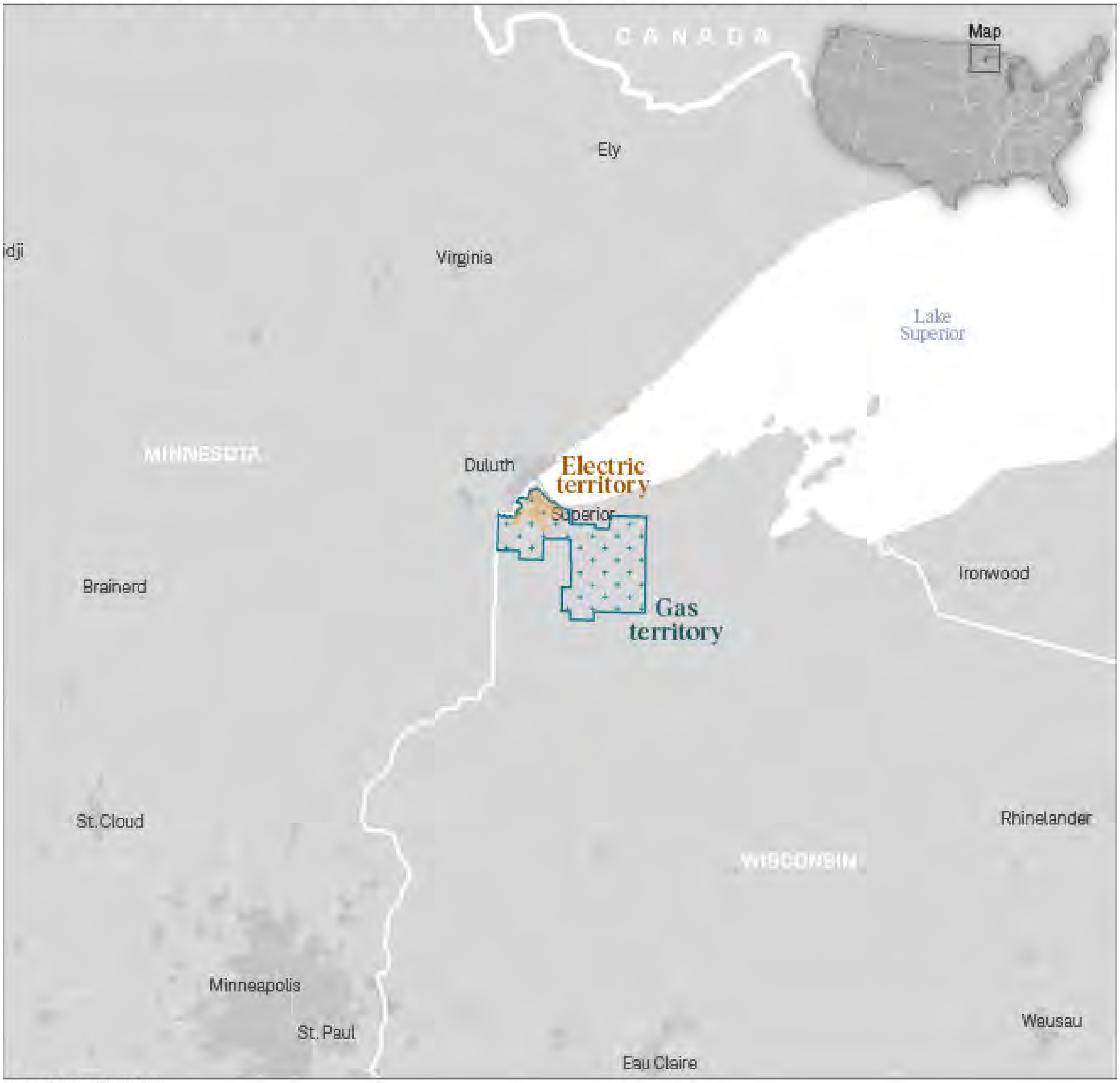
For further details pertaining to that acquisition, please refer to the Financial Focus Company Report entitled Wisconsin Energy/Integrys Energy Group: Acquisition Proposal.

Pending rate case proceedings

MP currently has a rate case proceeding before the Minnesota Public Utilities Commission. On May 3, it announced it reached a settlement with parties to the proceeding that would accord the company an $89.2 million permanent increase in base rates, or a net increase of about $34 million after excluding rolling certain riders into base rates. The proposed rate increase is premised upon a 9.78% return on equity (53.00% of capital structure) and a 7.25% overall return on an average rate base of about $2.37 billion and a test year ending Dec. 31, 2024. The 9.78% ROE in the settlement exceeds national averages tracked by RRA.

SWL&P currently has a rate case proceeding before the Public Service Commission of Wisconsin. However, the requested rate increases fall below RRA coverage criteria. SWL&P seeks a $2.0 million electric rate increase, a $3.4 million gas rate increase and a $1.8 million water rate increase. The company proposes maintaining the current authorized return on equity of 10.0%.

Superior Water Light and Power Co. electric and gas service territory



As of May 8, 2024.
Map credit: Joe Felizadio.
Source: S&P Global Market Intelligence.

Minn. regulatory environment

RRA accords Minnesota regulation an Average/2 ranking, indicating it remains balanced from an investor perspective.

As permitted by statute, significant interim rate increases are usually requested and authorized and, as a result, rate case test years are effectively fully forecast. In addition, adjustment clauses or riders permit the timely recovery of electric fuel, gas commodity, transmission, certain environmental and reliability projects and certain gas infrastructure costs. Utilities are permitted to file rate requests that annually adjust rates for up to five years, and the PUC may authorize two-step interim increases.

In the gas utility industry, large-use customers have been permitted to purchase gas from competitive suppliers for several years, but there is no movement to extend choice to small-volume customers. Legislation has established aggressive renewable portfolio standards and greenhouse gas reduction requirements, but the related compliance costs recovery does not appear to be in question. Also, the PUC has adopted revenue-decoupling mechanisms for several of the state's utilities, and the commission's merger review standard is not particularly restrictive. For more, refer to the commission profile.

Wis. regulatory environment

RRA considers Wisconsin regulation to be constructive from an investor perspective. Energy utilities are regulated under a traditional framework, and the most recently authorized equity returns have been above the prevailing national averages when established. The use of forecast test periods and other constructive financial practices, such as the reliance on comparatively equity-rich capital structures for rate-setting purposes and authorization of a cash return on 50% of construction work in progress, have provided the state's investor-owned utilities a reasonable opportunity to maintain solid credit quality metrics and to earn their authorized equity returns.

The PSC also allows periodic adjustments to reflect expected changes in electric fuel costs that are outside a variance range. The commission has taken an active role in integrated resource planning; thus, before constructing a generating facility, a utility must obtain a determination of need from the PSC, which includes an estimate of the facility's costs. While certain impediments to the construction of new nuclear facilities have been removed, none of the state's electric utilities have plans to develop nuclear generation.

Recent mergers involving the state's major energy utilities have been approved without onerous conditions being imposed. In the gas industry, gas-cost recovery mechanisms are currently in place for local distribution companies, and gas retail choice is effectively available for large-volume customers only. State statutes support the use of settlements between parties in rate cases to expedite the conclusion of such proceedings.

RRA accords Wisconsin energy regulation an Above Average/2 ranking, indicating it is constructive from an investor standpoint. For more information, visit the Wisconsin commission profile page.

For additional detail concerning RRA's energy rankings, refer to the latest RRA "Quarterly State Regulatory Evaluations" report.

Allete Sale Drives US Power Sector's Company-Level M&A Deal Values Higher in Q2

by Selene Balasta and Susan Dlin,
Standard and Poor's Global Market Intelligence – July 12, 2024

The combined value of company-level mergers and acquisitions in the US electric, multi-utility and independent power producer sector surged in the second quarter of 2024 compared with the year-ago period. In stark contrast, the value of asset-level transactions nose-dived.

The combined value of corporate-level M&A deals in the quarter was $6.55 billion through 12 transactions, soaring from $390 million through 10 transactions a year earlier, according to an analysis of S&P Global Market Intelligence data.

Quarter over quarter, the value of whole-company and minority deals also jumped from the first quarter's $2.51 billion across 12 transactions.

However, for individual assets, the aggregate value of second-quarter deals plunged to $310 million through 20 deals compared to $6.03 billion through 37 transactions a year earlier.

Market Intelligence calculates the deal's transaction value from the amount paid for equity and in cash plus the value of assumed current liabilities, net of current assets.

Whole Company, Minority Deals

The biggest M&A deal in the power sector in the second quarter of 2024 was the **privatization of Allete** Inc.

In May, the Canada Pension Plan Investment Board and Global Infrastructure Management LLC agreed to acquire Allete for $67 per share in cash, taking the Duluth, Minn.-headquartered company private in a deal with a total enterprise value of approximately $6.2 billion, including debt.

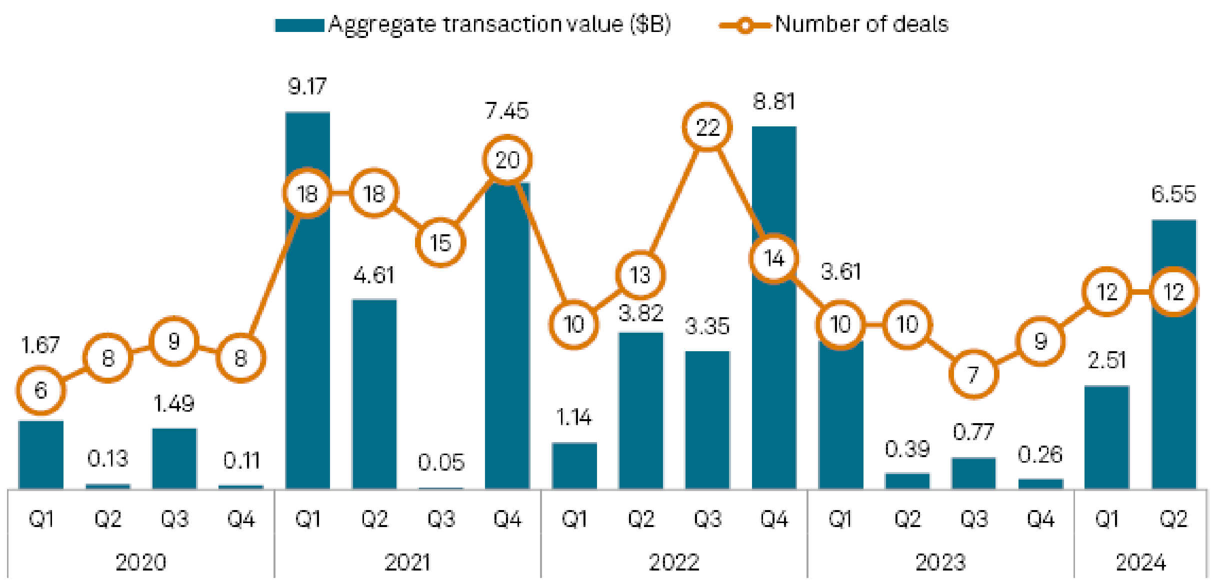
Asset Deals

Among notable asset deals, Innergex Renewable Energy Inc. agreed to sell its minority interest in an 826-MW Texas renewable energy portfolio to investment manager Irradiant Partners LP for C$257 million.

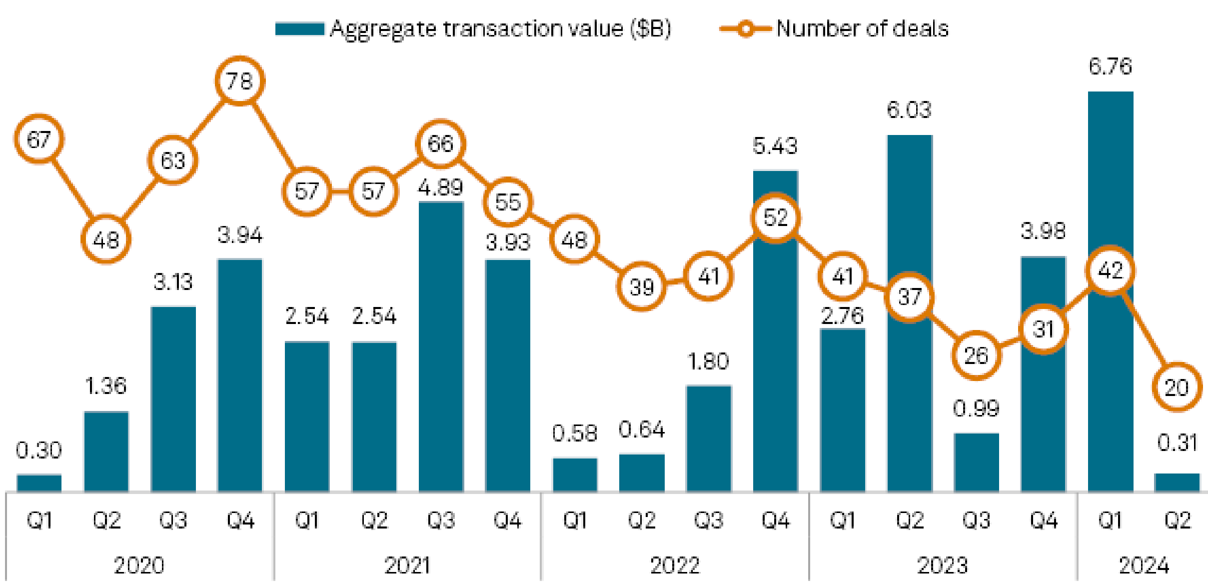
Tables Start on Next Page

US power sector deals since 2020

Whole-company, minority deals



Asset deals



Data compiled July 9, 2024.
Analysis includes US whole-company acquisitions, minority-stake and asset-based M&A deals in which target or assets are identified as electric utilities, multi-utilities, independent power producers and energy traders or renewable electricity.
Transaction values are as of the announcement date.
Transaction value is the deal value paid for equity and in cash plus the value of assumed current liabilities, net of current assets.
Source: S&P Global Market Intelligence.

US power sector whole-company, minority deals announced through Q2 2024

Ranked by transaction value

Buyer	Target	Announcement Date	Announcement Transaction value ($M)
Global Infrastructure Management LLC and Canada Pension Plan Investment Board	ALLETE Inc.	05/06/24	6,232.93
Iberdrola SA	Avangrid Inc.	03/07/24	2,482.41
Basalt Infrastructure Partners LLC	AEP Onsite Partners LLC	05/13/24	315.00
NuRetailco LLC	Via Renewables Inc.	01/02/24	28.30

US power sector asset deals announced through Q2 2024

Largest deals ranked by transaction value

Buyer	Asset(s)	Seller	Announcement Date	Announcement Transaction value ($M)
Stonepeak Partners LP	Coastal Virginia Offshore Wind Project	Dominion Energy Inc.	02/22/24	3,000.00
Global Infrastructure Partners LP	South Fork and Revolution Wind Project	Eversource Energy	02/13/24	1,181.28
City Public Service of San Antonio	Natural gas-fired generation facilities	Talen Energy Corp.	03/27/24	785.00
WEC Energy Group Inc.	Delilah I Solar Energy Center	Invenergy LLC	03/31/24	459.00
Eni New Energy US Inc.	Photovoltaic plants portfolio	EDP Renováveis SA	01/10/24	400.00
Stonepeak Partners LP	Portfolio of Wind Farms	Ørsted A/S	03/13/24	300.00
Ørsted A/S	Sunrise Wind Project	Eversource Energy	01/24/24	230.00
Irradiant Partners LP	826-MW renewable energy portfolio	Innergex Renewable Energy Inc.	06/20/24	188.00
Hannon Armstrong Sustainable Infrastructure Capital Inc.	605-MW renewables portfolio	AES Corp.	01/04/24	143.00
Altus Power Inc.	84 MW of solar assets	Vitol Solar I LLC	01/31/24	118.00
Yinson Holdings Bhd.	97 MW of solar assets in Peru	Grenergy Renovables SA	01/30/24	90.00
Alternus Clean Energy Inc.	Operating solar portfolio	Undisclosed seller	05/01/24	60.00
Clearway Energy Inc.	Dan's Mountain wind project	Dan's Mountain wind project	05/09/24	44.00
Algonquin Power Fund (America) Inc.	Sandy Ridge II Wind Facility	Undisclosed seller	02/15/24	36.20
Clearway Energy Inc.	Rosamond South Solar Storage Project	Undisclosed seller	05/09/24	21.00
Undisclosed buyer	Windsor Locks Thermal Facility	Algonquin Power & Utilities Corp.	03/01/24	17.72
Undisclosed buyer	Two American hydro projects	Charbone Hydrogen Corp.	04/23/24	0.73

Data compiled July 9, 2024.

Analysis includes US whole-company acquisitions, minority-stake acquisitions and asset-based M&A deals announced during the year of analysis with available transaction value, in which target or assets are identified as electric utilities, multi-utilities, independent power producers and energy traders or renewable electricity.

Transaction value is the deal value paid for equity and in cash plus the value of assumed current liabilities, net of current assets.

Source: S&P Global Market Intelligence.

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Berkshire Hathaway's Operating Profit Rises 15%, Cash Level at Record $277 Billion

by Andrew Bary – Barons – Aug. 3, 2024

Berkshire Hathaway's Operating Profit Rises 15 pct, **Cash Level at Record $277 Billion**.

Berkshire Hathaway's after-tax operating profit rose 15% in the **second quarter to $11.6 billion**, driven by higher insurance underwriting profits and increased income on the company's large cash holdings.

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Bond Funds Draw in Record Amounts

by Jack Pitcher – WSJ – Jul. 30, 2024

Investors poised for rate cuts, retirees looking to lower risk drive ETF inflow

The stock market may be roaring, but 2024 has been Wall Street's year of the bond fund.

Bonds are **paying** the **highest yields in a generation**, **and interest rates** are **poised to come down**. Meanwhile, a record number of retirees are looking to cut risk in their portfolios. That combination has investors pouring money into both indexed and actively managed funds. Wall Street is seeing dollar signs.

U.S.-listed fixed-income exchange-traded funds have taken in nearly $150 billion through late July, a record through this point in a year. When looking at mutual funds and ETFs together, taxable bond funds were responsible for nearly 90% of net U.S. fund inflows in the first half, according to Morningstar.

After more than a decade of paltry bond yields, and just two years removed from the worst year for bonds on record, the **combination of high rates and falling inflation offers investors** a **rare opportunity for investment income**. Rick Rieder, who oversees more than $2 trillion as Black-Rock's chief investment officer for fixed income, is calling the current period "the **golden age of fixed income**."

A crucial factor shifting bond prices is investors' expectations for short-term interest rates. When the Federal Reserve began to raise rates in 2022, investors flocked to cash-like investments. Now, as **Wall Street bets** that **rate cuts this year are all but certain**, investors are looking toward bonds instead, grabbing for yields that have already started to descend as bond prices rise.

"We're seeing people move out of cash and into bonds," Rieder said. "Cash has been flipping a lot of yield, but now there's a sense that the Fed is going to start lowering rates and that opportunity won't be there anymore."

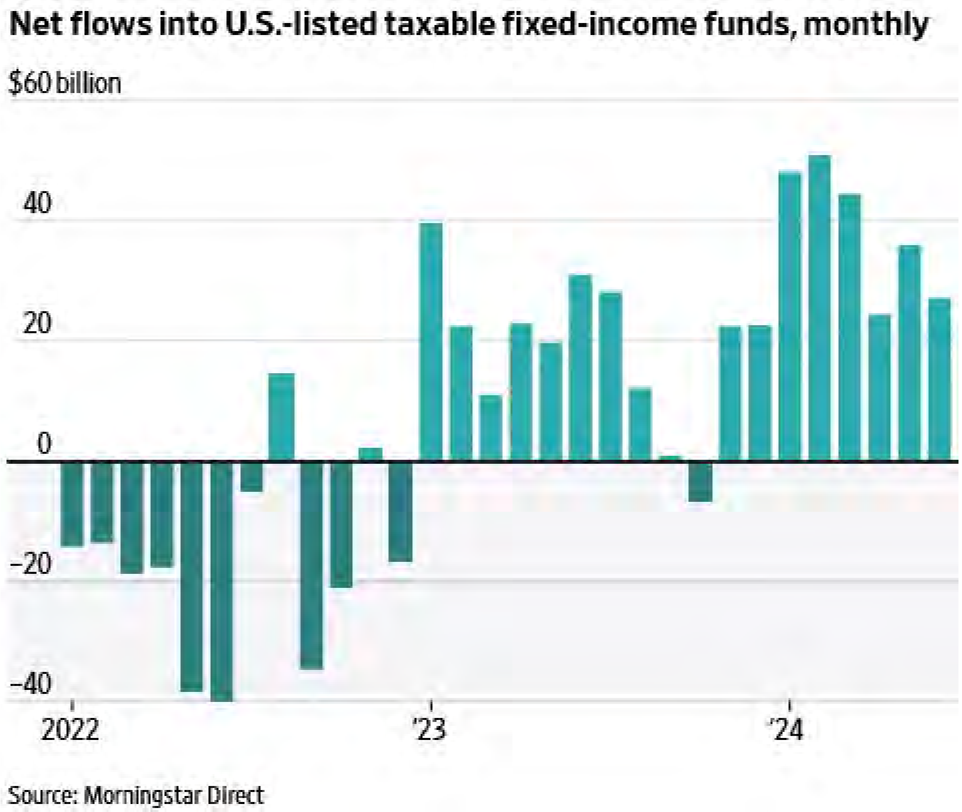
Bond funds have been a bright spot for a money-management industry that has struggled to contend with the growth of passive investing and a steep fall in management fees. While investors have largely begun to shun actively managed stock funds, bond pickers are thriving.

Of nearly 1,700 actively managed bond funds tracked by Morningstar, 74% beat their benchmark indexes during the past year. Active bond ETFs are already at an annual inflow record with five months to go. And money managers are trying to cash in with a host of new active fund offerings. Average ETF fees – long on the decline – actually rose in 2023, according to Morningstar, because so many active funds with higher fees were launched.

Investors big and small are buying a variety of fund categories, some riskier than others. Index-tracking Treasury ETFs have become a favorite tool for Wall Street traders to make interest-rate bets. Investors betting that rate cuts will soon boost bond prices plowed $6 billion into long-term Treasury ETFs in June alone, representing 7% of their assets at the start of the month.

Actively managed funds investing in junk-rated corporate debt with high yields have also raked in money. The most popular active fixed-income ETF this year, Janus Henderson's AAA CLO ETF, invests in collateralized loan obligations – securities made of bundles of low-rated corporate loans.

Many investors are also buying plain-vanilla funds focused on total returns from the highest-rated debt, welcoming the fact that even the safest returns finally feel meaningful.



Todd McConachie, a 62year-old, retired corporate-risk analyst in Portland, OR., said he has moved a substantial portion of his stock-heavy retirement portfolio into bond funds over the past year and a half.

He now owns funds that buy highly rated corporate bonds and higher-yielding junk bonds, along with U.S. Treasurys bought directly through the government's Treasury-Direct platform.

"When rates were so low, I held some total-bond-market index funds and didn't pay much attention, happy to clip coupons and get 3%," McConachie said. "Now it's like, 'Whoa, some of these funds are 7.5% payouts and I can double my cash flow from interest payments.' " All the enthusiasm marks quite the reversal from 2022. **Rising interest rates crushed bond funds**, sending the Bloomberg U.S. Aggregate bond index down a record 13%. Stocks fell, too, stinging investors who had expected bonds to cushion their portfolio during market turbulence. The **classic 60% stocks, 40% bonds portfolio had its worst year since the Great Depression**.

Wall Street thinks that is all done with, and analysts argue that now is the time to get back in before benchmark rates come down again, and with them the payouts on bonds. **Derivatives traders** are now **pricing in** a roughly **100% chance** the **Fed will cut rates in September**, and the **benchmark 10-year Treasury yield** has **dropped more than three-quarters** of a **percentage point since peaking** at around **5% in October.**

“The interest this year has been quite broad-based,” said Matthew Bartolini, head of Americas research for State Street’s ETF business. “**Flows** have been so **large** and to so many different products. They’re **coming from institutions**, **wealth managers and retail traders**.”

Another simple explanation for this year’s big bond-fund numbers: The bull market that has generated windfall gains in people’s stock portfolios, pushing investors to shift some money into bonds to balance out their risks.

“Just because the stock market has been beating up on bonds for so long, people are needing to buy more bond funds when they go to rebalance,” said Ryan Jackson, senior manager research analyst at Morningstar.

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Brookfield Plans Giant Solar-Plus-Storage Project in Oregon

by Garrett Hering
Standard and Poor’s Global Market Intelligence – Aug. 6, 2024

An affiliate of Toronto-based developer **Brookfield** Renewable Partners LP is seeking approval to build a massive solar-plus-storage complex in **central Oregon**, which could easily be the largest such renewable energy-battery hybrid project in the northwestern US.

The up-to-**900-MW Speedway Solar facility**, **combined with 500 MW** of **eight-hour energy storage**, **could start construction** in **early 2026**, Brookfield Speedway Solar Holdings LLC, a subsidiary of Brookfield Renewable US, said in a recent filing to the Oregon Energy Department's facilities siting office.

Brookfield submitted its notice of intent to apply for a site certificate for the facility on July 30. The solar-storage project, proposed within an approximately 14-square-mile site in **Sherman County**, is located on a private land zoned for exclusive farm use. It would **connect to** the **grid** at a **new B**onneville **P**ower **A**dministration **switchyard** to be located **across from** an **existing 500-kV transmission line**.

The Oregon Energy Department said it intends to begin coordination with state agencies and local and tribal governments in early August. Public hearings are anticipated in the fall.

The eight hours of planned **lithium-ion battery storage** goes beyond the typical up to four hours offered by most projects today. The actual size, duration and technology of the battery system "will be refined over the next several years" as the application advances, a company official said in an Aug. 5 email.

Brookfield is exploring different ways to integrate the facility with the central Oregon environment, including through the creation of wildlife corridors and working with local farms "to ensure that the most productive agricultural areas can continue to be farmed, and farming equipment can continue to move through and around the project area," the official said.

The company is also exploring the potential to incorporate **sheep grazing** in the project area, a practice commonly referred to as **agrivoltaics**.

Brookfield did not respond to a request for information on prospective customers for the output from the massive project. **Central Oregon is a top 10 US datacenter market**, with several technology companies acquiring renewable energy in the region.

Brookfield in May announced an **agreement with Microsoft** Corp. to supply more than 10.5 GW of new renewable energy to help power the latter's global energy needs.

Other NW Activity:

Oregon – **P**ortland **G**eneral **E**lectric Co. – A **settlement conference** is to be held **Aug. 19** in Portland General Electric's rate case (Docket **UE-435**). The company supports a $205.1 million rate increase premised upon a 9.75% return on equity (50.00% of capital) and a 7.19% return on a $7.517 billion rate base.

Oregon – **PUC staff supports** a **drastically lower rate increase driven by** downward **adjustments** to **ROE**, **PacifiCorp's wildfire management plan** and a **proposed catastrophic fire fund**, **transmission spending**, and **other** proposed **adjustments**. **Staff believes** that the **company** has **not fully formed or supported** its **wildfire-**related **proposals**.

Washington – **Cascade** Natural Gas Corp. – A settlement conference is scheduled for Aug. 7–8 in MDU Resources Group Inc. subsidiary Cascade Natural Gas's rate case (Docket UG-240008). The company seeks a $55.5 million multiyear base rate hike based on a 10.50% return on equity (50.29% of capital) and a 7.89% return on a $792.0 million rate base. The company is also proposing to establish new rate adjustment tariffs related to its COVID-19 and commission fee deferral balances, with rates effective in March 2025. The total revenue increase associated with the adjustments is about $5.1 million, bringing the rate year one increase to $48.9 million.

Possible case filings

Jurisdiction	Company	Parent (ticker)	Service type
California	Southwest Gas Corp.	SWX	Gas
Missouri	The Empire District Electric Co.	AQN	Electric
Missouri	Union Electric Co.	AEE	Gas
Montana	Cascade Natural Gas Corp.	MDU	Gas
New Jersey	South Jersey Gas Co.	--	Gas
Ohio	Vectren Energy Delivery of Ohio Inc.	CNP	Gas
Oregon	Avista Corp.	AVA	Gas
Oregon	Cascade Natural Gas Corp.	MDU	Gas
Wyoming	MDU Resources Group Inc.	MDU	Gas

As of July 31, 2024.
-- = not publicly traded.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

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Buffett Details Plans to Give Away Fortune

by Karen Langley – WSJ – Jun. 29, 2024

Warren Buffett has refined his plans for giving away one of the great fortunes of the modern era.

In an interview with The Wall Street Journal, Buffett – the chairman and chief executive of Berkshire Hathaway – said that after his death **nearly all** of his remaining **wealth will go to** a **new charitable trust overseen by** his **daughter and two sons**.

The legendary investor also made clear his **giving to** the **Bill & Melinda Gates Foundation**, to which he has donated billions, **will** come to an **end**.

“The Gates Foundation has no money coming after my death,” Buffett said.

The Omaha, Neb., billionaire has already given away more than half his shares of **Berkshire**, the company he took control of in 1965 and built into a powerhouse.

After the **latest round of charitable contributions** unveiled **Friday** morning, **Buffett owns** nearly **$130 billion of** the **company’s stock**.

His three children must decide unanimously which philanthropic purposes the money then goes to serve.

Buffett, who is 93 years old, said he hasn’t laid out marching orders for **Susie**, **Howie and Peter Buffett**. But he shared his personal perspective about giving.

“It should be used to help the people that haven’t been as lucky as we have been,” he said. “There’s eight billion people in the world, and me and my kids, we’ve been in the luckiest 100th of 1% or something. There’s lots of ways to help people.”

Back in 2006, Buffett, who had espoused saving philanthropy until his death, announced that he was ready to give. He pledged to make annual gifts throughout his lifetime to the Gates Foundation and four foundations connected to his family. Less clear was what would happen to wealth that remained after his death.

Buffett told the Journal that his donations to the five foundations will continue only while he is alive.

Buffett said he has changed his will several times. He arrived at the current plan after seeing how his children matured over the years.

Susie Buffett, who is 71, lives in Omaha and **chairs** the **Sherwood Foundation**, which promotes early childhood education and social justice. She **also** **chairs** the **Susan Thompson Buffett Foundation**, named for her mother, Buffett's first wife, who died in 2004. The foundation funds reproductive rights as well as college scholarships, according to tax filings.

Howie Buffett, who is 69 and lives in Decatur, Ill., farms and **heads** the **Howard G. Buffett Foundation**, which works for food security, conflict mitigation and combating human trafficking. Both Susie and Howie Buffett serve on the Berkshire board.

Peter Buffett, 66, a music composer living near Kingston, N.Y., and his wife, Jennifer Buffett, **lead** the **NoVo Foundation**, whose projects include working with indigenous communities.

"I feel very, very good about the values of my three children, and I have 100% trust in how they will carry things out," Warren Buffett told the Journal.

The Berkshire chief executive added that his children will have an advantage over him in responding to any future changes to the laws governing taxes and foundations.

"I like to think I can think outside the box, but I'm not sure if I can think outside the box when it's 6 feet below the surface and do a better job than three people who are on the surface who I trust completely," he said.

Berkshire said Friday that Buffett would convert 8,674 of his Class A shares into Class B shares to make another round of donations.

The **Bill & Melinda Gates Foundation Trust** is **receiving Class B shares worth** about **$4 billion** as of Thursday's closing price, while the **Susan Thompson Buffett Foundation** is **receiving** about **$400 million**.

The **foundations of Buffett's daughter and sons** are **each receiving** more than $**280 million** in **shares**. One Class A share carries the ownership stake of 1,500 Class B shares, and A shares have an even greater advantage in voting power.

In 2006, Buffett wrote letters to each of the five foundations that laid out his planned contributions. He designated an allotment of shares for gifts to each foundation. Six years later, Buffett doubled the pledge to his children's foundations.

Every year, 5% of the remaining shares would be contributed to the respective foundation. That meant the number of shares donated would decline each year, though a rising share price could mean that the value of the gifts would increase. Class B shares are trading at more than six times their price at the end of June 2006, accounting for a 2010 stock split.

But the wording of those letters left some ambiguity about what would become of shares he owned at the time of his death.

The Gates Foundation, one of the world's largest, is known for its work in global health, as well as poverty and gender equality. From 2006 through 2023, Buffett gave the foundation $39.3 billion, according to a fact sheet on its website.

Chief Executive Mark Suzman said the Gates Foundation is grateful for Buffett's donations.

"Warren Buffett has been exceedingly generous to the Gates Foundation through more than 18 years of contributions and advice," Suzman said. "He has played an invaluable role in championing and shaping the foundation's work to create a world where every person can live a healthy, productive life."

Buffett served as a **trustee** of the **Gates Foundation until 2021**; he **resigned** less than two months **after** the **couple announced** their **plans to divorce**. **Melinda** French Gates **recently resigned from** the **foundation**, with her **last day earlier this month.**

Buffett declined to say how long his estate plan had been in place. He described its contours in a November press release about supplemental gifts of Berkshire shares to the four family foundations.

In interviews, Buffett's children said that they have yet to make decisions about how to disburse the billions of dollars.

"We have not talked about what we will do because it seems a little premature," said Susie Buffett. "I can imagine it will be probably some continuation of what we've been doing."

Peter Buffett said their eventual decisions could be affected by everything from stock prices to tax laws to social and political developments.

"There are so many variables, it is impossible really to know what the right decisions will be at the time," he said.

Howie Buffett acknowledged the size of the task ahead of him and his siblings.

"Somebody's going to have to take responsibility for the amount of money he wants to put into a charitable foundation," he said. "I think it's a privilege to do it."

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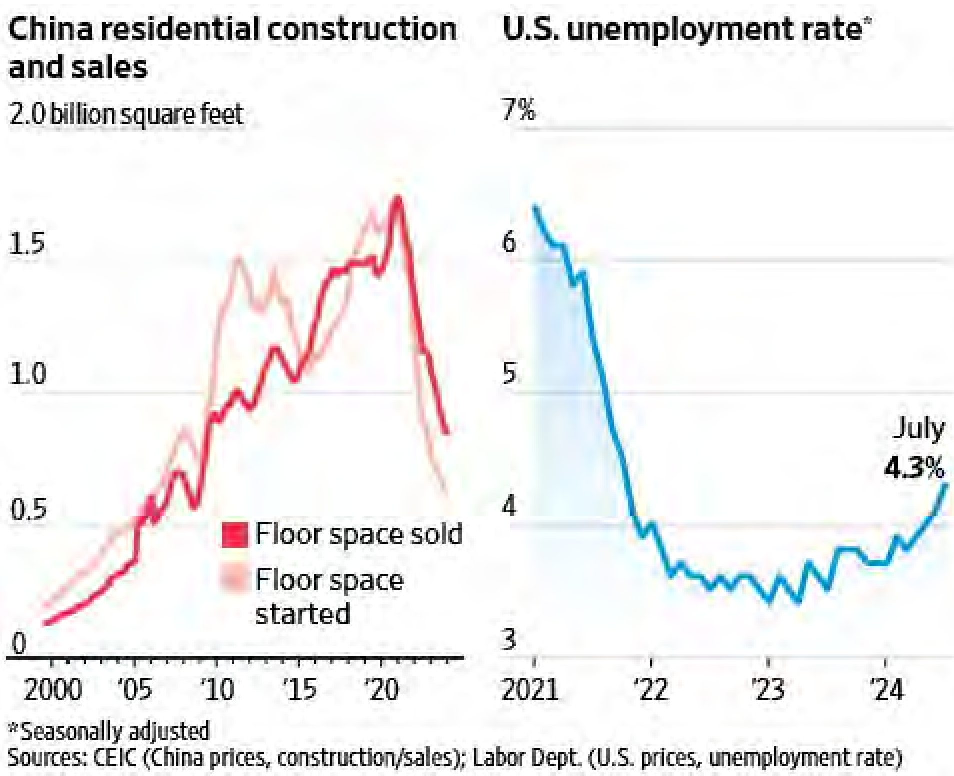
China, U.S. Consumer Pullback Rings Alarm in Executive Suites

by Natasha Khan and Theo Francis – WSJ – Aug. 5, 2024

Midway through the year, leaders of some of the biggest companies are seeing signs of troubles in the world's two biggest economies.

From McDonald's to Mercedes-Benz, executives are saying that many **consumers in China and** the **U.S.** are **pulling back on spending.** The reasons are different. In **China**, demand is being drained by a broken **housing market**, **wage** pressures and **worries** about a darkening economic storm.

In the **U.S.**, some **households**, especially those **with lower incomes**, are feeling **pinched after** a run of **high inflation**. The Labor Department reported that hiring slowed in July and the U.S. unemployment rate ticked up to 4.3%.



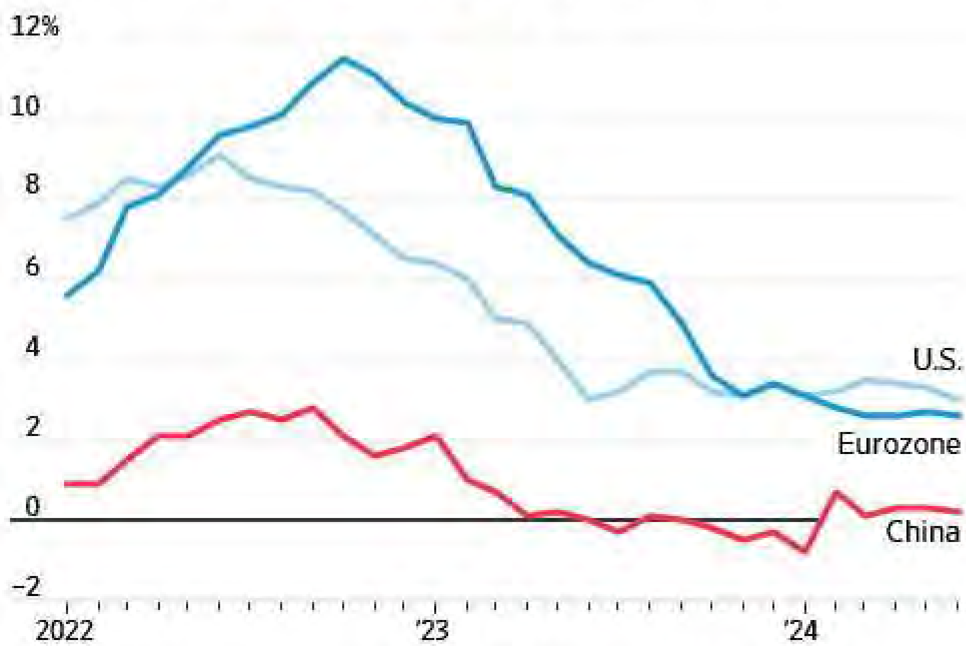
"With a large chunk of world consumer spending under pressure, companies now need to be more creative about avenues to generate revenue growth," said Gregory Daco, chief economist at Ernst & Young.

If consumer spending in the U.S. does falter, it would be a double whammy for multinational companies, which have been confronting weak demand in China for several quarters. As they report second- quarter results, a parade of companies have warned of softening sales and lowered their earnings forecasts, citing troubles in both countries.

So far, corporate profits have held up, propped up in part by stock buybacks. Overall, year-over-year growth in second-quarter earnings per share for the S&P 500 is on track for 12.4% on revenue growth of 4.9%, according to estimates from financial-data provider LSEG.

PepsiCo sounded an early alarm on consumer spending in both the U.S. and China. For the **past few years as prices soared**, **many consumers kept buying Doritos and Lay's while forgoing bigger splurges like restaurant meals or travel**. **Now** they are **giving up potato chips, too,** PepsiCo said. The company's Frito-Lay North America business reported a 4% drop in sales volume in the latest quarter.

Consumer prices, change from a year earlier



Sources: CEIC (China prices); Eurostat (Eurozone prices); Labor Dept. (U.S. prices)

In China, meanwhile, people are becoming increasingly wary about spending money, said Ramon Laguarta, PepsiCo's chief executive. "The consumer is clearly saving more than spending," he said on a July 11 call with analysts.

Shares in Heineken sank 10% July 29 after the Dutch brewer reported weaker-than expected earnings and wrote down the value of a big investment in China. Shares fell for Procter & Gamble the following day, after the maker of Tide detergent and Charmin toilet paper reported an unexpected 7% decline in earnings.

P&G said price hikes had slowed to just 1% globally, while sales from China's recent 618 shopping festival, an annual online shopping event, suggested that consumers there were spending less even with significant discounts from retailers.

"I've said many times: This will not be a straight line," P& G CEO Jon Moeller said. "There's still more work to do to continue improving areas in our control, which will be needed to offset the headwinds that are largely not in our control."

Although inflation measures are **moderating in** the **U.S.,** many **consumers** are **feeling** the **cumulative impact** of **years** of **rising prices for essentials** like groceries and menstrual products. **High borrowing costs** and **sharp increases** in **insurance costs** are putting further **pressure on household budgets**.

McDonald's reported a **slowdown** in **visits by lower income consumers**, a trend that the company said began last year and has deepened across the U.S. The burger giant reported a nearly 1% drop in same-store sales in the June quarter, the first such decline since 2020.

Inflation isn't a problem in China, where companies have struggled to raise prices for several years due to weak demand. Instead, economists said, Chinese spending is slowing because people are saving income to protect themselves in case of future hardship as they face a profound property slump and worries about where the economy is headed.

"U.S. households can look forward to lower interest rates in future," said Mark Williams, chief Asia economist at Capital Economics. "China's government has promised to do more to support consumers but there's nothing in the pipeline suggesting that much of a turnaround is likely."

China's retail sales growth, a gauge of consumption, slowed to 2% year over year in June from 3.7% in May. Chinese leaders said July 30 they would take more aggressive steps to boost consumer spending.

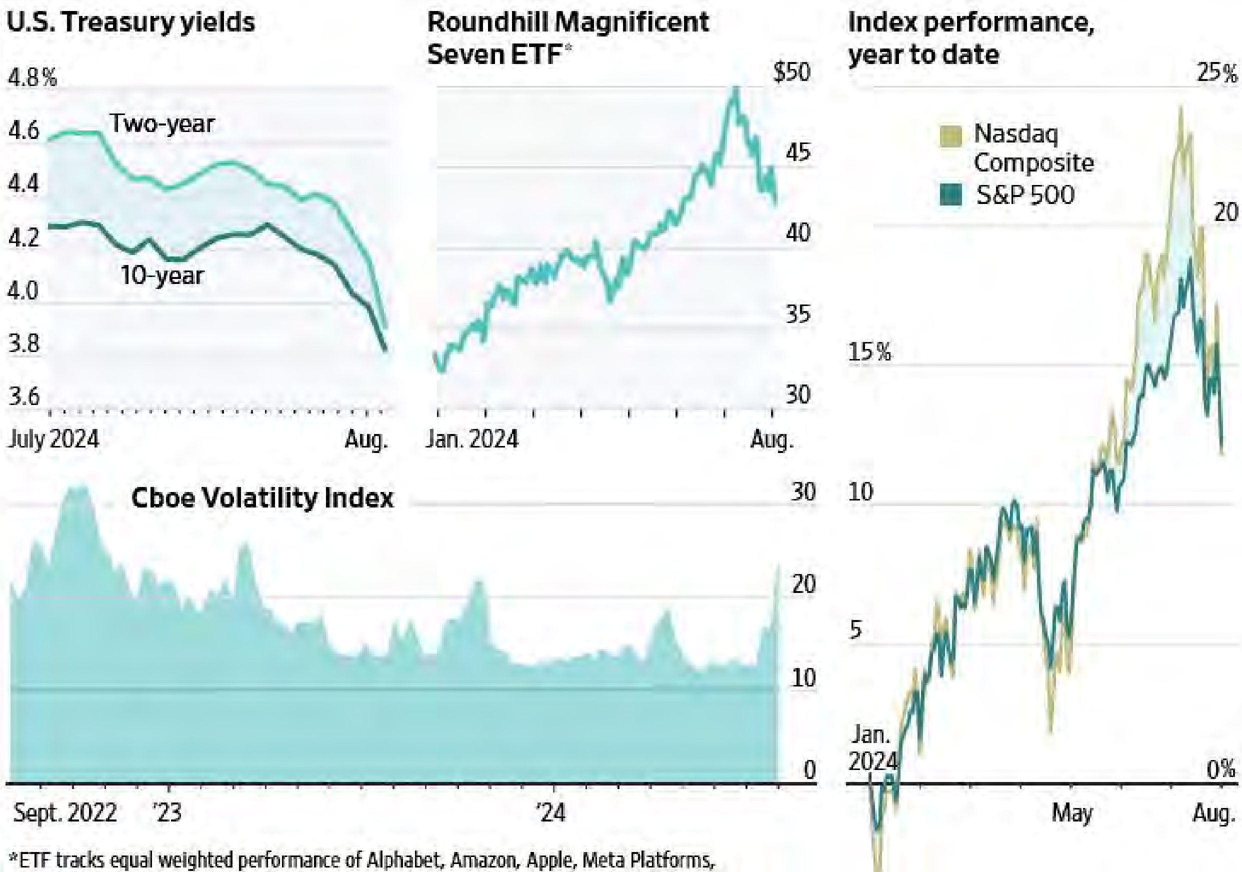
Botox maker AbbVie said headwinds in China hurt sales for its aesthetic pharmaceuticals division in the June quarter and lowered its outlook for those products in both the U.S. and in China. Starbucks said that its U.S. same-store sales declined 2% in its June quarter, the second consecutive decline. And in China, its same-store sales fell 14% as the coffee chain faced heightened competition from lower-cost rivals.

General Motors said strength in the U.S. market was offset by further erosion in China, where it lost money for the second straight quarter amid stiff competition from homegrown brands. Mercedes-Benz and Porsche both flagged a tougher environment and fiercer competition, in China.

Apple, too, is facing inroads from a Chinese champion, smartphone maker Huawei. The iPhone maker said revenue in the greater China region, its third-biggest market, fell more than 6% in the June quarter from the prior year.

But not all Western companies are reporting a slowdown in the country. Domino's Pizza said it still sees the country as an opportunity; its Chinese franchisee plans to open its 1,000th store there this year.

"The China stores, they've actually put out releases talking about their new store openings and the kind of record sales they're generating over there," Sandeep Reddy, the restaurant chain's chief financial officer, said on an earnings call. "So, very exciting to see the growth coming from China."



*ETF tracks equal weighted performance of Alphabet, Amazon, Apple, Meta Platforms, Microsoft, Nvidia and Tesla
Sources: Tullett Prebon (yields); FactSet (ETF, index performance, VIX)

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Court Vacates FERC Orders Calling for Refunds During 2020 Western US Heat Wave

by Tom Tiernan
Platts, Standard and Poor's Global Market Intelligence – Jul. 11, 2024

The **F**ederal **E**nergy **R**egulatory **C**ommission **needs to use** a **more strict standard when examining whether** it **should order refunds to electric utility customers during periods** of **soaring power market prices**, the **US Court of Appeals** for the **District of Columbia Circuit ruled July 9**.

In a case involving escalated prices during a 2020 heat wave in the Western US, the court determined that the commission should have applied the **Mobile-Sierra doctrine** when weighing whether refunds were warranted for deals reached at prices above a $1,000/MWh price cap. In **vacating and remanding** the orders at issue, the court said **FERC** "**necessarily will need to change its refund analysis** for above-cap sales going forward."

Under the **Mobile-Sierra doctrine, FERC must presume** that a **rate** in a **freely negotiated wholesale energy contract meets** the "**just and reasonable**" **rate requirement** of the **Federal Power Act**. That **presumption can be overcome only if FERC concludes** that a **contract** "**seriously harms** the **public interest**."

At issue before the court were a series of 2021 orders released in the aftermath of an extreme heat wave in the Western Electric Coordinating Council and the California ISO regions during August and September 2020. Under a "soft" price cap in place for certain short-term electricity sales that takes place in those regions, power sellers must justify to the commission any transactions that exceed the price cap or provide refunds.

FERC ultimately determined that some sellers failed to do so for their sales that exceeded the cap during the heat event and ordered partial refunds. In making that determination, the agency said the Mobile-Sierra doctrine did not apply because it was not modifying the contracts. Since the sales took place pursuant to the sellers' market-based authority, FERC said the sales were governed by their market-based rate tariffs and the associated restrictions on those sales, including the soft price cap.

Former Commissioner James Danly dissented from the refund orders, arguing the Mobile-Sierra doctrine should apply to those sales and that no showing had been made that the public interest had been seriously harmed.

In asking the DC Circuit to review the orders, several of the power sellers involved in the challenged cases – **Shell Energy** North America LP, **Tenaska** Power Services Co., **Tucson Electric** Power Co., **BP** Energy Co. Inc. **and** the energy trading arm of **Macquarie** Group Ltd. – **argued** that the bilateral deals reached above the price cap were at prevailing market prices and **subject to** the **Mobile-Sierra doctrine**.

The court's ruling

The court agreed with the sellers. "There is no dispute in this case that the rates for which FERC ordered refunds were rates for which the sellers and their customers had mutually contracted in a competitive marketplace," the court said in a per curium decision.

And even assuming that the order establishing the soft-cap was incorporated into the sellers' tariffs and contracts, the court ruled that "the commission did not displace the Mobile-Sierra presumption in the soft-cap order itself, and so that presumption continues to apply to the sellers' contracts."

The court acknowledged that the so-called soft price caps in the West are intended to ensure rates are just and reasonable, with provisions that require prices exceeding the caps to be justified and allow refunds when justification is deemed to be insufficient.

"But the mere invocation of the phrases 'just and reasonable' and 'justification and refund' does not alone suggest that the commission intended to remove prospectively an entire class of bilateral contracts from the Mobile-Sierra framework," the court said. "Importantly, the soft cap is best viewed as a means of flagging for the commission contracts that may warrant a public-interest analysis."

The decision also dismissed as moot additional challenges by the California Public Utilities Commission and Edison International subsidiary Southern California Edison Co., which argued that FERC committed errors in calculating the refunds ordered. In different refund reports filed with FERC in 2021, the refunds amounted to roughly $500,000 for Shell Energy North America, $350,000 for Mercuria Energy America LLC and $300,000 for Tucson Electric Power.

Until FERC engages in the required analysis as directed by the court, the precise methodology for calculating any refunds is an academic question that the court did not need to address in its ruling, it concluded.

Judges Sri Srinivasan, Patricia Millett and Cornelia Pillard handed down the per curium ruling. Shell Energy North America v. FERC (No. 22-1116)

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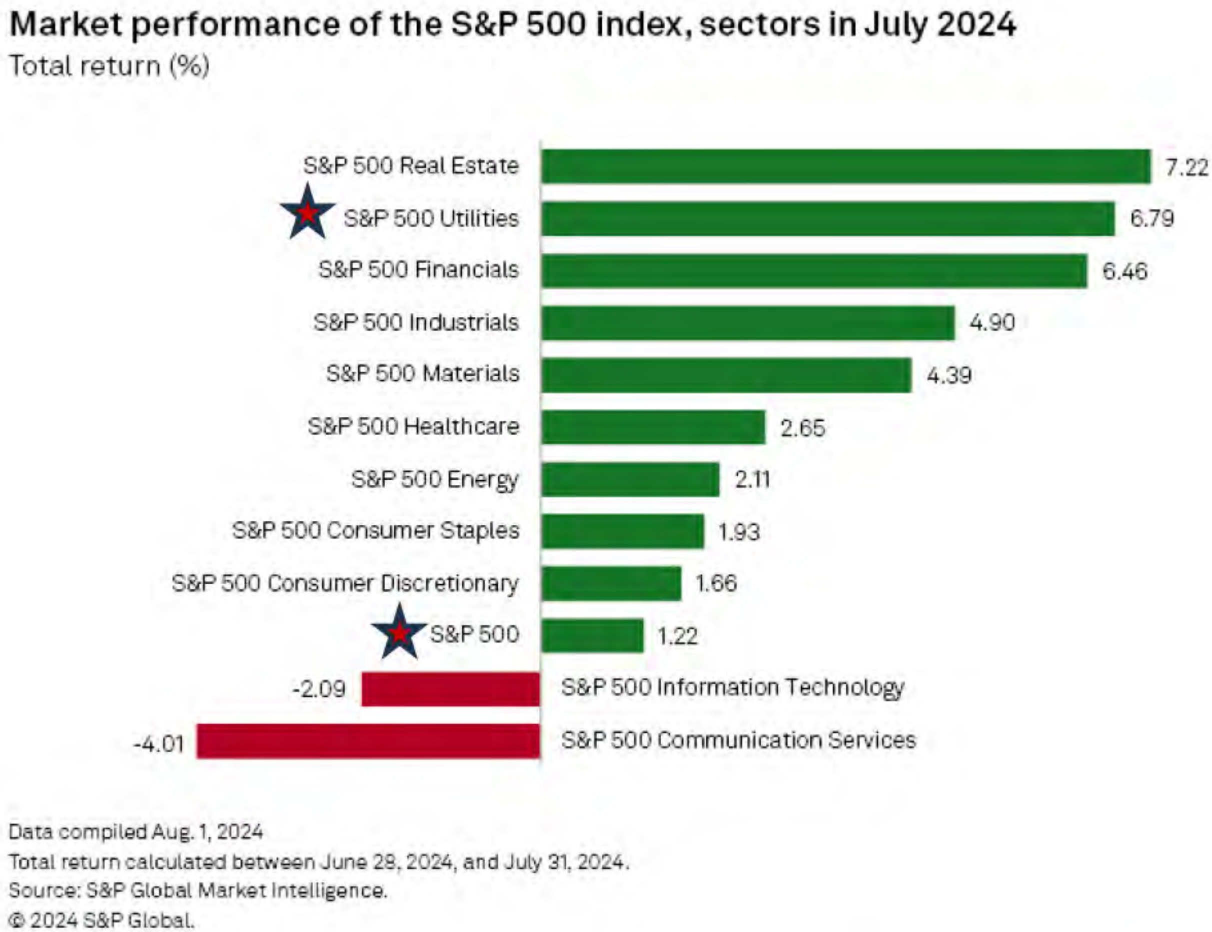
Energy, Utilities Outpace Broader S&P 500 in July

by Shambhavi Gupta
Standard and Poor's Global Market Intelligence – Aug. 6, 2024

Energy and **utility stocks outperformed** the **broader S&P 500 index** in **July** as both sectors recovered from negative returns in the prior month.

The S&P 500 received a late push July 31 after Fed Chairman Jerome Powell said monetary policy officials could be ready to lower benchmark interest rates in September after more than a year of holding them at their highest level in decades.

The S&P 500 Utilities index gained 6.79%, the S&P 500 Energy index rose 2.11% and the S&P 500 index inched up 1.22%.



Eversource Energy emerged as the best-performing utility company in **July**, with a total stock return of 14.5%. The company **completed** the **sale** of its **50% stake** in the planned 924-MW **Sunrise Wind offshore project to Ørsted** A/S for **$230 million**.

Edison International, which saw a positive stock return of 12.6%, is revising the 10-year power demand forecast for its Southern California service territory.

American Electric Power Co. Inc. logged a stock return gain of 11.8%. The company continues to see strong load growth expectations materialize and will soon update its capital spending plan. American Electric Power is also suing GE Vernova Inc subsidiary GE Renewables North America LLC for supplying hundreds of allegedly defective wind turbines.

Pinnacle West Capital Corp. and Ameren Corp. also posted double-digit percentage increases in their stock returns.

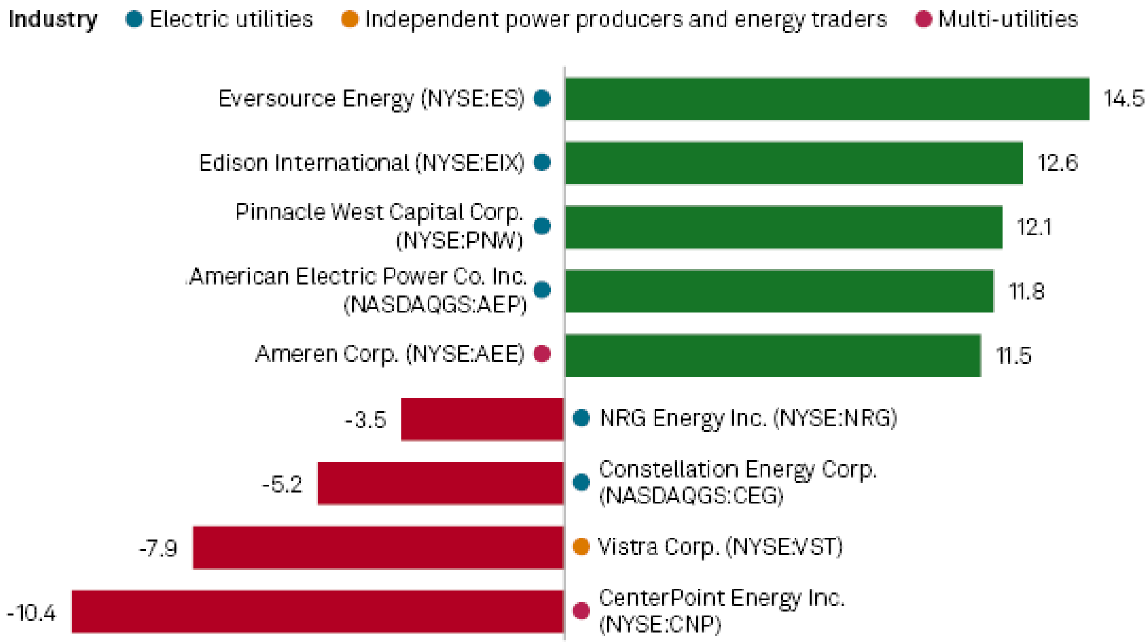
Among laggards, **CenterPoint** Energy Inc. recorded a negative stock return of 10.4% in July. Texas Gov. Greg Abbott directed state regulators to investigate CenterPoint's response to Hurricane Beryl since hundreds of thousands of its customers remained without service a week after the hurricane made landfall. CenterPoint executives touted the company's restoration efforts but promised to do better in future storms.

Vistra Corp. saw a negative stock return of 7.9%. The US Nuclear Regulatory Commission granted Vistra a license renewal to operate the 2,460-MW Comanche Peak nuclear power plant in Texas for an additional 20 years.

Constellation Energy Corp. and NRG Energy Inc. also joined the list of bottom-performing utility stocks for the recently ended month.

Top and bottom performers of S&P 500 Utilities index in July 2024

Total return (%)



Data compiled Aug. 1, 2024
Only four of the S&P 500 utilities index companies had a negative return during July 2024.
Analysis limited to S&P 500 Utilities constituents at July 31, 2024.
Total return calculated between June 28, 2024, and July 31, 2024.
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence.

In the energy sector, Baker Hughes Co. outpaced its peers and booked a positive stock return of 10.1% in July. Baker Hughes reported second-quarter adjusted net income attributable to the company of $568 million, a 44% increase from $395 million in the same quarter of 2023.

Kinder Morgan Inc., which saw a 7.8% total stock return, reported a net income of $575 million in the second quarter, down from $586 million a year earlier.

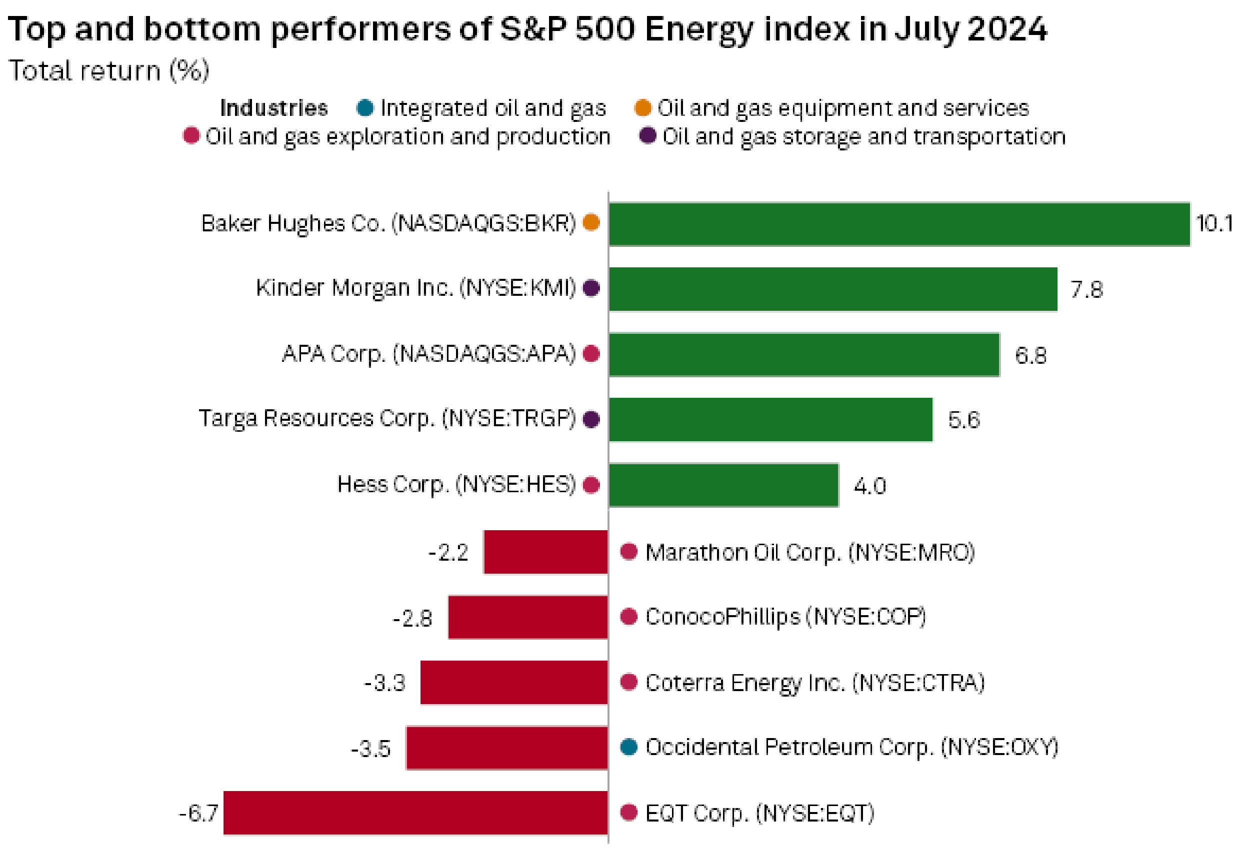
Hess Corp. logged a gain of 4%. A hearing has been set for May 2025 for arbitration related to Chevron Corp.'s proposed $53 billion takeover of Hess, which has been delayed over a claim to a right of first refusal by Exxon Mobil Corp. regarding a Hess-owned share of an oil production asset in Guyana.

APA Corp. and Targa Resources Corp. also logged positive stock returns in the month.

On the flip side, EQT Corp. recorded a negative stock return of 6.7%. EQT completed its all-stock acquisition of Equitrans Midstream in July. Company executives said that by the end of 2024, EQT would save an estimated 60 cents per Mcfe in expenses instead of paying Equitrans Midstream Corp. to gather and transport gas.

Occidental Petroleum Corp., which saw a 3.5% negative stock return, is selling certain Delaware Basin assets in Texas and New Mexico to Permian Resources Corp. for $817.5 million.

ConocoPhillips slid 2.8%, while Marathon Oil dipped 2.2%. In July, the Federal Trade Commission requested additional information from both companies on their proposed $17 billion merger.



Data compiled Aug. 1, 2024
Analysis limited to S&P 500 Energy constituents at July 31, 2024.
Total return calculated between June 28, 2024, and July 31, 2024.
Industries are classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence.

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Finance Chiefs Lean on Commercial Paper to Trim Costs, Prepare for Rate Cuts

by Kristin Broughton – WSJ – Aug. 9, 2024

Some companies are issuing the short-term debt to reduce interest expenses as the Fed looks set to lower rates.

Prologis during the second quarter began to reap savings from a $1 billion commercial paper program that the warehouse giant launched in March.

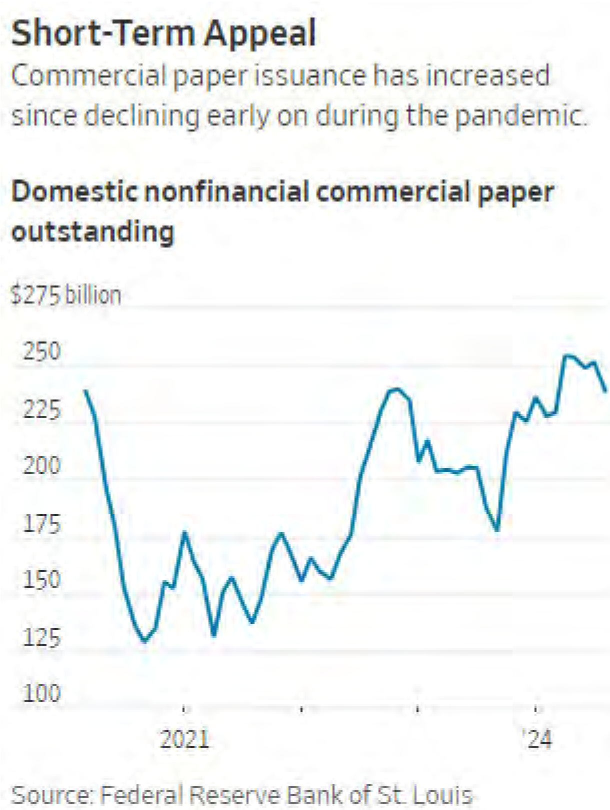
Finance chiefs are **issuing** debt in the **commercial paper** market **to save on interest** costs and **prepare** their **balance sheets for** a **likely rate cut from** the **Fed**eral Reserve.

The short-term debt appeals to big, highly rated companies because it can quickly capture the benefit of falling interest rates. As commercial paper has a **short maturity**, typically ranging from days to months, companies reissue this type of debt frequently and, when rates fall, can do so at a lower cost. Commercial paper also can provide a **less expensive alternative to bank loans**.

Companies issue commercial paper to fund working capital, weather seasonality in their cash flow or provide a bridge between long-term capital raises. Corporate bond sales this week, notably, have been strong despite volatility in the market on Monday stemming from fears about the economic outlook.

Issuance in the commercial paper market has broadly picked up since plunging during the pandemic, amid the initial economic shock caused by Covid and a surge in corporate bond issuance. As of Aug. 7, the **amount of domestic commercial paper outstanding from nonfinancial companies increased 27% from** a **year earlier**, to $238.7 billion, **according to** the **Fed**eral Reserve.

Commercial paper programs are **typically cheaper than credit facilities** from a bank. Chief financial officers carrying a balance on their credit lines determine whether the savings from a commercial paper program outweigh the fixed costs, which can include obtaining a credit rating and administering the program.



Some CFOs, particularly in the real-estate sector, are deciding it's worth the price. Prologis during the second quarter began to reap savings from a $1 billion commercial paper program that the warehouse giant launched in March. The program provided interest expense savings because, over the past few years, Prologis had been carrying a balance on its revolving lines of credit of between $500 million and $1 billion, after previously keeping those facilities unborrowed.

Once a company carries balances that are high enough, the savings behind a commercial paper program can "overwhelm all of the fixed costs," said Chief Financial Officer Tim Arndt. "And that's the mode we've been in lately."

With its new commercial paper program, Prologis is saving about a 0.6 percentage point compared with using its credit lines, Arndt said. The company should save millions of dollars a year by opportunistically shifting balances to its commercial paper program, he said.

The **Fed has laid** the **groundwork to cut interest rates** at its next policy meeting in **September**, with many investors expecting as much as a half-percentage-point reduction after Friday's weak jobs report and Monday's market rout. The **price** that companies pay to issue **commercial paper usually varies alongside** the **secured overnight financing rate**, or **SOFR**.

Colgate-Palmolive during the first quarter used commercial paper to fund the repayment of a $500 million bond. The consumer staples company has about $8.7 billion in total debt outstanding, including $1.6 billion in commercial paper, according to S&P Global Market Intelligence.

"At some point, we expect interest rates will come down…and that will help us keep our fixed-floating back in balance," CFO Stanley Sutula said on an April 26 earnings call, discussing why Colgate-Palmolive chose to pay off the bond with commercial paper.

A risk of issuing commercial paper is the possibility of a **market shock** that could reduce investor demand and leave companies with unexpected liabilities, credit analysts said. **To guard against this risk**, **companies keep** a **portion** of their **credit lines undrawn as** a **backup**.

In March 2020, at the beginning of the pandemic, the Fed intervened in the market to ensure companies could continue to borrow.

Office developer and owner BXP in April added a $500 million commercial paper program. With the Fed poised to cut rates, the company expects interest rates on floating-rate debt to fall faster than on fixed-rate debt, according to CFO Michael LaBelle.

BXP has about $15.4 billion in total debt outstanding. The company typically aims to keep between 5% and 10% of its debt in floating-rate facilities, according to LaBelle, who also serves as treasurer. At the moment BXP is parking nearly a third of its floating-rate debt in commercial paper, he said.

Under its **commercial paper program**, **BXP pays** what amounts to **SOFR plus about 0.25 percentage point**. **By comparison**, the interest rate on its **credit facility** is **SOFR plus 0.85 percentage point**. "It's **less expensive than** any **other floating-rate** debt that we **have access to**," LaBelle said.

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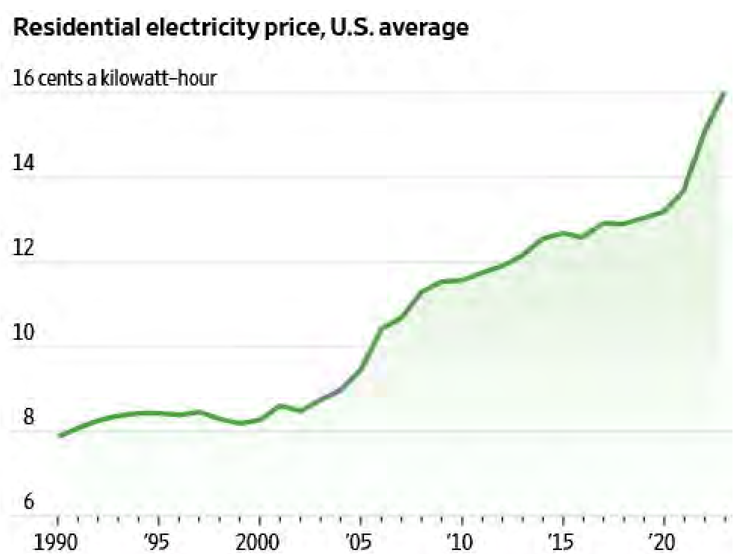
Get Ready to Pay More for Electricity

by Katherine Blunt – WSJ – Jul. 19, 2024



As the grid becomes increasingly unstable, utilities ramp up spending.

Americans used to spend little energy worrying about whether the lights would come on at the flick of a switch, or how much that electricity cost.

For a growing number of people, **those days are over**.

Larry Hilkene, who moved from Indiana to a quiet Detroit suburb just over a year ago, has since had nine power outages, the longest one lasting 16 hours. In the same period, his utility company, DTE Energy, raised electricity rates and sought regulatory approval for another increase as it works to improve the reliability of its system.

Until recently, DTE used an antiquated tile map board to monitor its decades- old grid. When changes occurred on the system, an employee would use a 20-foot pole to place magnetic markers showing open and closed circuits. In 2022, DTE unveiled a massive digital display board to replace it, part of a major spending push to modernize the grid that will be shouldered, in large part, by customers.

Hilkene, who works in cybersecurity, wrote to regulators to express his opposition to paying more for what he considers subpar service. "I call it DT(non)E because they do not appear to be about energy," he wrote, adding that he "cannot believe the abysmal state of power infrastructure here."

Utility customers across the **country** are **increasingly paying more for less-reliable service** – a trend driven home by a massive heat wave that has triggered outages around the country in recent weeks.

Utilities from Michigan to New York and beyond are planning their **largest capital investments since World War II as** the **grid becomes more unstable** as a **result of age and extreme weather.**

After **Hurricane Beryl** made landfall outside of Houston and pummeled the city as a tropical storm, more than 2.2 million of **CenterPoint** Energy's 2.8 million Houston area customers were without power, marking the company's largest-ever outage. Center-Point estimated it would take 12 days to fully restore power. The company this year sought regulatory approval to raise rates, which have remained relatively flat for 10 years.

Meanwhile, demand is poised to soar, with **millions of electric vehicles** and **massive data centers** powering **a**rtificial **i**ntelligence needing to draw power.

Sound of Generators

Customers of roughly 17 large utility companies may see **rate hikes above** the **rate of inflation** between 2022 and 2027, according to Sector & Sovereign Research. Utilities have generally kept rate increases at or below the rate of inflation to reduce the risk of pushback from regulators and customers.

Utilities say significant spending is needed in part to address serious reliability issues. Between 2013 and 2022, the nation's utility companies recorded a roughly 20% increase in outage frequency, according to the most recent federal data. Outage duration increased by more than 46% over the same period, largely as a result of weather-related disasters.

During his first few power outages, Hilkene noticed something he hadn't heard before in Indiana: the sound of his neighbors' **backup generators** firing up. He surveyed the neighborhood, a community of three- and four-bedroom homes near a small lake and an equestrian center, to find that more than a quarter of them had installed natural gas-powered generators.

On a recent spring day, a team of five men arrived with a trailer and unloaded a backup power unit to install on the lush lawn. The generator cost him about $12,000, a sum he considers substantial but worth it to avoid outages.

When a mid-June thunderstorm briefly knocked out the power, Hilkene said he sighed with relief as he heard the generator start up.

Days later, more than 25,000 people were without power in his county as more storms hit.

Price Hikes

After years of relatively modest increases, U.S. electricity prices are on a sharper rise. **Russia's invasion of Ukraine** in 2022 **drove up** the **price of natural gas** needed to fuel power plants. **Gas prices** have since **receded**, **but rate increases** are **still accelerating** as utilities invest tens of billions of dollars to stabilize the grid itself, and pass those costs onto customers.

Pedro Azagra, CEO of Avangrid, which operates utilities in New England and New York, said the company has substantially ramped up spending in recent years to address a range of reliability challenges.

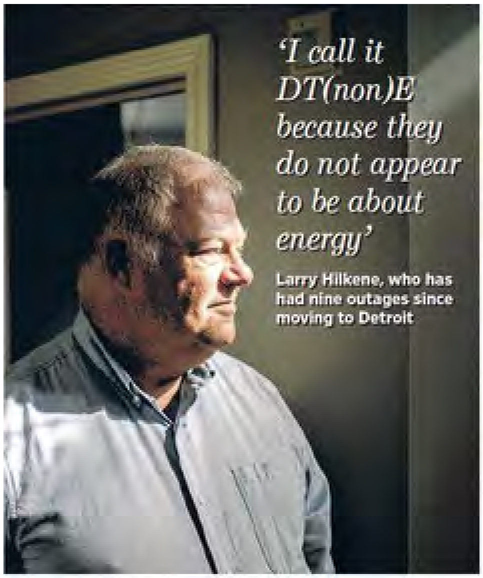
"The problem that we have right now comes from **decades of lack of investment**," he said. "You cannot catch up in one minute."

U.S. electricity prices increased 4.4% over the past year, according to data from the Bureau of Labor Statistics, faster than the broader inflation rate of 3%.

Hugh Wynne, Sector & Sovereign's co-head of utilities research, said gas price volatility, combined with higher interest rates and higher costs associated with replacing old equipment, is beginning to put pressure on rates for utility customers in regions where a substantial amount of work has been proposed. Some utilities aren't expected to seek major rate hikes in the coming years, but he said the firm is tracking an unusually high number that are.

"There were a lot of trends that were moving in a positive direction for the industry that are now going in the opposite direction," he said.

Utilities are expected to invest more than $165 billion a year in 2024 and 2025 to make significant upgrades and replacements, according to trade group Edison Electric Institute, more than any year since the group began collecting data. Many utilities are also **ramping up spending** on routine activities such as **maintenance** and **tree-trimming** to reduce outages, and, throughout the West, **wildfires** caused by fallen power lines.



The need for work is spread throughout the country, with parts of the mid-Atlantic, the Midwest and California expected to see some of the steepest rate increases in coming years. **Nationwide, large sections** of the **grid** are decades **old** and **need replacing**, and **labor and equipment have** each **become more expensive** as a result of inflation and supply-chain snarls.

Left: "Rates are going to go higher, and there's not much you can do about it," said Guggenheim analyst Shahriar Pourreza. "It's kind of the new normal."

Tree Trimming

Avangrid subsidiary New York State Electric & Gas, which serves much of the rural upstate region, has for years delivered some of the state's least-reliable power. NYSEG failed a state target for outage frequency for the fifth consecutive year in 2023, regulatory filings show, though the company improved that metric last year.

Left: Workers upgrade an aging power line in Detroit, part of a costly effort to improve service.

Trees were the primary reason. Some grow more than a foot each year, increasing the likelihood of contact with power lines.

NYSEG told regulators that it has struggled to trim trees frequently enough to maintain safe distances between lines and branches. A 2022 regulatory filing showed that in large parts of the system, vegetation hadn't been cut in at least six years, if ever.

NYSEG is now spending tens of millions of dollars to improve its **tree work**. That spending, combined with **investments** to **upgrade outdated substations**, **circuit**

breakers and **other equipment**, is projected to drive power bills up by about 22% between 2023 and 2025.

Avangrid's Azagra said system reliability is faltering largely because of age, as well as **more frequent storms** and changing weather patterns that are stressing the trees and creating other hazards such as **flooding**.

"If anyone says they don't see that, come to me," he said. "Come to upstate New York."

In **Oregon**, **P**ortland **G**eneral **E**lectric is **investing** **heavily** to **upgrade** the **grid** to withstand more extreme weather. The company has in recent years been working to reduce the risk of its power lines starting wildfires by **burying certain circuits**, **trimming** **more trees** and **expanding** its **network** of **weather** **stations** to monitor for risky conditions.

PGE is also preparing for an anticipated surge in demand to power **new data centers** and **semiconductor** **manufacturing**. The company last year significantly revised its expectations for industrial energy usage, telling regulators that come **2030**, the **need for additional power supplies could be more than 40% higher than earlier forecasts**.

CEO Maria Pope said many of the upgrades involve expanding system capacity to better distribute electricity supplies during periods of extreme demand, when power prices spike. The utility saw record summer power demand during a multiday heat wave last August. Eight months earlier, it saw all-time high winter power demand during an intense cold spell, breaking a record set about 25 years earlier.

PGE this year raised residential rates by about 17%. The company is seeking regulatory approval for another 7.2% increase next year.

Pope said the company needs to work with state and federal regulators to determine how to better manage costs and reduce the burden on customers as the utility completes the most substantial system overhaul in decades. She **likened** the **spending** **need** **to** the **initial buildout of the electric system in the Pacific Northwest more than a century ago**, a **massive undertaking** that involved the region's utilities as well as the federal government and other investors.

'Creative Solutions'

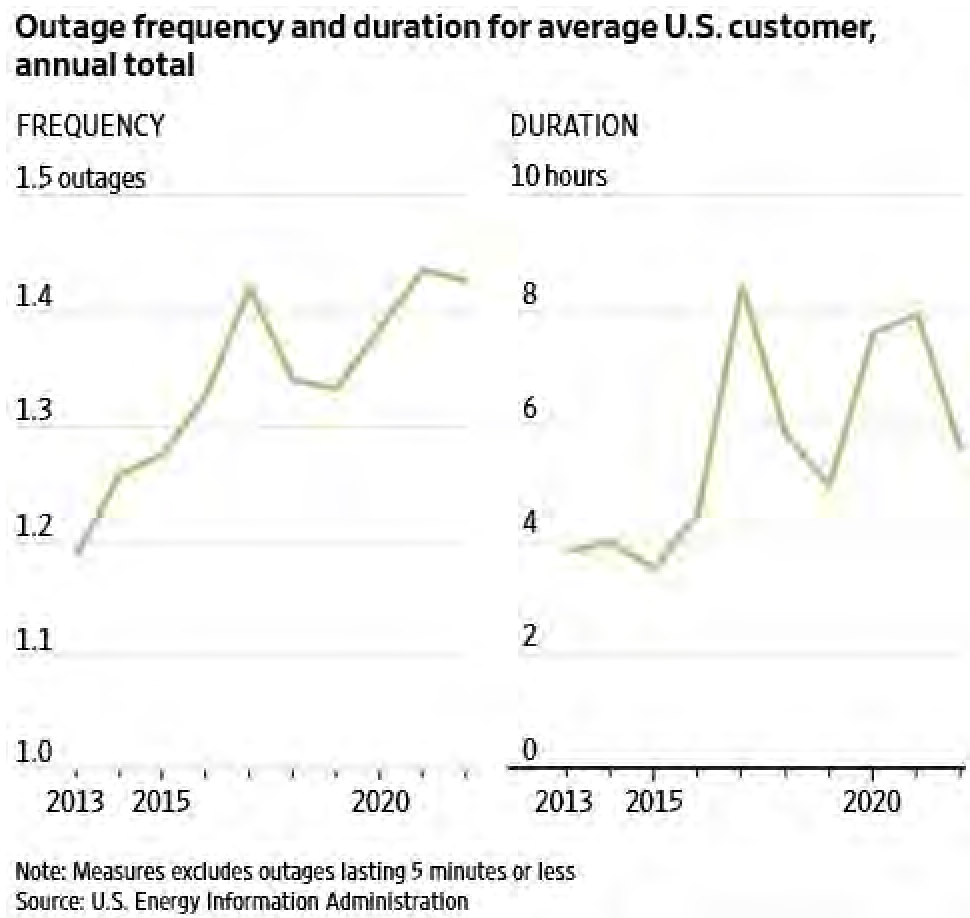
"There's no question that we need to accelerate the work that we're doing," she said. "We're **going to need** to come up with **creative solutions from** a **regulatory and** probably also a **legislative standpoint**."

DTE, which serves Larry Hilkene and 2.3 million electric customers in southeastern Michigan, has one of the least reliable systems in the country, with customers experiencing some of the longest outages each year. Outages are substantially more frequent as well for many customers, though not throughout the entire system.

The company is planning to invest $9 billion over the next five years to reduce outage duration and frequency by 50% and 30%, respectively. It spent $5 billion over the past five years.

CEO Jerry Norcia said the breakdown in reliability – and the need to spend heavily to address it – is the result of more frequent and intense storms exacerbated by climate change, as well as historical inadequacies in some of the utility's work programs. DTE for years failed to trim trees growing alongside its power lines at a frequency needed to avert major outage problems, particularly during severe wind and ice storms.

Until about 2019, the company patrolled its lines for vegetation on a nine-year cycle, nearly twice the industry average of roughly five years, regulatory filings show. To achieve a five-year cycle, DTE is now spending hundreds of millions of dollars on what it calls a "tree-trimming surge" expected to last through 2025. The company has sought to reduce the burden on customers by issuing low-interest bonds to recover the costs over time.



Population Growth

Norcia said the company's previous tree-trimming standard was untenable, especially as storm patterns intensify. The company has in recent years seen an uptick in summer and winter storms, some of which have occurred back-to-back and left hundreds of thousands of people in the dark for days.

"I'm in a much different situation than my predecessors were," Norcia said. "We have to accept this new reality that what used to happen every 50 years is now happening every three to five years."

On top of that, Norcia said, the system serving much of downtown Detroit, designed nearly a century ago, needs **near-complete replacement** to support population growth, the adoption of electric vehicles and other power-demand drivers.

DTE has been working to automate and digitize parts of its system with technologies that many utilities have been using for years, including the digital display board installed in 2022.

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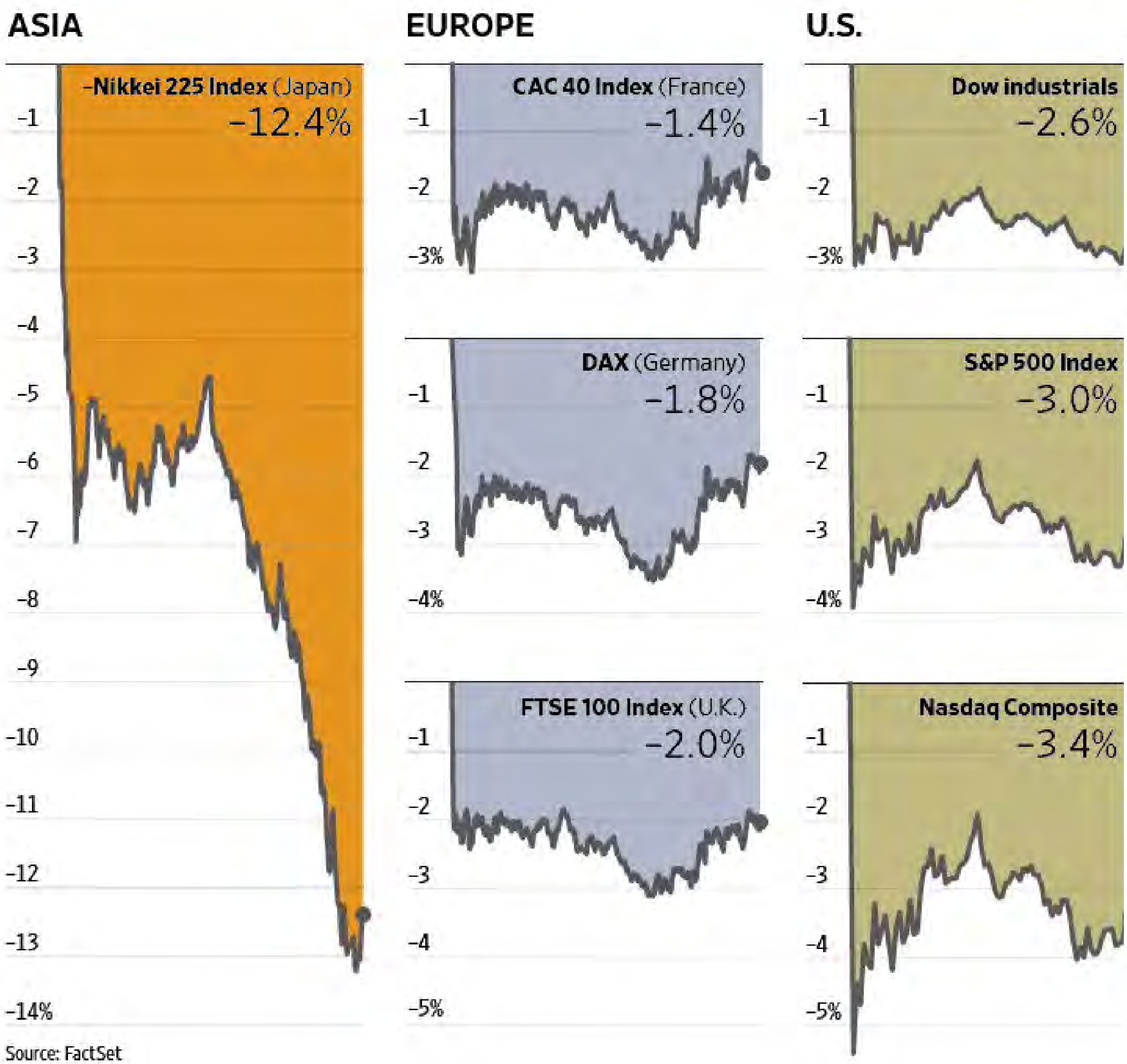
Global Stocks Dive as Trades Unravel

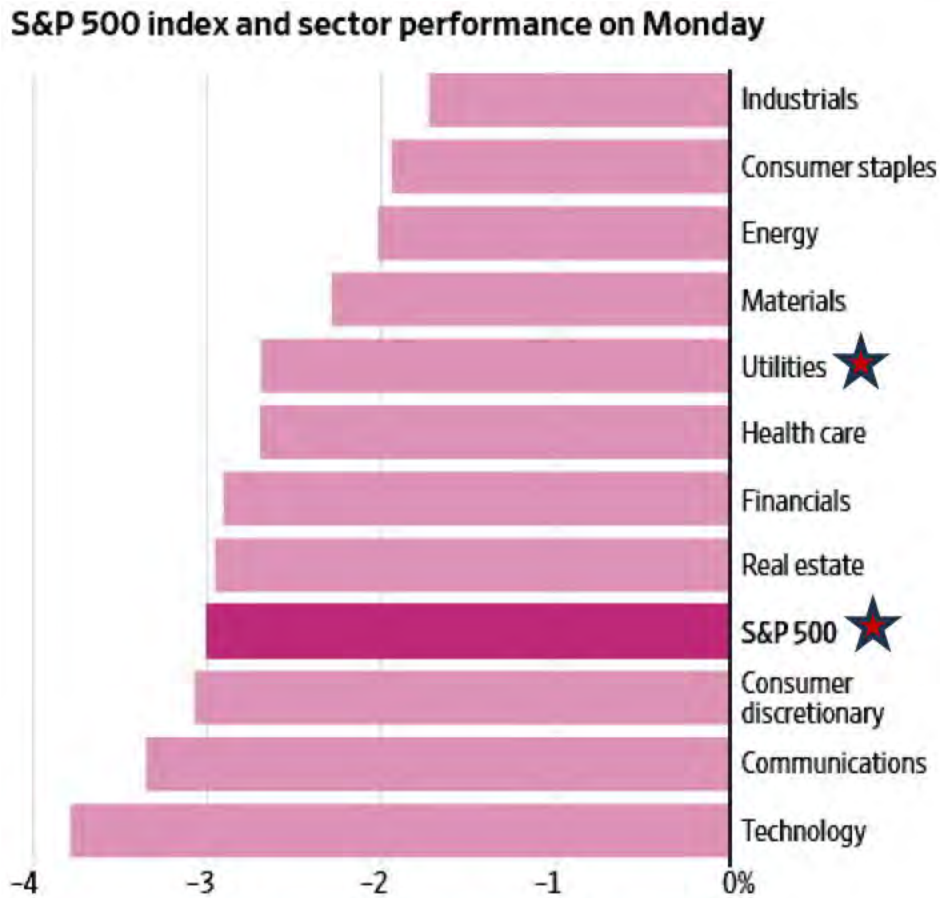
by Ryan Dezember – WSJ – Aug. 6, 2024
Kosaku Narioka and Rebecca Feng contributed to this article.

Blue chips fell more than **1,000 points**. **Japan's stock market** had its **largest one-day percentage decline** on Monday **since** October 20, **1987**. Other countries indexes followed with big tumbles as well and the **VIX volatility index skyrocketed**.



Source: FactSet

The unwinding of some of Wall Street's most popular trades intensified Monday, sending Japanese stocks to their worst day since the 1987 market crash and walloping U.S. technology shares.



Sources: FactSet (index and sector performance); Tullett Prebon (yield)

U.S. stock indexes opened sharply lower, tracing declines in international markets, before recovering somewhat after a survey of purchasing managers showed the services sector expanded last month at a slightly higher rate than expected.

The tech-heavy Nasdaq led the way lower, falling 3.4%. Every industry segment in the S& 500 declined, pushing the broad index down by 3%. All 30 stocks in the Dow Jones Industrial Average ended lower and the blue-chip index shed 1034 points.

The Russell 2000 index of small stocks, resurgent in recent weeks, lost 3.3%. Oil, precious metals and bitcoin fell. Wall Street's fear gauge, the CBOE Volatility Index, or VIX, jumped more than 50% during stock-trading hours to its highest level since 2020.

The rout began in Asia, where Japan's Nikkei 225 declined 12% amid a surging yen. It was the worst single-day percentage drop for the Nikkei since Oct. 20, 1987.

That was the Tuesday after Black Monday in the U.S., when the Dow industrials fell nearly 23%.

The selloff in Tokyo extended last week's **rout** that **followed** the **Bank of Japan's decision** to **raise interest rates**. That move **pushed** the **yen higher relative to other currencies**. Disappointing economic data in the U.S. stoked the selloff, unwinding a popular Wall Street bet known as the carry trade.

For years, investors around the **world bought riskier assets**, **such as U.S. stocks**, and **funded** the **trades with** the **yen**, **thanks to ultralow interest rates in Japan**. Until recently, many hedge funds and money managers **expected rates to remain low and the yen weak**.

Instead, the **strengthening yen** has **squeezed** the **carry trade**. **Investors who borrowed yen to fund their bets** have been **forced** to **buy more** of the **currency by bankers insisting on additional collateral**. That is **pushing** the **yen even higher**, **prompting more margin calls**.

The Japanese market rebounded sharply early Tuesday. At the midday break, the Nikkei was up 9.4%. Elsewhere in Asia, South Korea's Kospi was up 3.5%, Other big moves on Monday also were reversing themselves: The yen, which had strengthened sharply, has fallen back somewhat. The Japanese currency was trading at around 145 to the dollar. Japan's 10-year government bond yield had recovered to 0.87% from 0.75% Monday afternoon.

The losses Monday were an example of the popular trades that are coming unraveled as investors mull weakening **U.S.** economic data and tech shares' sky-high valuations while awaiting the **Fed**eral Reserve's next move on interest rates.

Investors have been **expecting** the **central bank** to **cut rates** at its **September** meeting. Now the debate centers on whether the Fed might take the rare steps of making a larger-than-usual half-percentage-point cut or even lowering borrowing costs between meetings.

In one sign that growth is continuing, Treasury yields recovered from sharp early declines following Monday's strong reading of the services sector.

The Institute for Supply Management's survey of service businesses rose to 51.4 in July from 48.8 in June, which was the lowest reading since the depths of the Covid-19 pandemic lockdown in 2020. Readings over 50 indicate expansion.

A similar ISM survey of manufacturing companies last week slipped deeper into contraction, prompting bonds to rally and a selloff in stocks. Monday's services reading suggests that the swath of the U.S. economy that employs the most people might not be in as bad shape as manufacturing.

The **yield** on the benchmark **10-year Treasury note ended** at **3.782%,** down from its Friday settlement of 3.795% and well off the 2024 high of 4.706% in late April.

The **two-year yield**, which often moves with expectations for short-term rates set by the Fed, inched up to **3.88%.**

While investors wait, they are dumping the technology stocks that propelled the market to new highs this year.

Each of the so-called **Magnificent Seven technology stocks declined at least 2.5%**. **Nvidia**, the must-own stock of the artificial-intelligence frenzy, **lost 6.4%.**

Investors have questioned whether those companies' share prices had outrun realistic forecasts for future profits. "The technology sector has come under particular duress in recent weeks amidst fear that companies are overspending on artificial intelligence infrastructure just as economic growth is beginning to slow," said John Belton, portfolio manager at Gabelli Funds.

Warren Buffett's Berkshire Hathaway on **Saturday disclosed** that it had **slashed** its **position** in **Apple** during the second quarter, **selling nearly half** of its huge **stake** in the iPhone maker.

The regulatory disclosure sent a strong signal to the droves of investors who look to the Nebraska-based billionaire, known as the Oracle of Omaha, for signs of shifting market sentiment.

"It's something that people pay attention to due to his historic track record of going against the greed-and-fear rotations of the market," said Brian Burrell, portfolio manager at Thornburg Investment Management in Santa Fe, N.M. "When a contrarian starts to move and everyone is positioned the other way, that's a reason to re-examine their positioning."

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Hawaiian Electric Nears Fire Settlement

by Akiko Matsuda and Soma Biswas – WSJ – Jul. 29, 2024

Hawaiian Electric is near a deal to resolve mass lawsuits over the Maui wildfires.

The Utility aims to avoid following California's PG&E into filing for bankruptcy

Hawaiian Electric is **nearing** a **deal** to **resolve mass lawsuits over last year's Maui wildfires** that **could avoid** a **bankruptcy filing** by the utility, people familiar with the situation said.

Hawaiian Electric and other defendants facing wildfire lawsuits in Maui have been in talks for a **settlement valued at over $4 billion**, **though** an **insurance dispute remains** a **risk to finalizing any deal**, the people said.

The proposal under discussion would also cover the Hawaiian state government and Maui County, according to people familiar and court documents.

Left: Hawaiian Electric and Maui County have blamed each other for last year's wildfires there.

The **county and** the **utility** have **blamed each other for** the **wildfire**, which destroyed more than 2,200 homes and businesses in Maui communities and the historic town of Lahaina and killed more than 100 people.

The **Maui fires triggered litigation and** a **financial crisis for Hawaiian Electric** that **led it to consult with restructuring**

advisers on a path forward. Fire victims have filed more than 450 lawsuits against Hawaiian Electric and other defendants, seeking compensation for billions of dollars in property damage and personal-injury claims.

Some personal-injury firms representing large numbers of victims have been in mediated talks for the settlement, which still faces risks and doesn't have the support of insurance companies that made payouts to victims on homeowners insurance and other policies.

An open question is how the settlement will be divided between victims and **insurance companies** that have **also sued** for reimbursement for payouts they have already made.

Potential holdouts to any settlement pose a risk to resolving Hawaiian Electric's fire-related liabilities outside of a bankruptcy. **Hawaiian Electric said** the **mediation process** is **ongoing and confidential** and declined to comment further. A Maui County official declined to comment, citing pending litigation.

Shares of **Hawaiian Electric Industries**, which owns Hawaiian Electric, finished **Friday's trading** at nearly **$17**, continuing a **rally from** less than **$8 last week** after Bloomberg reported on the potential settlement. The **stock** hasn't been worth that much since it was **trading around $37 just before** the **wildfires** in **August 2023.**

A **global settlement could help Hawaiian Electric avoid** the **fate** of California's largest utility, **PG&E**, which filed for bankruptcy in January 2019 as it struggled with liabilities from California wildfires in 2017 and 2018 that were sparked by its equipment. **PG& E exited bankruptcy after agreeing** to **pay $25 billion to individuals, businesses and insurers to compensate for wildfire-related losses**.

Hawaii's governor and its electric utility have sought to settle the wildfire litigation without having to resort to a bankruptcy filing for Hawaiian Electric. The **U.S. Supreme Court's recent ruling against Purdue Pharma made chapter 11** an even **less-attractive option for Hawaiian Electric**, according to people familiar with the company's thinking and lawyers involved in the situation.

The **Purdue ruling** in **June shut** the **door** on a **court's ability in chapter 11 cases** to **wipe away legal claims against entities that haven't themselves filed for bankruptcy**. That means a **Hawaiian Electric bankruptcy would now be unlikely** to **buy peace for Maui County**, the **state of Hawaii** and **other defendants** who are **named in** the **Maui wildfire lawsuits**, making the chapter 11 option less attractive, these people said.

Total liabilities from the **Maui wildfires could amount to nearly $5 billion**, according to estimates by Capstone, a consulting firm in Washing--ton, D.C., that advises investors and companies on regulatory matters. In **similar litigation against PacifiCorp over 2020 wildfires in Oregon**, **juries** have **handed down verdicts** that point to **average awards** of **over $9 million per person for loss of life**, said Alyssa Lu, an analyst for Capstone.

The first such trial against Hawaiian Electric is scheduled for November. Trial dates often motivate companies facing personal-injury lawsuits to seek chapter 11 protection before a jury reaches a verdict with a high damages figure.

"We don't expect Hawaii Electric to want to take these cases to trial," Lu said.

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How a Heap of Lithium on the Nevada-Oregon Border Could Ignite an Environmental Battle

by Andrew Miller – Oregonian – Aug. 10, 2024
https://www.oregonlive.com/business/2024/08/how-a-heap-of-lithium-on-the-nevada-oregon-border-could-ignite-an-environmental-battle.html

The clay mixture from which lithium will be extracted is held by Tim Crowley, spokesperson for Lithium Americas Corp., on June 7, 2021, in Reno, Nevada.

Oregon sits on a **colossal bounty** of **lithium straddling** the **border with Nevada**, sharing **one of** the **largest deposits on Earth** with a southern neighbor.

Lithium is one of the most important resources for the ongoing renewable energy boom, **vital for batteries** used in **electric vehicles** to **solar energy** technology. (Lithium batteries also likely power the device on which you're reading this story.) Right now, it's key to getting millions of polluting gas-powered cars off the road.

Miners are already prospecting the Oregon side of the massive deposit of "white gold" in an ancient volcanic caldera. But **getting** that **lithium out of the ground could emit about** as **much carbon as Oregon's last coal-fired power plant in** its **last 22 years in operation**. And environmental groups say mining the area would hurt a crucial ecosystem in Oregon's high desert.

The Nevada side of the deposit is estimated to contain a larger supply of lithium in higher concentrations. Companies with land in Oregon expect they're at least a decade away from tapping the Oregon side – where they expect tougher environmental regulation and more public resistance – by which time battery technology might well have moved on.

But at least three transnational Australian mining corporations are exploring the Oregon sites, drilling dozens of holes into its claystone rock to measure the amount of lithium. Representatives from one of the companiesmet with Gov. Tina Kotek last month.

So the site might yet set up a new clash between environmentalism and the rush toward sustainable energy. And Oregon may have to choose between a modern-day oil boom and the environmental values many of its residents cherish.

Environmentalism and sustainability

The prospect of lithium mining on Oregon's desolate but ecologically dense southeastern border has raised a litany of concerns for the state's **environmental** advocacy groups.

For one, they consider the area critical to the survival of the sage grouse, a bird native to Oregon's high desert that's considered "near-threatened." Mark Salvo, the Oregon Natural Desert Association's conservation director, said the area contains breeding grounds for the birds that mining would decimate.

And it's not just the sage grouse. Because the area is passable to wildlife during winter, even when nearby mountains are encased in deep snowpack, Salvo said many species depend on it. Mines could also disturb threatened Lahontan cutthroat trout, which lives in creeks that run near prospective mining sites.

It also includes species such as the pronghorn antelope, which Salvo said "frankly every other western state is concerned about" due to long-term population declines.

The **mines would also demand immense supplies of water** to extract the lithium. One mine in Nevada at Thacker Pass already plans to withdraw just under 1.7 billion gallons of water per year from local groundwater in its second phase.

Water usage is already a perennial issue in Oregon, where cities, industry, farmers and fish already compete over a finite supply. And environmental groups such as Salvo's are especially concerned about this in the proposed mines.

But one of the biggest environmental concerns reveals a tension between reducing carbon emissions through electrification and present-day battery technology.

John Dilles, a retired geology professor at Oregon State University who co-authored a transformative study that estimated the amount of lithium in the caldera, said the element is so heavily embedded with calcium carbonate in claystone rock that miners will need to dissolve the surrounding mineral to extract the lithium.

For every ton of lithium mined, the chemical process will release between four and 30 tons of **carbon dioxide**. (That ratio depends on the concentration of lithium in the rock the miners will extract it from, among other factors.)

Construction is underway at the Lithium Nevada Corp. mine site Thacker Pass project on April 24, 2023, near Orovada, NV. The vast lithium deposit of the McDermitt Caldera straddles the Oregon-Nevada border.

Dilles estimates the amount in Oregon could be on the higher end of that range – about 20 tons of carbon dioxide released for every ton of lithium extracted. On the conservative estimate of 2 million metric tons of lithium at the largest site on Oregon's side, that means 40 million metric tons of carbon dioxide released into the atmosphere.

That's equivalent to running Oregon's Boardman Coal Plant – the state's last coal power plant, decommissioned in 2020 – for 22 years.

Every ton of lithium used in electric vehicle batteries prevents the release of about 190,000 tons of carbon dioxide emitted by gas-powered vehicles. That means even if a small fraction of the deposit's lithium goes to EV batteries, it could halt the emissions of hundreds of millions of tons of carbon dioxide, far outstripping the carbon cost of its extraction.

But climate scientists say carbon emissions today, when greenhouse effects are accelerating, could be more damaging than future emissions – if global emissions are already in decline.

Scientists are researching ways to capture that carbon before it's released into the atmosphere, Dilles said, but it's not common practice.

Who would mine the sites?

At least three companies, all Australian or subsidiaries of Australian mining corporations, have laid claims on Oregon's lithium deposits.

The site was first scoped out by Chevron in the 1970s, which at the time was hunting for uranium. The Australian company Aurora Energy Metals has followed suit, laying claim to a portion of the northeastern edge of the caldera. The company says on its website that it hopes to mine both uranium and lithium at its site.

A U.S. subsidiary of another Australian lithium mining company, Chariot Corp., has stakes in significant portions on both sides of the border.

But the company has suggested it may never mine the Oregon side. Shanthar Pathmanathan, Chariot's managing director, told a mining industry podcast host in March that he expects difficulties.

"The Oregon part, we think, is going to be somewhat frustrated by politics in Oregon which prevent that from being developed into a mine," Pathmanathan said on the podcast. (His company, Chariot Corp., did not respond to an interview request.) "Nevertheless, the mineralization is also there."

The regulation for permitting is largely handled by the Bureau of Land Management, a federal agency, just as in Nevada. But Oregon authorities get some say. Water usage for drilling, for example, still has to go through an Oregon water master, and there are other constraints the state can place on a major mining operation.

The largest deposit on Oregon's side is staked out by Jindalee Lithium, another Australian firm, through its U.S. subsidiary, HiTech Minerals. But the company, like others, doesn't expect to have shovels in the ground for many years.

Brett Marsh, vice president of exploration and development at Jindalee, said it would be at least a decade, but likely much longer, until mining operations actually begin on the company's site.

Still, the company is close to obtaining an exploration project permit for its Oregon land, where the company plans to drill hundreds of holes and build miles of road.

Jindalee representatives met with Gov. Tina Kotek last month to discuss the company's project. A spokesperson for Kotek said she met with Jindalee at the company's request to discuss the company's business model, the process to extract lithium and world markets for the resource.

But getting shovels in the ground on Oregon's side may still prove to be much harder than in Nevada. It's possible, experts say, that battery technology passes by lithium in the meantime. Scientists and renewable tech are already looking at alternative battery technology that relies on potentially more sustainable resources, such as sodium.

A mirror over the border

If Oregon wants to know what it could expect from mine development, it can look to its southern neighbor.

Nevada's largest lithium mine, at Thacker Pass, has **drawn intense controversy and protest**.

An employee stands near the Lithium Nevada Corp. mine site at Thacker Pass on April 24, 2023, near Orovada, NV.

Lithium Americas, the Canadian company that operates the mine, estimates it contains almost $4 billion in extractable lithium, enough to satisfy a quarter of yearly global lithium demand.

The mine is projected to create hundreds of jobs in the remote corner of the state, with wages that average about $63,000 a year. The state's average salary is about $55,000.

Three tribes have sued the Bureau of Land Management, alleging the mine is being constructed near the site of a massacre where U.S. Cavalry killed dozens of Native Americans. A federal judge ruled last year that the tribes failed to prove the project site was where the massacre occurred.

Activists allege the company rushed environmental reviews and say the mine represents threats to wildlife similar to those feared by environmental groups on Oregon's side.

Karly Foster, a former campaign manager for the Oregon Natural Desert Association, vehemently opposes the development of mines on the Oregon-Nevada border. She supports the use of lithium, but she said this site is too important to local wildlife and cultural resources. (Foster wrote an ode to the site's "vibrant ecological haven" for The Bulletin in Bend earlier this summer.)

But beyond her own opinion on the matter, she said the lithium lode illustrates the tension between environmental protection and the race toward net zero, to the widespread adoption of electric vehicles and of renewable technology. Both, she said, are crucial.

"It's an incredible mirror," Foster said, "that just happens to live in Oregon."

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Intel and Nike Stumble, Shaking Two of Oregon's Economic Pillars

by Mike Rogoway – Oregonian – Aug. 7, 2024

Intel and Nike play a foundational role in Oregon's economy:
"If you're rooting for Oregon, you're rooting for these two firms to succeed.

For decades, **Oregon** has **depended on Intel and Nike as major employers** – each with a **vast workforce** and **paying wages few other local companies can match**.

They have been **economic engines in good times and bad**, **easing** the **state's dependence on natural resources** and connecting Oregon to the 21st Century economy. To a large degree, the state has crafted a corporate tax system designed specifically to please those two companies – sometimes to the exasperation of other businesses

Now, both companies are on their heels.

Intel said Thursday it plans **to eliminate 15,000 jobs** across the company **by mid-November**, the biggest cuts it has ever announced. Many of those job cuts will surely come in Oregon, the chipmaker's largest site, though Intel hasn't said which departments and which regions will take the biggest hits.

The chipmaker's dismal news follows layoffs by Oregon's other major business, **Nike**, which **cut 5%** of its **jobs last year** – including several hundred positions in Oregon. The sportswear company's **stock suffered** its **biggest decline ever** in **June as Nike warned** of **falling sales in** the **months ahead**.

Intel and Nike's current travails aren't directly connected. Each has made strategic missteps, failing to keep up with changing dynamics in their industries.

In Oregon, their concurrent stumbles are an ominous portent. Each company is a little over a half-century old.

While Intel and Nike both say they're committed to their futures in the state, their setbacks this year raise the possibility that – for one or both – their best days might be behind them. Even if the companies endure for many years to come, they might never match the dynamism that propelled them, and Oregon, in earlier times.

"Absent their vibrancy, I think you start to see a trend more in the direction of a place like Idaho," said John Tapogna, senior policy advisor with the Portland research firm ECONorthwest.

Oregon relies on Intel and Nike to attract highly educated workers, Tapogna said, **and to sustain a network of suppliers and contractors that support their core businesses**. He said the region doesn't have other companies that operate on that scale, and there are **no up-and-coming businesses who can match** the impact of Intel or Nike.

"If you're rooting for Oregon," Tapogna said, "you're rooting for these two firms to succeed."

Similar Troubles

Intel's woes stretch back several years, to **missteps** that **cost** the **company** its **technological lead in** the **semiconductor industry**. Rivals swooped in with more advanced manufacturing processes and soon, more sophisticated computer chips. Intel has been left behind in the roaring market for artificial intelligence technology.

CEO Pat Gelsinger took over in 2021 and pledged to rebuild the company's engineering, committing tens of billions of dollars to new factories across the U.S. and around the world.

The **federal government** awarded **Intel $8.5 billion** in federal **subsidies** to help restore domestic chip manufacturing and **Oregon tossed in** another **$115 million** to **encourage Intel** to **continue expanding in Washington County**, **where** it **already employs 23,000**.

As Intel's spending climbed, though, its sales fell. Annual revenues are down by more than a third over the past two years and last week Intel forecast another 8% decline during the current quarter.

The company's executives say they can't keep up its pace of spending given the diminished revenues, so Intel is slashing jobs and cutting $10 billion in expenses next year to keep the business upright.

Intel leaders say their strategy hasn't changed and they plan to keep investing in new technologies, but Wall Street is increasingly dubious. The stock lost about $30 billion in market value Friday as shares plunged 26% to their lowest point in more than a decade.

Nike's troubles are in some ways **similar**, though its cutbacks are less severe. As the company focused on **high-performance shoes** and sought to sell more of its products directly to consumers, everyday athletes shifted to rival brands like Hoka and On.

Sales stagnated and **Nike eliminated about 1,600 jobs** across the company **last year** – including more than **700 in Oregon**. The company **now employs 10,700 in** the **state** and says it's working to reinvigorate its business.

"There's a tremendous amount of hustle throughout the organization," CEO John Donahoe told Wall Street analysts in June. "And you can feel it."

Stagnant Growth

Intel and Nike's difficulties coincide with broader, unrelated drags on the Oregon economy. The state's population has stagnated in the pandemic's aftermath, ending a decade of robust expansion and contributing to the state's lackluster job growth over the last 18 months.

Job cuts at Intel and **Nike threaten** to **dig a bigger hole for Oregon**, particularly in the Portland area where technology and apparel are major industries.

"Layoffs are never good. The labor market today is a bit weaker with job openings down, hiring rates down, unemployed taking a bit longer to find a job," said Josh Lehner, Oregon's acting state economist.

While a few thousand additional layoffs won't have a huge impact in a state with two million jobs, Lehner said the question will be what they mean about the industries' long-term outlook.

"Anchor employers matter," Lehner said. "These two industry clusters matter."

Intel and Nike are especially important to the state's outlook because they employ many people and pay top-tier wages.

Oregon's semiconductor industry pays an **average annual wage** of **$150,000**, more than **double** the **statewide average**. **Nike's campus** near **Beaverton** is **home** to **highly paid executives and shoe designers**.

"It is very disconcerting to see these layoffs because these are folks that shop at small businesses," said Sarah Shaoul of Bricks Need Mortar, a Portland organization that advocates for local merchants.

Those kinds of highly paid jobs aren't easy to replace, and they have a spillover effect at merchants across the region, she said.

"Certainly there are times when we feel like small businesses don't get enough focus, especially because they are such an essential part of our economy here," Shaoul said. "At the same time, we do believe we need equal attention on supporting and sustaining jobs at bigger companies."

Money Well Spent?

Oregon has devoted years of tax and economic policy to Nike and Intel's benefit:

A dozen years ago, Oregon lawmakers met in special session at Nike's behest to lock in the state's formula for calculating corporate income taxes. The tax structure benefits both Nike and Intel because it bases corporate tax liability on sales within the state. Since those two companies sell almost all their products outside Oregon, that puts a ceiling on their Oregon tax bill.

A corporate activity tax the Legislature approved for education in 2019 contains similar provisions that protect Intel and Nike, included at the urging of former Nike government affairs chief Julia Brim-Edwards. The tax structure infuriated Oregon manufacturers who sell most of their products inside the state, but they weren't able to muster support for a repeal.

Intel enjoys exemptions from local property taxes worth $235 million last year alone, sparing it from huge tax bills on its expensive manufacturing equipment.

The $115 million Intel received from the **Oregon Chips Act** last year is tied to the company's plan for a $36 billion upgrade to its Washington County factories. It hasn't set a timetable for completing that work.

The chipmaker hasn't said how its spending cuts will affect its Oregon expansion plans but did say Thursday that its larger strategy hasn't changed.

Intel committed to adding nearly 2,600 Oregon jobs in conjunction with last year's incentives, and it must pay back some or all of the money if it doesn't meet those hiring targets.

"Are those investments still going to happen? I would think so unless I hear otherwise," said Lehner, the state economist. "It's not like the incentives are going away, and the national importance of domestic manufacturing isn't going away, either."

Pulling Together

Intel declined to comment on its future in Oregon, except to reiterate that its strategy for reinvigorating the company – which includes investing tens of billions of dollars to upgrade its Oregon factories – remains intact despite the pending layoffs and many other spending cuts.

"Our strategy isn't changing," CEO Pat Gelsinger told employees on an all-company call Thursday evening. "But we have to accelerate what we do. We have to accelerate our profitable growth."

In a statement to The Oregonian/OregonLive this past weekend, Nike said it looks forward to a bright future employing thousands of Oregonians.

"We actively invest in and engage with the community, including providing grants to local schools and partnering with community-based organizations and others to help create opportunity and access for youth play and sport, volunteering time to get kids active, and through the community participation of our Nike teammates," the company said. "We remain committed and confident in our future in Oregon."

Both Nike and Intel still have a lot going for them.

Nike remains one of the world's most prominent brands, with a dominant position in athletics. It's the biggest company in its industry, with more than $50 billion in sales last year.

Intel's research factory in Hillsboro is among the most advanced semiconductor research sites on Earth and it has thousands of scientists working in Oregon to engineer new generations of leading-edge technologies.

Oregon economists and business organizations say they're watching closely to see how the region's two major companies deal with their troubles.

"It's certainly concerning that two anchor companies in the region are facing challenges," said Monique Claiborne, president of Greater Portland Inc. Her organization works with local governments and companies to promote the region as a destination for growing businesses.

As large as they are, though, Claiborne said the Portland area has more going for it than Intel and Nike. She noted recent expansion announcements from footwear company Hoka and Daimler Truck North America and said she has recently observed a surge of interest in the region from business prospects.

Among civic leaders and in the state Legislature, Claiborne said there is a much greater interest in growing Oregon businesses than there was when she arrived in the state in 2021. She said government officials are far more assertive about pursuing economic opportunity and have a broader understanding of how to collaborate in landing business prospects.

"We are all rowing in the right direction," Claiborne said. "I don't think that's always been the case."

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Intel CEO's Dream Job Became a Nightmare

by Asa Fitch – WSJ – Aug. 3, 2024

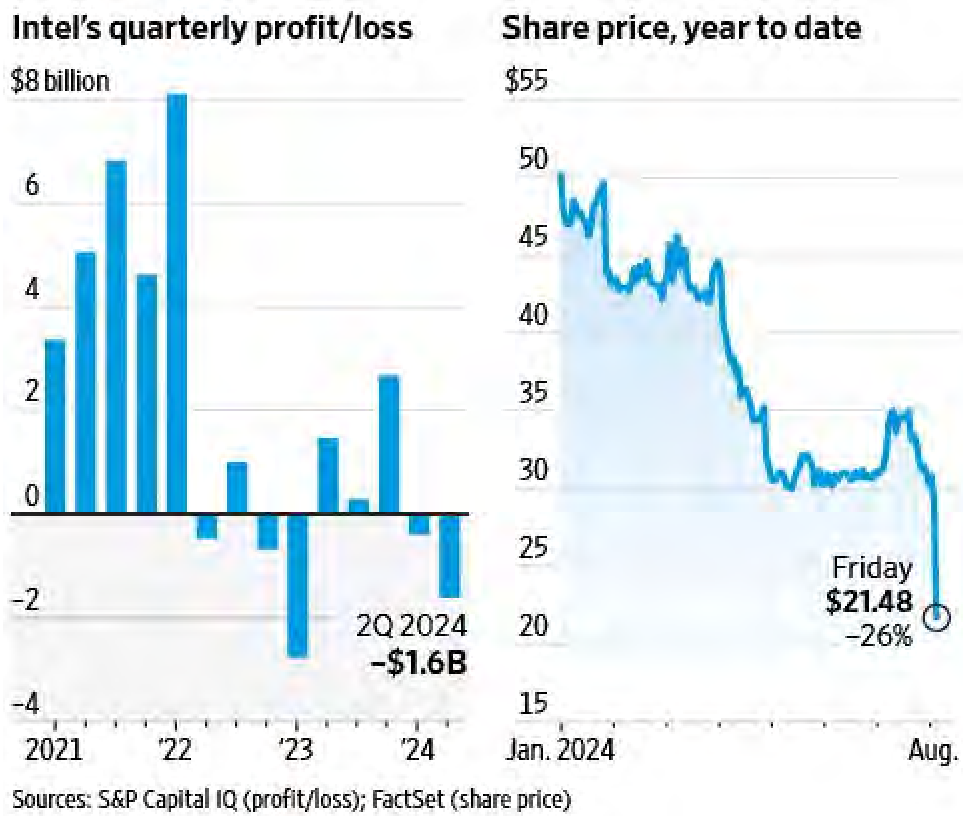
Running Intel was always a dream job for **Pat Gelsinger**. More than **three years into** his **tenure as chief executive**, prospects for the success of his turnaround look increasingly nightmarish.

Intel's share price **plunged 26% during Friday trading**, a day after it reported financial results and an outlook that disappointed Wall Street with lower-than-expected revenue and profit-margin forecasts. The **stock fall knocked** more than **$30 billion off Intel's market value**, bringing it to a level last seen 15 years ago.

Some investors and analysts questioned whether it was now possible to pull off the costly reconfiguring of Intel's business that Gelsinger launched when he took over in early 2021, pledging to bring glory back to a company that was already stumbling.

"Turnarounds in tech are not very easy," said Ivana Delevska, chief investment officer of Spear, an asset manager that owns chip stocks. "You really need to have a lot of things going for you, and it needs to come from the technology side. Leadership changes can only do so much."

Intel also on **Thursday said** it **would lay off** around **15,000 employees**, **target $10 billion in cost cuts next year** and **suspend dividend payments** in the **fourth quarter**. It will be the first time in more than three decades the company doesn't pay a dividend.



Gelsinger said in a letter to employees that the decision to pare back and cut costs was the hardest thing he has done in his career, but he maintained his resolve in an interview after the measures were announced.

"There's clearly a lot of work in front of us, but this rebuilding of the iconic Intel is huge, and now we're moving into the next phase" of fitting the transformation into a sustainable economic model, Gelsinger said.

Revitalizing the company back has been as much a personal quest for Gelsinger as a business case study.

He grew up at Intel, having joined fresh out of a vocational school in Allentown, Pa. Over 30 years, he helped develop some of Intel's most successful personal-computer chips in the 1980s and 1990s, and became a disciple of legendary Intel CEO Andy Grove. Gelsinger rose to become the company's first chief technology officer in the early 2000s, but was forced out in 2009 amid the failure of a graphics chip effort he oversaw.

Afterward, Intel thrived for a number of years before slipping around a decade ago in the high-stakes race to make chips with the tiniest, fastest-calculating transistors possible. Eventually, **Taiwan Semicon-ductor Manufacturing**, or **TSMC**, **and** South Korea's **Samsung** Electronics took the crown for chip-making technology.

When Gelsinger returned as CEO in **2021**, he **said** it was "the greatest honor of my career." He outlined a sweeping turnaround plan. Intel, he said, would make five major advancements in its chip-making technology in four years to regain its lead. As it did so, **Intel would double down** on its **chip-manufacturing** footprint, **building new factories** in **Arizona**, **Oregon** and **Ohio as well as in Europe** – projects that cost tens of billions of dollars each. At the same time, Intel would start a business making chips on contract for outside circuit designers.

Left: Pat Gelsinger rose to become Intel's first chief technology officer in the early 2000s.

At first, Gelsinger's plan was buoyed by a chip shortage and a surge in buying of computers during the pandemic. In his first quarter as CEO, the company reported about $19.7 billion in revenue – about $7 billion more than in its most recent quarter.

Cracks soon appeared. As a post-pandemic world returned to old work habits, sales sagged for PCs and for the chips used in data centers. By mid-2022, Gelsinger was lamenting a "rapid decline in economic activity" and promising investors that "we must and will do better."

Meanwhile, a **generative AI boom** was starting to take shape that would make things worse for Intel. The investment surge in computing infrastructure for artificial intelligence following OpenAI's release of ChatGPT in late 2022 went largely to rival **Nvidia**. That crimped customer budgets for Intel's chips. As Nvidia rose to a valuation at one point above $3 trillion, Intel's stock fell, shedding more than 42% of its value this year even be-fore Friday's plunge.

Gelsinger continued to plow resources into the turnaround, hoping for large financial efficiencies from the revamp. To offset a factory expansion that could cost more than $100 billion in the coming years, he made partnerships with investment firms and applied successfully for up to $8.5 billion in government money through the **Chips Act,** passed in 2022.

He also slowed the company's expansion to control expenses, extending an initial timetable for a factory in Ohio. Last February, the company cut its dividend by 66% and announced an initial round of cost cuts.

In an email to employees after Thursday's earnings report, Gelsinger called the decision to further cut costs and begin another large round of layoffs a difficult but necessary step toward righting the company.

Those moves – and the tumble in the company's stock price – are testing the patience of investors who bought into Gelsinger's turnaround plan.

Ariel Investments, a New York-based firm with about $14 billion under management, built a position in Intel's stock late last year believing that Gelsinger could orchestrate a resurgence and make Intel once again the leader in chipmaking technology.

Ariel portfolio manager Micky Jagirdar said Gelsinger's technology strategy was still on track, and the support the company is getting from the U.S. government through the Chips Act gave it an added margin of safety. Still, he said Ariel would reassess Intel's prospects before buying more of the stock after its slide on Friday.

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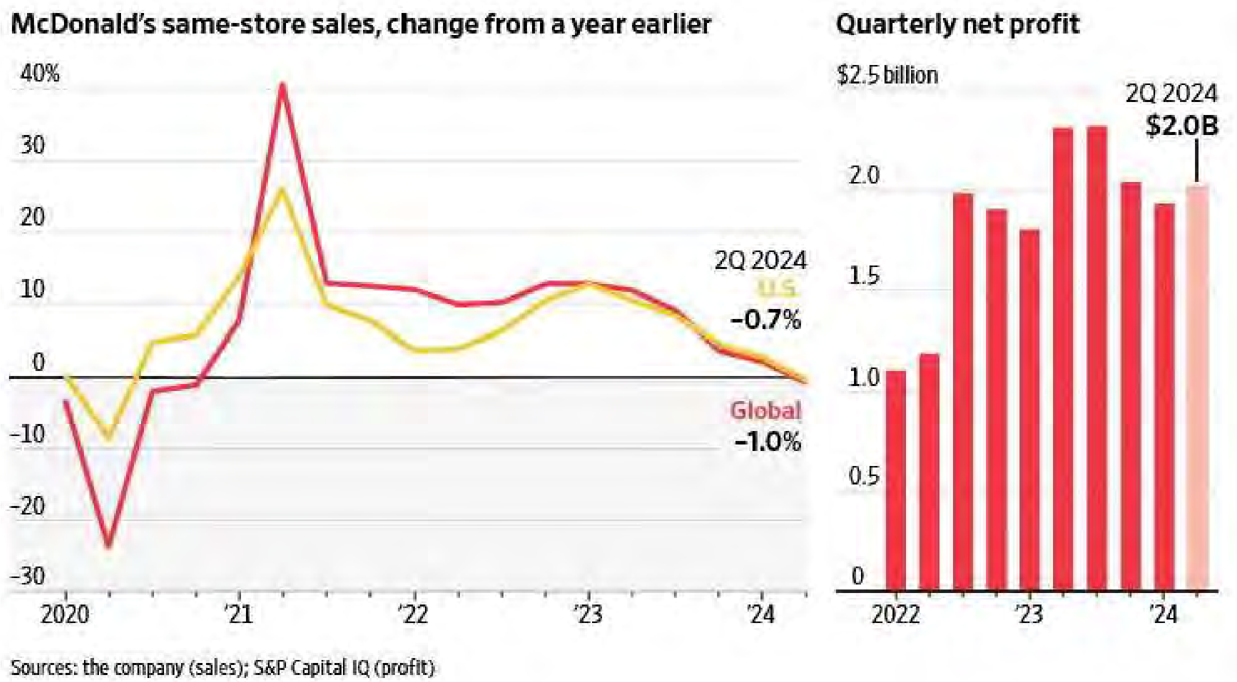
McDonald's Sales Cool as Diners Pull Back

by Heather Haddon – WSJ – Jul. 30, 2024

Fast-food company acknowledges meals have become less affordable.



McDonald's said its sales last quarter sputtered as the burger giant grappled with consumers reining in their spending, sounding a warning for the restaurant sector.

Chief Executive Chris Kempczinski said **lower-income consumers began reducing their visits last year**, but the **slowdown** has **deepened** and **broadened** across the U.S. and other major markets.

Consumers have been **buying fewer items per visit or selecting cheaper ones**, he said. Many people are opting to dine at home because grocery prices have become less expensive than dining at restaurants.

The fast-food giant said U.S. same-store sales in the June quarter were down nearly 1%, the first such decline since 2020. Analysts had expected the metric reflecting sales at stores open at least 13 months to be flat. The company also reported declines globally, with conflict in the Middle East and a weaker performance in France.

The weak trends are continuing in the current quarter, according to the company.

"The consumer across a number of these markets is being very discriminating, and I would point out consumer sentiment in most of our major markets remains low," Kempczinski said in an earnings call Monday.

Chicago-based McDonald's kicked off a string of quarterly reports from U.S. restaurant chains this week. Restaurant stocks have slid in recent months as **consumers' discretionary spending** comes **under pressure**, and Wall Street analysts expect some chains to fall short of earnings expectations.

Investors have allowed little room for error from restaurants that have recently posted their quarterly results. Domino's Pizza and Chipotle Mexican Grill both reported growth in profits, but investors sent their shares lower after both companies gave a tepid outlook on the year.

The Domino's Pizza chain said it would open fewer stores globally than it originally expected, while Chipotle said its sales growth was cooling.

Still, McDonald's maintained its overall guidance for new stores, capital expenditures and operating margins for the year. Shares rose 3.7% in Monday trading.

The company's stock is down around 11% in the past 12 months. An S&P 500 restaurant subindex declined 8.7% during the same period.

McDonald's is putting emphasis on its new meal bundle and the opportunity to capture customers seeking deals. The chain's U.S. restaurants in June started selling a bundle of four items – a McDouble or McChicken sandwich, small fries, small soft drink and a four-piece Chicken McNuggets – for $5.

Left: The chain said consumers have been buying fewer items per visit or selecting cheaper ones.

Sales of the $5 bundle were performing well, and lower-income consumers in particular, were buying it, said Joe Erlinger, the company's U.S. president. The average check was around $10 for those who purchased the meal as they added on other food. The promotion was scheduled to last a month, but 93% of franchisees were continuing to offer it into August, Erlinger said.

Kempczinski said the company's edge on **affordability** had shrunk as its operators have raised prices in recent years in response to steep inflation. The company had work to do to prove it was still a good value to its customers and would improve its affordability options, he said. “This won’t happen overnight. But it will happen,” Kempczinski said.

While higher prices in the U.S. helped offset weaker sales volumes, the company said further increases would be muted this year.

To keep customers interested in the brand, McDonald’s is working to boost offerings of chicken and its loyalty program. It was also testing a new bigger burger with two beef patties in international markets.

Overall, McDonald’s reported net income in the June quarter of $2.02 billion, down more than 12% from a year earlier. Earnings per share were $2.80, as analysts polled by FactSet had expected $3.08.

Revenue was flat at $6.49 billion, coming in below analysts’ expectations of $6.62 billion. Last year, McDonald’s got a big sales bump from a Grimace- hemed shake.

McDonald’s said it was also booking a pretax charge of $97 million for the quarter, mostly related to a coming sale of its South Korean business this year.

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Metal Producer Wrestles with Energy Costs

by Bob Tita – WSJ – Jul. 8, 2024

A **Chicago-based aluminum company** is betting billions of dollars that it can solve one of the biggest challenges in American manufacturing: paying for electricity.

Century Aluminum aims to roughly double domestic output of aluminum from smelters by **building** the **country’s first new smelter in 45 years**. The company’s **biggest hurdle** to starting the project is **securing** an **affordable power supply**.

“As a U.S. aluminum producer in a market where there is a huge deficit, why don’t we produce more? It’s all about the power,” said Matt Aboud, vice president for strategy and business development for Century Aluminum. The company has lined up a **$500 million grant from** the **Energy Department** to **support** the planned **facility**, which could **cost** as much as **$5 billion**.

Steadily climbing electricity costs have been a major factor behind the shrinking ranks of U.S. aluminum smelters, leaving buyers increasingly reliant on imports as demand is growing.

Automakers, energy companies and the aerospace industry are hungry for more of the aluminum from smelters, prized for its purity and ability to blend with other metals. The U.S. imported nearly 4 million metric tons of such aluminum last year, while 4.7 million metric tons was produced from recycled aluminum, from old beverage cans to manufacturing scrap.

Domestic production of smelter aluminum – which is known as **primary aluminum** – is **on pace this year for 689,000 metric tons**, which would be the **lowest since 1950**. **Smelters** have been **steadily going out of business** for years, pinched between stagnant aluminum prices and escalating power costs, which in some cases have climbed by more than one-third in recent years.

Century is still arranging financing and seeking a site for its smelter, which would be the largest in the U.S. with about 600,000 metric tons a year of production capacity. Aboud said much depends on where the company can find a steady supply of affordable power.

Century aims to secure a power-supply deal and complete the plans for the plant in the next two years and then start construction, which is expected to take about three years.

In manufacturing, few things are as power-intensive as smelting powdery aluminum oxide into aluminum. The **process takes** about **24 hours**, and **producing a ton typically uses more electricity than** a **single household consumes in** an entire **year**. **Century expects** its **planned smelter** to **produce** about 1**,500 metric tons** of **aluminum a day**.

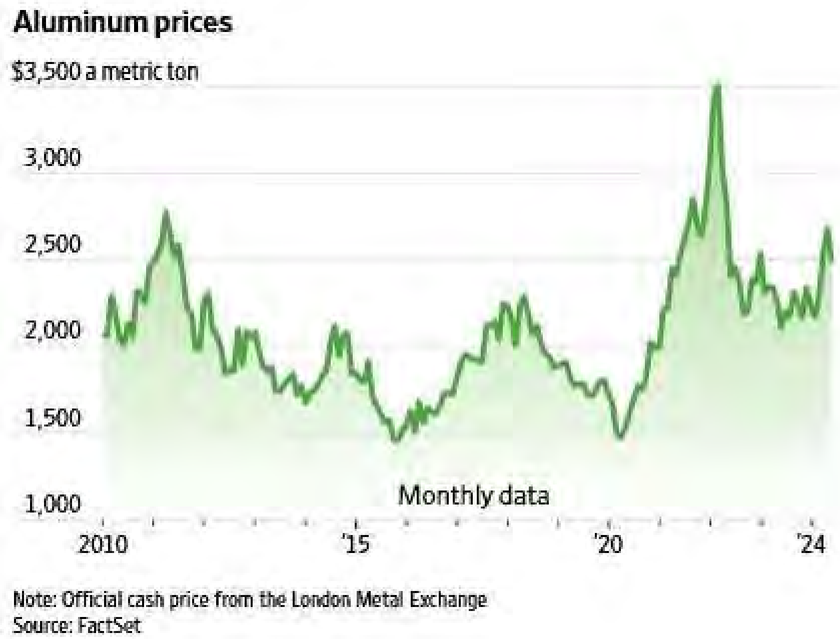
Four smelters remain in operation in the **U.S., down from** seven in 2020 and **23 in 2000**, when the U.S. was the world's leading producer of primary aluminum. A smelter in southeast Missouri was the most recent to close in January after reopening in 2018. **Century and Alcoa now account for nearly all** the **U.S.-made primary aluminum**.

Electricity accounts for **40%** of **smelters' operating expenses**. Century said that for over a decade it was able to secure enough reasonably priced power for its 55-yearold aluminum smelter in Hawesville, Ky.

When Russia invaded Ukraine in **2022**, the **cost** of **U.S. natural gas used** to **generate electricity rose** as the U.S. exported more gas to Western Europe to offset the loss of Russian supplies. The average cost for a megawatt-hour of electricity for U.S. smelters jumped to $54 in 2022 from $39 in 2021, according to commodities analyst CRU Group.

Century idled the **Hawesville smelter** in the **summer** of **2022** and has **no plans to restart it**, though CRU said smelters' average price for electricity receded to $36 a megawatt-hour last year. Century said **forward prices for electricity in Kentucky** are **above $45 per megawatt-hour through 2027 – too high for Century to recover** its **restart costs and make** a **profit**.

Power accounts for 40% of smelters' operating expenses.



Century Aluminum hopes to build a new smelter, but the company faces a big hurdle: securing an affordable power supply.

Century Aluminum's new smelter would be the biggest in the U.S. with about 600,000 metric tons a year of production capacity.

For every dollar increase in the **price** of a **megawatt-hour of electricity**, **Century said** it **costs** the **company** at least **$3 million in annual profit**.

Century and other primary aluminum producers also have been hamstrung by low prices that have been held down by China's massive production of the metal. The annual average inflation- adjusted price of aluminum on the London Metal Exchange slipped 2.1% from 2010 to 2023, CRU said.

Still, Century is betting that it can conquer the power conundrum. **In addition** to the **Energy Department grant**, its **planned smelter** will be supported with **tax breaks** created by the Biden administration **to revive U.S. aluminum smelter operations** and **reduce carbon dioxide emissions from** the **electricity they consume**.

"This is going to be a **test case for America's reindustrialization**," said Joe Quinn, executive director for the Center for Strategic Industrial Materials. The Washington- based group advocates for more domestic aluminum production to support electric vehicles, solar- energy panels and other manufacturing.

Century is **counting on** the aggressive build-out of solar- and wind-powered generating capacity now under way to start yielding excess power after 2030, and the company hopes to lock down supply in exchange for a decade's worth of steady electricity demand from a new smelter.

Much of that **renewable-energy capacity isn't yet connected to power grids**, making it difficult for industrial users to access it. Grid-connected renewable energy is expected to attract high demand, said Greg Wittbecker, an aluminum-industry analyst.

Other big users of electricity also are vying for large loads of renewable energy, including **new semiconductor chip plants** and **computer server centers** that are expanding to accommodate **artificial**-**intelligence** products such as ChatGPT.

Renewable power currently costs about **$10 more per megawatt-hour** than electricity generated by conventional power plants using coal or natural gas, according to analysts. The price gap could be narrowed with a provision in the **Inflation Reduction Act** that **allows primary aluminum producers** to **receive** a **federal tax credit** for **up to 10%** of their **production expenses**, **including electricity**.

Aboud said Century purposely opted for yearslong lead time for the plant to give executives enough time to obtain a favorable deal for electricity. "We need to see a sustained low-cost power environment and a sustained improvement in aluminum prices," Aboud said.

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Milder Inflation Bolsters Rate-Cut Chances

by Sam Goldfarb and Nick Timiraos – WSJ – Jul. 12, 2024
Alison Sider, Nicholas G. Miller and Will Parker contributed to this article.

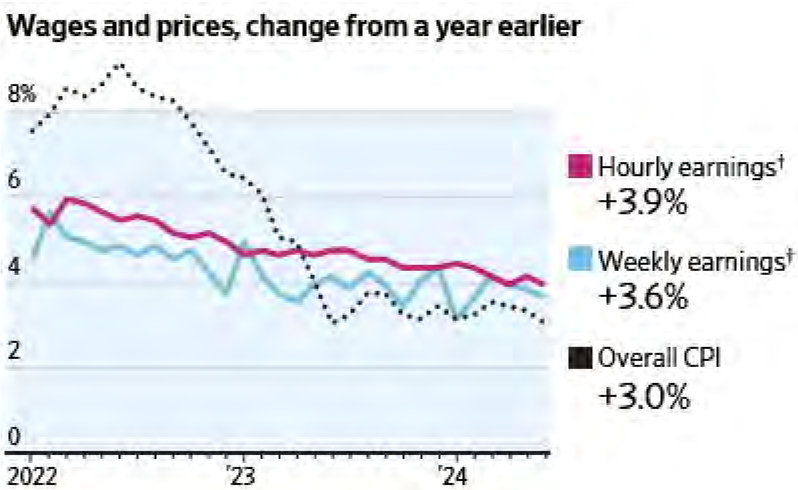
Consumer-price data eased to 3% in June, fueling possible Fed action in September.

U.S. inflation eased substantially in June, extending a recent slowdown in price **increases** that opens a **path for** the **Fed**eral Reserve **to cut rates by** the **end** of the **summer**.

The **C**onsumer-**P**rice **I**ndex, a measure of goods-and-services costs across the economy, **fell slightly from May**, **dropping** the **year-over-year inflation rate to 3%**, which was the lowest since June 2023.

Core prices, which exclude volatile food and energy items and are seen as a better gauge of underlying inflation, rose 0.1% since May. That was the mildest increase since January 2021, when large swaths of the economy were still frozen by the pandemic.

Altogether, the report showed prices cooled broadly in the second quarter and were below economists' expectations – the reverse of what happened in the first three months of the year, when inflation was surprisingly brisk.



"We've definitely seen a pretty sharp slowing," said Kevin Cummins, chief U.S. economist at NatWest Markets. "This is certainly a confidence booster for the Fed."

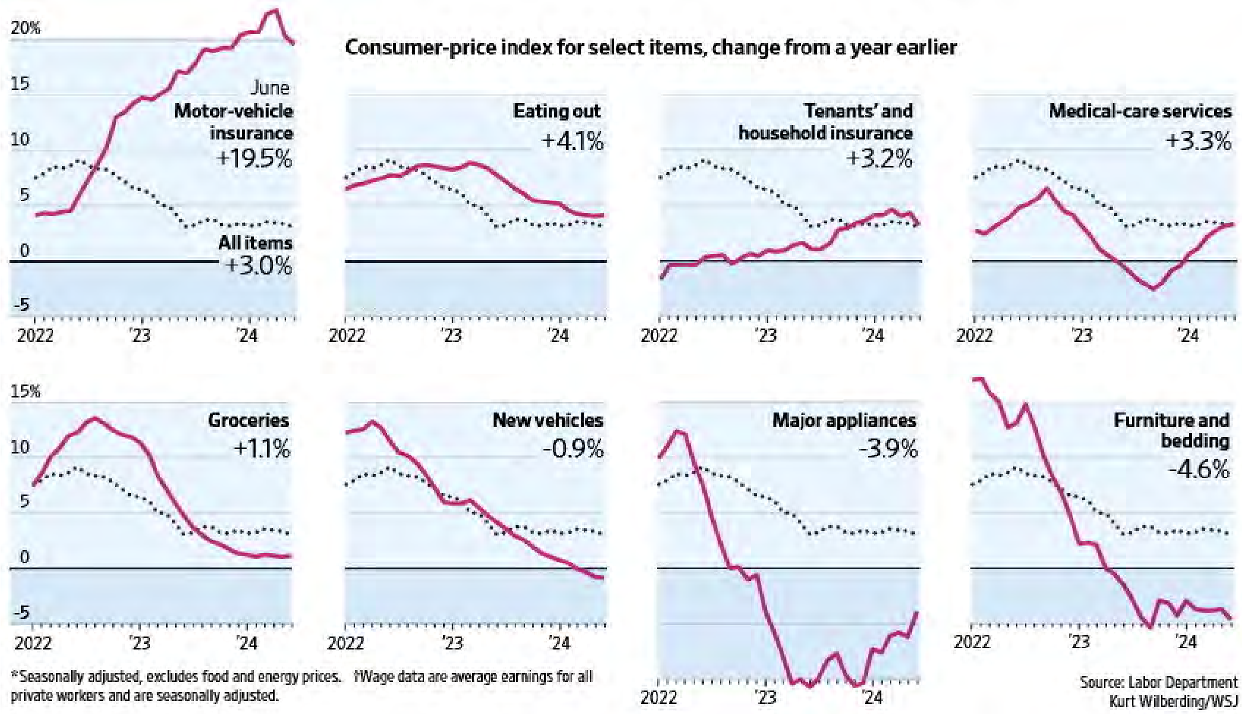
The report keeps the door wide open to a September interest- rate cut. This week, Fed Chair Jerome Powell laid the groundwork to cut by suggesting the labor market is slowing in a way that has diminished a major source of inflation and risks further weakness that wouldn't be desirable.

Investors don't expect the **Fed** to **lower interest rates** at its **next meeting**, **July 30-31**. Officials haven't publicly attempted to rally a consensus around such a move and, outside of extraordinary cases, resist taking markets by surprise.

A bigger question for that meeting is the degree to which officials lay the groundwork for a September cut.

After the report was released, investors dialed up bets that the Fed would cut rates twice this year, and the odds of a third cut climbed, implying the central bank could lower rates at its last three meetings of the year, in September, November and December.

Thursday's report could be especially comforting to policymakers because it showed housing costs are slowing after a mammoth run-up following the pandemic.



Housing inflation, which measures the cost of renting and **accounts** for about **one-third** of the **CPI**, has kept overall prices high.

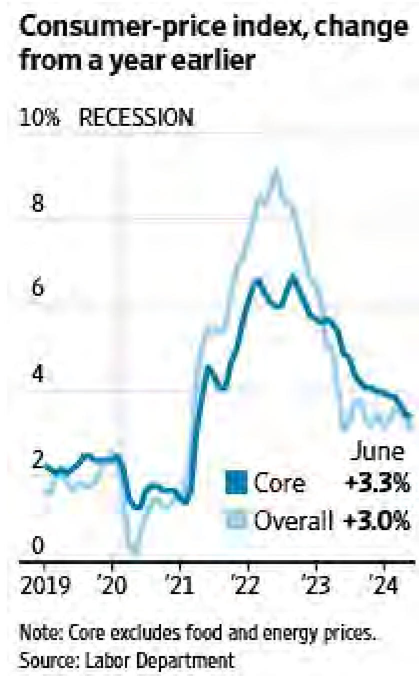
Economists and Fed officials have long anticipated that this inflation would ease because **rents** for new housing units have been cooling for 1½ years. But the figure **often trails market conditions by many months**. The latest report seemed to provide welcome confirmation that official inflation gauges are now capturing those developments.

Price increases were generally subdued across a range of categories. The costs of air travel and staying at a hotel fell particularly sharply from the previous month.

U.S. airlines have been cutting ticket prices – a reversal from a year ago, when airlines strained to expand flying quickly enough to meet demand. Then, "everyone was traveling, and it didn't really matter what it cost," Delta Air Lines Chief Executive Ed Bastian said on Wednesday.

This summer, airlines have added more than enough flying to accommodate the record numbers of passengers at U.S. airports, and fares have eased. The discounting contributed to a sharply lower second-quarter profit when Delta reported results on Thursday.

Executives at PepsiCo, which also reported quarterly results on Thursday, indicated that **inflation-weary shoppers** are **cutting back**.



The run-up in the price of everything from cars to restaurant meals to housing since 2021 has been abnormally large.

For the past few years, even as prices soared, many consumers kept buying affordable treats like Doritos and Lay's in lieu of bigger-ticket splurges such as restaurants, concerts or travel. But now, they are limiting their spending in all areas, said Jamie Caulfield, chief financial officer.

"There is a cohort of consumers that have become more price conscious," Caulfield said. "They're looking for more deals to get more for their money."

Car insurance, meanwhile, remained a hot spot for inflation, reflecting in part the lingering impact of a previous increase in car prices. Those have come down more recently, including in June.

Declines in large tech stocks pulled the S&P 500 lower on Thursday. But the Russell 2000, an index of small and midsize companies, posted a big gain, reflecting enthusiasm about the inflation report.

A move by the Fed to start cutting interest rates could be especially helpful to smaller businesses because they tend to have more floating-rate debt than larger companies.

U.S. Treasurys also staged a robust rally, driving their **yields lower**. The yield on the benchmark **10-year Treasury note settled** at **4.192%,** down from 4.280% Wednesday. **Movements in yields tend** to **broadly reflect investors' expectations** for **short-term rates set by** the **Fed**.

Heading into Thursday, there had been signs the economy has cooled – not enough to stir fears of a recession but sufficient to spur a change of tone from the Fed. Officials are trying to balance the risk of cutting rates too soon and allowing inflation to persist with the risk of waiting too long and causing unnecessary damage to the job market.

Inflation soared to 9.1% in **June 2022**, a **40-year high**, as the economy faced a series of shocks that prompted the Fed to raise rates at the fastest pace in four decades. The **central bank increased** its **benchmark rate most recently** in **July 2023 to** around **5.3%**, the **highest level since 2001**.

While inflation has cooled notably over the last two years, many people have taken little comfort from milder 12-month inflation readings because the run-up in the price of everything from cars to restaurant meals to housing since 2021 has been abnormally large.

The White House cheered Thursday's news. President Biden has spent the week attempting to stop a stream of Democratic defections from his re-election support after a devastating debate performance and public appearances that haven't reassured voters concerned about his age.

"The report shows that households are getting some much-welcome breathing room in key areas of their family budget – not just lower inflation but price declines in gas, cars, airfares," said Jared Bernstein, chair of the Council of Economic Advisers, in an interview. "Our work is far from done, but this is a very solid move in the right direction."

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OECD Expects Jobs Markets to Cool

by Paul Hannon – WSJ – Jul. 10, 2024

Unemployment rates are **set to pick up only slightly across** the **world's rich countries** in the **short term**, **while real wages will continue** to **rise as profit growth cools**, the **Organization for Economic Cooperation and Development said** Tuesday.

In its annual report on the jobs market, the **Paris-based policy advisory body** said wages have been rising faster than prices during the past year, but real wages remain below their levels from late 2019 in a number of countries, including the U.S.

The OECD said there are signs that the jobs market is cooling, with the number of vacancies falling relative to the number of people looking for work. But it doesn't expect to see the sharp rise in jobless rates that have accompanied past periods in which central banks have raised their key interest rates to cool inflation.

"The labor market remains pretty strong," said Stefano Scarpetta, the OECD's director for employment. "The labor market is easing, but slowly."

In the U.S., the **OECD expects employment** to **increase by less than 1%** in **both 2024 and 2025**, **with** the **unemployment** rate remaining **around 4%.**

That is broadly in line with the outlook across the OECD's 38 members, which are mostly rich countries. The OECD forecast that employment will grow by 0.7% this year and next, having increased by 1.7% in 2023.

Workers suffered a decline in their real wages during the surge in consumer prices that began in early 2021. The OECD said that during the year through the first quarter of 2024, real wages were rising again as inflation cooled. Out of the 35 countries for which data was available, 29 recorded a rise in real wage. Among those that didn't were France and Japan.

On average, real wages were 3.5% higher than a year earlier, a development that should support consumer spending and economic growth. However, **real wages** were **still below** their **2019 levels in** 16 countries, including the **U.S.**, where the **shortfall** stood at **0.8%**.

The OECD expects the recovery in real wages to continue this year. Offsetting that upward pressure on prices, profit growth has slowed in most countries. While profits grew much more rapidly than wages in 2021, the OECD estimates that since the start of 2022, labor costs grew more rapidly than profits in about two-thirds of the countries with data available.

In the OECD's view, a squeeze on profits can allow for further wage rises without triggering a fresh pickup in inflation. That is an outcome that central banks have feared since the start of the inflation surge.

"There are no signs of a price-wage spiral," the OECD said.

However, it warned that wage rises could yet have an impact on inflation.

"Looking ahead, it will continue to be important to strike a balance between allowing wages to make up some of the ground they have lost in terms of purchasing power and limiting further inflationary pressures," the OECD said.

The recovery of the job market from the initial blow delivered by the spread of the Covid-19 virus has been particularly strong for workers in lower-wage parts of the economy, and for women, the OECD said. In 17 of the 33 countries with available data, traditionally lower-pay industries recorded a faster rise in real wages between 2019 and 2023, while employment growth for women has outpaced that of men over the same period.

"Wages are performing better in the lower end than in the middle or high end," Scarpetta said.

Looking forward, the OECD said the transition to jobs that produce lower greenhouse gas emissions could have big regional impacts, with many of the new jobs that are created being in different locations to those that are lost. The OECD estimates that just 7% of employment is in what it describes as high-emission industries, but those who lose their jobs might face a lengthy period of lower earnings without retraining.

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Northwest Senators Urge Caution as Bonneville Weighs Day-Ahead Power Markets

by Zack Hale,
Standard and Poor's Global Market Intelligence – Jul. 26, 2024

US senators representing parts of the Pacific Northwest are **urging** the **B**onneville **P**ower **A**dministration to **carefully assess participation** in competing **day-ahead wholesale markets in** the **US West**, given the long-term impacts of the choice and some uncertainties surrounding both markets.

"We urge you to act carefully and deliberately," **Sens**. Ron **Wyden** (D-OR.), Jeff **Merkley** (D-OR.), Patty **Murray** (D-**WA**.), and Maria **Cantwell** (D-**WA**.) said in a July 25 **letter** to the federal power marketing administration.

The letter comes after Bonneville Power Administration (**BPA**) **staff** in **April recommended** that the federal utility **join Southwest Power Pool's proposed Markets+ offering**, a suite of day-ahead and real-time products designed to optimize wholesale power market operations in the Western Interconnection. The 14-state grid operator plans to launch Markets+ sometime in 2027 after receiving approval from the Federal Energy Regulatory Commission.

Most wholesale power market transactions occur in the day-ahead market.

The **California ISO**, meantime, has already secured FERC's approval for its Extended Day-Ahead Market (**EDAM**), which aims to **build on** the success of CAISO's Western Energy Imbalance Market (**WEIM**). The CAISO is targeting a go-live date for EDAM in 2026.

"Given ongoing uncertainties and the changing landscape with regard to both day-ahead electricity markets, we are concerned that BPA has expressed a preference for one market before complete and final information is available for clear decision-making," the senators said.

Governance concerns

In April comments on SPP's Markets+ filing, BPA noted that "critically, Markets+ has had fully independent governance from day one, including the establishment of an interim Markets+ Independent Panel, with oversight from SPP's independent board of directors."

"Bonneville believes that the Markets+ framework would provide a level playing field for participants at the outset and on an ongoing basis as the market evolves," BPA said.

In contrast, **BPA raised governance concerns** in September 2023 comments filed in the CAISO's **EDAM** proceeding.

"Bonneville's primary concern focuses on the governance structure's lack of independence from the state of California because the [**CAISO's**] **board** of governors members are **appointed by** the **California governor** and the **CAISO's enabling statutes require** the **board** of governors to **specifically consider** the **interests** of **California consumers and ratepayers** when taking action," BPA told FERC.

In their July 25 letter, the Pacific Northwest lawmakers noted that **Step 1** of a straw proposal advanced under the **West-Wide Pathways Initiative** – a multi-state effort to eventually transition the WEIM governing body to an independent regional organization – is **on** the **verge** of **being triggered with** the **admission** of Berkshire Hathaway Energy subsidiary **NV Energy Inc. as** an **EDAM participant**.

The five-member governing body currently holds "joint authority" with CAISO's board of governors. Step 1 of the Pathways Initiative would create a dispute resolution process allowing dual "jump ball" tariff filings with FERC when consensus cannot be reached, similar to an existing framework between the ISO New England and its stakeholder group, the New England Power Pool.

"The firm position taken by BPA that governance reforms were necessary helped inspire the West-Wide Governance Pathways Initiative last year," the lawmakers said July 25. "Signing of the market implementation agreements will trigger Step 1 of the governance changes proposed in the Pathways Initiative."

Lawmakers seek answers on market tradeoffs

With those considerations in mind, the senators asked BPA to respond to a series of questions about the tradeoffs between Markets+ and EDAM.

Among other things, they asked BPA to address which of the day-ahead markets will result in lower energy costs for the Northwest, "including both federal and nonfederal power." The lawmakers also asked BPA to address grid reliability and extreme weather considerations, market seams concerns, and potential greenhouse gas emission reductions.

"The decisions BPA makes now will have lasting consequences on the modernization and expansion of the electrical grid and energy generation resources across the West," the lawmakers said. "BPA's decision to join a day-ahead market is monumental – BPA must be able to demonstrate that it is in the best interests of communities across the Northwest that are reliant on BPA for both power and transmission services."

The senators added that a full analysis should include the option to join neither market "at this time."

Step 2 of the Pathways Initiative's straw proposal would form a new nonprofit legal entity, a "regional organization," with independent governance over the WEIM and

EDAM. That step would likely require enabling legislation from California, according to legal analysts.

California Assembly Member Chris Holden introduced regionalization legislation in 2023 that would authorize the CAISO Board of Governors to develop and submit a proposal for a multi-state regional transmission organization, with independent governance reforms that include a "western states' committee." However, the bill – **AB 538** – **failed** to **advance out of committee**. The bill was the third effort by California lawmakers in seven years to transition the CAISO to an independent multi-state organization.

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Oregon Utility Watchdog Asks State to Intervene on Proposed Double-Digit Electricity Rate Hikes

by Alex Baumhardt – Portland Tribune – Aug. 6, 2024

Portland General Electric and Pacific Power say their latest proposed rate increases are due to the rising cost of insurance and needed investments to expand electrical grids and make them resilient to extreme weather.

If the state's two largest electric utilities get what they've asked for, their **1.5 million customers in Oregon could pay 40% more for electricity next year than they did just three years ago**.

Those utilities – Portland General Electric, or **PGE**, **and Pacific Power** – **say** their latest proposed increases are due to the rising cost of insurance and needed investments to expand electrical grids and to make them resilient to extreme weather.

But Oregon's Citizens' Utility Board, a watchdog group established by voters in 1984 to represent the interests of consumers, **says** the companies are using rate hikes to make massive investments in infrastructure in too short a period, as well as creating slush funds for potential wildfire payouts in the future.

PGE wants to raise residential rates by 11% next year while Pacific Power asked for a 15% residential rate increase. But the board asked the state's Public Utility Commission to cap them at 7% plus the rate of inflation, or 10% annually, whichever is lowest. A rate increase to cover costs that go over that would need to be pushed to the next year or beyond.

The board asked the commission, which is charged with regulating the rates of privately owned utilities, to apply this cap to natural gas companies as well.

"In normal circumstances, it should be rare for utilities to increase rates by more than 10%," the Citizens' Utility Board said in a news release. "Unfortunately, we have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. This is a call to Oregon regulators to implement a cap for all for-profit utilities."

The latest rate requests from the two utilities are not driven by the costs of producing electricity, but by factors such as capital investments, insurance, profit margins and employee pay. In November, when the electric utilities will incorporate the costs of energy production into the rate proposals, they could ask for higher rates again.

The Public Utility Commission will make a decision in December, and the rates will go into effect in January.

The **commission declined to** comment on the specific proposals. Kandi Young, an agency spokesperson, said it can't **discuss active rate reviews**.

PGE

Portland General Electric's request for an 11% residential hike comes on top of an 18% increase in January and a 15% increase in 2023.

PGEs rates have gone up more than 30% since 2022, according to the Citizens' Utility Board.

The company said in its rate proposal that the increases were due to needed investments in grid resilience, energy storage and renewable energy.

But Bob Jenks, executive director of the Citizens' Utility Board, said PGE is making massive and long overdue investments all at once on the ratepayers' dime. He said big capital projects are appealing to investors who get a financial return on the money they lend to the company, but not to the ratepayers who have to pay those investors back.

"At some point, you've got to say you can't do this all in a three- or four-year period of time. You've got to set priorities," Jenks said. " If the customers can't afford it, and if the company's not going to try to manage this situation and set priorities and keep rates affordable, then the Public Utility Commission regulators are going to have to crack down and create restraints on the company."

In April, three months after a cold snap in January, PGE shut off power to a record number of households – 4,700 in one month alone – due to nonpayment. Citizens' Utility Board officials said this is clear evidence Oregonians are struggling to pay.

"Because utilities disconnect for nonpayment after 90 days, it is clear that the combination of rising rates and extreme temperatures has pushed customers into debt to PGE," the board said in a news release.

Pacific Power

If Pacific Power gets its 15% increase in 2025, customers would face electric bills more than 40% higher next year than they were just two years ago. Pacific Power raised rates by 11% at the beginning of 2024 and 21% in 2023.

The company said that would translate to $21.50 more per month for an average consumer.

The company said in its proposal that about half of the 15% increase would cover infrastructure upgrades, including grid and clean energy expansion and weatherization. The other half would help pay for wildfire mitigation as well as insurance and liability coverage.

For both Pacific Power and PGE, corporate liability insurance has gone up rapidly.

Pacific Power, owned by the company PacifiCorp, settled in June with more than 400 Oregon victims of the 2020 Labor Day Fires, paying out nearly $180 million after a judge found the company was negligent and responsible.

Though Pacific Corp can't raise rates to cover payouts from previous fires, it can start creating a slush fund for future payouts, Jenks said.

"There's a point at which it's better for them to just put together a pot of money and call it self insurance that they could use in these cases," he said. "But it means customers have to fund it up front and build that pot of money up."

Both PGE and Pacific Power have also asked for some of the rate increases to cover higher staff wages and company profit margins.

Beyond asking for rate caps, the Citizens' Utility Board asked that the electric utilities stop raising rates in the middle of winter. Bills are significantly higher during the winter because heating homes takes more energy than cooling them, and heat is often left on at night while air conditioning is not. For companies hoping to show big revenues for the first quarter, boosting rates in the lead-up to January when energy demand is high can be lucrative. But, Jenks said, it's taking advantage of the utilities' poorest customers.

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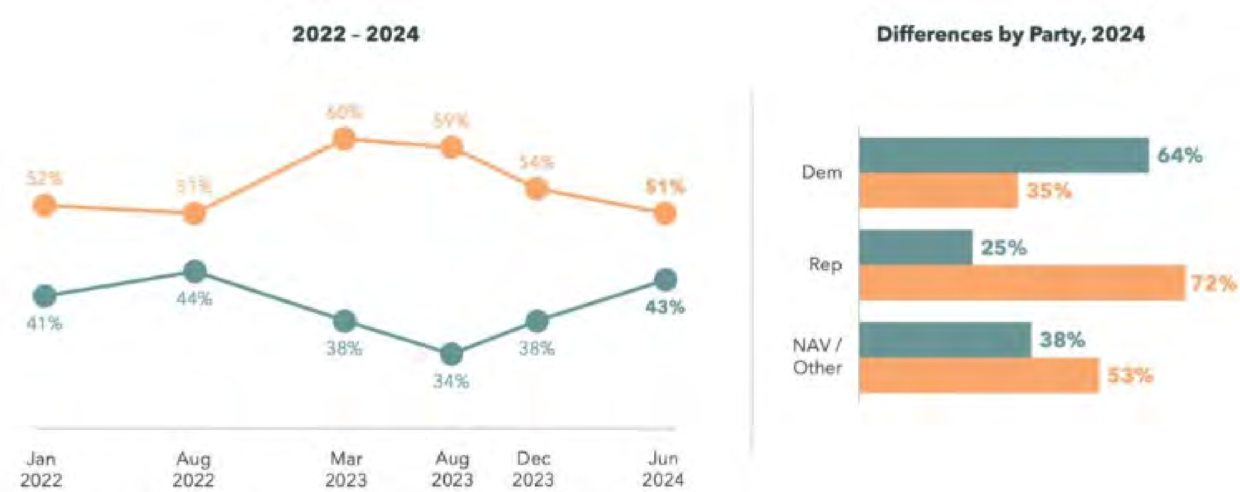
Oregonians Are Still Worried About the Economy

by Mike Rogoway – Oregonian – Aug. 4, 2024

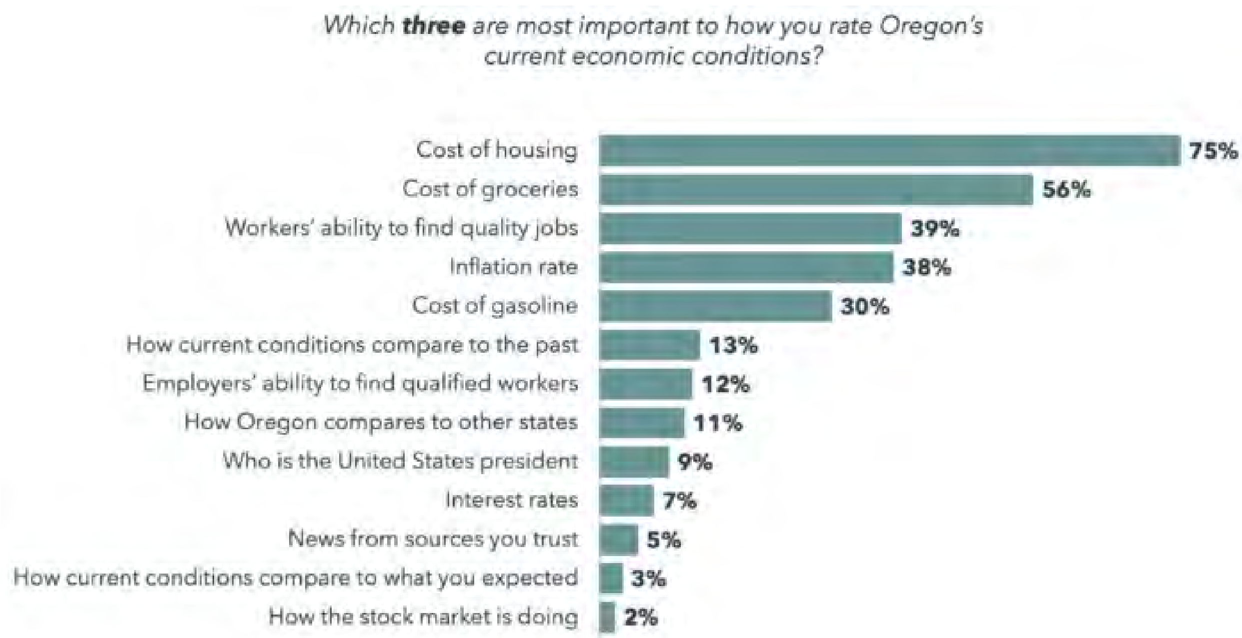


A **slim majority of Oregonians** continue to **believe** the **state's economy** is **performing poorly**, and **nearly as many say conditions are getting worse**, according to a new poll from DHM Research.

It's the latest indication of economic pessimism despite relatively low unemployment, rising wages and falling inflation.

Why do Oregonians feel so bad? **Higher prices remain** a **major issue**.

Poll respondents listed the costs of housing, groceries and gasoline, and inflation generally, among the most important factors influencing their perceptions of the economy.



Inflation peaked more than two years ago, but consumers still feel the sting of price increases that briefly approached double-digit percentages. And while some prices aren't climbing much at all now, other **costs** – **like** the **monthly electric bill** – **continue** to **rise steeply**.

People are also concerned about whether workers can find quality jobs, according to the poll. While unemployment remains near a historic low, at 4.1%, state data shows that a **rising share of people are working part-time jobs because they can't find full-time work**.

Oregonians have had a persistently gloomy view of the economy in the pandemic's aftermath though the share of people rating the economy as poor has declined by 9 percentage points since last summer. Overall, a majority of Oregonians haven't rated the economy as good since 2019.

Intriguingly, though, most poll respondents say their own finances are OK.

Among those responding to DHM's latest poll, 54% said their personal finances were good or very good. Thirty percent called their circumstances poor, and 15% said they were very poor.

Detailed poll results offer some more insight into why people feel the way they do.

Two-thirds of Oregonians with just a high-school diploma or less rate their finances as poor. Just 24% of those with a college degree feel that badly.

There's a similar gender divide. Among men, just 39% rate their financial situation as poor. Fifty-one percent of women say their finances are in poor shape. (There wasn't much difference between how white and nonwhite Oregonians view their situations.)

Nothing affects Oregonians' perceptions more than housing. Three-quarters of those who own their own homes say their finances are in good shape. Just a third of renters feel the same way.

Taken together, the poll suggests **Oregonians' outlook** depends a lot on the economic opportunity they see for themselves and the **vulnerability** they feel **if** they're they feel if they're **renting** their homes.

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Oregon's Tech Industry Is Shrinking

by Mike Rogoway – Oregonian – Jul. 14, 2024

[Oregon's software industry is shrinking - oregonlive.com]

Oregon's software industry, which helped anchor the economic boom that followed the Great Recession, has turned south over the past two years.

Software employment statewide is **down 7.4% from** its **peak** in the **summer** of **2022**, according to data from the Oregon Employment Department. That's a period during which overall Oregon jobs grew steadily.

It could be just a blip. Perhaps Oregon's software industry is simply catching its breath after two years of strong growth in the pandemic's immediate aftermath.

"Some of those losses are likely related to a broader tech correction as some of the pandemic related demand subsidies," employment department economist Brian Rooney wrote in a recent analysis of one segment of the software industry.

Google, for example, laid off about 12,000 workers last year – about 6% of its total workforce. **Microsoft**, **Salesforce** and **other big tech companies have** also **cut jobs**, too, **over** the **past two years** as they repositioned their businesses.

The software cutbacks may mirror what's happening in **Oregon's chip industry**, which boomed during the pandemic and then lost jobs last year. **Economists expect semiconductor manufacturing will bounce back as** chipmakers cash in on **state and federal subsidies awarded** this year.

The **software industry isn't getting** any of those **government perks**, though. And there are reasons to worry about the health of Oregon software specifically.

For one, **venture capital investment in Oregon startups fell sharply last year** – to its lowest level since 2017. Relatively few entrepreneurs are starting tech companies in Oregon and those that are launching don't seem to be attracting much attention.

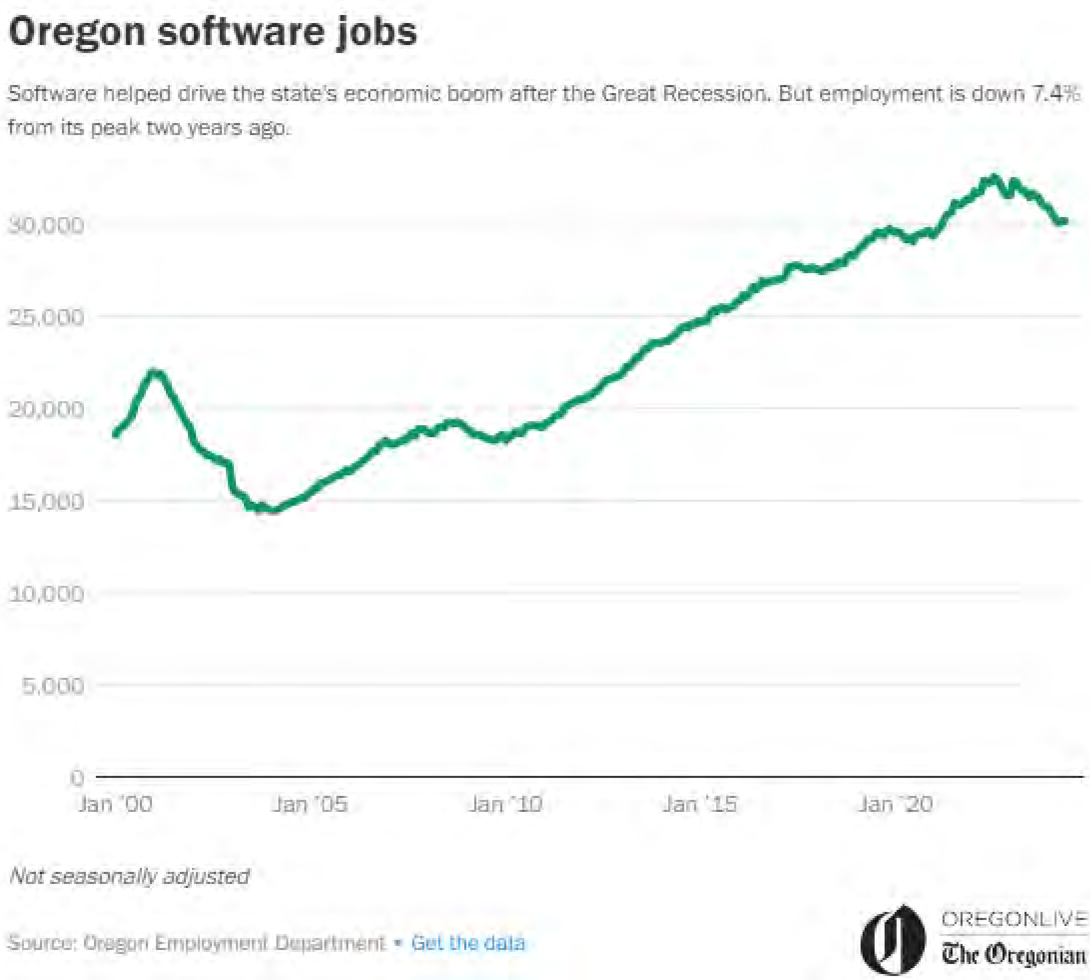
Multnomah County now has one of the highest personal income tax rates for high earners. That could make Portland less attractive for ambitious entrepreneurs hoping to build valuable new businesses.

The Portland Incubator Experiment, which was at the center of Oregon's software boom a decade ago, shut down its tech component last summer as tech entrepreneurship waned.

Software is a relatively small part of Oregon's total workforce, with just about 30,000 people working in the industry. But many others do some computer programming as a component of their jobs in other industries.

And software is economically significant because the industry pays an average wage of about $140,000 annually, more than double the average across all industries.

Portland used to be an attractive destination for remote software workers because the cost of living was so much lower here than in Silicon Valley or Seattle. The city is still cheaper than its neighbors to the north and south.



But the gap has narrowed, and the region's population has stagnated. Now, **slightly more people are leaving Oregon than** are **moving in**.

It could be that new generations of software developer and tech entrepreneur will find other places more appealing.

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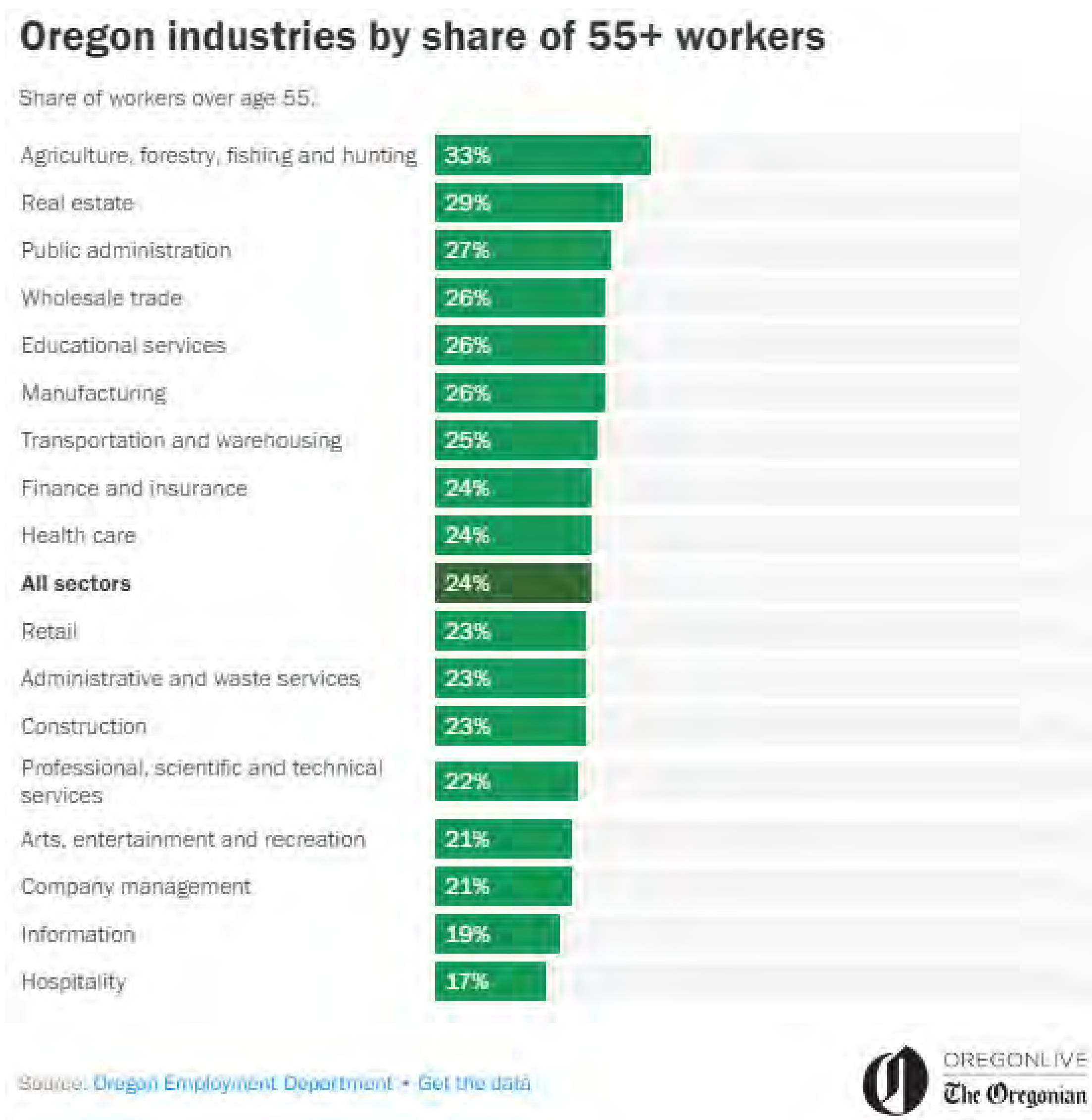
Oregon's Workforce is Aging.
Here Are the Industries with the Oldest Workers

by Mike Rogoway – Oregonian – Jul. 21, 2024
Oregon's workforce is aging. Here are the industries with the oldest workers - oregonlive.com

Nearly 1 in 4 Oregon workers is **over 55**, **nearing or beyond** the **typical retirement age**.



The **share of older workers in** the **state's labor force** has more than **doubled since 1990**, according to a new report from the Oregon Employment Department. If there's a **big wave of retirements** in the offing, that **could limit future economic growth** – especially in those industries with the highest share of older workers.

Oregon is **one of** the **oldest states in** the **nation**, with the median resident about 17 months older than the median American. That's showing up in **added demands on social service** agencies and on the state's **health care** system.

And it **could have** a **big impact on Oregon's economy**, too.

After three decades of the rapid growth that began in the 1990s, the **state's population** has **stagnated since** the **pandemic**. **Birth rates** are relatively **low**, and **slightly more people** have been **moving out of** the **state than moving in**.

Older workers leaving the labor force could create an even tighter labor market. That might be good for employees in some ways, pushing up wages as companies compete to attract workers. And older workers' departures would open up pathways for career advancement.

For employers, though, a smaller labor pool could make it tough to staff their operations and to expand.

Employment department economist Gail Krumenauer catalogued the Oregon industries with the oldest and youngest labor forces.

Agriculture, real estate and public administration are the oldest industries, all with more than a quarter of their workers over 55.

In terms of total number of workers over 55, though, health care is the largest with 70,000, followed by manufacturing (49,000) and retail (48,000). Those fields will all face big challenges in filling their ranks in the years ahead.

Oregon's hospitality and information industries have the smallest share of workers under 55 – 17% and 19%, respectively.

Hospitality includes hotels, bars and restaurants, which are often service jobs that don't require a lot of prior experience. And that attracts a younger set of people new to the workforce.

The information sector includes telecommunications, website development, online publishing and customer service. Those fields tend to skew younger and might not feel the pressures of Oregon's aging workforce quite as soon as other fields.

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Reuters

Warren Buffett Donates Record $5.3 Billion of Berkshire Shares to Charity

by Jonathan Stempel – Reuters – Jun. 28, 2024
Warren Buffett donates record $5.3 billion Berkshire shares to charity | Reuters

Berkshire Hathaway Chairman Warren Buffett attends the Berkshire Hathaway Inc annual shareholders' meeting in Omaha, Nebraska, U.S., May 3, 2024.

Warren Buffett donated another $5.3 billion of **Berkshire Hathaway stock** to the **Bill & Melinda Gates Foundation and four family charities**, his biggest annual donation since he began making them in 2006.

Buffett's donation **boosted his overall giving to** the **charities to about $57 billion**, including to the in the last two Novembers.

The **latest donation**, announced on Friday, **included about 13 million Berkshire Class B shares**.

Buffett donated 9.93 million shares to the **Gates Foundation**, and has donated more than **$43 billion** of Berkshire shares there **overall**.

He also donated 993,035 shares to the **Susan Thompson Buffett Foundation**, named for his late first wife, and **695,122 shares** to **each** of **three charities led by his children Howard, Susan and Peter**: the **Howard G. Buffett Foundation**, the **Sherwood Foundation** and the **NoVo Foundation**.

Buffett, 93, plans to give away more than 99% of the fortune he built at Omaha, Nebraska-based Berkshire, which he has run since 1965, with his children serving as executors of his will.

Berkshire is an **approximately $880 billion conglomerate** that owns dozens of businesses including the BNSF railroad and Geico car insurance, and stocks such as Apple.

Buffett still owns 14.5% of Berkshire's outstanding shares, a Friday regulatory filing shows, despite having given away more than half of his stock since 2006.

His $128.4 billion fortune makes him the **world's 10th-richest person**, according to Forbes magazine.

In a statement, Buffett said he was worth about $44 billion when the donations began, but that the benefits of compounding, "simple and generally sound capital deployment" at Berkshire, and the "American tailwind" produced his current wealth.

Buffett, Bill Gates and Melinda French Gates also pioneered the Giving Pledge, in which 245 people like OpenAI's Sam Altman, Michael Bloomberg, Carl Icahn, Elon Musk and Mark Zuckerberg committed at least half of their wealth to philanthropy.

The **Susan Thompson Buffett Foundation** works in reproductive health. The **Howard G. Buffett Foundation** works to alleviate hunger, mitigate conflicts including in Ukraine, and improve public safety. The **Sherwood Foundation** supports Nebraska nonprofits, and the **NoVo Foundation** has initiatives focused on girls and women.

Friday's filing suggests based on Buffett's holdings that Berkshire has repurchased little or none of its own stock since April 19.

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Portland Is Aging Faster Than the Rest of the Country.

by Riya Sharma – Oregonian – Jul. 5, 2024

The Community for Positive Aging hosted a "Memory Care Cafe" on Thursday, an event for seniors with memory loss and their caregivers and families.

Even on a typically quieter day of the week, a Northeast Portland senior center bustled with activity.

About 20 seniors sat in a circle last Thursday – some in wheelchairs or sharing tables with their caregivers – and waved colorful scarves to the strum of a music therapist's guitar. Others stopped by the pantry to take home fresh vegetables or fill their mugs with coffee.

The phone rang constantly. Jaden Saloum, a center assistant at The Community for Positive Aging, answered requests for legal support, tax help and health assistance. One caller had nothing to ask for, but the conversation lasted 13 minutes anyway. As it ended, the woman on the phone thanked Saloum for listening, saying she lives alone and had no one else to go to.

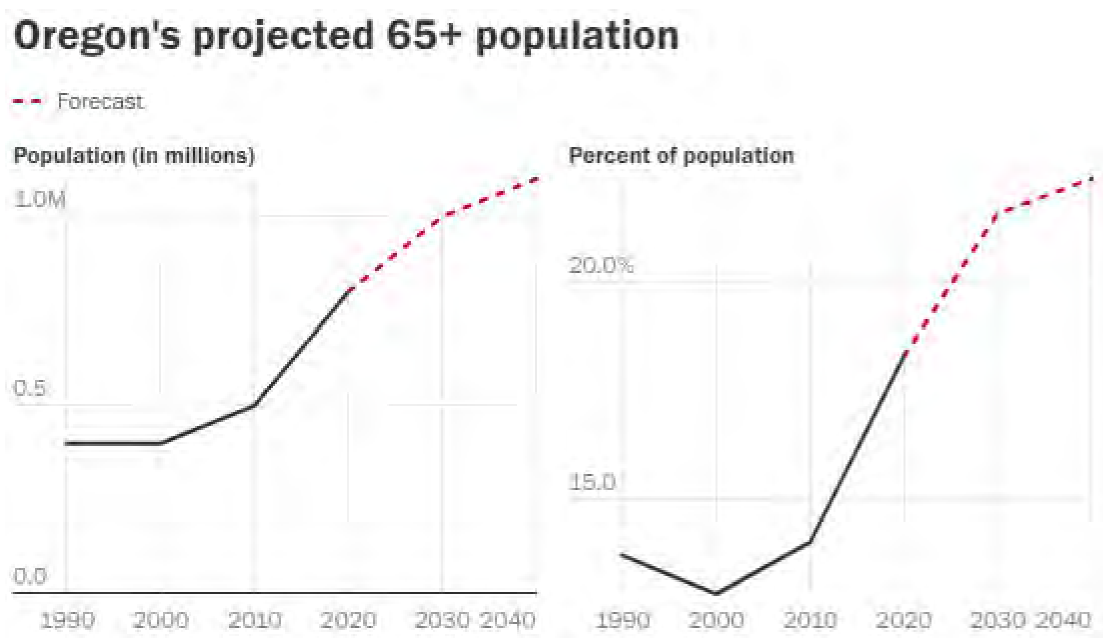
"It's a big issue with seniors, the social isolation is huge," center manager Kaylyn Peterson said.

Groups like The Community for Positive Aging, formerly the Hollywood Senior Center, serve an ever-growing population of retirement-age adults. New numbers released Thursday by the U.S. Census Bureau underscore the demographic shift underway – one for which researchers say the region is unprepared, even though it could be predicted decades ago.

The **numbers show** the **effect** will be **magnified in** the **Portland area**, **where** the **65-and-older population** is **growing even faster than** the **U.S. average**.

And this is **just** the **start**. **Oregon's aging population** is **not expected to peak until 2050**, said Carolyn Aldwin, director of the Program on Aging Studies at Oregon State University.

The **state's low fertility rates combined with rising life expectancy contribute to** the **trend**, said **Neal M**arquez**, forecast manager** at **Portland State University's Population Research Center**.



Social service strain

The **aging population threatens to overwhelm underprepared social services**.

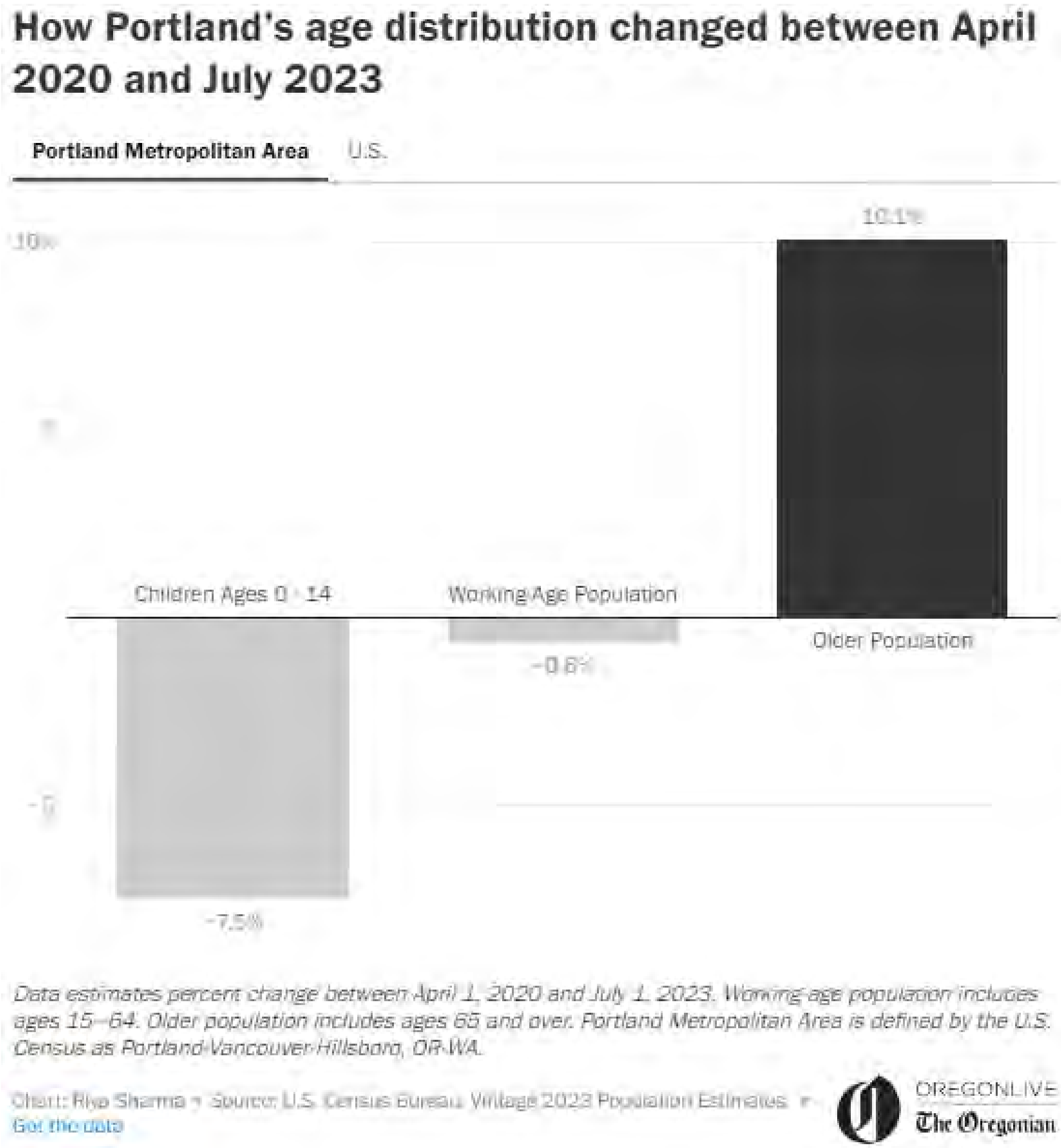
Calls to Northwest Pilot Project – a nonprofit that helps low-income seniors in Multnomah County find housing – have tripled in the last three years.

In the same time period, the **number of older adults** who are **homeless** in **Multnomah County increased by 15%,** said Laura Golino de Lovato, executive director of Northwest Pilot Project. **Adults over 60 make up a quarter** of the **homeless population in** the **county** and projections suggest this number will increase, she added.

"There are **more people at risk of eviction** and there are **more older adults** who are **becoming homeless for the very first time** in their lives because the **fixed**

income that they're on **does not cover** the **increasing rents** that they have to pay," Golino de Lovato said. "We are overwhelmed with calls and requests for support."

The majority of Golino de Lovato's clients rely on social security. But because the model is based on earnings over time, people who have worked low-wage jobs their whole lives don't receive enough to support themselves, she said.

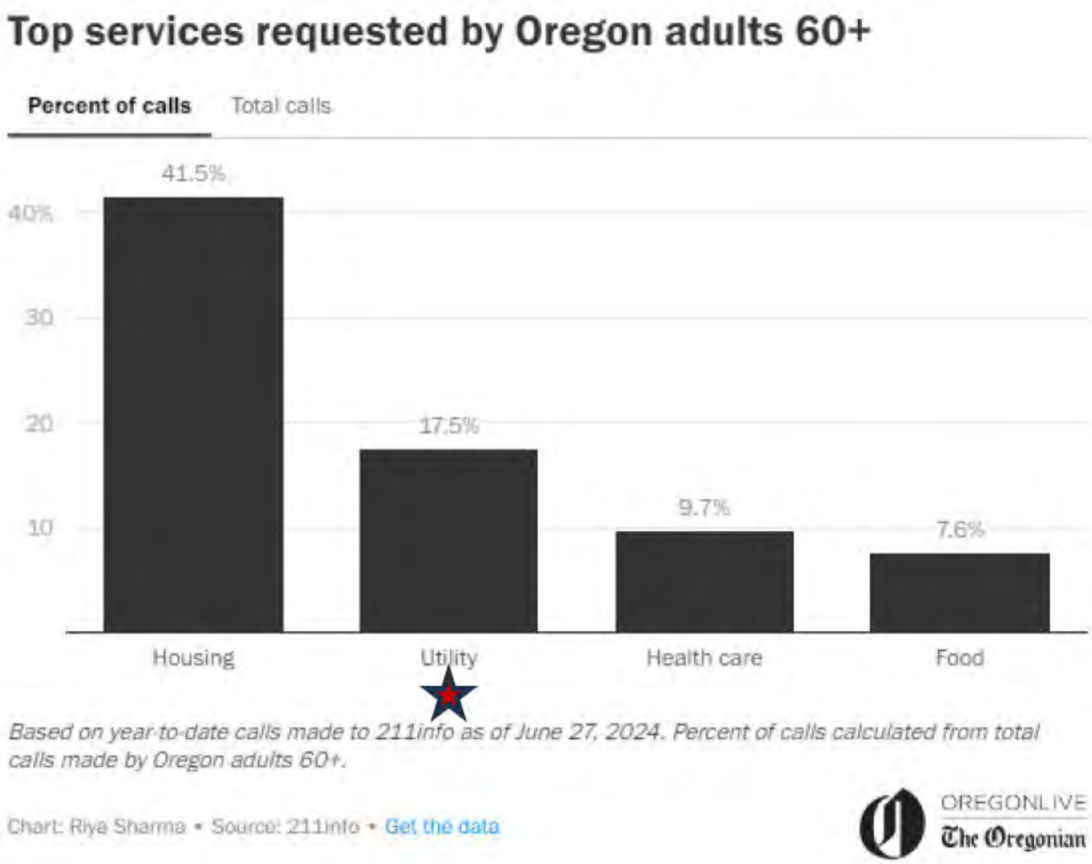


One in five adults aged 50 and older have no retirement savings, according to an AARP survey conducted in January.

The result? "We've been operating for almost 55 years," Golino de Lovato said. "This is definitely the **biggest increase** in the number of **low income, older adults** that we've **seen** in **Multnomah County in our history**."

Calls and requests to 211info, a statewide social service referral hotline, show that affordable housing is just one piece of the puzzle. Seniors, officials for the program say, routinely reach out for a range of additional services.

"The main thing we're hearing from older adults is, 'I worked my whole life and I've never had to ask for help before,'" said Dary Nutter, a spokesperson for 211info.



Evolving needs

When Amber Kern-Johnson first started working at The Community for Positive Aging in 2007, things looked different.

The senior center's executive director remembered the center as a place to relax, dance and socialize and where a group of regulars came to kick back around the pool table.

But the laid-back model couldn't keep up with seniors' growing needs. In her 15 years with the organization, Kern-Johnson has seen a significant increase in demand for social services.

“Now, people have serious needs around affordable housing, around food security, around mental health, physical health,” Kern-Johnson said. “Our organization made a very intentional shift to move from more of a traditional senior center to providing more direct service and response to needs because we saw that need.”

The center started an additional free meal service in March for participants 60-years-old and older. Friday’s lunch had almost 50 attendees, which Kern-Johnson said underscored the need for food and community.

“We’re seeing folks whose needs are a lot higher than they have been in the past,” she said.

More than 90% of The Community for Positive Aging’s clients are low-income, with over half living at or below the poverty line of $15,060. Requests to the food pantry have more than doubled in the last year alone.

The center sees up to 5 to 10 new clients requesting specialized assistance each week. Upwards of 80% of case-managed clients are living with disabilities, mobile or cognitive impairments, chronic health conditions, or alone without any natural support.

“We’re seeing more people coming in who are classified as high-need,” Kern-Johnson said.

Resources are stretched thin, though, and the waitlist for clients seeking case-management support is growing.

“We don’t have unlimited staff,” she said. “I see the toll it takes on my team.”

Another meal service held at the Community for Positive Aging is a monthly Asian Food Pantry, providing culturally-specific foods for people who might otherwise have trouble accessing them.

Health care challenges

Mary Kay Brennan arrived early for a storytelling class at the senior center Thursday. As she waited, she greeted Carol Emens and pointed out the new permanent crown on her tooth; the dentist had tried to delay the procedure, but to Brennan's relief, it got done just in time for a trip to San Diego.

"It's the little things when you get older, like getting your crown on time," the 77-year-old said.

Emens, who just had a root canal, said that teeth are only one of the health issues that become common with age. As they waited for class to begin, the two women discussed their friend's unfortunate accident that resulted in a broken hip.

The problem, 85-year-old Emens said, is that nobody goes into geriatric medicine.

"You go to a general practitioner and she doesn't really know the foibles of old people, and it is really difficult."

The growing number of seniors is already overwhelming health care systems, said Aldwin, the Oregon State researcher.

"Some facilities will no longer take new Medicare patients because the health care system folks argue that Medicare systems don't really cover their costs. That's a bone of contention between how much Medicare should pay, how much they can pay, and how much the care actually costs," Aldwin said.

The crisis facing rural Oregon is even worse. Aldwin described it as a "double whammy" – older adults often relocate to rural areas for the lower cost of living while younger adults often move to cities for jobs.

"So you have a smaller population which is older, frailer, and in need of more services and the rural counties don't have the economic base to support this," Aldwin said. "It's going to keep increasing and the problem is going to get worse."

In Oregon coast city of Gearhart, calls to volunteer firefighters have more than doubled since 2019 with the majority of requests being for slip-and-fall injuries and other medical services, city attorney Peter Watts said.

During the same time period, an increased number of older adults moved to Gearhart from the Portland metro area, creating what Watts called a "critical housing shortage." The workers who might provide clinical or home care can no longer find an affordable place to live, Watts said, so they leave, or they don't move to Gearhart in the first place.

Hospitals in Gearhart have had to rely on travel nurses that stay in hotels, he said. "I think they're really struggling to keep up."

At some point, Aldwin said, urban centers won't be able to keep up either.

Contributors to society

The growing senior population will doubtless stress the system, but researchers say it's easy to overlook the contributions of older Oregonians.

At the Community for Positive Aging gift shop last Thursday, Georjean Wilkerson, 85, wrapped an ornament in purple tissue paper while chatting with a regular customer. Next to her, Madeline Stark, 87, sorted through a box of new donations, dusting off a set of four lemon-printed glasses on the counter.

The two women volunteer every Thursday at the shop – a thrift-style store that features handmade crafts made by seniors. The artists split the proceeds with the senior center.

Volunteers Georjean Wilkerson (left) and Madeline Stark (right) assisted customers at the senior center's on-site gift shop.

Stark moved to Portland from Santa Fe three years ago to be closer to her daughter.

“I decided I would come here and see what it’s like and volunteer,” said Stark, who’s also taken classes offered by the center on living with chronic conditions. “It was very welcoming. I was so happy, and I met Georjean and the other women.”

Wilkerson, who was born and raised in Portland, first got involved with the center when she took a class on how to care for her husband, who had been diagnosed with Alzheimer’s disease. “I’ve been coming for over 20 years for different things,” she said.

At least 85% of the center’s 140 active monthly volunteers are 55 and older, Peterson said.

Research has shown that older adults are more likely to create startup companies, support arts and cultural centers, and be active volunteers. Aldwin said the unpaid contributions of older adults are part of what allows the working-age population to contribute to the economy.

There are benefits to an aging population too, Aldwin said. “It’s not all doom and gloom.”

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Powell Tees Up Fed Rate Cut Next Month

by Nick Timiraos – WSJ – Aug. 1, 2024

Officials hold policy benchmark steady but signal progress in fighting inflation

Fed Chair Jerome **Powell said officials could cut interest rates at their meeting** in **September**, moving closer to a new phase that seeks to avoid weakness in the labor market amid signs inflation is heading lower.

While Powell and his colleagues **didn’t commit** to any such move when they held rates steady on Wednesday, he appeared to **suggest** a **cut** was more **likely** than not during a news conference.

“The broad sense of the committee is that the economy is moving closer to the point at which it will be appropriate to reduce our policy rate,” Powell said. “A reduction in the policy rate could be on the table as soon as the next meeting in September.”

Powell cited better news on inflation, a desire to prevent a material rise in unemployment, and his view that policy is beginning to more meaningfully slow activity during a 50-minute news conference that did little to dispel widespread expectations in financial markets of a rate reduction at the Fed’s next meeting.

U.S. stocks opened the day sharply higher, then held on to their gains after the Fed’s news conference. **Treasury yields edged lower**.

While **Wednesday’s decision** to **leave rates in** a **range between 5.25% and 5.5%**, a two-decade high, was unanimous, Powell suggested that at least one official had argued in favor of lowering rates at this week’s two-day meeting.

“That was big, because if they were seriously talking about whether or not to go in July, September seems like a done deal unless we get something crazy between now and then,” said Jamie Patton, cohead of global rates at TCW, a Los Angeles asset manager.

Investors now expect an **initial quarter-point reduction to be followed by two more at meetings** in **November and December**. “What speeds up the cycle is weakness in the labor market and what slows down the cycle is stickiness on inflation,” said Michael de Pass, global head of rates trading at Citadel Securities.

Officials made two important changes to their policy statement that acknowledged recent progress in their inflation fight and that pivoted closer to lowering rates without making any explicit commitment.

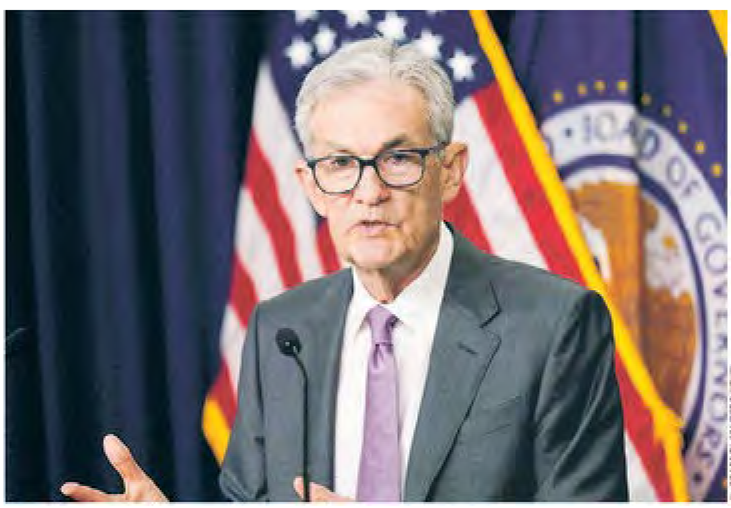
They described inflation as “somewhat elevated,” a notable downgrade. And they underscored that this progress meant they could treat both sides of their mandate – to maintain low and stable inflation with sturdy labor markets – on a more equal footing for the first time since they rapidly raised rates starting two years ago to combat high prices.

"The committee is attentive to both sides of its dual mandate," the statement said, retiring language that for the past two years described policymakers as "highly attentive" to inflation risks.

The stakes are high for Fed officials, who have been trying to navigate two risks. One is that they ease too soon, allowing inflation to become entrenched at a level above their 2% target. The other is that they wait too long and the economy crumples under the weight of higher rates.

The economy has been sturdy this year. **G**ross **D**omestic **P**roduct, the broadest measure of U.S. economic output, **rose** at a **2.1% annual rate** during the **first half** of the **year**. While inflation was unexpectedly hot in the first quarter, more recent readings suggest a slowdown in price growth during the second half of last year has resumed and might be broadening.

"What we're seeing right now is better than last year," when price growth slowed rapidly but declines were concentrated in goods and not services, said Powell. "This is a broader disinflation."



Left: Fed Chair Jerome Powell at his news conference Wednesday in Washington.

In addition, recent earnings reports suggest **corporate America is enjoying less pricing power as consumers tighten their belts and push back against hefty price increases of the last three years**.

McDonald's said sales sputtered in the April-to-June quarter, falling nearly 1% from a year earlier, and sounded a warning for the restaurant sector. "The consumer across a number of these markets is being very discriminating," said Chief Executive Chris Kempczinski in an earnings call on Monday.

Fed officials raised rates at the fastest pace in 40 years when inflation surged to a four-decade high in 2022. They feared rapid price increases could lead high inflation to grow entrenched across the economy, particularly if prices and paychecks rose in lockstep.

But recent data suggest that hasn't occurred. There were **1.2 job openings for every unemployed worker in June**, down from a high of 2 when the Fed began lifting rates in March 2022 and back to levels seen before the pandemic. Powell said on

Wednesday he no longer saw the labor market as a source of inflation risk. "I would not like to see material further cooling in the labor market," he said.

While layoffs remain low, hiring rates have also **tumbled**. It is **taking workers longer to find jobs**, and the **unemployment rate** edged up to **4.1% in June** from 3.7% at the beginning of the year. Pressed over whether officials were concerned that this might presage further labor- market weakness ahead, Powell said, "We're watching really carefully for that."

Wage growth is cooling after the reopening from the pandemic ignited a rehiring frenzy. Private-sector wage and salaries grew 0.8% in the second quarter, the Labor Department said on Wednesday, the softest rise since 2020.

Moreover, some industries most sensitive to higher rates are facing more pressure. The number of housing units under construction nationally plateaued in 2022, after borrowing costs soared, but residential construction turned negative earlier this year and was down nearly 8% in June from a year earlier, the biggest drop since the 2006-11 housing bust.

A decline in mortgage rates below 7% in recent weeks hasn't done anything to boost demand for new mortgages, the Mortgage Bankers Association said on Wednesday.

The economy has been more resilient to higher interest rates than most economists expected, in part because many households and businesses locked in low borrowing costs during the pandemic. But those same buffers that weakened the transmission of interest rates on the way up could also work against the Fed on the way down if it needs to stimulate the economy, TCW's Patton said.

"That's why we think the Fed is a little overconfident thinking they can just ease rates as soon as they see weakness, and everything will be fine," she said.

Other sectors are dealing with the potential payback from a surge of demand unleashed by the Covid-19 pandemic. Brunswick, the world's largest maker of pleasure boats, said last week revenue had fallen 15% in the second quarter. The introduction of new model year products in June "did not catalyze boat purchases as we had anticipated," Chief Executive David Foulkes said.

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Racked by Extreme Heat, One Worker Died on the Job. His Story Is a Warning.

by Arian Campo-Flores – WSJ – Aug. 3, 2024

Cory Foster's death shows perils of prolonged exposure to extreme heat worsened by climate change.

Justin "**Cory**" **Foster**, a **lineman** who **often traveled to storm-ravaged communities to help restore electricity,** was **used to working in searing summer**

weather as he **perched atop utility poles to install wires**. **But** as the heat index climbed to **113 degrees Fahrenheit on** a **job** in Marshall, **Texas**, **last year**, the temperature **baked his body**.

His **head hurt**, his **legs cramped**, and he **threw up**, Foster told his fiancée, Amanda Hightower. Co-**workers drove him back** to their **hotel**, **where he drank fluids**, stripped off his clothes and **took** a **cold shower**.

"I got too hot today," Foster told Hightower on a FaceTime call that evening.

Left: Cory Foster loved his work as a lineman, his family said.

Hightower, 28 years old, said she wasn't too worried because she was accustomed to seeing him come home flushed and sweaty. She didn't imagine the severity of the ordeal he was facing.

Workers who perform strenuous tasks in sometimes sweltering settings, from outdoor locations such as farms and construction sites to indoor ones including foundries and warehouses, have long been vulnerable to injury or illness. Now, as climate change drives temperatures to record highs, they are more susceptible than ever.

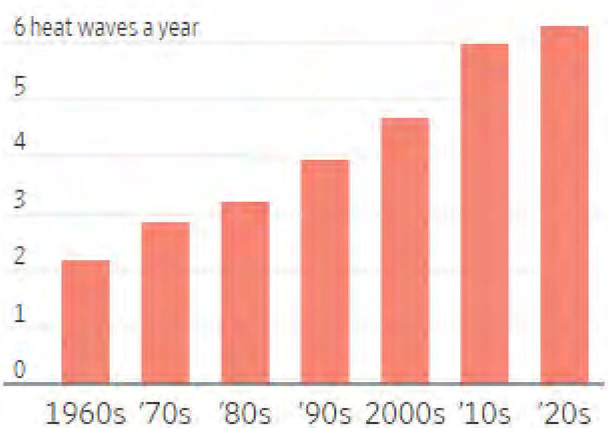
What happened to Foster, an **otherwise healthy 35-year-old**, underscores the perils of prolonged exposure to extreme heat and how deeply it can damage the body if not treated properly.

Work-related deaths from exposure to environmental heat are trending up in the U.S. They reached 43 in 2022, the most recent year for which data exists, compared with 31 in 2012, according to the Bureau of Labor Statistics. Between 2011 and 2020, work-related heat injuries and illnesses averaged 3,389 a year, BLS data show. An Occupational Safety and Health Administration panel said the figures are likely vast underestimates because of underreporting and other factors.

Heat waves across the **U.S. have become longer**, **more frequent** and **more intense** over the past six decades, **according to** the **N**ational **O**ceanic and **A**tmospheric **A**dministration. The global surface temperature in June was the warmest on record for that month. It was the 13th consecutive month with an all-time high, NOAA said.

As heat increases, so does risk for some workers. The probability of work-related accidents grows by 5% to 6% when maximum daily temperatures rise above 90 degrees Fahrenheit, compared with a day when temperatures range from 65 to 70 degrees, according to an analysis of claims data by the Workers Compensation Research Institute.

Average number of U.S. heat waves a year, by decade



Source: National Oceanic and Atmospheric Administration

Last month the Biden administration released **proposed rules** that would create the first federal safety standard to protect workers from extreme heat, adding that it was the leading cause of weather-related deaths in the U.S. Among other provisions, employers would be required to evaluate heat risks and, when necessary, provide workers drinking water, rest breaks and shade. OSHA plans to solicit public comments and hold a hearing before developing final rules.

States are grappling with the issue as well, sometimes moving in opposite directions. California recently approved rules to protect indoor workers from extreme heat, while Florida this year passed a law barring local governments from requiring heat protections for workers.

In Arcadia, Fla., a 42-year-old farmworker died from heat stroke in December after picking oranges in a grove under the sun. In Pontiac, Ill., a 36-year-old roofer died from heat-related illness in August 2023 after collapsing on the job.

Foster, a **lineman** with **Appalachian Power** in **West Virgi**nia, **got** a **call** to **deploy** to Marshall **after powerful storms** and **tornadoes tore across East Texas** in mid-June of last year, **toppling power poles and knocking out electricity**. After arriving with fellow crew members on June 18, he told Hightower that they would start work the following morning installing new poles and lines in a swampy area.

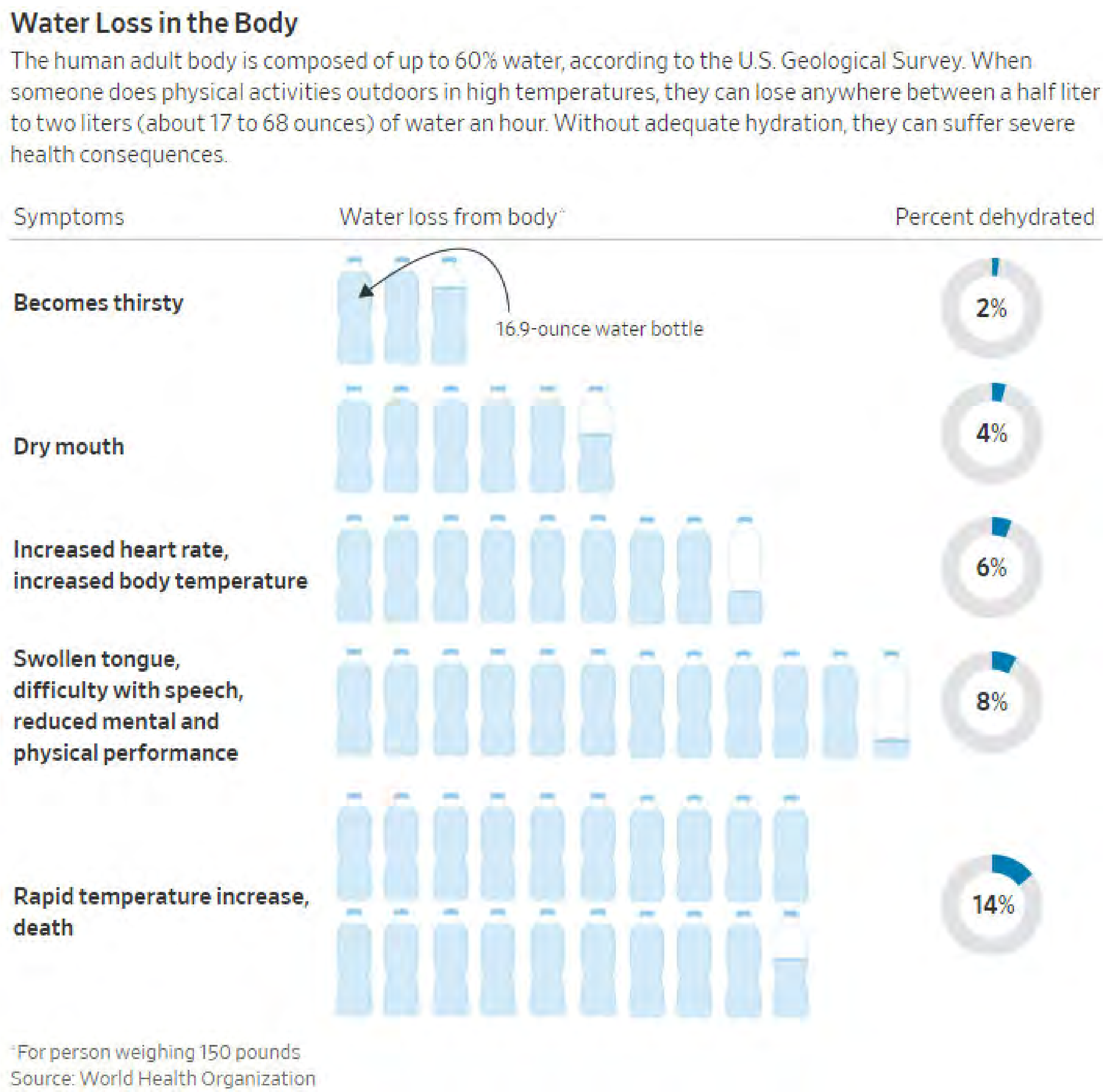
“Please be careful,” Hightower said she told him.

The **duties of linemen** are **physically demanding**. **Using bucket trucks to get high in** the **air**, they sometimes **work under** a **blazing sun**. They we**ar thick rubber gloves and sleeve**s to **guard against accidental contact** with **energized lines** and **flame-retardant clothing** that **isn’t very breathable**.

“It ain’t nothing but a **great big sweatsuit**,” said Bill Bosch, founder of the National Association of Journeymen Linemen.

Foster previously experienced episodes of heat exhaustion, co-workers later told an OSHA compliance officer, according to an agency inspection report. That day in

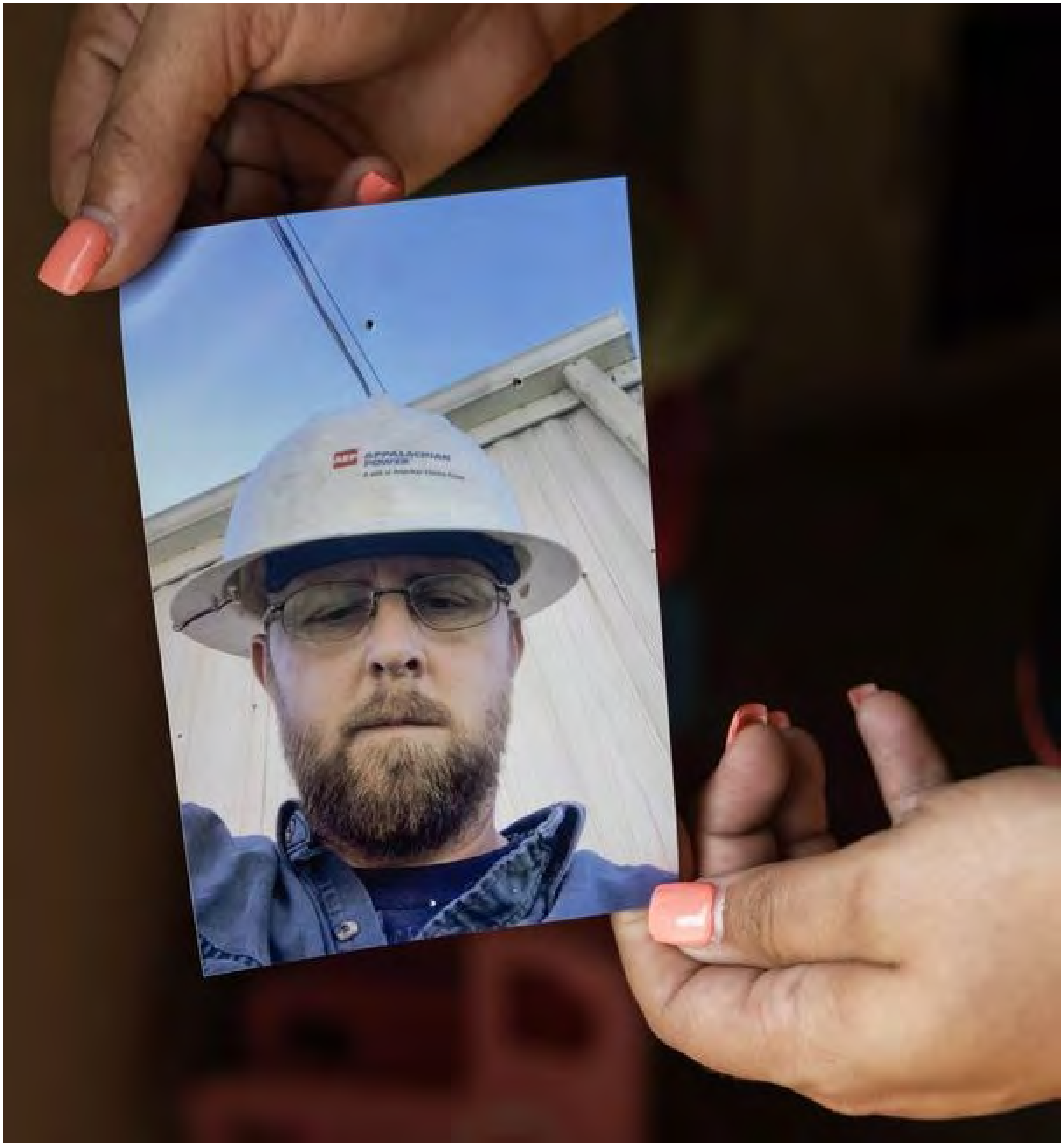
Marshall, he **complained** of **chest pains** and **other signs of severe heat stress**, **but refused** to be **taken to** a **hospital** and asked to be returned to the hotel, they said.



When the **body overheats**, it **begins** to **lose control** of its **cooling mechanisms**, said Brenda Jacklitsch, a health scientist at the National Institute for Occupational Safety and Health. A **person's condition can deteriorate quickly or slowly**, from **weakness and dizziness** to **cognitive changes** such as **confusion** and **slurred speech**, she said. Eventually, **organs** can **become so hot** that they start to **shut down**.

Crew members drove Foster to the **hotel** at around 6:30 p.m. and **helped** him **hydrate**, shed his clothes and cool off in one of their rooms on the ground floor, Hightower said he told her. They **asked** him **if he wanted** to **join them for dinner**, but **he declined**, and **they headed out**.

With only a towel wrapped around him, **Foster** headed up a stairwell to his room, where he **said** the **air conditioning** wasn't working, according **to Hightower**. He put on some basketball shorts and made a FaceTime **call** to Hightower a little before **7:30 p.m.**, she said.



Foster previously experienced episodes of heat exhaustion, his co-workers said.

Foster looked sweaty and sticky and complained that his legs were cramping severely, Hightower said. She urged him to drink water, which he did, but he said his stomach hurt each time he took a sip. He told her he needed to take another cold shower. She asked him to text or call her as soon as he was done.

Around 7:45 p.m., Hightower sent him a text: “I love you babe I wish I could take your cramps away.” Foster didn’t respond.

Left: Hightower says she told Foster to be careful before he started work in Texas

When **Foster's co-workers returned from dinner** at about **8:25 p.m.**, his roommate **found him unresponsive** on the bathroom floor, said Judge John Oswalt, a justice of the peace in Harrison County, Texas, who investigated the incident. Someone **called 911**, and **when emergency medical services responders arrived**, they said **Foster wasn't breathing** and had **no pulse**, according to Oswalt. Foster was partly **covered** in **vomit**, and his **ankles** and **feet** were **stiff**.

The emergency team **administered CPR**, used a chest-compression device and **injected medication** intravenously to no avail, Oswalt said. A little after **9 p.m.**, they **stopped trying** to **resuscitate him**.

Despite Foster's efforts to cool himself down, the heat had **already seriously damaged** his body. A forensic pathologist determined that the **cause** of **death** was complications of **hyperthermia**, **or overheating**, according to an autopsy report. The findings added that he had **cerebral and pulmonary edema**, a **buildup** of **fluid** in the **brain and lungs** that can be triggered by hyperthermia.

The OSHA compliance officer conducted an inspection of the work site two days after Foster's death and later reviewed Appalachian Power's safety and health program and heat-related policies, according to the inspection report. OSHA closed the case without issuing a citation against the company.

Left: Hightower and Delilah enjoying a moment on the swing.

Appalachian Power declined to comment but last year said it was conducting an investigation of the incident.

Foster is **survived by** an **11-year-old son and a 3-year-old daughter**. His family wrote in an obituary that he loved working as a lineman, chasing storms around the country to help restore power. The day of his funeral, linemen hoisted an American flag between two bucket trucks.

When Hightower received a bag of Foster's belongings that authorities shipped to her after his death, she said she took out his clothing. "His pants were still wet with sweat," she said.

Authorities shipped Foster's work boots and pants to Hightower after his death.

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Rising US Power Prices Reflect New Reality for Utilities in Warming World

by Karin Rives
Standard and Poor's Global Market Intelligence – Jul. 29, 2024
Susan Dlin contributed to this article.

During a July 2023 heat wave in New York, people rushed to buy air conditioners. The need for more cooling has contributed to rising power bills, straining household budgets.

Halfway through a US **summer of punishing heat domes** and **record-high temperatures**, **air conditioners** are **churning** and **energy bills** are **soaring**.

But a closer look at how such costs play out reveals vast disparities among states and demographic groups – suggesting a complex American energy reality that goes beyond partisan talking points and shows the challenges utilities face in a warming world, industry experts said.

Between 2018 and 2023, **average US household electricity prices rose 21.9%**, data from S&P Global Commodity Insights showed. Within that average were increases **as high as 65.6%** in **Maine** and **51.3%** in **New Hampshire**, while New Mexico and North Dakota saw only a 6.6% rise. Wyoming and Kansas residential power prices were slightly lower in 2023 than in 2018, while Florida's jumped 36%.

Economywide cumulative **inflation** was 22.2% during the same six-year period, according to the Federal Reserve Bank of Minneapolis.

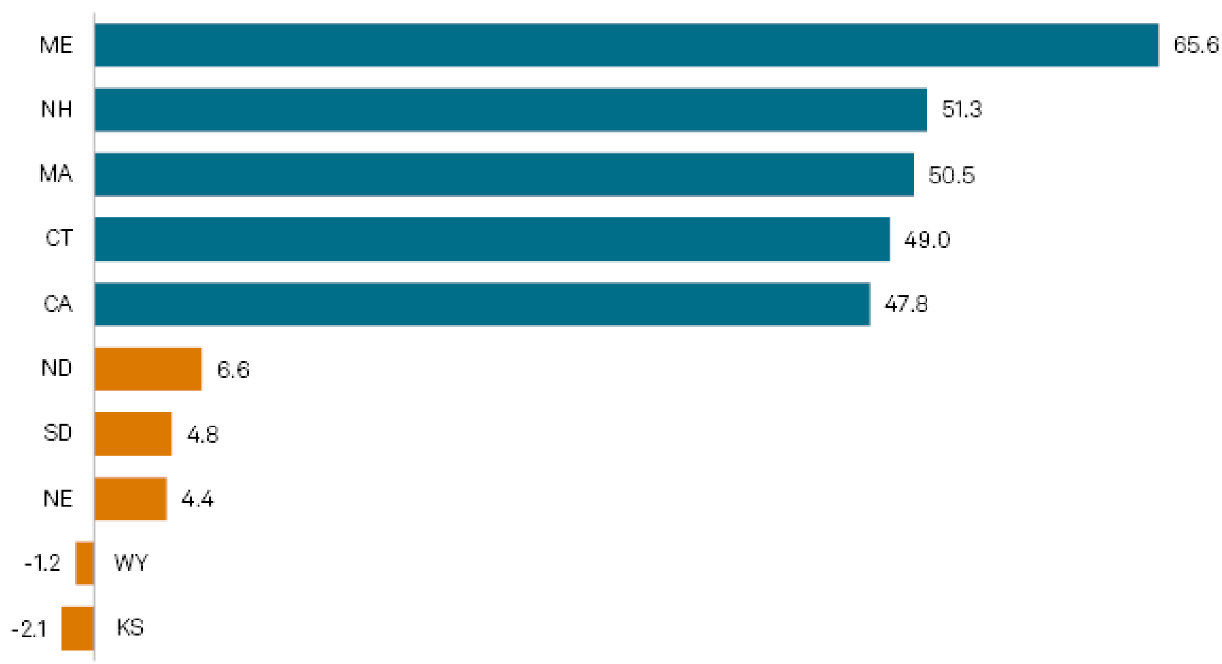
US power retail costs are inconsistent because bills now include charges that may have nothing to do with the costs that utilities incur when generating and distributing electricity, said Severin Borenstein, director of the University of California, Berkeley's Energy Institute at Haas and board member of the California ISO.

"I think the common theme here is we pay for a lot of stuff through price per kilowatt hour that is not a cost per kilowatt hour," Borenstein said in an interview. "Wholesale power prices have been very moderate over the last year, but we're still seeing retail prices grow."

In California, for example, costs associated with wildfire mitigation and liabilities accounted for nearly 13% of the average monthly bill that Pacific Gas and Electric Co.'s residential customers paid in 2023, according to the state's Public Utilities Commission. Wildfires that have devastated parts of California in recent years have been attributed to climate change.

Maine had the highest power cost increase of any state between 2018 and 2023, per Commodity Insights data. The hike was driven mainly by deferred costs of imported natural gas but also reflects **deferred storm costs** and **stranded assets** from a net metering program, a spokesperson for the Maine Public Utilities Commission said in an email.

Changes in household power rates in 10 states between 2018 and 2023



Data compiled July 24, 2024.
Includes public power, cooperatives, investor-owned utilities and/or other types of utility owners within each state.
Excludes American Samoa, Puerto Rico, Guam, Northern Mariana Islands, Marshall Islands, Virgin Islands and other outlying territories.
Source: S&P Global Market Intelligence.

Behind the Rhetoric

Rising energy prices have become a political football during this election year, as critics of the Biden administration's climate policies and state clean energy mandates have argued that American families are caught in the middle.

"Doubling down on policies to restrict oil and gas, to retire baseload power generation and to promote widespread unaffordable, unreliable electrification is not how we secure our energy future," Rep. Cathy McMorris Rodgers (R-Wash.), chair of the US House Energy and Commerce Committee, said during a May 1 congressional hearing. "Unfortunately, it's Americans that are feeling the impacts of this rush-to-green agenda."

Brendan Pierpont, director of electricity modeling at the think tank Energy Innovation, decided to dig into the data to try to understand why utilities in recent years began to ask regulators for large rate increases. Those requests coincided with the narrative arguing that clean energy investments drove such cost increases, he said.

"What we found was, first, that there's not really a systematic relationship between states that have increased renewable energy shares and those that saw large rate increases," Pierpont said in an interview. "And then when you zoom into some of the states that had rate increases that exceeded inflation, like California, you see costs associated with **mitigating wildfire risk** just **ballooning**."

Such costs continue to climb. California regulators in 2023 approved a $2.6 billion multiyear rate increase for Pacific Gas and Electric Co. that went into effect in January. More than 85% of the revenue will be used to reduce risks in the utility's electric and natural gas operations, primarily from wildfires.

Power lines against a California wildfire

New England and some Appalachian and Midwestern states also experienced rapid increases in electricity costs in recent years, and all for unique reasons, Pierpont concluded in a study published July 9.

Volatile wholesale gas prices caused power bills to spike in recent years in Massachusetts and several other New England states that are heavily dependent on imported natural gas, Pierpont said. The Energy Innovation analysis covered increases going back to 2010.

Appalachian states such as West Virginia have sought to delay the **retirement** of **coal plants**, necessitating expensive environmental upgrades whose costs are passed on to consumers. West Virginia household power rates rose 26% between 2018 and 2023, the Commodity Insights data showed.

Households Feel the Squeeze

At the receiving end of rising power rates are millions of residential customers.

Nearly 24% of **US households said** they were **unable** to **pay at least one monthly energy bill in** the **past year**, according to a July 16 report from the National Energy Assistance Directors Association and the Center for Energy Poverty and Climate. That number rose to **32% for households of color** and to **37% for low- and moderate-income households**, according to the study based on US Census data.

"We don't have an entitlement program for energy bills like we have for foods or Medicaid," Mark Wolfe, executive director of the National Energy Assistance Directors Association, said in an interview. "With energy assistance as a discretionary grant program, when the money runs out, it's over."

The federal **L**ow **I**ncome **H**ome **E**nergy **A**ssistance **P**rogram, which helps struggling households with their energy bills, **received** about **$4 billion** from Congress for fiscal year **2024**, **down from** over **$6 billion** in fiscal year **2023**. Wolfe said the reduced funding adds more pressure on the states. **Until** a **few years ago**, he noted, **80%** of the funding **went to home heating** in the **winter** and **20%** to **cooling**, **but** with summer heat waves lasting longer, the **ratios** are **changing**.

Whose Affordability Problem?

Some utilities in high-cost states have responded by rolling out programs to try to mitigate rising energy costs and address the needs of households whose cooling needs are growing in tandem with global temperatures. Without help, people can die, Wolfe said.

In 2023, Eversource Energy said it would offer up to a 50% discount on bills for New England customers facing financial hardship. The states the utility serves – Massachusetts, Connecticut and New Hampshire – were among the top five for residential power rate increases between 2018 and 2023.

"The affordability problem falls heaviest on utilities," Wolfe said. "They have to collect when people run behind on their bills and have to run shut-off programs and you talk to any utility, they don't like shutting people off from power. But utilities are not social service organizations. They're set up to make sure the power plant runs and the wires are up."

In states with high power rates, such as California, energy assistance programs provide some help without solving the underlying problem, Borenstein said.

"Which is why I'm a bigger fan of taking a lot of these costs off the bills and instead put them on the state budget," the business professor said. "We're paying for seawalls, flood protection, wildfire protection, because politicians like to have somebody else pay for things."

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The Rush to Shore Up the Power Grid Against Hurricanes, Heat and Hail

by Phred Dvorak – WSJ – Jul. 29, 2024

Energy companies are working to adapt as they confront record-setting temperatures, floods and windstorms.


A CenterPoint Energy employee worked to restore power in Houston this month.

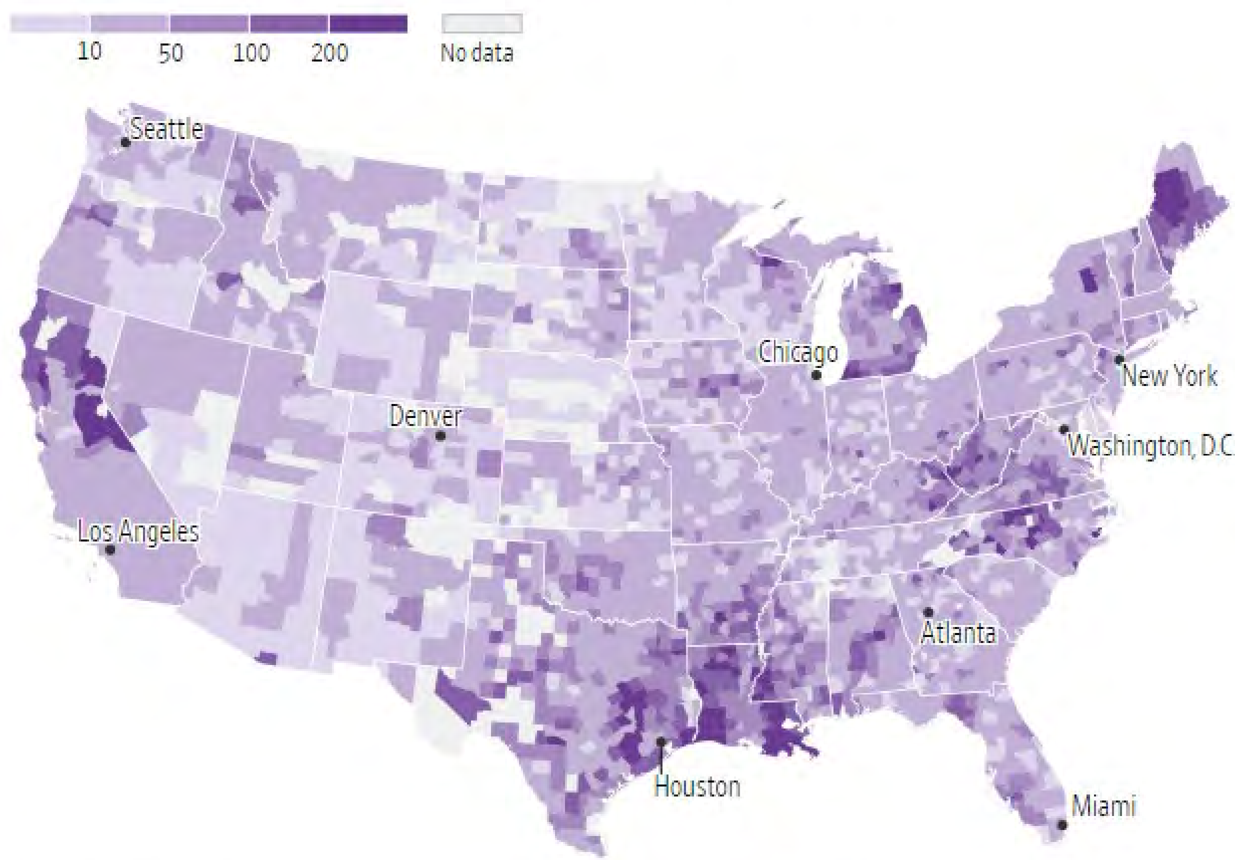
Extreme weather is putting power supplies around the U.S. to the test. Energy companies are racing to find answers.

Hurricane Beryl knocked out power for millions in Houston and surrounding areas this month. **CenterPoint** Energy the **city's main utility**, **took nearly two weeks to get power completely restored.**

Earlier this year, **floodwaters washed away an electric substation in Minnesota**, while **central states experienced** at least **four major tornado and windstorm outbreaks** that **left hundreds of thousands** of **customers without power**.

Energy companies are working to adapt to record-setting temperatures, floods and windstorms, as climate models forecast the weather will keep getting wilder. But researchers caution that the effects of global warming and current extreme-heat conditions still aren't well understood, making solutions hard to come by.

Average annual reported power outages per customer, 2019-2023



Note: Reported outages are for every 15-minute period. Customers per county as of 2022.
Source: Oak Ridge National Laboratory
Carl Churchill/WSJ

New York utility Consolidated Edison is trying to stay ahead of weather risks by working with New York state and Columbia University to predict what effect climate change could have on its operations and systems. In mid-**July**, a **heat wave and surge** in **air-conditioning use caused** some of the company's **underground power cables to fail in Harlem**.

Con Edison's latest climate-risk study, released last year, said all types of severe weather – from flooding to heat waves – are expected to increase in intensity or severity. Temperatures are likely to rise faster than it projected four years before, with levels that were expected in 2040 now coming a decade earlier, the study said.

Con Edison's engineers took those predictions and applied them to its electric systems to model its potential increase in equipment-failure rates, which go up as the temperature rises, says Christopher Jones, chief engineer for the company's electric distribution system. To help protect the system, **Con Edison** is **planning** to **add switches to** its **underground network** that would **limit** the **spread** of any **failures**.

The company is **also proposing** to counter increased flooding by **replacing hundreds** of **underground transformers** and **circuit breakers with units that work underwater**. It is stringing tough underground electric cables in place of about 100 miles of overhead power lines to reduce damage caused by storms blowing down trees and poles.

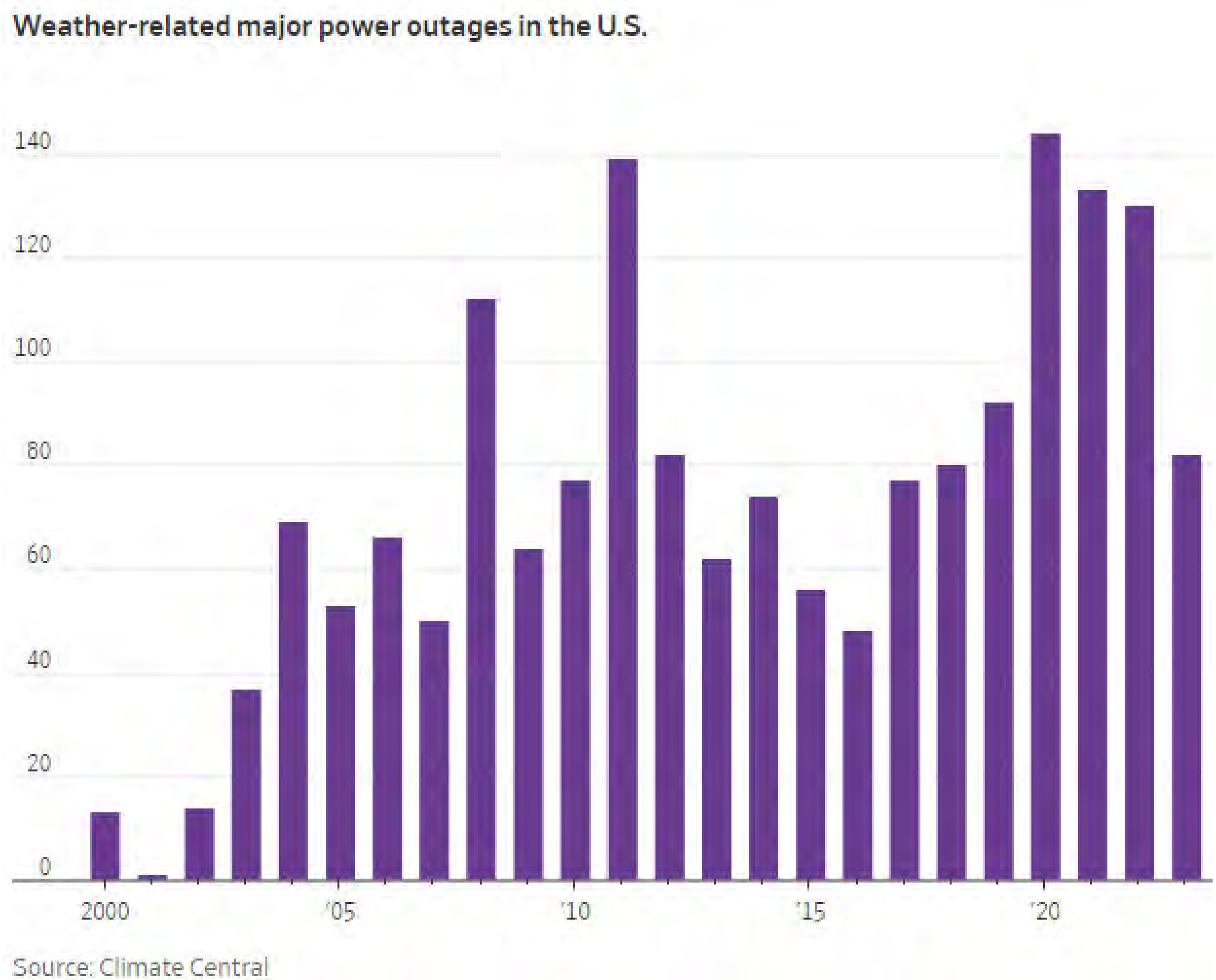
"Everything that you're doing has to be built for the future climate," says Nelson Yip, Con Edison's director of climate resilience.

Worse weather, unclear science

Bad weather is hitting more frequently across the country and costing a lot more now than in previous years, according to the U.S. government.

Over the past five years, the U.S. has seen an average of 20 weather-related disasters a year with a price tag of $1 billion or more, adjusted for inflation, compared with a 43-year average of 8.5, according to data collected by the National Oceanic and Atmospheric Administration. There have already been 15 such disasters this year through June.

Severe weather is the **No. 1 cause** of **power outages nationally**, and a major factor in grid problems of all kinds.



Researchers say it will get worse. Although the exact effects of climate change on today's weather aren't clear, many scientists say it has made some weather events – such as heavy precipitation, droughts and heat waves—more severe and more frequent.

If greenhouse-gas emissions continue to increase at a high rate and global warming progresses, residents of Houston could experience a 72% rise in the number of major power outages toward the end of the century compared with now, according to a recent study by the Electric Power Research Institute and the Pacific Northwest National Laboratory.

"If companies don't adapt to better-withstand hurricanes, we will see worsening outages," says Andrea Staid, a researcher at EPRI.

Heat, storms and hail

Last year was declared the hottest year since global records began, and many forecasters are saying this year could surpass it.

While **heat** doesn't tend to knock out power like storms do, it **stresses** nearly **every part** of an electric**-supply chain**. It **lowers** the **performance** of **everything from gas-fired generators and wind farms** (**their turbines won't spin** as freely) **to nuclear plants** (**their cooling systems won't work as well**) **to electric wires** (they could **overheat and sag too much**).

Utilities deal with those risks in part by building extra capacity into their systems so they can meet demand at the highest expected temperatures. Some companies in especially-hot areas such as **Arizona** are **asking vendors** to make sure new **components** can **operate** at an **average daily temperature** of as much as **122 degrees Fahrenheit**, **rather than** the **current industry standard** of around **104**, says Andrew Phillips, EPRI's vice president of transmission and distribution infrastructure.

Storms are another big problem because they are expected to **increase** in **severity and frequency**. That means utilities, grid operators and power-plant owners will have to spend a lot more on things such as strengthening electric poles, transmission towers and other infrastructure, says Ed Hirs, an energy economist and fellow at the University of Houston.

A lot of Hurricane Beryl's damage to Houston's power lines likely came from trees and shrubs that were hurled by powerful winds; CenterPoint said it had removed more than 18,600 trees as it struggled to restore power. **Vegetation causes** roughly **30%** of **power outages in** the **U.S**., **estimates** Josh Wepman, who advises on energy-industry challenges at **Leidos**, a defense and technology company.

Figuring out which trees are a threat to power lines and removing them is tough and expensive, he says, particularly because there are so many of them over a large area. **Many outages** are **caused by trees** that are **outside** of the **areas where utilities have** the **right to cut**, says Wepman.

Meanwhile, **hailstorms** have become a **big source of damage for solar farms** during the past few years, causing hundreds of millions of dollars in losses for insurers. As a result, **renewables insurer** GCube and others have **increased rates and lowered caps on hail claims**.

Two years ago, a hailstorm hit the huge **Prospero solar farm** in **West Texas**. The plant's solar panels were rocked by gale-force winds and **baseball-size hail**, with some areas clocking as many as 9,000 strikes. Prospero suffered more than **$30 million** in **damage and lost** about **16%** of its **power capacity**, **even though** it was **using new technology to protect panels from hail**.

Now **Longroad Energy** is **building** a **solar plant** near its Prospero project **with** more advanced and expensive hail protection. The new plant will be one of the first to mount its **solar panels on Nextracker racking** that **can tilt 75 degrees rather** than the **current 60**. That steeper angle will hopefully limit damage from hailstones even bigger than the ones that hit Prospero, although nobody will know for sure until the next big storm hits, says Michael Alvarez, Longroad's chief operating officer.

"At almost every project, we get some sort of record that has broken – it's the most rain, the most snowfall, the most whatever," says Donny Gallagher, vice president of engineering at Solv Energy, which built the Prospero project for Longroad.

Powerful winds caused much of Hurricane Beryl's damage to CenterPoint's power lines in Houston.

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Search for Safety Buoys Treasurys

by Sam Goldfarb – WSJ – Jul. 17, 2024

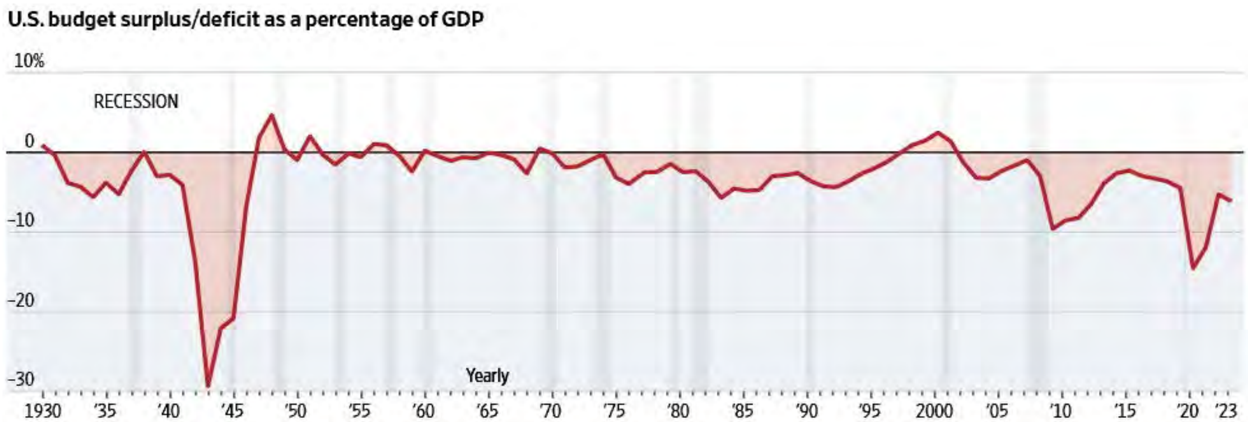
Demand is soaking up a huge increase in the supply of U. S. government debt.

The U.S. fiscal outlook is deteriorating. Wall Street doesn't seem bothered.

U.S. government bonds rallied this past month on the same day that the **C**ongressional **B**udget **O**ffice said that it expects the **fiscal 2024 budget deficit** to **reach $1.9 trillion** – up from $1.7 trillion last year and its previous estimate of $1.5 trillion. A broader rally has pulled Treasury yields well off their highs from 2023, despite a series of jumbo-sized debt sales needed to fill the gap between the government's spending and revenue.

That is surprising some analysts, who thought the growing debt pile might spark more market disruptions.

A **larger deficit means** the **government needs to sell more Treasurys**, and right now that deficit is unusually large when measured against the size of the economy. That is especially true for a time when the country isn't facing a crisis such as a world war or a pandemic.



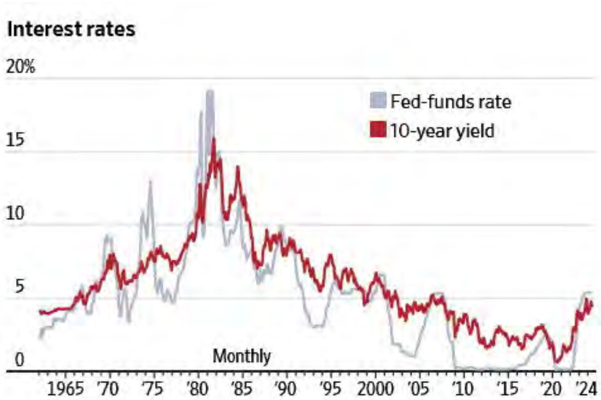
Bonds can be subject to the forces of supply and demand like anything else. If investors are satisfied with the amount of bonds they are holding, but are still offered more, that should drive down prices, pushing yields higher.

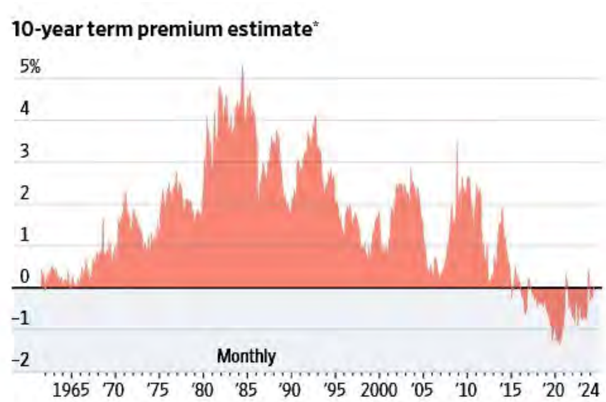
That could be risky for several reasons. Treasury yields reflect the cost of new borrowing for the U.S. government, which is seen as much less likely to default on its debt than any business or individual. As a result, rising yields up borrowing costs broadly.

Higher yields also can drag on stocks by providing investors with a more appealing safe alternative.

Typically, changes in the outlook for government borrowing affect yields only on the margin. But there can be moments when they matter more.

In August, for example, a sharp selloff in Treasurys followed an increase in the Treasury Department's quarterly borrowing estimates, which forced the government to boost the size of its bond auctions by more than investors had been anticipating.





That selloff raised alarms on Wall Street that the supply of Treasurys might be a bigger influence on yields going forward.

Ultimately, though, the yield on the 10-year note peaked at around 5% in late October. A subsequent rally in bonds got a boost when the Treasury surprised investors by increasing the size of its next round of auctions by a little less than they had expected.

Economic data also softened, and by the end of the year, the 10-year yield was back below 3.9%.

Benefit of safety

Today, the **10-year yield is around 4.2%**, **while** the **total** amount of **outstanding Treasurys has topped $27 trillion**.

How could investor demand keep up with so much supply?

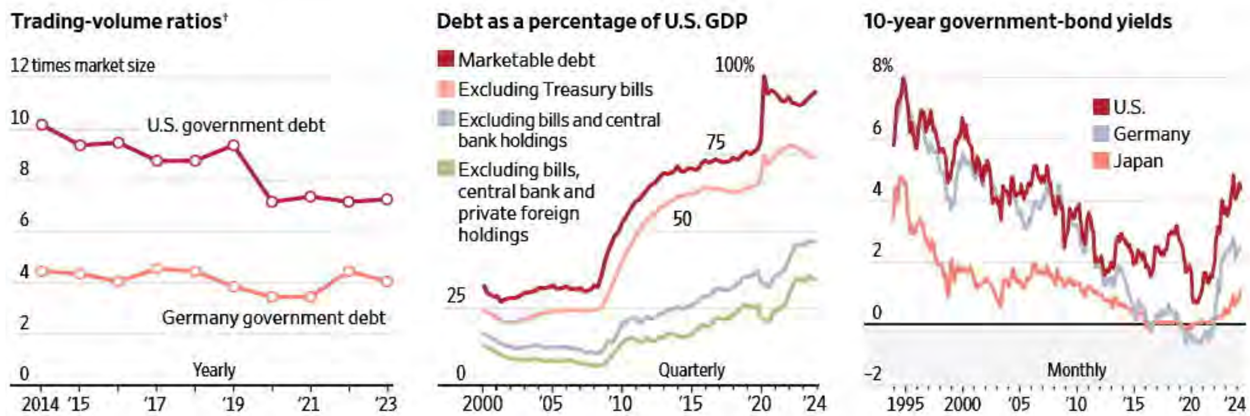
One major reason is that **Treasurys** still **offer** a **reasonable return for basically no risk**, **as long as they are held to maturity**.

Investors have alternative ways to earn a risk-free return. They can essentially lend to the Federal Reserve until the next day, getting paid an interest rate set by Fed officials at their regular policy meetings. They could do this for 10 years, continually rolling over their investment, and earning more when rates rise and less when rates fall. Or they could just lock in a return now by buying a 10-year Treasury note.

That generally keeps Treasury yields tethered to investors' expectations for what short-term rates will average over the life of a bond. If an influx of new bonds pushes the 10-year Treasury yield above what investors could get by rolling over short-term loans, there would be a strong incentive for investors to choose the 10-year notes instead. That rush of demand would then drive their yields back lower again.

Indeed, the key short-term rate set by the Fed and the 10year Treasury yield have exhibited a tight relationship over the past six decades.

It is impossible to know for sure how much the 10-year yield reflects forecasts for short-term interest rates versus other factors – such as supply and demand or concerns about unexpected inflation – that economists generally label as "**term premium**."



*Shows Adrian, Crump, and Moench (ACM) term premium estimate
†Shows ratio of trading volume to year-end volume of outstanding debt securities. Some differences in trading volumes could be due to different reporting methods.
Sources: Federal Reserve Bank of St. Louis (U.S. budget surplus/deficit, interest rates, debt held by public, yields); Federal Reserve Bank of New York (10-year term premium); Sifma (U.S.), Federal Republic of Germany - Finance Agency (Germany), WSJ calculations; Brad Setser (other categories for debt)

But economists have devised models to try to provide an answer. One, created by **New York Fed economists**, currently shows that the **10-year term premium is slightly negative**. The **implication** is that if the **supply of bonds** is pushing up yields, it is being **canceled out by** other factors, such as **investors wanting** to **buy Treasurys as** a **hedge against potential losses in stocks**.

Foreign demand

Countries such as Germany and Japan also sell government bonds that investors consider ultrasafe. But Treasurys have additional attributes that make them especially attractive to global investors.

One big advantage is that Treasurys are easier to trade than other bonds. **Size**, in this case, is **helpful**. The huge volume of outstanding Treasurys means investors can easily buy large amounts of bonds of practically any maturity. They also can feel free selling their own holdings knowing that they can quickly find replacements.

Some **$190 trillion** of **U.S. Treasurys** were **bought and sold in 2023**, more than **seven times** the **size** of the **market**, according to Sifma, a securities industry trade group. Trading volume of German government bonds totaled roughly $7 trillion, just four times the amount of the bonds that were outstanding at the end of the year, according to Germany's finance agency.

The **liquidity** of Treasurys is one reason why the dollar is known as the world's reserve currency, according to analysts.

For decades, Treasurys have also generally offered higher yields than their peers – a result of broad economic and demographic trends and a lack of government borrowing in Germany. This has ensured steady demand from **overseas buy-and-hold investors** such as **pension funds** and **life insurers**.

The road ahead

Many investors and analysts remain at least a little concerned about the mounting supply of Treasurys.

Last year's selloff served as a reminder that demand for Treasurys "is variable over time," said Gennadiy Goldberg, head of U.S. rates strategy at TD Securities. "The worry is that investors are buying Treasurys today – that doesn't mean they have to be buying tomorrow."

Still, Blake Gwinn, head of U.S. rates strategy at RBC Capital Markets, said that, to a large degree, forecasted deficits may already be reflected in current bond yields.

"Issuance from Treasury is a very long, slow, secular thing that we have lots and lots and lots of time as markets to digest," he said.

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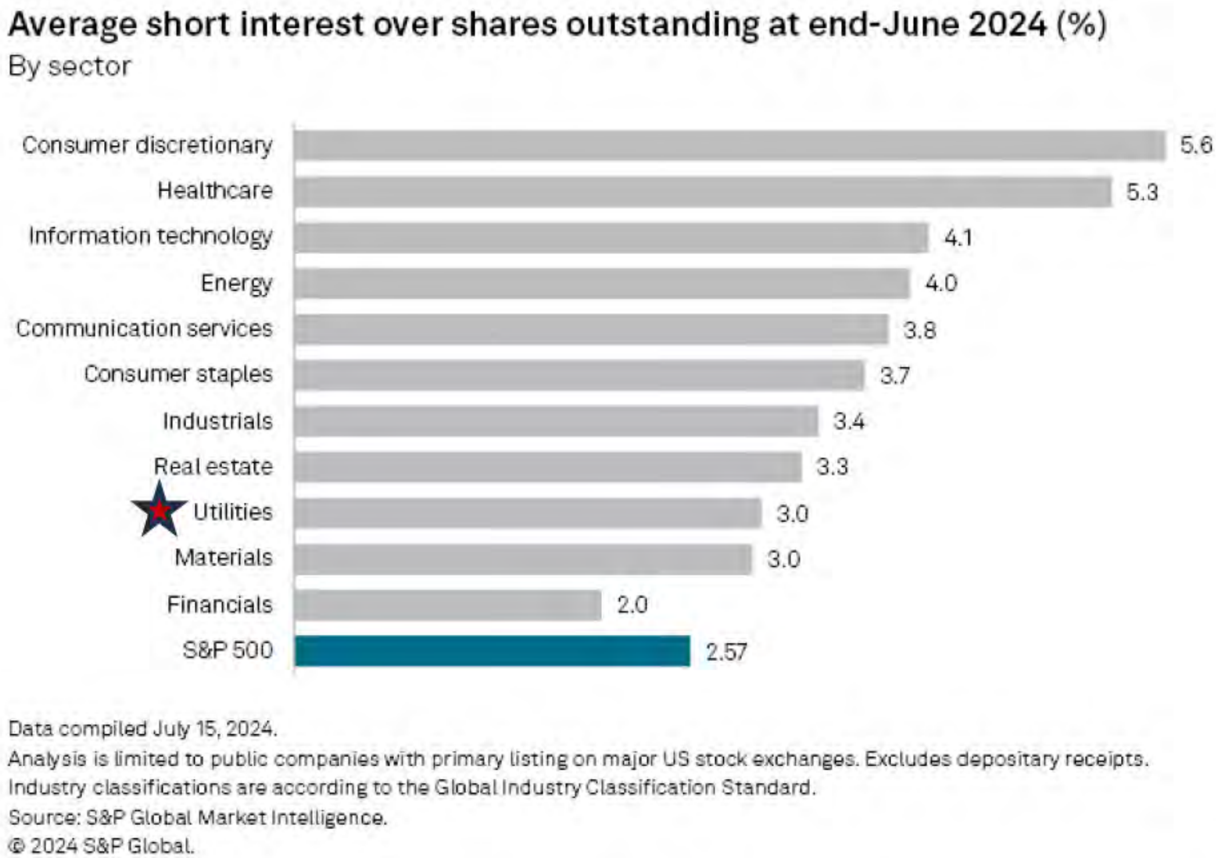
Short Sellers Boost Bets against Utility Stocks to Highest Level in Years

Brian Scheid and Annie Sabater,
Standard and Poor's Global Market Intelligence – Jul. 22, 2024

Short sellers increased their **bets against utility stocks** in **June** to the **highest level in** at least **eight years**.

Short interest in utilities, a sector that includes electric, gas and water companies, was at 3.0% at the end of June, up 70 basis points from the same point a year earlier, according to the latest S&P Global Market Intelligence data.

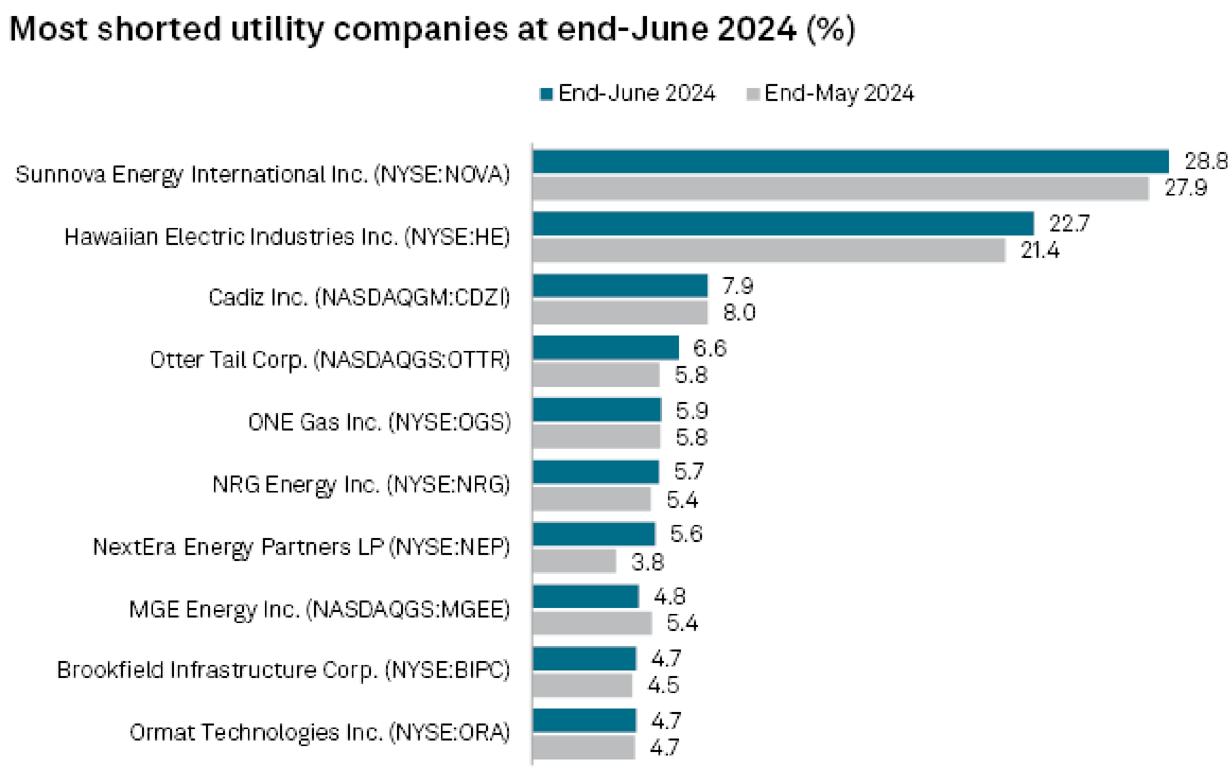


Short interest in utility stocks jumped to the highest level since 2016, to 3.0% at the end of June from 2.8% at the end of May, as the S&P 500 utilities sector fell by 5.8% during the month. As of July 17, the sector has rallied about 9.1% since the start of the year, despite its stumble in June.

Short interest increased in most sectors from the end of May to the end of June. Consumer discretionary remained the most-shorted sector, with short interest climbing from 5.4% to 5.6%, the highest level of bets against this sector since the end of April.

Sector breakdown

Within the utility sector, commercial and residential solar power company Sunnova Energy International Inc. was the most-shorted company with short interest at 28.8% at the end of June, up from 27.9% at the end of May. Sunnova's stock fell nearly 77% from the start of 2024 to May 1, but it has since rallied nearly 107%.



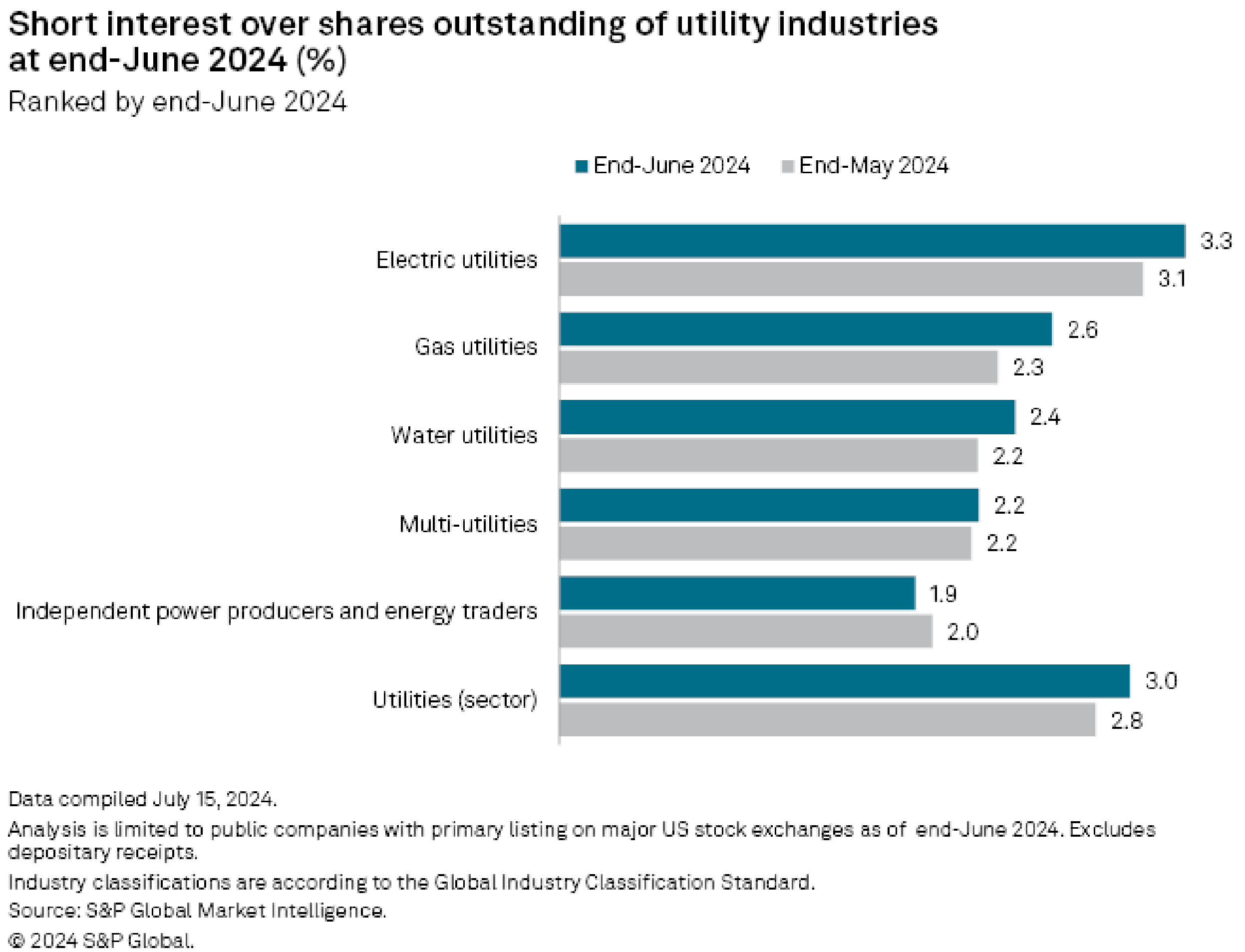
Data compiled July 15, 2024.

Analysis is limited to public companies with primary listing on major US stock exchanges as of end-June 2024. Excludes depositary receipts.

Industry classifications are according to the Global Industry Classification Standard.

Source: S&P Global Market Intelligence.

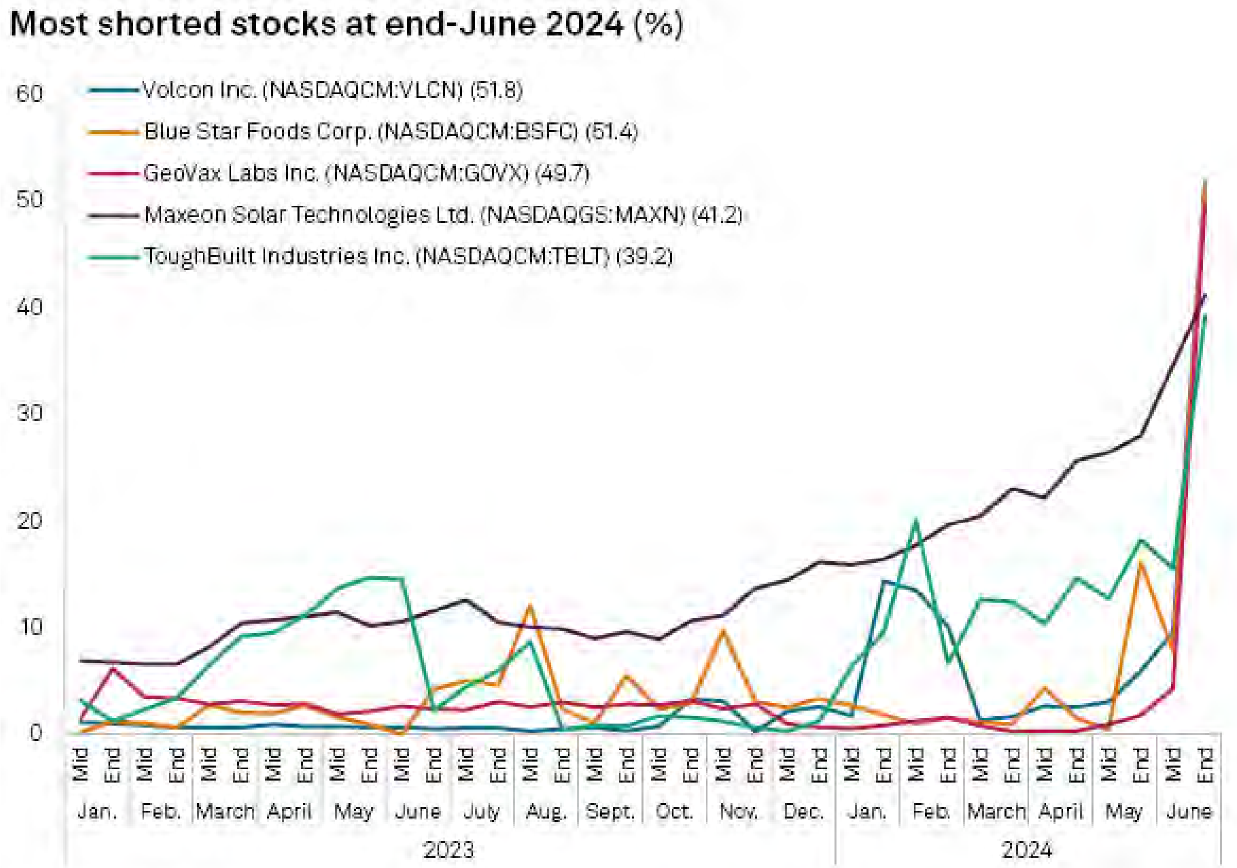
Hawaiian Electric Industries Inc. was the second most-shorted utility stock, with 22.7% short interest, up from 21.4% at the end of May. Hawaiian Electric's stock plummeted more than 75% after the devastating Maui fires in August 2023. The stock has gained 42% since the end of June on reports that Maui County is preparing a settlement for thousands of people impacted by the fires, which could potentially keep the electric company from some legal proceedings.



Within the utility sector, electric utilities were the most shorted industry at the end of June with 3.3% short interest, up from 3.1% at the end of May.

Most shorted overall

Volcon Inc. was the most-shorted stock on major US exchanges at the end of June, with 51.8% short interest, followed closely by Blue Star Foods Corp. with short interest at 51.4%



Data compiled July 15, 2024.
Analysis includes the five most shorted companies with largest short interest over shares outstanding at end-June 2024. Limited to stocks with primary listing on major US exchanges. Excludes depositary receipts.
Industry classifications are according to the Global Industry Classification Standard.
Source: S&P Global Market Intelligence.

GeoVax Labs Inc. was the third most-shorted stock, with short interest at 49.7% at the end of June.

Short interest in the three stocks increased dramatically from mid-June when short interest in all three was still in the single digits.

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Slowing US Inflation Boosts Chances of 3 Fed Rate Cuts in 2024

by Brian Scheid,
Standard and Poor's Global Market Intelligence – Jul. 12, 2023

The most reassuring inflation data since the US Federal Reserve began its battle against inflation through higher interest rates in March 2022 has lifted the odds of the central bank cutting rates as many as three times before the end of 2024.

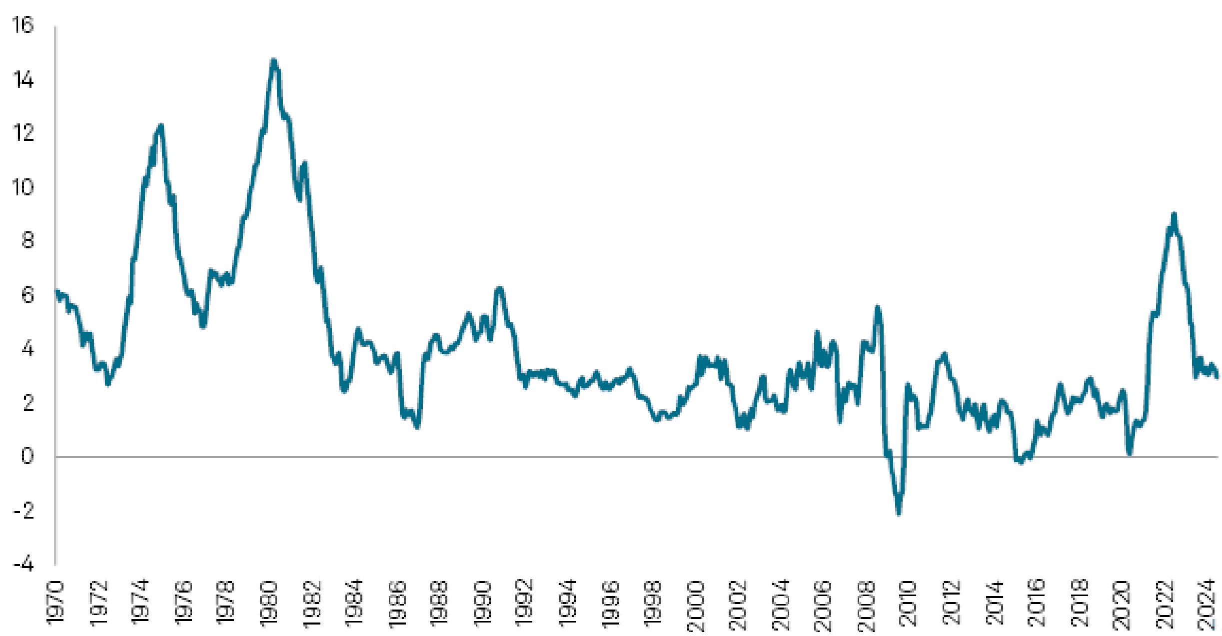
The Consumer Price Index increased just 3% from June 2023 to June 2024, the US Bureau of Labor Statistics reported July 11. That is the lowest annual increase in the market's preferred inflation measure since March 2021 and a significant drop from June 2022, when annual growth peaked at about 9%. On a monthly basis, prices fell 0.1% from May.

Inflation now appears firmly on track toward the Fed's 2% target. While the latest data is not enough for Fed officials to seriously consider a cut at their next meeting at the end of July, it may be enough to justify cuts at the September, November and December meetings, economists said.

"This report doesn't solidify the case for three rates by year-end, but it will likely increase the odds of that scenario playing out," said Bret Kenwell, a US investment analyst at eToro. "The inflation trend is moving in the right direction and when combined with the recent softness in the labor market, it justifies a rate cut from the Fed."

Consumer price index all items YOY change (%)

January 1970–June 2024



Data accessed July 11, 2024.
Based on data released July 11, 2024.
Data includes year-over-year change in non-seasonally adjusted consumer price index for all items.
Source: US Bureau of Labor Statistics.
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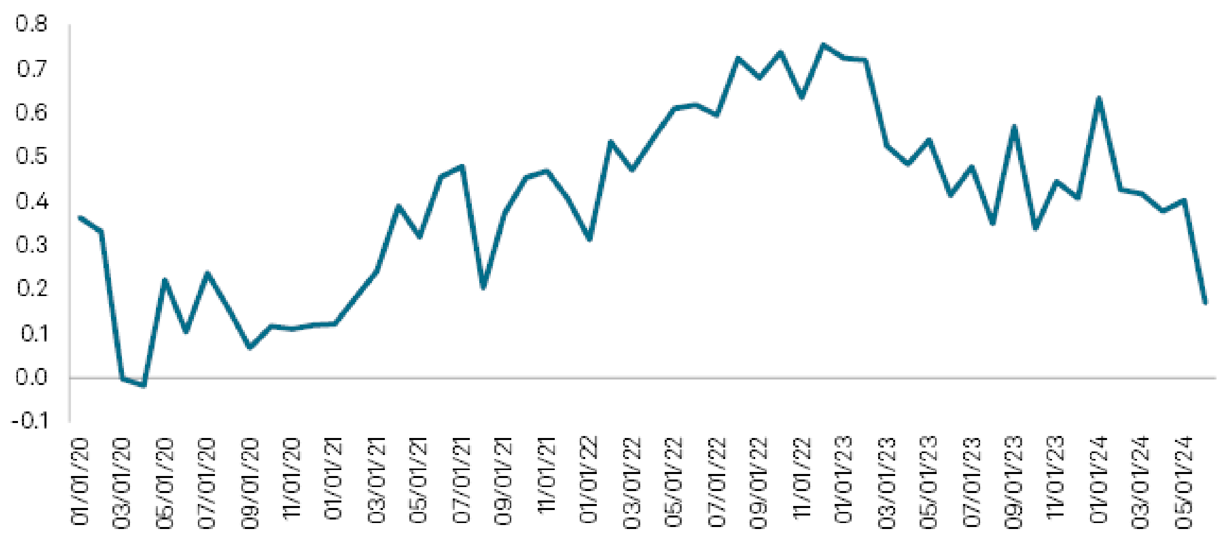
On Track to Target

The odds of at least three rate cuts of 25 basis points each by the end of 2024 was at nearly 50% on July 11, up from about 15% a month earlier, according to the CME FedWatch Tool, which measures investor sentiment in the fed funds futures market.

The **Fed**, **which lowered** its **benchmark federal funds rate** to **near zero in** response to the **pandemic**, **raised rates** by a total of **525 basis points** during 11 meetings **from March 2022 to July 2023**. It has **held rates steady over** the **past year**, as the economy has averted a recession, inflation has proven stickier than anticipated and the labor market has remained resilient.

Shelter prices climbing at lowest rate since January 2021

Consumer price index: shelter
Change from previous month (%)

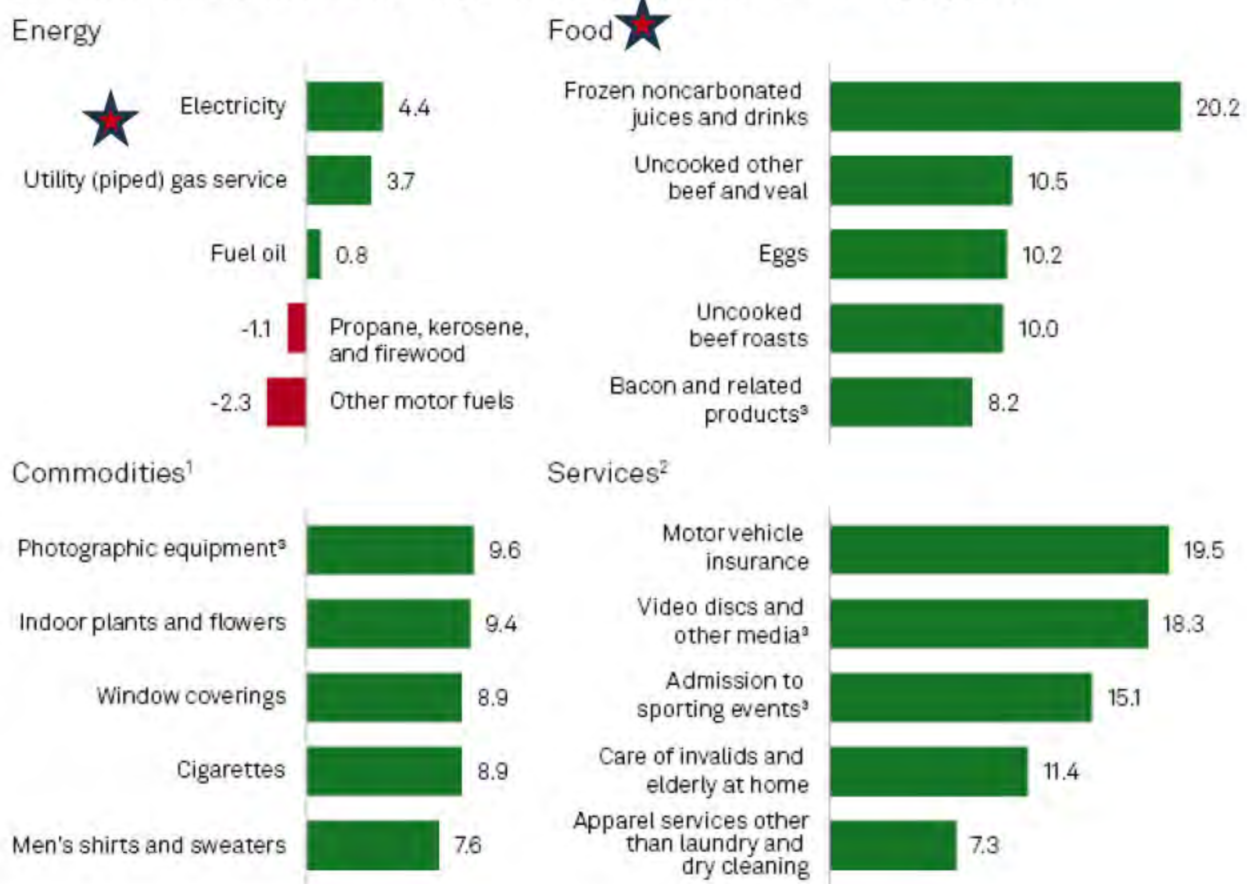


Data accessed July 11, 2024.
Source: US Bureau of Labor Statistics.

Inflation data is now on track to reach the Fed's 2% target in late 2025 and with more evidence of a cooling job market and decelerating consumer spending growth, a rate cut in September now looks nearly certain, said James Knightley, chief international economist with ING.

Fed Chairman Jerome Powell may use the central bank's annual conference in August to explicitly signal that more interest rate cuts are coming, Knightley said.

YOY inflation in June 2024 by detailed expenditure category (%)



Data accessed July 11, 2024.
Based on data released July 11, 2024.
Data includes year-over-year change in non-seasonally adjusted consumer price indexes.
[1] Excludes food and energy commodities.
[2] Excludes energy services.
[3] Special index based on a substantially smaller sample.
Source: US Bureau of Labor Statistics.

Little Need to Cut Twice

Still, after cutting once in September, the Fed may feel little need to cut again before the end of the year with unemployment remaining relatively low, at about 4%, and the number of job openings still outpacing the number of job seekers, said David Russell, global head of market strategy at TradeStation.

"The Fed probably won't feel a need to cut three times because the employment data hasn't broken into recession territory yet," Russell said. "Such aggressive easing could even spook markets."

In addition, the Fed may be reluctant to cut again in November and December due to US elections. If former President Donald Trump wins in November, he is expected to push forward policies that could increase inflation, including tariff hikes, tax cuts, and a crackdown on immigration, which could reheat the job market, said Stephen Pavlick, head of policy at Renaissance Macro Research.

"Why cut more when you're likely going to have to raise [rates] again?" Pavlick said.

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US, Canadian Power Utility Market Cap Falls 1.3% YOY, Led by Exelon, Eversource

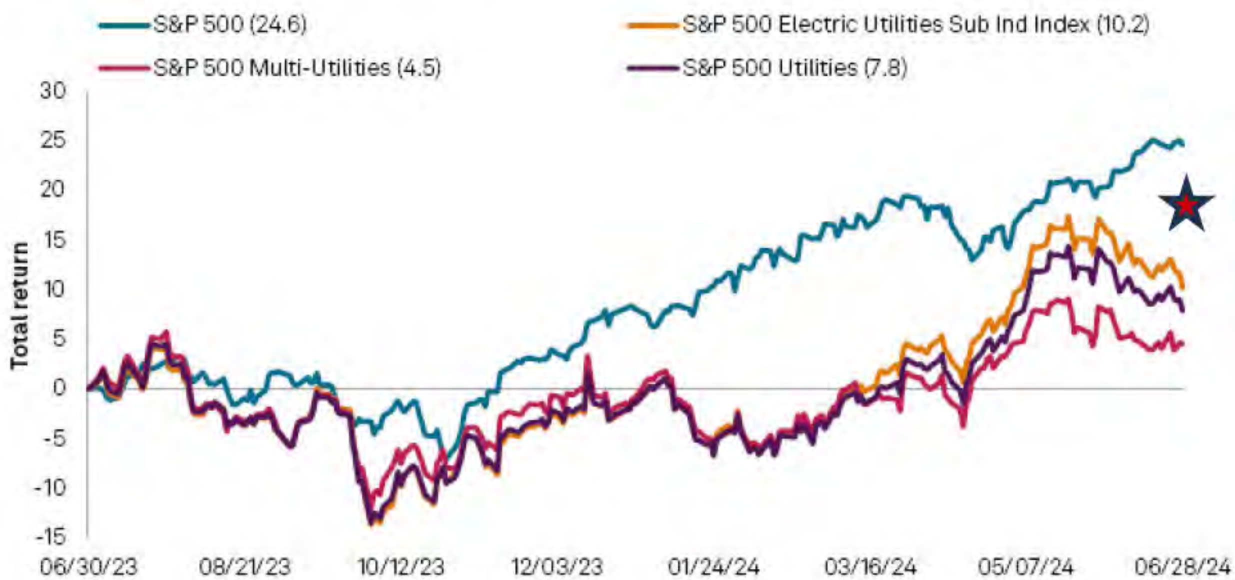
by Shambhavi Gupta,
Standard and Poor's Global Market Intelligence – Jul. 12, 2024

Market capitalization of the largest electric and multi-utility companies in the US and Canada slightly declined in the second quarter of 2024 as the sector continued to underperform the broader market.

Despite positive returns through the 12-month period ended June 28, sector indexes trailed behind the S&P 500's performance. The S&P 500 returned 24.6% during that period, compared with the S&P 500 Electric Utilities Sub Ind index, which returned 10.2%; the S&P 500 Multi-Utilities index, which logged a return of 4.5%; and the S&P 500 Utilities index, which recorded a return of 7.8%.

S&P 500 Utilities indexes vs. S&P 500

Total return (%)



Data compiled July 1, 2024.

Analysis is limited to electric utilities and multi-utilities companies that currently trade on major US stock exchanges Nasdaq, NYSE and NYSEAM and major Canadian stock exchanges Toronto Stock Exchange and TSX-V. All indexes are market-cap weighted.

Source: S&P Global Market Intelligence.

Overall, the median market capitalization fell 0.2% from the previous quarter and 1.3% from the second quarter of 2023, based on an S&P Global Market Intelligence analysis.

The combined market value of the top 20 utilities totaled $855.92 billion as of June 28.

Exelon Corp. logged the largest quarter-over-quarter drop in market value in the sector on a percentage basis, shedding 7.9% in value to $34.61 billion at the end of the second quarter. The company slipped down to 10th place from seventh a year earlier as it recorded a 14.6% year-over-year drop in market value. In June, **Maryland regulators rejected** a **forward-looking multiyear rate plan proposed by Exelon subsidiary Potomac Electric** Power Co., **deciding in favor of** a **one-time rate increase for** the utility.

Top 20 North American electric and multi-utilities companies by market capitalization as of June 28, 2024

Ranking 06/28/24	Ranking 06/30/23	Company (exchange:ticker)	Market cap ($B)	Change in market cap from (%) Q1 2024	Change in market cap from (%) Q2 2023
1	1	NextEra Energy Inc. (NYSE:NEE)	145.48	10.9	-3.1
2	2	Southern Co.(NYSE:SO)	84.82	8.4	10.7
3	3	Duke Energy Corp. (NYSE:DUK)	77.35	3.7	11.9
4	12	Constellation Energy Corp. (NASDAQGS:CEG)	63.13	8.4	112.6
5	4	Sempra (NYSE:SRE)	48.13	5.9	5.1
6	5	American Electric Power Co. Inc. (NASDAQGS:AEP)	46.25	2.0	6.7
7	6	Dominion Energy Inc. (NYSE:D)	41.07	-0.3	-5.1
8	8	PG&E Corp. (NYSE:PCG)	37.31	4.3	8.2
9	11	Public Service Enterprise Group Inc. (NYSE:PEG)	36.71	10.3	17.5
10	7	Exelon Corp. (NASDAQGS:EXC)	34.61	-7.9	-14.6
11	10	Consolidated Edison Inc. (NYSE:ED)	30.92	-1.4	-1.3
12	9	Xcel Energy Inc. (NASDAQGS:XEL)	29.68	-0.5	-13.3
13	14	Edison International (NYSE:EIX)	27.63	1.5	3.9
14	13	WEC Energy Group Inc. (NYSE:WEC)	24.78	-4.4	-11.0
15	16	DTE Energy Co. (NYSE:DTE)	22.97	-1.0	1.3
16	20	Entergy Corp. (NYSE:ETR)	22.85	1.4	11.0
17	17	FirstEnergy Corp. (NYSE:FE)	22.03	-0.7	-1.1
18	21	PPL Corp. (NYSE:PPL)	20.40	0.5	4.6
19	15	Eversource Energy (NYSE:ES)	19.98	-4.7	-19.3
20	22	CenterPoint Energy Inc. (NYSE:CNP)	19.82	9.9	7.7
		Industry median		**-0.2**	**-1.3**

Primary industry ● Electric Utilities ● Multi-Utilities

Data compiled July 1, 2024.
Analysis is limited to electric utilities and multi-utilities companies that currently trade on major US stock exchanges: Nasdaq, NYSE and NYSE AM, and major Canada stock exchanges: TSX and TSX-V.
Industry is classified according to the Global Industry Classification Standard of S&P Global Market Intelligence.
Source: S&P Global Market Intelligence.

Eversource Energy recorded the largest year-over-year drop in value at 19.3% and slipped down to 19th place from 15th a year ago. Quarter over quarter, the company's market value declined 4.7% to $19.98 billion as of June 28. The company's stock is among the bottom performers for the electric utility sector in the second quarter.

NextEra Energy Inc. **remained by far** the **largest utility**, with a **market value** of **$145.48 billion as of June 28**. The Juno Beach, Fla.-headquartered company posted the highest quarter-over-quarter improvement in market cap at 10.9%, although it lost 3.1% in value on a year-over-year basis.

During the second quarter, NextEra moved CFO Kirk Crews to the role of chief risk officer. Crews was succeeded by Brian Bolster, a long-time Goldman Sachs employee, as finance chief. Separately, the company announced plans to spend up to $107 billion through 2027 to facilitate increasing electricity demand.

Among other large-cap US and Canadian power companies, Constellation Energy Corp. logged the largest year-over-year increase in market capitalization in the sector on a percentage basis, jumping 112.6% to $63.13 billion at the end of the quarter. The company is the fourth-largest company in the sector as of June 28, with a market cap nearly double that of Exelon, from which it was spun off in 2022.

In May, Constellation executives said they are looking at restarting a shuttered unit at the Three Mile Island plant in Pennsylvania to expand the capacity of its nuclear power fleet by up to 1,000 MW in the coming years.

Other notable power utilities that improved their rankings on the list included Public Service Enterprise Group Inc., which moved up to ninth place from 11th after market value gains of 10.3% quarter over quarter and 17.6% year over year, and Entergy Corp., which gained 11% in value year over year to land at 16th place from 20th a year ago.

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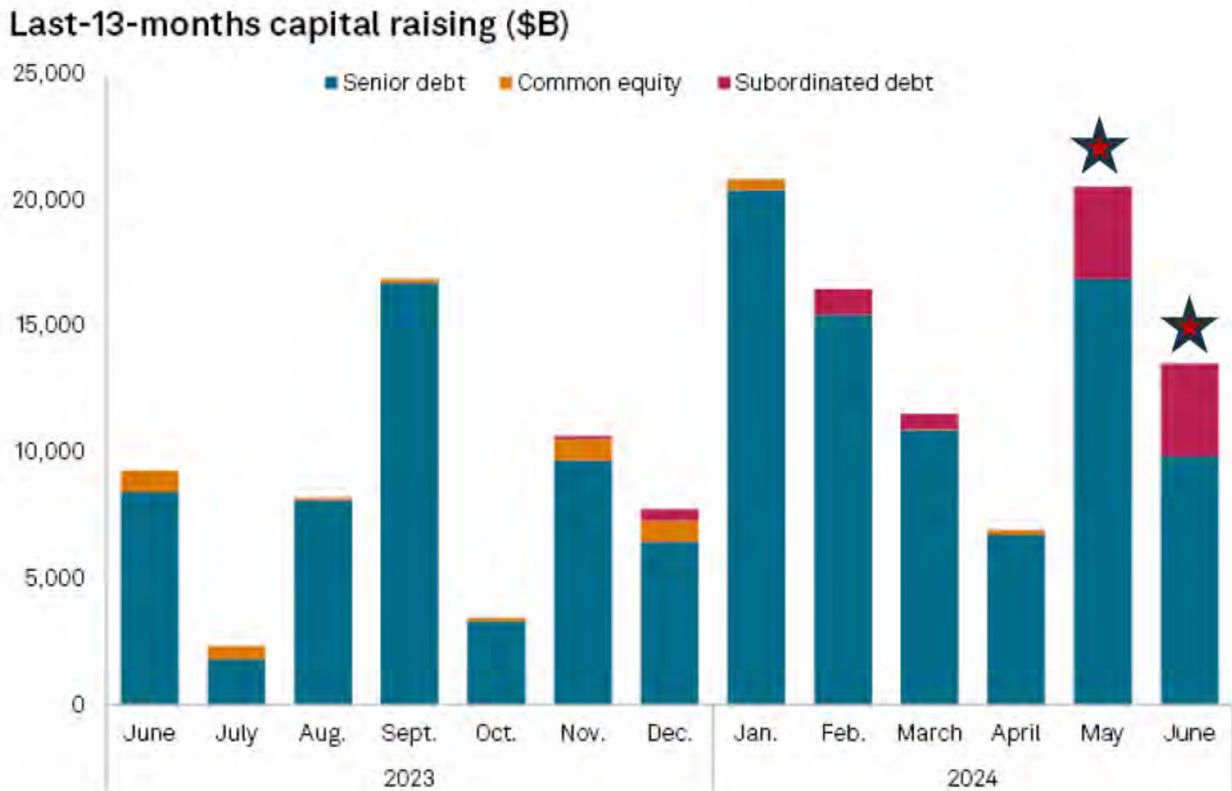
US, Canadian Utilities Raise $13.52B in June; YTD Total Reaches $89.82B

by Stephen Cedric Jumchai
Standard and Poor's Global Market Intelligence – Jul. 11, 2024

US and Canadian electric, gas and water utilities, power producers, and energy traders raised about $13.52 billion worth of capital in June, bringing year-to-date capital raises to $89.82 billion, according to S&P Global Market Intelligence data. The year-to-date total was up 1.4% from the $88.58 billion raised in the same period in 2023.



Data compiled July 5, 2024.

Includes capital raises of US and Canadian companies classified by the Global Industry Classification Standard of S&P Global Market Intelligence as electric, gas and multi-utilities; independent power producers and energy traders; or renewable electricity.

Amounts displayed reflect gross proceeds raised by the company in instances where offerings had primary and secondary components.

Excludes exchange and shelf offerings.

Debt does not include medium-term notes, branded notes or structured finance issues.

Source: S&P Global Market Intelligence.

As of the end of June, the **utility sector's financing consisted mostly of senior debt**, with some subordinated debt and common equity transactions.

US and Canada power, gas utilities capital raises by security type ($B)

Year to date

Data compiled July 5, 2024.

Includes capital raises through June 30 of respective years for US and Canadian companies classified by the Global Industry Classification Standard of S&P Global Market Intelligence as electric, gas and multi-utilities; independent power producers and energy traders; or renewable electricity where capital raised is greater than zero.

Amounts displayed reflect gross proceeds raised by the company in instances where offerings had primary and secondary components.

Excludes exchange and shelf offerings.

Debt does not include medium-term notes, branded notes or structured finance issues.

Source: S&P Global Market Intelligence.

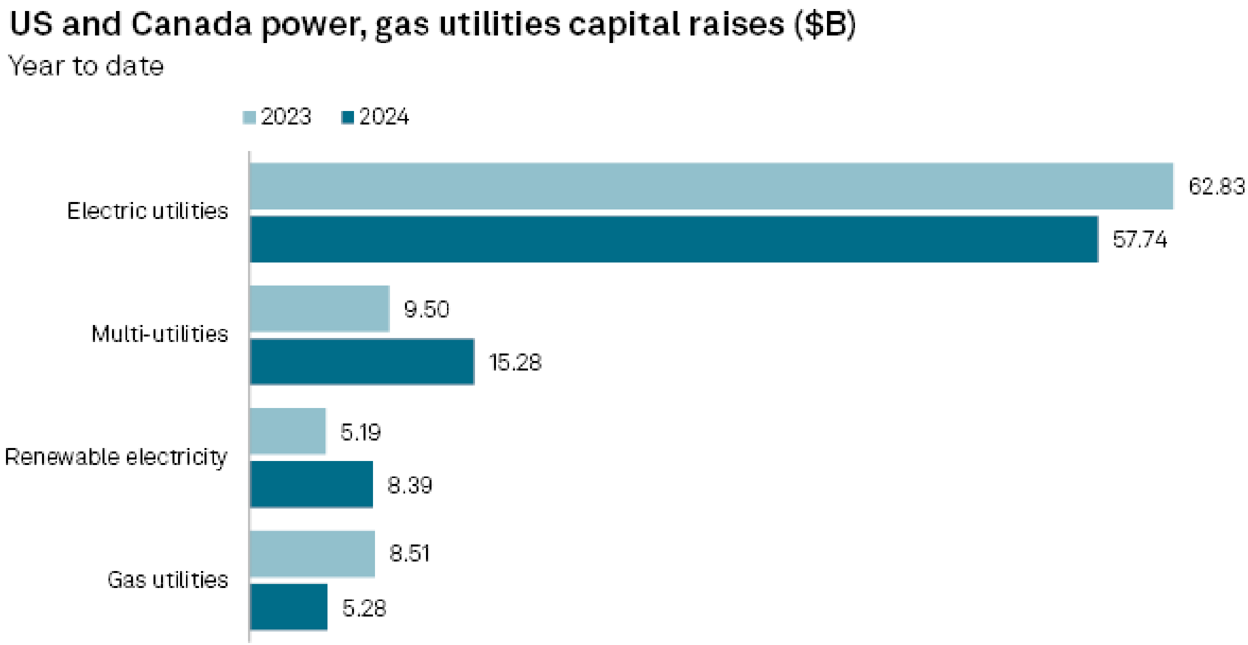
Electric, Gas Utilities Continue YOY Declines Through June

Two of the three covered utility segments recorded year-over-year decreases in capital raised through June.

The electric utilities segment raised $57.74 billion through June, a $5 billion decrease from the amount raised a year earlier. Natural gas utilities raised $5.28 billion, a nearly 38% drop from $8.51 billion in the year-ago period.

In contrast, multi-utilities raised $15.28 billion, an increase of $5.78 billion from the amount raised in the same period of 2023.

Renewable electricity producers raised $8.39 billion, up from the $5.19 billion raised through June 2023.



Data compiled July 5, 2024.
Includes capital raises through June 30 of respective years for US and Canadian companies classified by the Global Industry Classification Standard of S&P Global Market Intelligence as electric, gas and multi-utilities; independent power producers and energy traders; or renewable electricity where capital raised is greater than zero.
Amounts displayed reflect gross proceeds raised by the company in instances where offerings had primary and secondary components.
Excludes exchange and shelf offerings.
Debt does not include medium-term notes, branded notes or structured finance issues.
Source: S&P Global Market Intelligence.

Largest Offerings in June

The sector completed 22 senior debt transactions in June. Duke Energy Corp. had the largest offering of the month with the sale of $1.50 billion of securities comprising $750 million of 5.45% senior notes due 2034 and $750 million of 5.80% senior notes due 2054. The company plans to use net proceeds to repay a portion of its outstanding commercial paper and for general corporate purposes.

UGI Corp. had the second-largest offering with the sale of $1.31 billion of securities comprising a private placement of $700 million of 5% convertible senior notes due 2028 and an offering of $610 million of 5% convertible senior notes due 2028. The utility plans to use the proceeds from the $610 million offering to refinance debt and for general corporate purposes.

Also of note for the month was **NextEra** Energy Inc. subsidiary NextEra Energy Capital Holdings Inc.'s sale of $1.20 billion series R **junior subordinated debentures** due June 15, 2054. NextEra Energy Capital plans to add the net proceeds to its general funds, which will be used to finance investments in energy and power projects and for other general corporate purposes, including the repayment of a portion of the company's outstanding commercial paper obligations.

Other notable issuers for the montl

US and Canada power, gas utilities capital raises in June 2024

Issuer	Completion date	Amount offered including exercised overallotments ($M)
Senior debt		
Ontario Power Generation Inc.	06/28/24	365.3
Ontario Power Generation Inc.	06/28/24	365.3
Florida Power & Light Co.	06/27/24	167.1
Mississippi Power Co.	06/27/24	100.0
Oncor Electric Delivery Co. LLC	06/21/24	750.0
Oglethorpe Power Corp.	06/18/24	350.0
Atmos Energy Corp.	06/18/24	325.0
Ameren Illinois Co.	06/17/24	625.0
NiSource Inc.	06/17/24	600.0
Georgia Power Co.	06/13/24	55.0
UGI Corp.	06/11/24	700.0
UGI Corp.	06/06/24	610.0
Duke Energy Corp.	06/05/24	750.0
Duke Energy Corp.	06/05/24	750.0
Pinnacle West Capital Corp.	06/05/24	350.0
Capital Power Corp.	06/05/24	328.2
Pinnacle West Capital Corp.	06/04/24	475.0
Puget Sound Energy Inc.	06/04/24	400.0
Puget Sound Energy Inc.	06/04/24	400.0
Southwestern Public Service Co.	06/03/24	600.0
Baltimore Gas and Electric Co.	06/03/24	400.0
Baltimore Gas and Electric Co.	06/03/24	400.0
Total		**9,866.0**
Subordinated debt		
Edison International	06/25/24	500.0
American Electric Power Co. Inc.	06/17/24	600.0
American Electric Power Co. Inc.	06/17/24	400.0
CenterPoint Energy Resources Corp.	06/17/24	400.0
NextEra Energy Capital Holdings Inc.	06/05/24	1,200.0
PNM Resources Inc.	06/04/24	550.0
Total		**3,650.0**
Common equity		
Solar Alliance Energy Inc.	06/27/24	0.1

Data compiled July 5, 2024.

Includes capital raises of US and Canadian companies classified by the Global Industry Classification Standard of S&P Global Market Intelligence as electric, gas and multi-utilities; independent power producers and energy traders; or renewable electricity.

Amounts displayed reflect gross proceeds raised by the company in instances where offerings had primary and secondary components.

Excludes exchange and shelf offerings.

Debt does not include medium-term notes, branded notes or structured finance issues.

Source: S&P Global Market Intelligence.

Exelon Corp. subsidiary Baltimore Gas and Electric Co. and Puget Holdings LLC subsidiary Puget Sound Energy Inc.

The S&P 500 Utilities index logged a 7.8% increase for the 12 months through June 30, while the broader S&P 500 index gained 24.6% over the same period.

S&P 500 Utilities index vs. S&P 500 1-year performance (%)

Total return shown to June 30, 2023, compared to June 28, 2024

Data compiled July 5, 2024.
Source: S&P Global Market Intelligence.

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U.S. Economy Grew at Robust 2.8% in Second Quarter

by Harriet Torry – WSJ – Jul. 25, 2024

Household spending, the main driver of the U.S. economy, rose at a 2.3% rate in the second quarter.

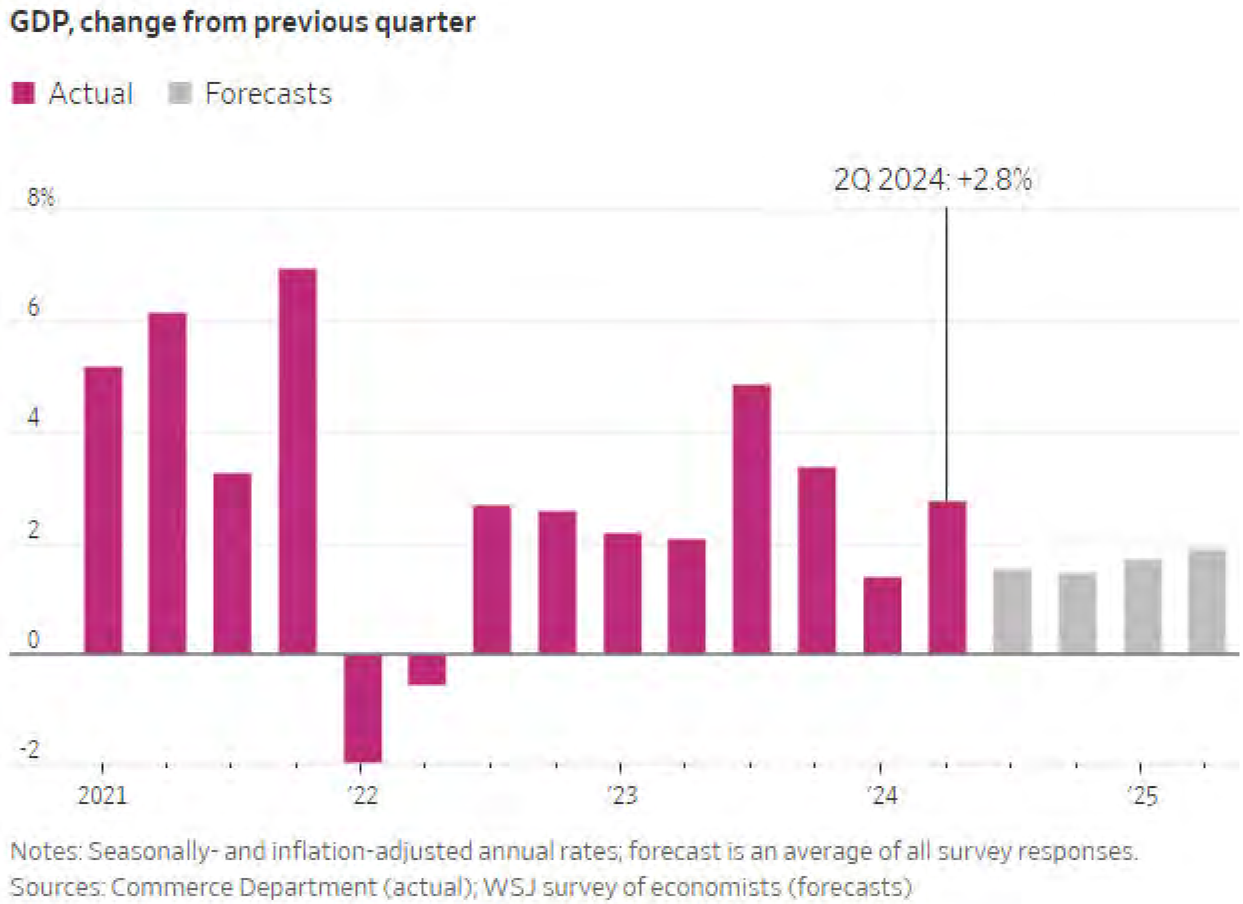
The **U.S. economy accelerated** in the second quarter as **consumers increased** their **spending**, **businesses invested more** in **equipment and stocked inventories**, **and inflation cooled**.

Gross **D**omestic **P**roduct – the value of all goods and services produced in the U.S., adjusted for inflation and seasonality – **rose** at an **annual rate** of **2.8%** for **April through June**, the Commerce Department said Thursday. That was more than the 1.4% rate during the first quarter, and well above the 2.1% rate economists had expected before the report.

Household spending, the **main driver** of the U.S. economy, **increased** at a **2.3%** rate in the second quarter, picking up from 1.5% in the first. Spending on goods increased while services spending moderated slightly.

The report shouldn't change the outlook for the Federal Reserve's next moves. Officials have signaled that they expect to hold interest rates steady at their meeting next week but could cut at their subsequent meeting, in September, if inflation continues to cool.

Thursday's report is one of the last major readings of the economy's temperature that Fed officials will see before next week's meeting. The report suggests the U.S. economy remains on solid footing.



"The sharper-than-expected pickup in second-quarter GDP growth to 2.8% annualized should make the Fed a bit more comfortable about keeping policy unchanged next week, but the recent loosening of labor market conditions and signs of slower price growth still mean that there is a strong case for a cut at the following meeting in September," Stephen Brown, an economist at Capital Economics, said in a note to clients.

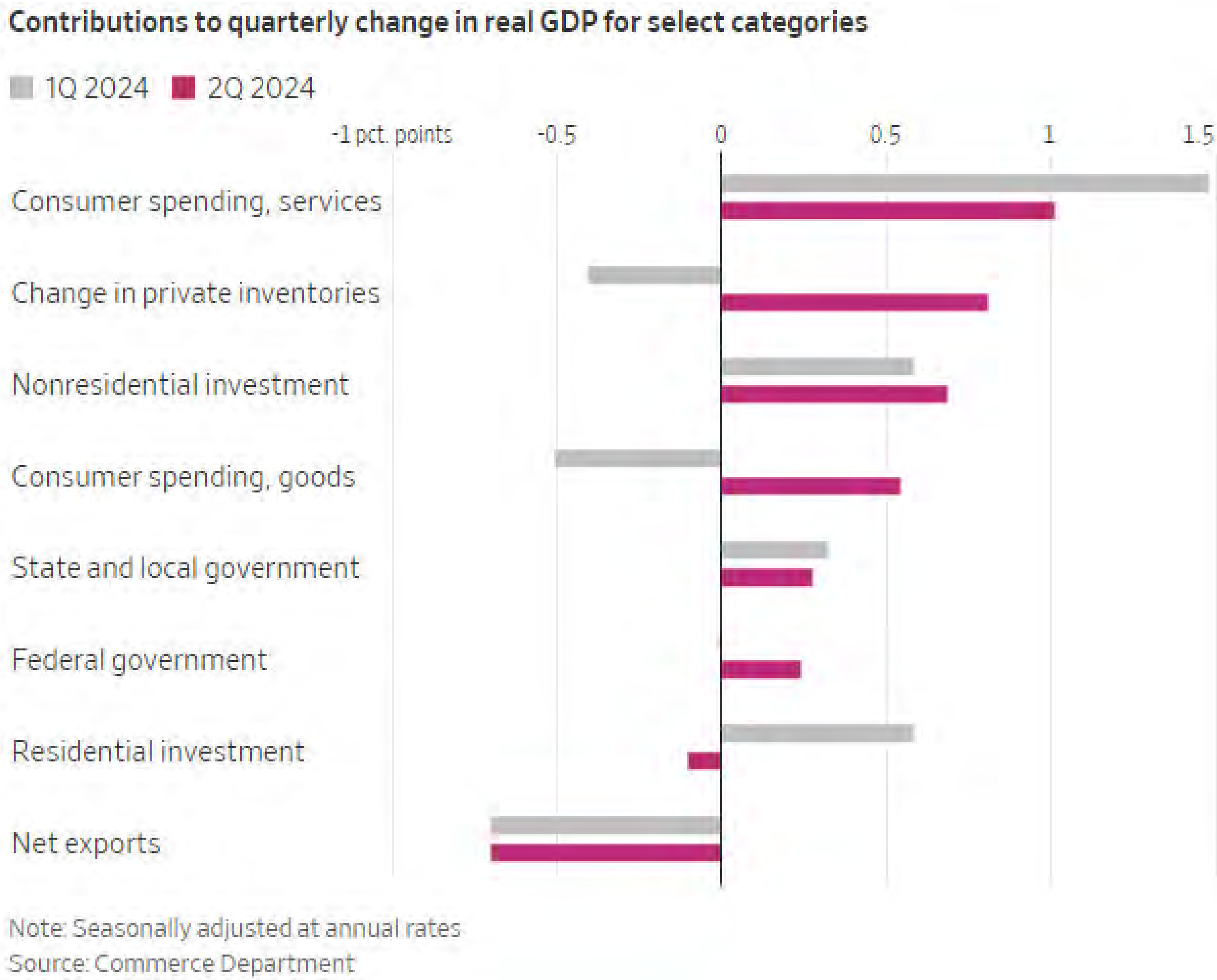
The pickup in consumer and business spending offset negative developments such as a decline in spending on residential investment. The spring home-buying season, usually the busiest time of year for the housing market, was a dud thanks to high prices and elevated mortgage rates. **Sales of existing homes decline in June** for the fourth straight month, **but prices hit** a **record**, **locking out many would-be buyers**.

A key category of **business** spending picked up: Nonresidential fixed investment, reflecting **spending** on **commercial construction**, **equipment** and **software**, **rose** at a

5.2% rate. **Capital expenditures** were **led by 11.6% growth** in **spending on equipment**, **while spending on structures declined**.

Excluding volatile food and energy prices, the **Personal-Consumption Expenditures Price index rose 2.9%** in the second quarter at an **annualized** rate, cooling from 3.7% in the first quarter.

Stocks were muted shortly after the opening bell, with the S&P 500 flat and the Dow Jones Industrial Average slightly higher.



Thursday's report provides a snapshot of how the economy is doing, two years after soaring inflation prodded the Federal Reserve to start raising interest rates at the fastest pace in decades. Higher rates are meant to slow the economy.

While the U.S. by many measures is doing well even amid high rates, and the pace of inflation has cooled, many Americans are unhappy that prices for groceries, cars and homes are so much higher than they were a few years ago.

And even though predictions of a recession have faded, there are signs of weakness.

A red-hot jobs market, which allowed millions of Americans to switch to jobs that paid more or fit them better, is starting to slow. **Although** the **unemployment** rate is **still historically low**, **employers added jobs at** a **slower pace** in the **second quarter** compared with the first.

Consumers are also facing mounting headwinds from still-high borrowing costs.

Companies are warning that consumers are increasingly tapped out. Packaged-food companies PepsiCo and Conagra Brands earlier this month reported weak quarterly results and said they see U.S. shoppers under pressure. United Parcel Service this week lowered its revenue outlook for the year. The company said **customers** were **trading down to cheaper options**, like lengthier ground delivery.

"Right now is a moment when many consumers are feeling stretched with low confidence in the economy and with less money to spend on discretionary items," Etsy Chief Executive Josh Silverman said at the company's annual shareholders meeting last month. "But it's a moment we believe will pass."

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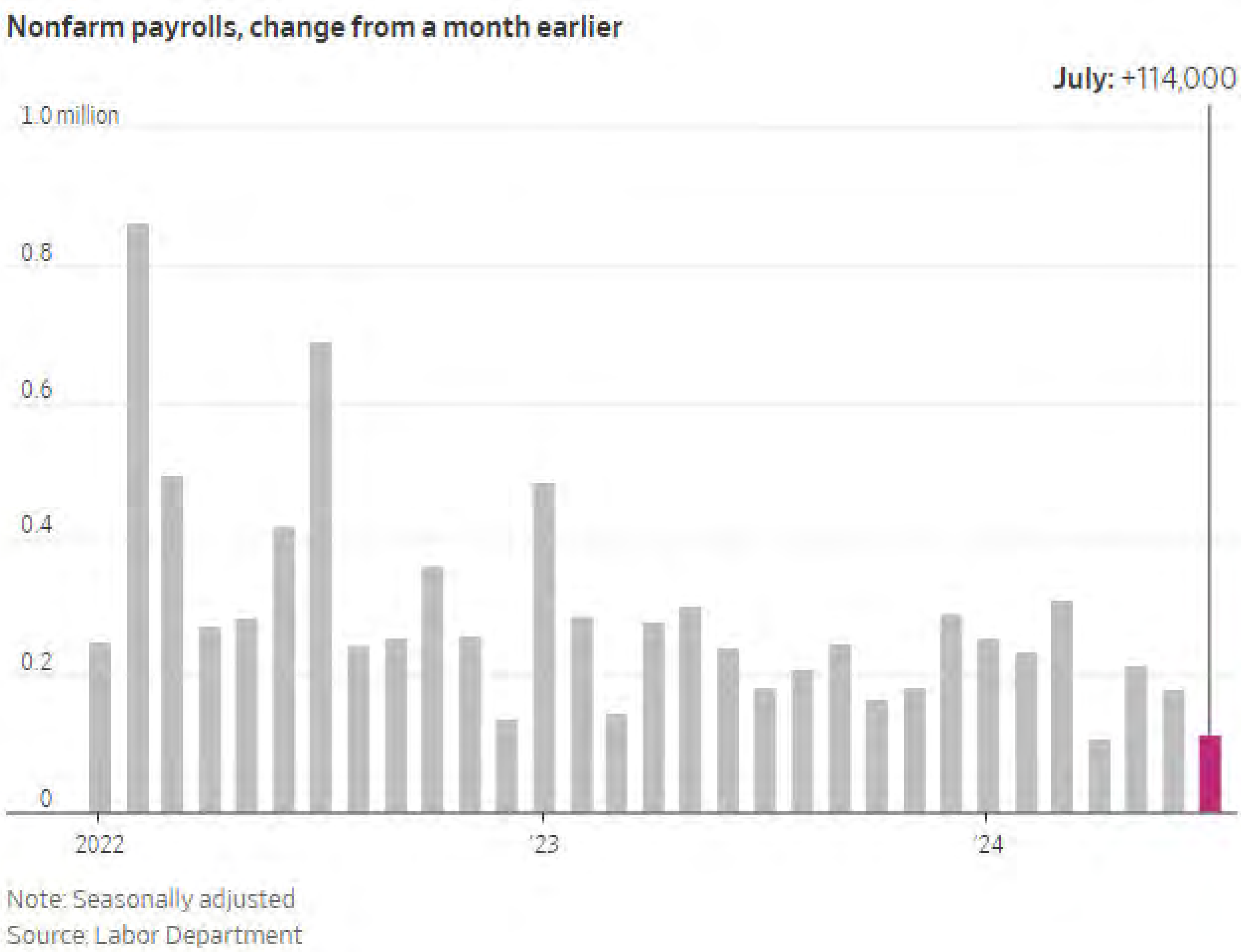
U.S. Hiring Slowed Sharply, with 114,000 Jobs Added in July

by Justin LaHart – WSJ – Aug. 2, 2024

Jobs report shows unemployment climbs to 4.3%

Job growth slowed sharply in July and the unemployment rate rose to its highest level since 2021, adding to evidence that a labor market whose strength is fading could actually be on its way to weakness.

America is **still adding jobs**, **but no longer at** a **red-hot pace**. The Labor Department reported on Friday that employers added 114,000 jobs last month, missing expectations. The **unemployment rate jumped to 4.3%** – its highest level in nearly three years, when the labor market was still clawing its way back from the pandemic.



Average hourly earnings were up 3.6% in July from a year earlier – above the recent pace of inflation, but the smallest gain since May 2021. The jobs count for May and June was revised down by a combined 29,000.

But the jump in the unemployment rate was from more people looking for jobs, rather than people losing their jobs. The labor-force participation rate, the share of working-age people who were employed or seeking work, rose to 62.7% from 62.6% in June. Absent the increase in participation, the unemployment rate would have stayed at 4.1%.

Stocks were down sharply in early trading, and **Treasury yields sank**, reflecting investors' renewed worries about a slowdown in the economy.

Some investors have started to question whether the Federal Reserve has waited too long to trim interest rates.

Interest rate futures went from implying Federal Reserve policymakers **would cut** their **benchmark interest rate** by a **quarter percentage point** when they next meet in **September to** a **half-point cut**.

July's job gains were **concentrated** in the **healthcare** sector, which added 55,000 jobs, **construction**, which added 25,000, and **leisure** and **hospitality**, which added 23,000. On the other side of the ledger, the **information sector shed** 20,000 **jobs**.

Better news on inflation and a desire to prevent a significant rise in joblessness are two major reasons why Fed policymakers on Wednesday cleared the path for a September interest-rate cut. "I would not like to see material further cooling in the labor market," said Fed Chair Jerome Powell at his press conference following the central bank's policy meeting.

To a degree, the slowdown in job creation last month might reflect the effects of **Hurricane Beryl**. The hurricane made landfall in Texas on July 8, near the start of the week the Labor Department uses for its employment readings. In the storm's wake, there was a notable move up in weekly readings on initial claims for unemployment insurance filed in Texas.

The Labor Department on Friday said that 461,000 people with jobs were unable to work because of weather in July. The average number of people missing work because of weather over the previous 10 Julys was 37,000. The August jobs figures could see a rebound, as those storm effects reverse.

Warning signs

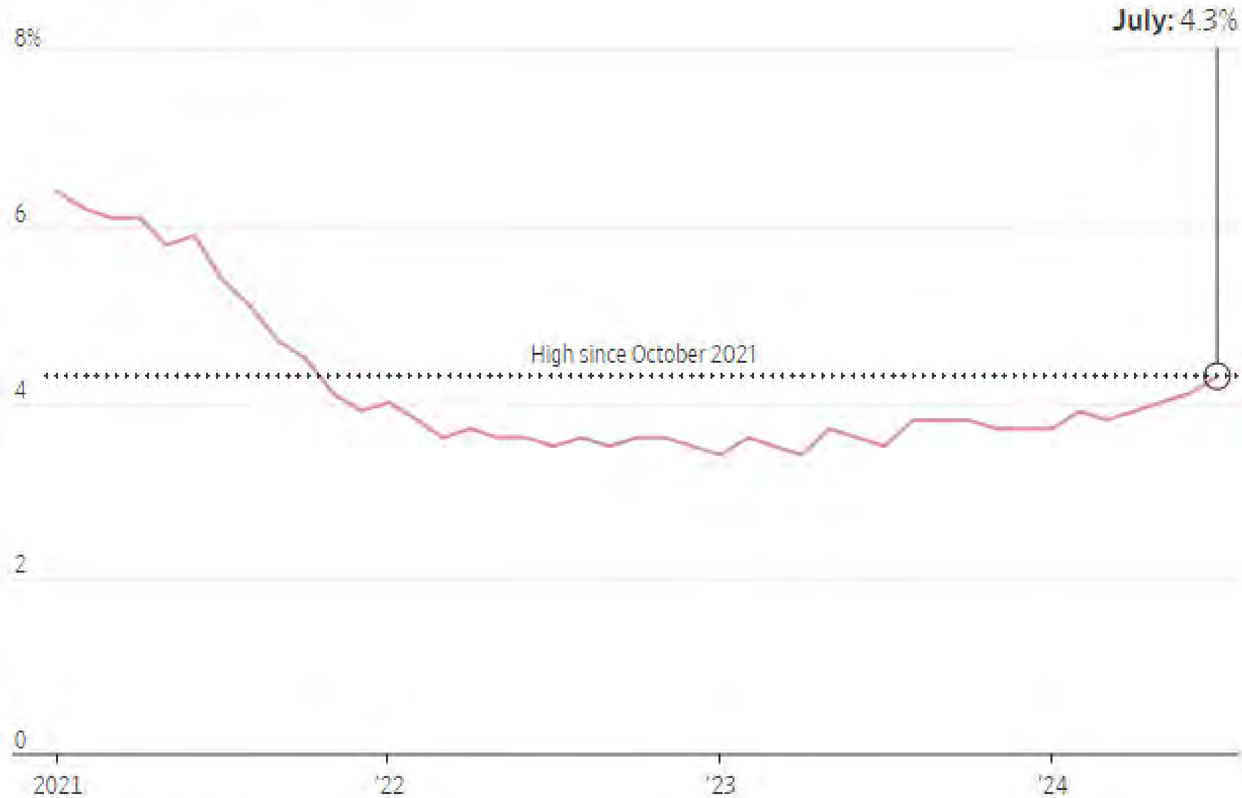
But other labor market measures are flashing warning signs.

The **Sahm rule**, an indicator popularized by economist Claudia Sahm, says that if the average of the unemployment rate over three months rises a half-percentage point or more above the lowest the three-month average went over the previous year, the economy is in a recession. Over the past three months, the unemployment rate has averaged 4.13%—0.53 percentage point above the three-month average low of 3.60% over the past year.

Powell characterized the Sahm rule as a "statistical regularity" on Wednesday. "It's not like an economic rule, where it's telling you something must happen," he said.

Sahm herself doesn't think the economy is on the immediate cusp of a recession. She reckons that changes in the supply of labor since the pandemic, including the recent jump in immigration, have led the Sahm rule to overstate how weak the job market is. But she worries about the direction things are heading: The unemployment rate is historically low, but it has been trending higher; the number of jobs the economy has been adding each month is still historically strong, but it has been trending down.

Unemployment rate



Note: Seasonally adjusted
Source: Labor Department

"We are still in a good place, but until we see signs of stabilizing, of leveling out, I'm worried," said Sahm, a former Fed economist who is now the chief economist at New Century Advisors.

Thursday, the Institute for Supply Management reported that its measure of manufacturing employment deteriorated in July, helping spark a **selloff in stocks**. After the close Thursday, **Intel** posted disappointing quarterly sales, and announced plans to lay off 15,000 people.

The pace of hiring has also slowed markedly, with the Labor Department on Tuesday reporting that the hires rate – the number of hires as a share of total jobs – slipped to 3.4% in June, marking its lowest level since April 2020, when the pandemic had just hit the economy. In 2019, that rate averaged 3.9%. One reason that the economy has been able to keep adding jobs despite the low hires rate is that layoff activity has been muted, too, with the June layoff rate matching its lowest level on record.

Ernie Tedeschi, director of economics at the Budget Lab at Yale University, reckons the recent data are consistent with an economy that is at full employment – one when there are fewer gains to be had than a year ago, when many employers were still struggling to find workers.

"In one sense, that is a positive story," he said. "In another sense, it should make us even more attuned to the risks involved."

For now he said he isn't too worried. But if there were signs of sharp deterioration – a significant increase in the number of people filing unemployment claims, say, or a drop in the share of people in their prime working years who are employed – he would be.

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US Would Keep More Hydropower under Agreement with Canada on Treaty Governing Columbia River

by Gene Johnson – Oregonian, AP – Jul. 21, 2024

The **U.S. and Canada** said Thursday they have agreed **to update** a **six-decade-old treaty** that **governs** the **use** of one of North America's largest rivers, the **Columbia**, with **provisions** that officials said would provide for effective **flood control**, **irrigation**, and **hydropower generation** and **sharing** between the countries.

The "agreement in principle," reached after six years of talks, provides a framework for updating the Columbia River Treaty. It calls for the **U.S. to keep more** of the **power generated by** its **dams** while **improving cooperation** between the Bonneville Power

Administration, which markets power from dams in the northwestern U.S., and Canadian utilities, **to help avoid blackouts**.

The **U.S. would pay Canada for reservoir capacity** to hold back water during flood seasons, protecting downstream communities, at a rate that would **begin** at **$37.6 million per year** and **increase with inflation**. And the agreement would **provide Canada** with **more flexibility** in **using** the **water stored in its reservoirs**.

“After 60 years, the Treaty needs updating to reflect our changing climate and the changing needs of the communities that depend on this vital waterway,” U.S. President Joe Biden said in a written statement Thursday.

But environmental groups lamented the deal as a missed opportunity to provide more water for imperiled salmon and steelhead runs that have been decimated by dam operations in the Columbia River basin over the past century. the original treaty ratified in 1964 was designed to cover flood control and hydropower generation, conservationists and Indigenous tribes have long argued that it should be updated to include river health and salmon restoration as a third principle.

Left President Joe Biden talks to Canada's Prime Minister Justin Trudeau, during a G7 world leaders summit at Borgo Egnazia, Italy, June 13, 2024. The U.S. and Canada said Thursday, July 11, that they have agreed to update a six-decade-old treaty that governs the use of one of North America’s largest rivers, the Columbia, with implications for electricity prices, irrigation, flood control and imperiled salmon runs.

“Our community is frustrated and disappointed today,” said Joseph Bogaard, of the nonprofit Save Our Wild Salmon. “The treaty needs to be a tool to address challenges for these fish. There are benefits and certainty for the power sector and for flood risk management, while salmon basically get status quo treatment.”

The Biden administration earlier this year brokered a $1 billion plan to boost salmon runs in the Northwest.

The Columbia River begins in Canada but flows mostly in the U.S. on its 1243-mile (2000.41 kilometer) journey to the Pacific Ocean. It forms most of the border between Washington state and Oregon. Its tributaries account for 40% of U.S. hydropower, irrigate $8 billion in agriculture products, and move 42 million tons of commercial cargo annually, officials noted Thursday.

The **Columbia River Treaty came together after** a **1948 flood washed away** the **Oregon** community of **Vanport**, **leaving** more than **18,000 people homeless**.

It provided for the construction of one dam in Montana, which flooded land in Canada, and three in British Columbia, completed between 1968 and 1973, that together more than doubled the amount of reservoir storage in the basin, providing benefits for both flood prevention and hydropower. The British Columbia dams also flooded tribal lands and retained much spring runoff that would otherwise be available for migrating salmon.

The treaty provided for what came to be known as the "**Canadian Entitlement**," under which Canada receives $250 million to $350 million a year worth of **electrical power in exchange** for **storing water in huge reservoirs** that can be released to boost U.S. hydropower generation. The cost is higher than anticipated by the United States when the treaty was signed, and it increased prices for U.S. customers, lawmakers in the Pacific Northwest long complained.

Under the agreement announced Thursday, the U.S. will immediately reduce by 37 percent the amount of Columbia Basin hydropower it delivers to Canada, with further cuts amounting to 50 percent by 2033. BPA administrator John Hairston said Thursday that will save the agency about $70 million next year and about $1.2 billion over the next two decades.

"These new terms will go a long way toward helping meet the growing demand for energy in the region and avoid building unnecessary fossil fuel-based generation," Hairston told reporters during a briefing Thursday.

U.S. Sens. Maria Cantwell, D-Washington, and Jim Risch, R-Idaho, who have pushed for updates to the treaty, called the agreement a positive step, but said they would need to review the details. Government negotiators will finalize details before the treaty is submitted to the U.S. Senate for ratification.

Indigenous tribes have long wanted the Columbia to flow more like a natural river, instead of a series of reservoirs with slow-moving water that often heat up to temperatures that kill migrating salmon.

U.S. and Canadian officials said the agreement would establish a tribal-led body that will provide recommendations on how treaty operations can better support ecosystem needs and tribal and indigenous cultural values.

In a written statement, Chief Keith Crow, of the Syilx Okanagan Nation in British Columbia, said the agreement gave him hope that one day his grandchildren might harvest salmon in the upper Columbia River region.

“We still have lots of work to do with Canada and B.C. to start addressing the past and ongoing impacts to our lands, waters and people,” Crow said.

Canada has been providing up to 1 million acre-feet of water a year to help juvenile salmon on their migration to the Pacific, with up to an additional half-million acre-feet in dry years, subject to negotiation between the countries, Bogaard, of Save Our Wild Salmon, said.

Researchers insist that the fish need 3 million to 5 million acre-feet per year released by Canada, but the agreement announced Thursday would reinforce the current amount, with the minor improvement that in dry years Canada would automatically provide the extra half-million acre-feet if available, he said.

“Salmon have suffered tremendous losses through the industrialization of the Columbia Basin’s rivers, in part, as a result of this Treaty," Neil Brandt, executive director of WaterWatch of Oregon, said in a written statement. “A modernized Treaty must do better for salmon."

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Wall Street Wants in on America’s Battery Storage Boom

by Amrith Ramkuma – WSJ – Jul. 17, 2024

Solar surge lets battery companies charge up when power prices are low, sell when high.

Intersect Power is installing Tesla Megapack batteries to store and dispatch electricity in Scurry County, TX.

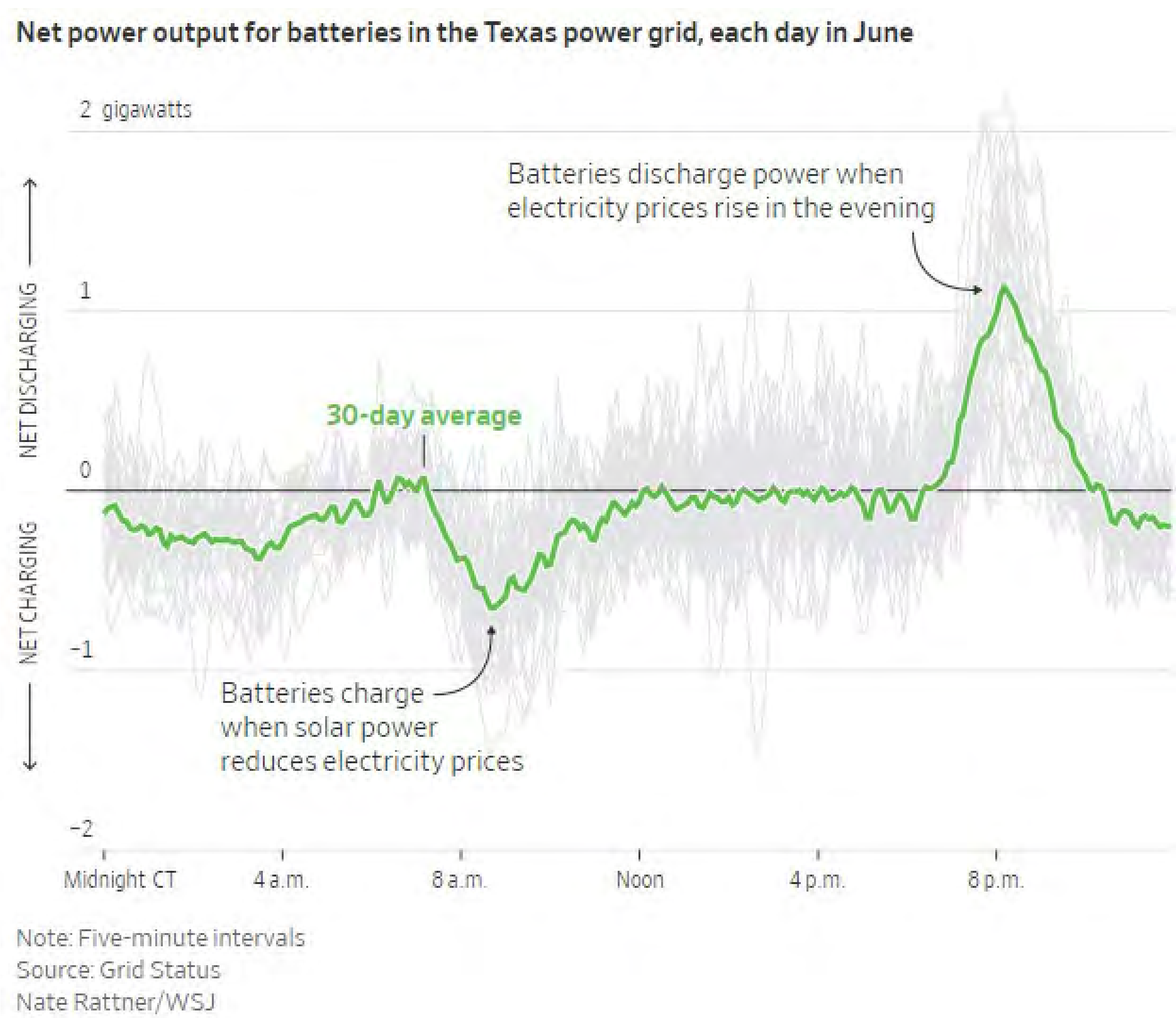
Sheldon Kimber sees a lucrative opportunity in bottling sunshine.

The 46-year-old entrepreneur is installing hundreds of giant batteries the size of shipping containers around sun-soaked Texas and California. The batteries charge up during the day when solar power is abundant. When electricity demand rises in the evening, straining the power grid, Kimber sells that stored energy at higher prices.

Kimber is betting that surging power demand and extreme weather events will make it an increasingly profitable trade.

"The only thing we can guarantee in the energy transition is that volatility will increase," said Kimber, chief executive of renewable energy developer Intersect Power.

Kimber is part of a **nationwide race to profit from battery storage**, which helps stabilize the outdated power grid and smooth out intermittent electricity sources such as wind and solar. It is a rapidly growing sector that is being fueled by a boom in solar energy and billions of dollars from Washington and Wall Street.



In one of the largest battery storage deals, Intersect is raising $837 million in debt and equity tied to tax credits from Morgan Stanley, Deutsche Bank and HPS Investment Partners.

The money will fund three giant battery storage projects in Texas. Together, the 258 Tesla Megapack batteries will be able to provide enough power for nearly 400,000 homes for two hours when they begin operating in the coming months, Intersect says.

The sector's potential has been in the spotlight after **Hurricane Beryl** left millions of Houston residents without power. Many homeowners and businesses have been installing batteries to provide power during blackouts, as well as for other grid disruptions that are more common in the summer.

Storage capacity in the U.S. has grown enough in recent years to be able to power many millions of homes, according to S&P Global Market Intelligence. California and Texas dominate the industry, but projects are in the works in Nevada, Arizona and elsewhere to help meet growing power demand from artificial-intelligence data centers and manufacturing plants.

Private-equity firm Cerberus Capital Management recently agreed to a $315.5 million debt investment in Eos Energy Enterprises, a startup producing zinc batteries that could store energy for longer periods. A developer called rPlus Energies just raised over $1 billion for a big solar and storage project in Utah.

“It definitely feels like there’s a bit of a gold rush,” said Jacob Mansfield, a former power trader and CEO of Tierra Climate, a startup developing a financial product that would let battery companies get paid more for charging and discharging clean energy.

Founded in 2016, Intersect Power has raised billions of dollars to build solar projects for Apple, Morgan Stanley and others. Now the company is setting its sights on battery storage.

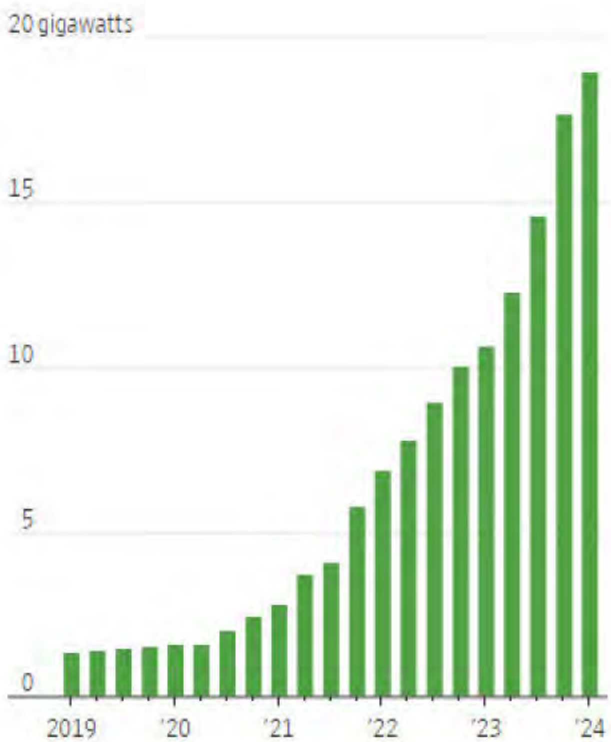
The company has agreed to buy billions of dollars worth of Tesla Megapack batteries to accelerate installations in California and Tesla is known for making electric cars, but its newer, smaller energy storage business is expected to grow faster.

Sheldon Kimber is CEO of Intersect Power, part of a nationwide race to profit from battery storage.

Having a domestic battery supplier lets Intersect qualify for more subsidies in the 2022 climate law. Tax credits are expected to cover roughly half the cost of the Texas battery projects.

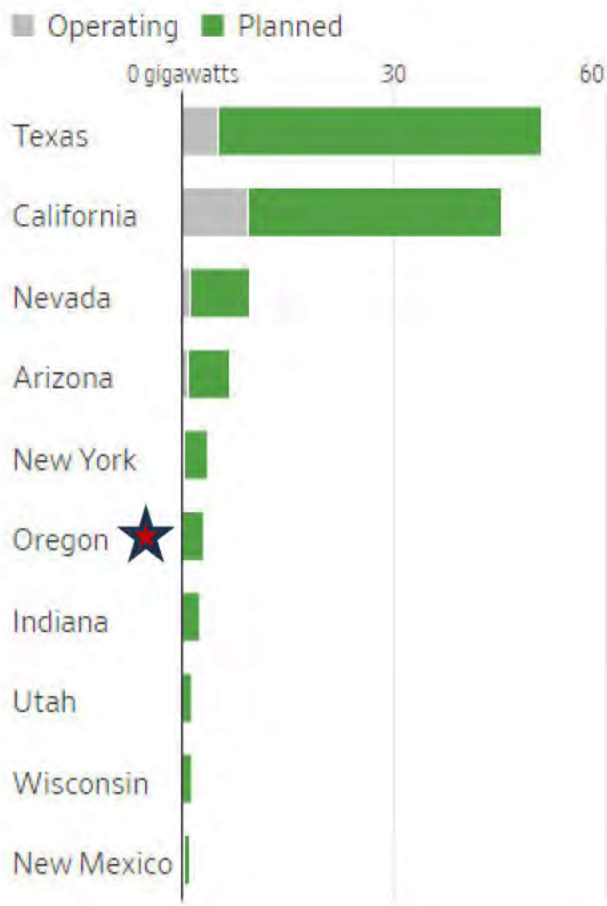
Instead of the **long-term customer contracts with low, fixed prices** that are used by most clean-energy companies, **Kimber prefers shorter deals with more flexible pricing**. The strategy is riskier but **boosts revenue if prices surge**.

Cumulative large-scale U.S. energy storage installations, quarterly



Notes: Includes standalone and co-located storage projects; excludes pumped hydro storage; minimum project size for inclusion in data is 200 kilowatts
Source: S&P Global Market Intelligence

States with the most large-scale energy storage



Notes: Includes standalone and co-located storage projects; excludes pumped hydro storage; minimum project size for inclusion in data is 200 kilowatts; data through late May
Source: S&P Global Market Intelligence

The payoff could be especially rich in **Texas**, where power traders play a big role in the state's **deregulated electricity market**. It is one of the markets where the difference between electricity prices during the day and evening has gotten so consistent that Intersect can include fixed prices in contracts with utilities and other customers.

Traders have guaranteed the company a minimum payment for its battery projects, based on the spread of electricity prices between when companies typically charge and discharge batteries. When the spread climbs above that level, Intersect keeps more of the money.

In states with more tightly regulated electricity markets, storage companies rely more heavily on other types of revenue, such as payments from utilities when their batteries are used.

The sector still faces speed bumps. **Other types of batteries** that **might potentially store energy for longer could make some projects relying on today's lithium-ion batteries obsolete**.

The rush of storage installations could also make electricity prices less volatile – and battery projects less profitable. Permitting snags and challenges hooking projects up to power grids in some states could hamper growth.

Investors are betting the surge in solar and falling costs for storage will make their bets pay off.

"It has been the hot topic over the last 24 months," said Michael Bonafide, director on the infrastructure and energy financing team at Deutsche Bank, which has invested in six storage deals over the last two years.

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Warren Buffett's Berkshire Hathaway Slashes Apple Stake

by Karen Langley – WSJ – Aug. 3, 2024

The company sold stocks – including much of its giant Apple stake – in the second quarter.

Attendees of the annual meeting earlier this year in Omaha, NB.

Warren Buffett's Berkshire Hathaway has been in selling mode.

The famed investor's Omaha, NB., company revealed Saturday that it sold nearly half its Apple shares in the second quarter, slashing its mammoth position in the iPhone maker after significant sales earlier in the year.

Berkshire sold a net $75.5 billion in stocks in the three months through June, helping boost its **cash hoard** to a **record $276.94 billion**, **including cash equivalents**, the company's financial statements show.

The disclosures come after Berkshire in recent days methodically trimmed its investment in Bank of America, its second-largest stock position after Apple.

The stock sales and mountain of cash show the challenge Buffett has encountered finding good investments that are priced low enough to make a solid return likely. The stock market has grown more expensive: The S&P 500 recently traded at nearly 21 times its projected earnings over the next 12 months, above a 20-year average of nearly

16 times, according to FactSet. **Buffett spoke** about the difficulty of deploying the cash at Berkshire's annual meeting in May.

"We'd love to spend it, but **we won't spend it unless we think we're doing something that has very little risk and can make us a lot of money**," he said.

Berkshire sold about $3.8 billion worth of Bank of America stock over the 12 trading days through Thursday, according to filings with the Securities and Exchange Commission, leaving it with a 12.15% stake in the bank that would have been worth more than $35 billion at Friday's close.

Bank of America shares had rallied in recent months, rising 75% from a low in late October to the time Berkshire began selling in July.

"He doesn't seem to be in love with banks," said James Shanahan, a senior equity research analyst at Edward Jones. "There's been a lot of selling activity among bank holdings in recent years."

A quarterly filing released Saturday showed Berkshire sold about 49% of its Apple stock in the second quarter, leaving it with a position worth $84.2 billion at the end of June.

That was after cutting the investment 13% in the first quarter. Buffett praised Apple from the stage of Berkshire's annual meeting in May, calling it "an even better business" than American Express and Coca-Cola, two other big holdings. He suggested an expectation that tax rates might rise played into the call to take some profits on the position, which has gained enormous value as Apple's stock soared in recent years. Apple shares have risen 14% in 2024.

Buffett's reputation as one of the greatest stock pickers of all time means his moves carry significant weight with many investors.

Macrae Sykes, a portfolio manager at Gabelli Funds, holds Berkshire and Bank of America shares in an exchange-traded fund. He said the fact that Buffett's company was selling the bank's stock gives him pause.

Chairman Warren Buffett attending the Berkshire Hathaway annual shareholders' meeting in Omaha, NB., in May.

"He's one of the world's foremost investors and obviously has an incredible history of allocating in financial services," Sykes said. "Something like this is important to pay attention to and check our research."

Berkshire invested in Bank of America in 2011 in the aftermath of the financial crisis, offering a vote of confidence at a time when investors were questioning the bank's health. It became the bank's largest shareholder in 2017 and held that position after Thursday's sales.

Buffett's company has sold other bank holdings in recent years, exiting positions in JPMorgan Chase and in Wells Fargo.

Berkshire, which owns businesses including insurer Geico, railroad BNSF Railway and sportswear maker Brooks Running, posted net income of $30.3 billion, or $21,122 a class A share equivalent, for the second quarter. That compared with net income of $35.9 billion, or $24,775 a share, in the year-earlier period.

Operating earnings, which exclude some investment results, rose to $11.6 billion, from $10 billion a year earlier. Increases in insurance underwriting and insurance investment income pushed operating earnings higher for the quarter.

Buffett has said that operating earnings are the better measure of the company's performance. Berkshire is required by accounting rules to include unrealized gains and losses from its giant investment portfolio when it reports net income, so short-term fluctuations in the stock market influence those results.

Berkshire spent $345 million buying back shares in the second quarter, down from $2.6 billion repurchasing stock in the first quarter. **Berkshire's Class A shares** are **up 18%** in **2024, outpacing** the **S&P 500's 12% gain.**

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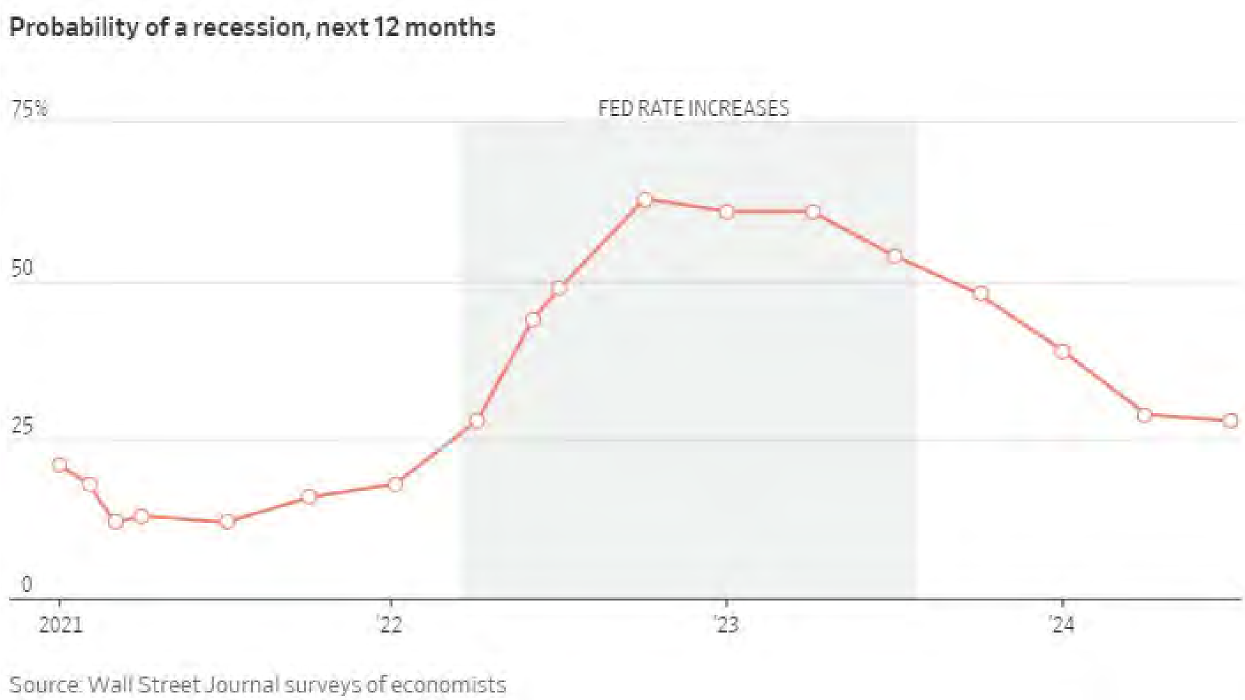
Where Do Economists Think We're Headed?

by Sam Goldfarb, Peter Santilli, and Anthony DeBarros – WSJ – Jul. 18, 2024

WSJ's latest quarterly survey shows economists' expectations for growth, inflation and interest rates.



The Wall Street Journal's latest quarterly survey of business and academic economists shows forecasters remain firmly optimistic about the economic outlook, despite some hints of weakness in recent data.

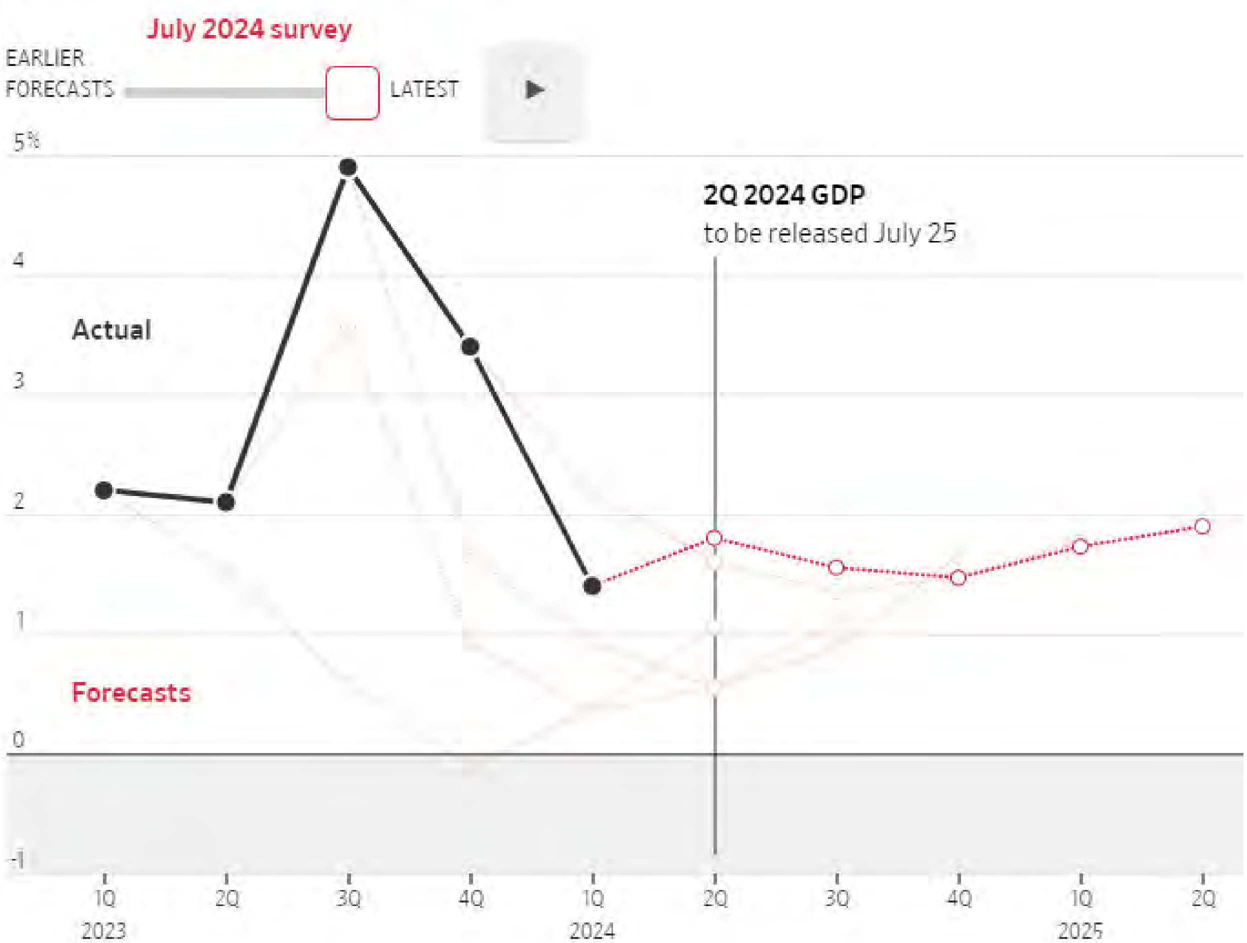
The following graphics show what economists are thinking now and how their forecasts – and the economy – have evolved over recent months and years. After looking at the charts, see if you can guess how economists answered questions about when the Federal Reserve will cut interest rates and how the election could affect the deficit, inflation and interest rates.

Welcoming normalization

For about two years, economists consistently underestimated the strength of the U.S. economy, forecasting the economy would grow slower than it did.

That changed recently when growth was lower than expected in the first three months of the year. Still, most economists believe that a slowdown was inevitable after a period of rapid expansion and too-high inflation. The economy, they argue, is normalizing rather than deteriorating.

GDP growth, with economists' forecasts



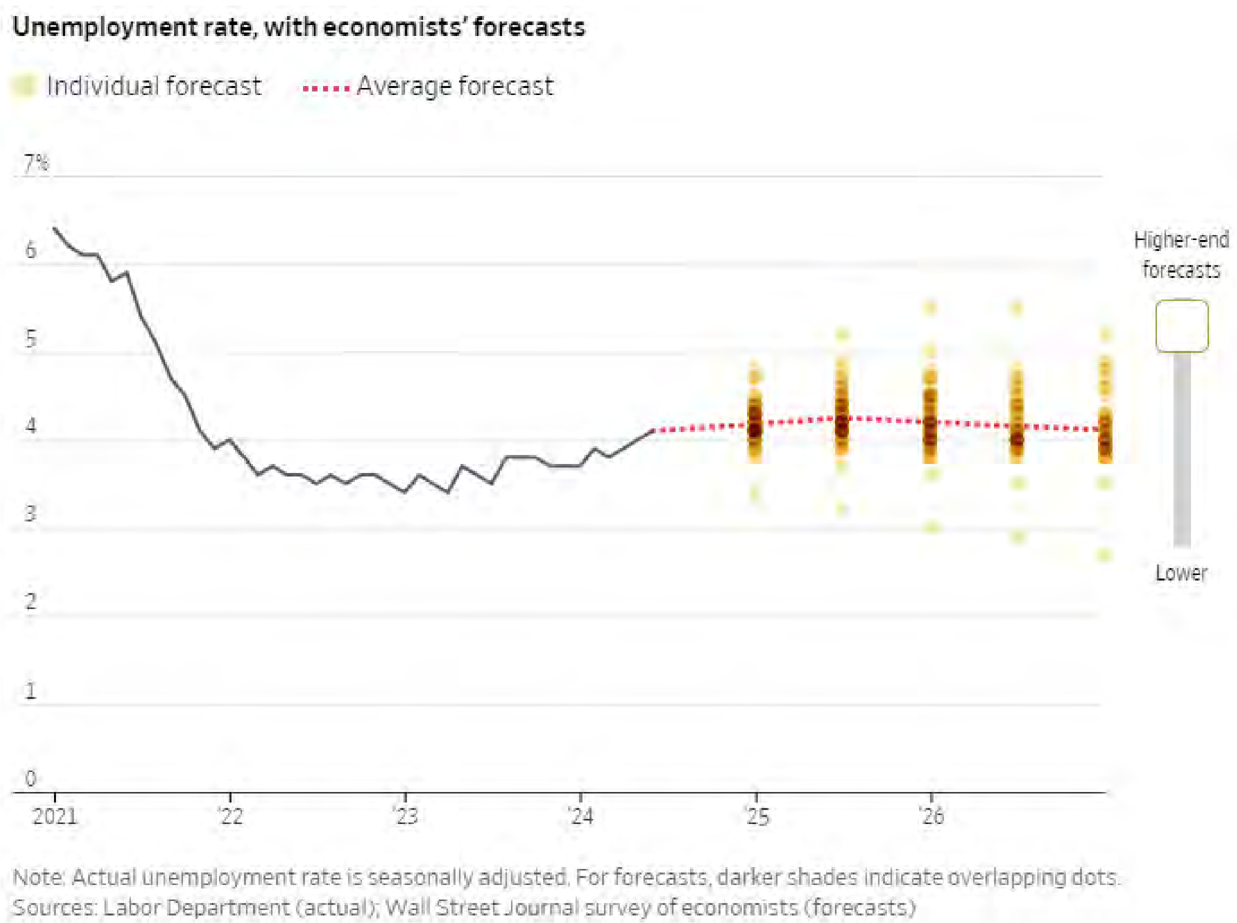
Note: Chart shows annualized change in real GDP from a quarter earlier, seasonally adjusted, and average forecasts among survey respondents.

Sources: Commerce Department (actual); Wall Street Journal survey of economists (forecasts)

Seeing no acceleration in unemployment

In another shift, the unemployment rate has also recently climbed a little faster than economists were expecting – rising to 4.1% in June from 3.4% in early 2023.

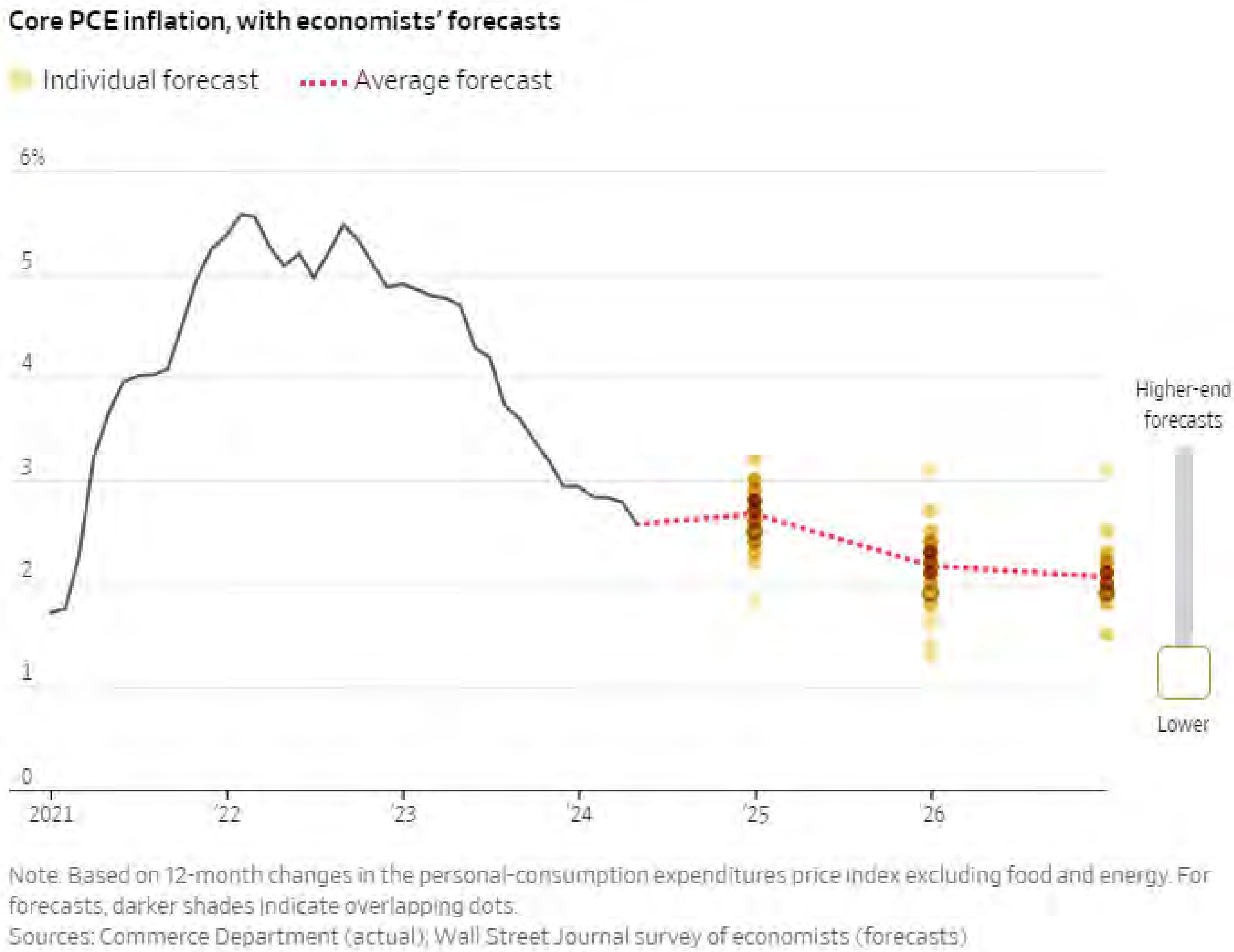
Demand for workers seems to be cooling even as job growth remains solid, thanks in part to increased immigration. Again, economists are optimistic that this represents a return to a more stable environment.



Slow but steady progress on inflation

The Journal's latest survey of economists concluded July 9, two days before consumer-price index data showed inflation easing substantially in June. T hat may partially explain why inflation forecasts nudged a bit higher since the last survey in early April.

The difference, though, is marginal. Current forecasts – like previous forecasts – show strong confidence that the Fed will succeed in bringing inflation down to its 2% target. The question has been what it would take to get there.

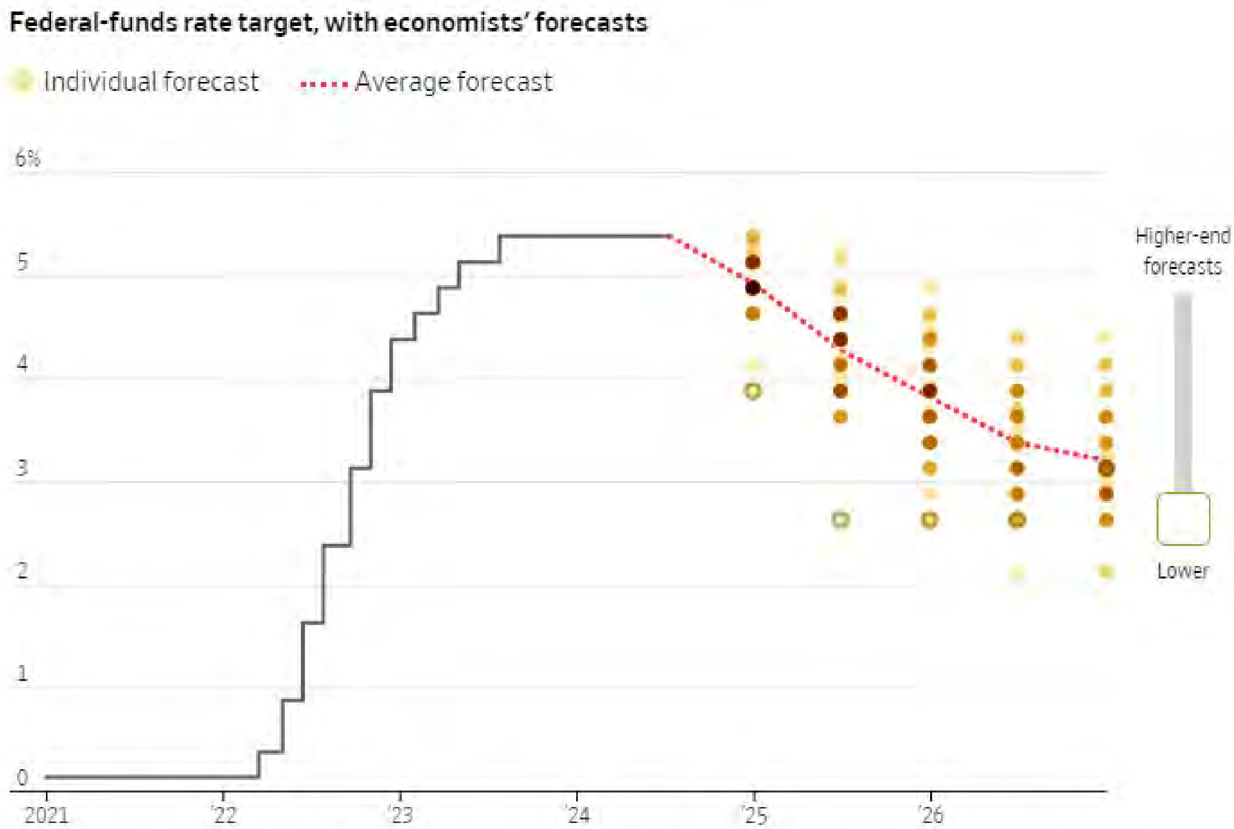


Higher-for-longer interest rates

The recent uptick in the unemployment rate and decline in inflation has rekindled hopes among investors that the Fed could cut short-term interest rates as many as three times this year – starting most likely in September.

Still, the recent good news on inflation has only come after a series of disappointing readings, including one that came out just after the April survey was conducted. As a result, the latest survey of economists shows a slightly higher path for rates.

Economists' optimistic outlook can be seen in the dispersion of rate forecasts. The Fed would likely cut rates more aggressively if it were worried about a recession. However, 22% of survey respondents think that rates will fall below 3.75% by June 2025 – down slightly from 25% of respondents in April.



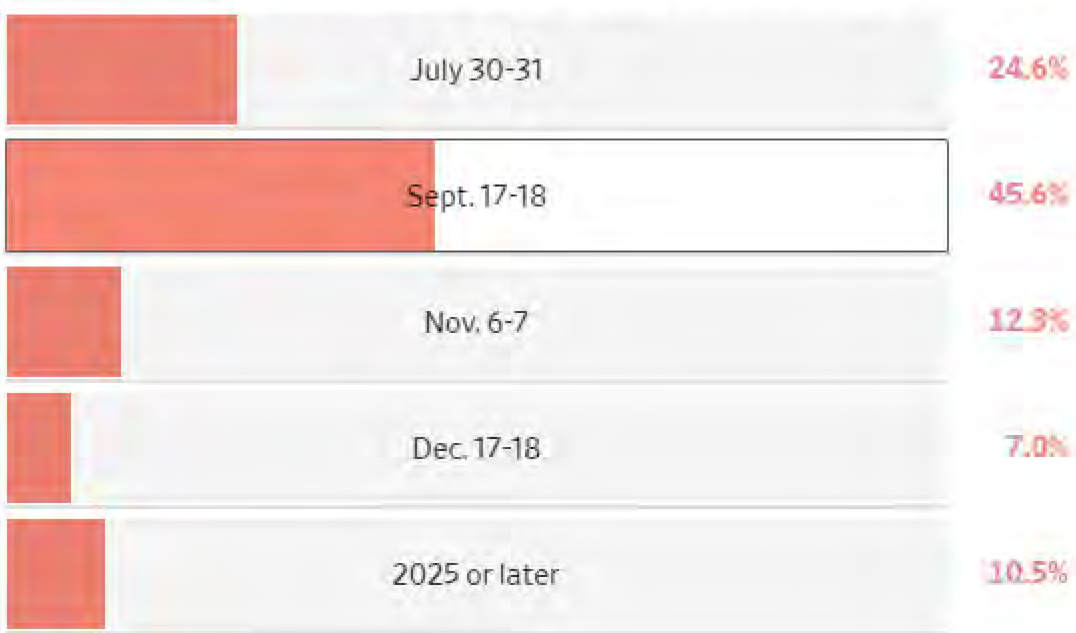
Note: Chart shows the midpoint of the target range. For forecasts, darker shades indicate overlapping dots.
Sources: Federal Reserve (actual); Wall Street Journal survey of economists (forecasts)

Test yourself against the economists

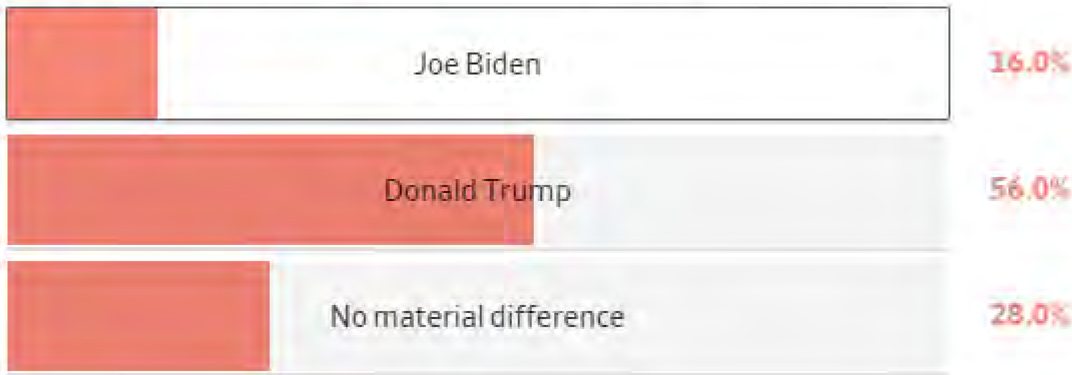
We asked survey respondents a number of questions on the economy.

At which meeting do you expect the Federal Reserve to make its next rate CUT?

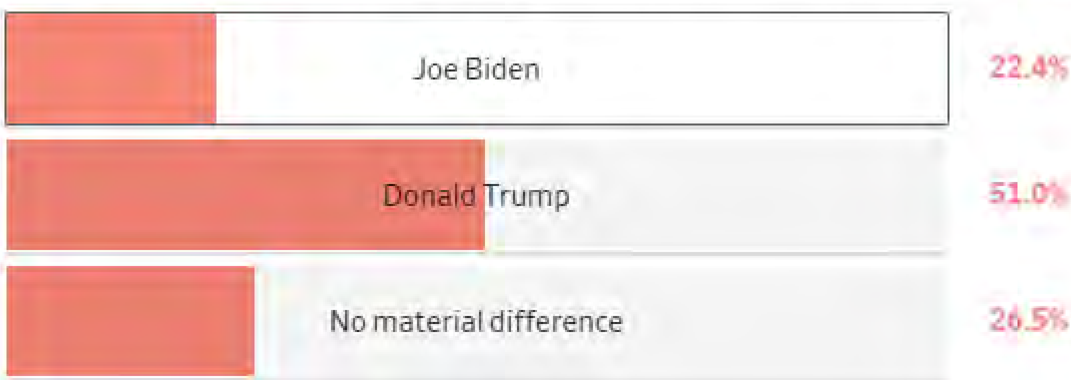
At which meeting do you believe the Federal Reserve SHOULD make its next rate CUT?



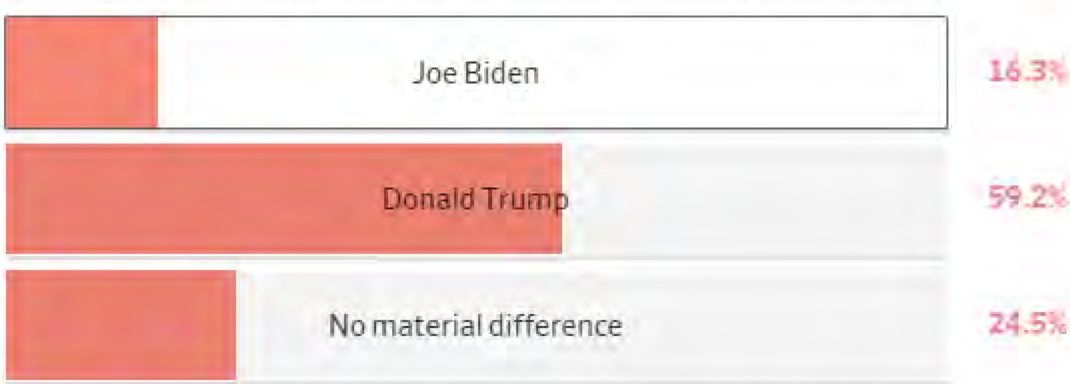
Under which presidential candidate is inflation likely to be higher?



Which presidential candidate's policies would put more upward pressure on the deficit?



Under which presidential candidate are interest rates likely to be higher?



Note: The survey was conducted July 5-9. For some questions, the wording here has been shortened. For complete results, visit the survey archive.

Source: Wall Street Journal survey of economists

In their own words

Here’s what some of the survey respondents said about the economy.

While it is too early to declare victory in the pursuit of an economic soft landing, consumer and business spending has remained more resilient than not. That has kept a recession at bay so far, a trend that should continue over the coming months.”

—Chad Moutray – National Restaurant Association

“The U.S. economy has proven economic forecasters wrong since the start of the Fed's tightening. Consumers keep shaking off talk of troubles. We are seeing business bankruptcies rise back to pre-pandemic levels – that is either worrisome regarding recession risk or reassuring that the economy is back to normal. I can't decide which it should be.”

—Amy Crews Cutts – AC Cutts and Associates

“While the presidential election and the control of Congress are the great unknowns, there is little reason to think a recession is likely over the next twelve months. That implies inflation is not going to hit the Fed's target anytime soon.”

—Joel Naroff – NAROFF ECONOMICS LLC

“Growth, inflation and hiring in the United States are all cooling toward a more sustainable pace which will most likely define the second half of the year as the Federal Reserve gets ready to reduce its restrictive policy rate.

—Joe Brusuelas – RSM US

“Downside risks are mounting given a slower glide path on rate cuts and delays to investment due to heightened uncertainty surrounding the outcome of the election. Policy uncertainty acts as a tax on the economy.”

—Diane Swonk – KPMG

“Two years ago, forecasters were way too pessimistic while today the stock market appears far too optimistic. It may feel better, but excessive optimism is the more dangerous bias.”

—Christopher Thornberg – Beacon Economics

“Consumers are in good financial shape.”

—Russell Price – Ameriprise Financial

“Recent labor market developments are worrisome. In a world where the Fed pays equal attention to inflation and full employment, it would be cutting in July.”

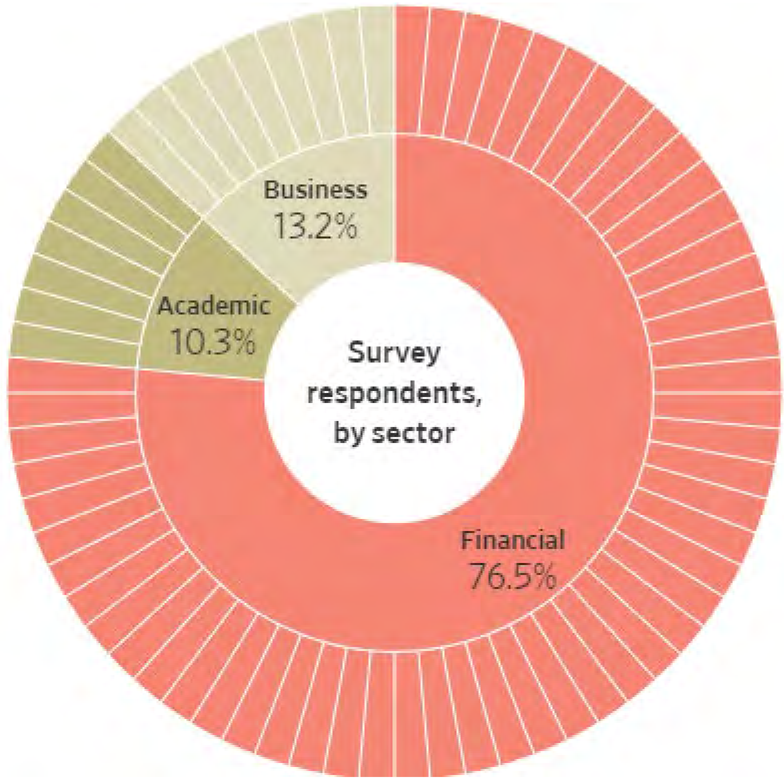
—Daniil Manaenkov – Research Seminar in Quantitative Economics, U. of Michigan

“The speed of increases in the unemployment rate of late raises the probability of not-so-soft landing.”

—Yelena Shulyatyeva – BNP PARIBAS

Who participates

The Wall Street survey has been publishing consensus forecasts from a panel of academic, business and financial economists for nearly 40 years. Not every economist answers every question.



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Why Americans Aren't Having Babies

Rachel Wolfe, Christiana Botic – WSJ – Jul. 20, 20024

The costs and rising expectations of parenthood are making young people think hard about having any children at all.


Beth Davis says not having kids gives her and husband, Jacob Edenfield, more time to focus on their relationship.

Americans aren't just waiting longer to have kids and having fewer once they start – they're less likely to have any at all.

The shift means that childlessness may be emerging as the main driver of the country's record-low birthrate.

Women without children, rather than those having fewer, are responsible for most of the decline in average births among 35-to44-year-olds during their lifetimes so far, according to an analysis of the Census Bureau's Current Population Survey data by University of Texas demographer Dean Spears for The Wall Street Journal. Childlessness accounted for over two-thirds of the 6.5% drop in average births between 2012 to 2022.

While more people are becoming parents later in life, 80% of the babies born in 2022 were to women under 35, according to the Centers for Disease Control and Prevention's National Vital Statistics data.

"Some may still have children, but whether it'll be enough to compensate for the delays that are driving down fertility overall seems unlikely," says Karen Benjamin Guzzo, director of the Carolina Population Center at the University of North Carolina at Chapel Hill.

The **change is far-reaching**. **More women** in the **35-to-44 age range across all races, income levels, employment statuses, regions and broad education groups aren't having children**, according to research by Luke Pardue at nonprofit policy forum the Aspen Economic Strategy Group.

Birthrates among 35- to 44-year-olds give demographers who study fertility an early look into millennials' changing approach to parenthood. But these researchers also look closely at women over 40, reasoning that if a woman doesn't have a child by then, she is more likely to remain childless.

The number of American women over 40 who had no children was declining until 2018, according to Current Population Survey data, when it then began to rise again. Now, some demographers and economists expect the increase in childlessness will be sustained due to shifts in how people think about families.

In New Orleans, 42-year-old Beth Davis epitomizes some millennials' new views. "I wouldn't mess up the dynamic in my life right now for anything, especially someone that is 100% dependent on me," she says.

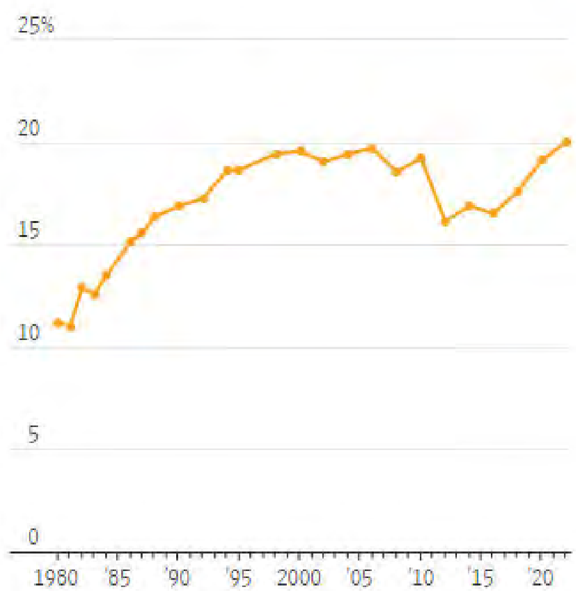
Edenfield and Davis.

'What Are Children For?'

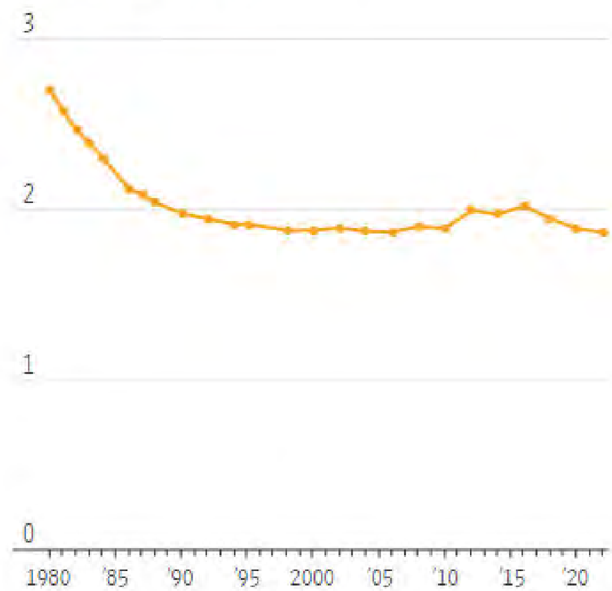
Throughout history, having children was widely accepted as a central goal of adulthood.

Yet when Pew Research Center surveyed 18- to 34-year-olds last year, a little over half said they would like to become parents one day. In a separate 2021 survey, Pew found 44% of childless adults ages 18 to 49 said they were not too likely, or not at all likely, to have children, up from 37% who said the same thing in 2018.

Share of women in the U.S. age 35 to 44 who don't have children



Average number of live births per woman in the U.S. age 35 to 44



Source: Current Population Survey data via the Aspen Economic Strategy Group

As more women gained access to birth control and entered the workforce in the 1970s, reshaping family life and expectations around gender, Americans began having fewer kids. By 1980, the average number of children per family was 1.8, down from a high of 3.6 during the post-Depression baby boom, according to Gallup.

Now, researchers say, having children at all has begun to feel optional.

"To be a human being, for most people, meant to have children," says Anastasia Berg, co-author with Rachel Wiseman of the new book "What Are Children For?: On Ambivalence and Choice.

"You didn't think about how much it would cost, it was taken for granted," she says.

But unlike their parents and grandparents, the authors say, younger Americans view kids as one of many elements that can create a meaningful life. Weighed against other personal and professional ambitions, the investments of child-rearing don't always land in children's favor.

With less pressure to have kids, economists say, more people feel they need to be in the ideal financial, emotional and social position to begin a family.

Giovanni Perez and Mariah Sanchez with their beagle, Prowler, at their apartment in the Bronx.

Giovanni Perez, 38, has been trying to convince his wife, Mariah Sanchez, 32, that they're ready to become parents.

"People less well-off than us are having kids and I see it every day, and I'm pretty sure we could do better than most of them," says Perez, an after-school art teacher in the Bronx, N.Y.

Sanchez isn't sold.

With a single mom during her early childhood and a brother 15 years her junior, Sanchez grew up helping with diaper changes and bottle feedings. Before she has kids of her own, she wants to move from the couple's one-bedroom apartment into a bigger place. She also hopes to climb the ranks at the advertising agency where she works, ideally doubling their combined income of $100,000.

"I know what it's like for a child whose parent wasn't prepared for them," says Sanchez. Still, she admits, the amount she thought she needed to earn before having children was far lower a few years ago. "It feels like a moving target," she says.

Her mom, Michelle Morales, had Sanchez when she was 21. That was late by her Brooklyn community's standards, she says. (A dramatic drop in teenage births is another factor driving the fertility rate down.)

"There was no planning for kids, you just had them," says Morales, a 53-year-old college adviser in Naples, Fla.

While she worries she may never be a grandparent – "which I'd like to experience before I leave this Earth" – she respects the intention with which her children are approaching parenthood.

"These kids are a lot smarter in making decisions for themselves," she says.

Sanchez and Perez have different views on when is the right time to start a family.

How much kids actually cost

Nobody will dispute that kids are expensive. Whether they have become more so in recent years – and the extent to which that is driving down birthrates – is more complicated.

Parents *are* spending more on their children for basics such as housing, food and education – much of that due to rising prices. Another factor, however, is the drive to provide children with more opportunities and experiences.

Middle-class households with a preschooler more than quadrupled spending on child care alone between 1995 and 2023, according to an analysis of Bureau of Labor Statistics and Department of Agriculture data by Scott Winship at think tank the American Enterprise Institute.

Yet only about half of the increase is due to rising prices for the same quality and quantity of care. (Child care prices are up 180% overall since the mid-90s, according to BLS data.)

The remaining half is coming from parents choosing more personalized or accredited care for a given 3- to 5-year-old, or paying for more hours, Winship says.

"People say kids are more expensive, but a lot of this comes from parenting becoming more intensive so people are spending more on their kids," says Melissa Kearney, an economist at the University of Maryland who researches children and families.

It has always been costly and time-consuming to raise kids, she says, and it has always come into conflict with other priorities. What's changed is that more people are deciding not to have children at all.

"If it were socially acceptable for people in the past to remain childless, I wonder how many of them would have made the same decision," Kearney says.

'My autonomy'

Beth Davis loves her niece and nephew. But she isn't envious of how much time and money her siblings spend bouncing between volleyball tournaments, baseball games and trips to the mall to replace outgrown clothes.

Davis and Edenfield enjoy their life in New Orleans.

Davis, who works in marketing, and her husband, Jacob Edenfield, 41, both say they always expected to hit a moment when they, too, wanted to become parents. When that still hadn't happened by the time they started dating in their mid-30s, they decided to start reorienting their lives.

"People told me when I was younger, 'Oh, you'll grow into it, you'll develop those feelings, you'll want to start a family,' and that just did not happen," says Edenfield, a creative director.

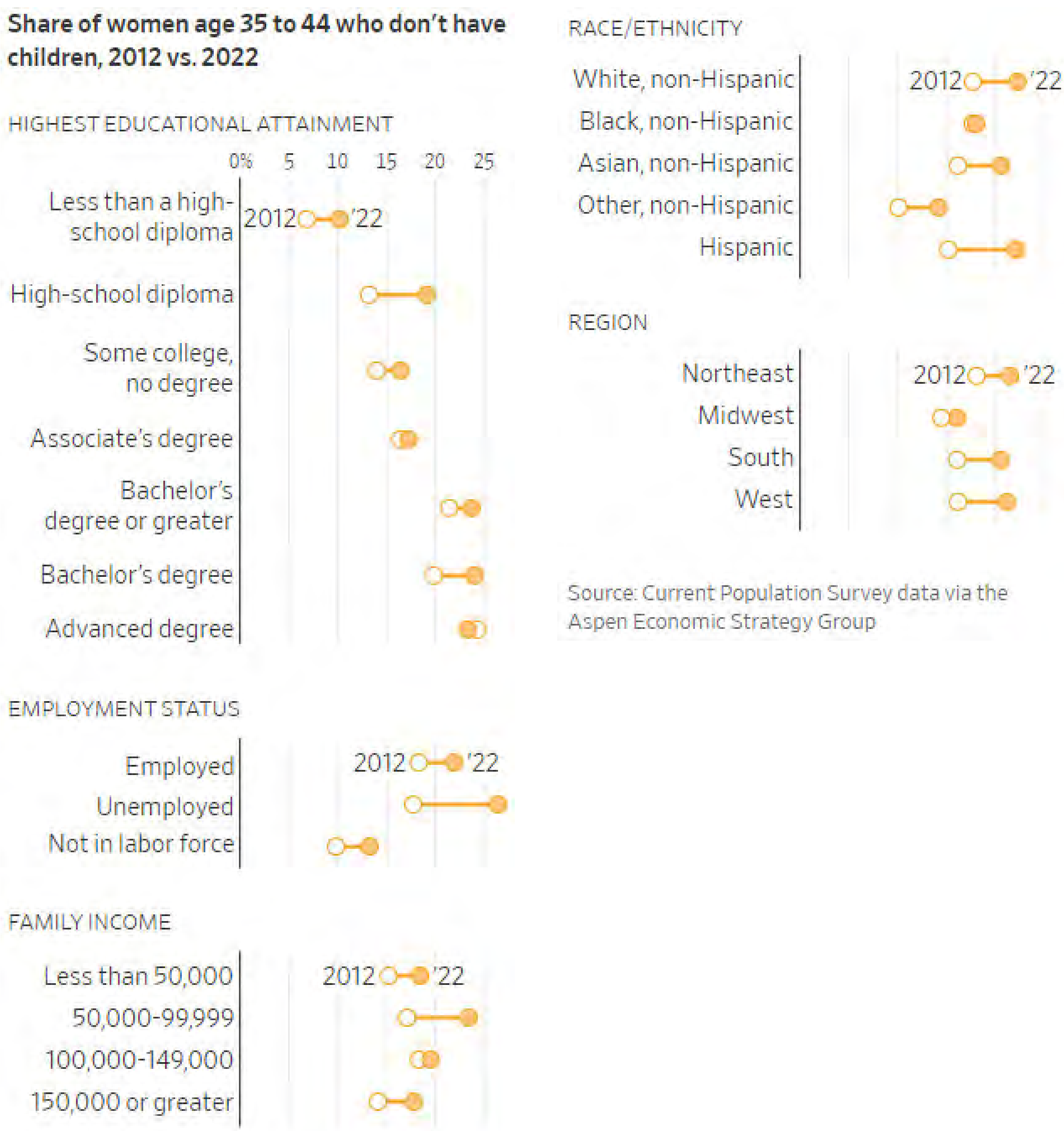
They moved to New Orleans a year ago in search of the city's joie de vivre – and other childless millennials.

With a combined income of $280,000, the couple is able to put about $4,500 a month toward what they hope will be a mid-50s retirement. Another $2,600 pays rent on a sprawling Creole townhouse. The remaining $8,000 or so – much of which they assume would have been eaten up by child-rearing – goes primarily toward enjoying their lives.

Edenfield takes a class at a holistic wellness center. He is also working on a novel.

The couple often dines at the city's upscale restaurants (including two recent $700+ dinners), regularly works out at a high-end wellness center and recently paid cash for a BMW. Edenfield meditates for an hour every morning and works on the novel he's writing at the local corner bar many nights. For companionship, the couple fosters a rotating cast of Bengal cats.

Edenfield's sibling, Caitlin Hopkins, was inspired in part by her brother and sister-in-law's lifestyle to also remain childless. While she and her husband, Will, love kids, they say they would rather focus on being the best possible aunt and uncle. "And then I get to still have my autonomy and routine," says Caitlin, a 35-year-old oyster farmer in Portland, Maine.



Changed expectations

The longer people wait to have kids, research shows, the less likely they are to have them.

One reason is biological: Women 35 and older are at increased risk of infertility and pregnancy complications. The other is social. People who already have fully formed adult lives are more reluctant to give up their freedom, says Brown University health economist Emily Oster. “All of a sudden you’ve chosen a different identity,” she says.

Trevor Galko and Keri Ann Meslar, 44 and 42, both grew up in the suburbs assuming kids were in their futures.

“I had never known someone that was 40 and married without kids, that would have been the weirdest thing I had ever heard,” says Galko, who works in software sales from Arlington, Va.

The couple, now engaged, dated for three years in their 20s before spending the next decade in other relationships, thinking kids would happen someday. But when they got back together in 2019, they decided they were too old and too set in their existing lives to start a family of their own.

While they both mourned that other possible path, they say they are content and have no regrets. Much of their disposable income now goes to travel, including recent trips to Greece, Spain and Guatemala in the span of three months.

For Meslar, who works in growth strategy for a CBD company, part of the justification for leaning into her kid-free reality was wanting to avoid making the same sacrifices she saw her parents make.

She says she can’t remember her mom or dad buying anything new for themselves while she was growing up so they could afford for her and her three siblings to join sports leagues and attend out-of-state colleges.

“I don’t think I could really live up to the example they set. Or I think I could, but I don’t think it would bring me the same joy,” she says.

MJ Petroni and Oleg Karpynets both went into their 20s wanting to be dads. Now in their late 30s, the couple no longer sees children in their future.

“It was almost shocking to me when I realized having a fulfilling life didn’t necessarily include my own kids,” says Petroni, 39, who runs an artificial-intelligence strategy firm from home in Portland, Ore. For 38-year-old Karpynets, who runs a neighborhood library, that has meant going back to school to get his business administration degree, hosting monthly parties sometimes with over 100 people and going out with friends whenever he wants.

An only child, Petroni says continuing the family name and giving his parents grandchildren was “always just kind of a given” during his suburban upbringing on the central coast of California. More recently, however, it’s his parents who have required care. He says he’s spent over $100,000 on their medical and living expenses, as well as travel to visit them, over the past three years.

MJ Petroni and his husband, Oleg Karpynets, in Portland, OR.

"I would like to be able to put more toward that than I'm currently able to," he says, adding it would be more difficult to do so if the couple decided to have kids.

The other side of that coin, points out Oster, the Brown University researcher, is how an increase in childlessness will play out as millennials age.

"A lot of our social structures kind of assume when people get old the person who is responsible for them is their children," Oster says.

Climate concerns

When Allie Mills and Connor Laubenthal get married next year, they'll be flanked on both sides of the altar by friends and family members who they say mostly intend to remain childless.

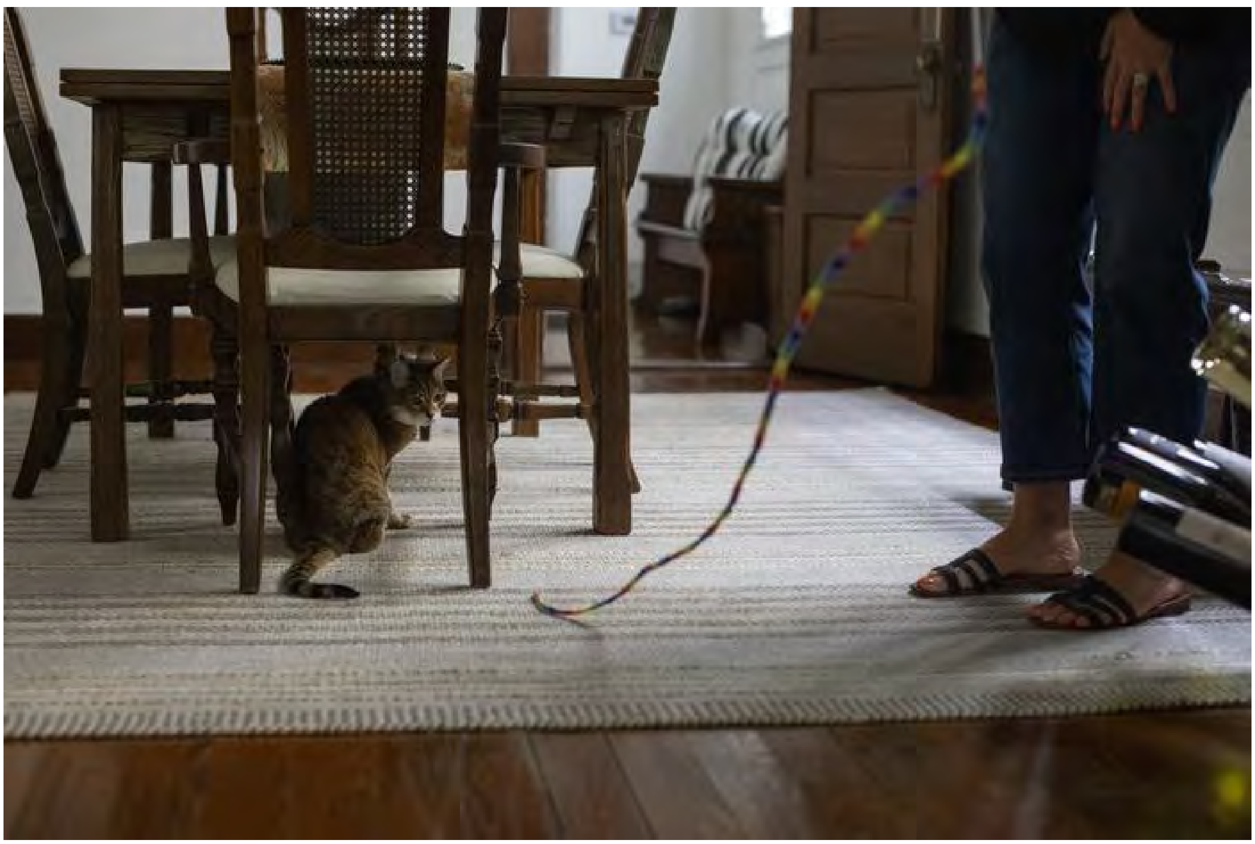
"With geopolitical issues, climate change, it's like what are you bringing them into and then dropping them off and saying, 'good luck!'" says Mills, who is 27 and works for a tech company. "There's no real confidence that things are going to get better."

Mills, who was raised in an evangelical Christian household, says her mindset is a radical departure from growing up wanting to be a mother and a homemaker. She struggles with anxiety, and worries how her own mental health would affect a child. And though her email signature proudly displays her status as “dog mom of two,” she says the only form of human parenthood she could picture at this point is fostering.

The couple’s other consideration is financial. Despite both having well-paying jobs, they say they haven’t been able to afford a house in Boston, where they live, amid low supply and high interest rates.

Laubenthal, a 27-year-old asset manager, calculated that they could retire at 55 with the same spending power if they don’t have kids. He then did the math to account for two children, factoring in costs of daycare, college, clothing and other essentials. That pushed their retirement back by 13 years, to age 68.

“That’s a big gap,” he says. His conclusion: Retire early and skip kids.



Davis and Edenfield foster cats in their spare time,
which Davis says would be more difficult if they had kids.

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Wildfire Claims Against PacifiCorp Surge to $46B on Oregon Mass Complaints

by Garrett Hering – Standard and Poor's Global Market Intelligence – Aug. 5, 2024

PacifiCorp faces at least $46 billion in **claims related to** Western US **wildfires** following recent lawsuits in Oregon, **parent** company **Berkshire Hathaway Energy disclosed Aug. 5** in a **Form 10-Q filing**.

Plaintiffs in **four separate mass complaints filed** between April 29 and July 31 in the **Multnomah County Circuit Court** in **Portland, OR**., are **seeking $43 billion** in **economic, noneconomic and punitive damages linked to** catastrophic **wildfires** in **September 2020**, known as the **Labor Day fires**. The complaints, which name 1,443 individual class members, are part of broader litigation – Jeanyne **James** et al. v. PacifiCorp et al. – that has yielded several jury verdicts against PacifiCorp. The **utility** is **appealing** those **verdicts**.

"PacifiCorp believes the magnitude of damages sought by the class members in the James mass complaints to be of remote likelihood of being awarded based on the amounts awarded in the jury verdicts," the filing said.

A James case jury in June 2023 found PacifiCorp and its Pacific Power division liable to 17 named plaintiffs and to the class associated with four 2020 Labor Day wildfires, followed by several related trials that awarded damages.

Berkshire Hathaway Energy, a subsidiary of Warren Buffett's Berkshire Hathaway Inc., reported an additional roughly $3 billion in outstanding complaints and demands filed against PacifiCorp in Oregon and California, "excluding any doubling or trebling of damages."

Various investigations into the causes of wildfires linked to PacifiCorp in Oregon and California are ongoing.

So far, **PacifiCorp** has **paid $1.02 billion** in **settlements related to wildfires in Oregon and California** and has reached **agreements** to **pay another $199 million**, the filing said. The Portland-based utility, which serves retail customers in six Western US states, **reported $2.66 billion** in **cumulative estimated probable wildfire**-**related losses through** the **second quarter**.

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Wildfires Pollute the Air, Threaten Visibility in West

by Ginger Adams Otis – WSJ – Jul. 29, 2024
Ken Thomas contributed to this article

Smoke from multiple wildfires ripping through the **U.S. and Canada** has created **air quality issues** in parts of the West, with officials warning of **reduced visibility** in some places.

The air quality was especially bad in proximity to some of the biggest fires in northern California and **Oregon**. But the impacts from smoke and particulate matter may be felt across the northern U.S. Plains and Midwest in coming days, according to the National Weather Service.

A series of blazes last summer in Canada created a dense and dangerous haze that altered air travel and disrupted daily life for millions of people. The current situation is similar but unlikely to reach the same intensity, weather service meteorologist Andrew Orrison said Sunday.

The **worst effects** are **currently over southern Oregon**, where the **air** is "**very unhealthy**," he said. There is also a substantial amount of smoke over places such as Montana and Idaho, he said.

"It's **not good** to **be outside in southern Oregon** in that smoke. People should not be breathing that kind of air," he said.

In places such as Las Vegas, people can feel the effects of smaller fires burning in Southern California, he said. Smoke conditions may worsen in Nevada over the next few days.

"It's the combination of all the fires, collectively," he said. "We'll see a continuation of smoke across the northern U.S. Plains and into the Midwest, and it may get a little bit worse in the latter part of the week."

Thousands of firefighters have been battling more than 100 wildfires across the Pacific Northwest and Canada in recent days, including the Park Fire in Northern California that has torn through 350,000 acres, an area roughly the size of Los Angeles.

Roughly two million acres have been damaged by fires in total to date, according to the National Interagency Fire Center.

The Park Fire erupted Wednesday and spread rapidly. As of Sunday, it was 12% contained, according to the California Department of Forestry and Fire Protection, known as Cal Fire. It is already the seventh-largest wildfire in California history, Cal Fire said. The largest to date was 2020's August Complex Fire that burned over a million acres, the agency said.

Arson caused the Park Fire, Cal Fire said. A man suspected of pushing a burning car into a gully and sparking the blaze was arrested by California authorities last week.

The White House said Sunday that President Biden had been briefed on the Park Fire. The White House said in addition to the federal assets that had already been deployed, Biden "directed his team to do everything possible to support ongoing fire suppression efforts."

The Park Fire burned Sunday along Highway 32 near Forest Ranch, Calif. The blaze was caused by arson, Cal Fire said.

Firefighters are unlikely to get any help from the weather this week, Orrison said. Temperatures in the West had cooled over the weekend, but it won't last, according to the forecast.

"Temperatures will warm up in the interior of the West but also in the central U.S. and central Plains," he said. "It's going to get quite hot out there—we expect some record highs to be set."

The **rise in temperatures** will also bring a **drop in humidity** by midweek, exactly what you "don't want to see when fighting fires," he said.

Arizona and New Mexico are other parts of the country expected to get rain this week, but there is no precipitation forecast for the western U.S. over the next five to seven days, according to Orrison.

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Algonquin Power to Sell Renewables Business to LS Power for $2.5B

by Selene Balasta and Allison Good,
Standard and Poor's Global Market Intelligence – Aug. 12, 2024

Algonquin Power & Utilities Corp. struck a deal **to divest** its **renewable energy business**, **excluding hydroelectric**, **to** a **subsidiary** of **LS Power** Development LLC **for $2.5 billion**, the companies said Aug. 9.

The business largely comprises **wind and solar assets**, including 44 operating assets with more than 3 GW of capacity and an 8-GW pipeline of wind, solar**, battery energy storage and renewable natural gas projects** in various stages of development, LS Power said in a news release. Approximately **2.7 GW** of the **assets** are **in** the **US**, with the **remaining 300 MW in Canada**.

"This represents a significant strategic investment in and expansion of LS Power's renewable energy portfolio," LS Power CEO Paul Segal said. "This business complements our existing fleet of more than 19,000 MW of top-performing renewable, energy storage, flexible gas and renewable fuels projects."

The transaction "is the result of a highly competitive strategic sale process," Algonquin CEO Chris Huskilson said in an Aug. 9 deal announcement.

In **August 2023, Algonquin** announced a decision to offload its renewable energy business following a **strategic review** that was launched **after** the **company terminated** a **deal to acquire A**merican **E**lectric **P**ower Co. Inc.**'s Kentucky utility assets**.

Hedge funds Ancora Holdings Group LLC and Starboard Value LP had called on Algonquin to execute asset sales, with Starboard specifying the unregulated renewables business, to reverse a then-plummeting stock price.

"This major milestone, coupled with our previously announced agreement to support the sale of our [Atlantica Sustainable Infrastructure PLC] shares, delivers on our plan to transform Algonquin into a pure-play regulated utility, optimize our regulated business activities, strengthen our balance sheet and enhance our quality of earnings," Huskilson said.

"Proceeds from the renewable sale plus our Atlantica shares will leave us with a very strong balance sheet," Algonquin CFO Darren Myers said Aug. 9 in a second-quarter earnings conference call.

"We are looking at spending capital at a level just above requisite maintenance, safety and environmental requirements in order for the company to digest the impacts of investments already made on behalf of our customers," Myers said. "Once we improve our returns to a more appropriate level, we will have the opportunity to increase our capital spending in a disciplined way."

The latest transaction excludes debt and consists of $2.28 billion of cash at closing and up to $220 million of cash pursuant to an earnout agreement relating to certain wind assets. The company expects to receive estimated cash proceeds of $1.6 billion, excluding the earnout, after repaying construction financing, and net of taxes, transaction fees and other closing adjustments.

Algonquin's board of directors has already approved the sale.

The deal is subject to customary closing conditions and is expected to close in the fourth quarter of 2024 or the first quarter of 2025.

JP Morgan is **exclusive financial adviser to Algonquin** on the transaction. **Milbank** LLP is **legal** adviser and **Scotiabank and BMO Capital Markets** Corp. are **financial advisers to LS Power**.

Q2 results

Algonquin shares, however, were **down** more than **11% in heavy trading** at about 3 p.m. ET on **Aug. 9 after** the **company also cut** its **third-quarter 2024 dividend by 40% to 6.5 cents.**

"We're not chasing a high payout ratio and excessive equity raises," Huskilson emphasized during the call. "We're reducing our capital spend and dividend to position the company for greater long-term value creation."

Algonquin, which is **headquartered in** Oakville, **Ontario**, **but reports in US dollars**, reported second-quarter adjusted net earnings of 9 cents per share, up from 8 cents per share in the same period in 2023. The results beat the S&P Capital IQ consensus estimate of 8 cents per share.

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Liquid Is New Tack to Cool Data Centers

by Yang Jie – WSJ – Aug. 12, 2023

One of the latest innovations at artificial-intelligence chip maker Nvidia has nothing to do with bits and bytes. It involves liquid.

Nvidia's coming GB200 server racks, **which contain** its **next-generation Blackwell chips**, will **mainly** be **cooled with liquid circulated in tubes snaking through** the **hardware rather than by air**. An Nvidia spokesman said the company was also working with suppliers on additional cooling technologies, including dunking entire drawer-sized computers in a nonconductive liquid that absorbs and dissipates heat.

Cooling is suddenly a hot business as engineers try to tame one of the world's biggest **electricity hogs**. **Global data centers** – the big computer farms that handle AI calculations – are **expected** to **gobble** up **8% of total U.S. power demand by 2030**, compared with about **3% currently**, according to Goldman Sachs research.

The Nvidia GB200 series is likely to be sought after as technology companies race to deploy AI in content creation, autonomous driving and more.

Data centers, housing as many as tens of thousands of servers, tend to be cacophonous and chilly places. **At older facilities** that **use fans and air conditioning**, **cooling** accounts for up to **40% of power consumption**, a proportion that **could be reduced to 10%** or less with more advanced technology, according to Shaolei Ren, associate professor of electrical and computer engineering at the University of California, Riverside.

Liquid cooling has become a **common feature of high-end gaming computers**, but on a larger scale has traditionally been limited to the hardest challenges, such as nuclear power plants. The **upfront cost** of circulating liquid through delicate electronics can be **many times** the cost of installing **AC and fans**. Some parts are in short supply.

Leakage is the **biggest risk**. "If a single drop of water falls onto a server, such as the million-dollar GB200, it could cause

catastrophic damage," said Oliver Lien, general manager of Forcecon Technology, which works with semiconductor makers on cooling.

More than **95% of current data centers use air cooling** because of its **mature design and reliability**, according to a recent Morgan Stanley report.

Nvidia both makes its own servers and supplies chips to other server makers that build devices for tech giants working on AI applications. Decisions on cooling tend to be made jointly by those companies.

Taiwan-based contract manufacturer **Foxconn** is taking a leading role in manufacturing the Nvidia GB200 series in Taiwan and Mexico, according to people involved in the plans.

The sensitivity of the cooling issue was highlighted in late July when shares of Foxconn and two suppliers of cooling components fell more than 5% following social-media posts suggesting the GB200's cooling system had leaks.

People familiar with the production said suppliers were working through normal issues that arise in preproduction testing. They said the cooling system issues weren't likely to significantly affect the GB200's shipping schedule. Shares of Foxconn and the suppliers quickly recovered. Nvidia declined to comment, and Foxconn didn't respond to a request to comment.

Many in the business think the **next step could be total immersion in heat-absorbing fluid**, although the technology faces skepticism because the fluid and custom tanks are costly and maintenance is messier.

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Consumers Feel Inflation's Sting on Hard-to-Do-Without Things

by Harriet Torry and Terell Wright – WSJ – Aug. 13, 2024

Inflation is slowing. So why doesn't it feel that way?

After all, price increases for lots of items, like cable and shampoo, are indeed cooling. Prices for vehicles, gasoline, TVs and plane tickets have even dropped over the past year. And the overall pace of year-over-year inflation as measured by the Labor Department's **Consumer-Price Index** was **down to 3%** in its most recent reading – much, **much lower than** the **high of 9.1%** that it clocked **two years ago**.

But prices for many of the **things** that are **hard to do without** are **still posting eyewatering price increases**. **Rent and electricity bills** are **up 10% or more over** the **past two years**, and **car-insurance costs** are **up** nearly **40%**, according to the Labor Department's index. **Shoppers** might be **able to trade down** from prime steak **to cheaper** cuts of meat **at** the **supermarket**, **but** they **can't** really do the same thing **with** the **water bill**.

"We're beginning to run **out of rope** in **how much** we **can substitute out**," said **David Bieri**, an **economist** and **professor** at **Virginia Tech**.

Rising prices have been front and center in the U.S. over the past three years, **affecting how consumers feel** about the economy and how they are planning to vote. A **softening jobs market** will **only amplify** their **concerns**.

Investors and policymakers are scheduled to get another look at price pressures on Wednesday, when the Labor Department plans to release its latest print on the CPI.

Jake Tromburg and his family moved into a smaller home last year in Chesapeake, Va., and were surprised to get an electricity bill one month last summer for more than $500.

Their new house has a pool, and they installed an air-conditioning unit in their daughter's room above the garage. Both helped push the bill higher. So Jake and his wife, Marie, bought an energy-efficient refrigerator secondhand, lowered the voltage of the pool's pump and told the children to turn off the lights during the day. Their recent monthly bill was $250.

To save money elsewhere, the Tromburgs have downgraded their home-insurance plan. But they still pay more than $1,700 a year, an increase of more than $300. They likewise trimmed their spending on their kids' youth sports leagues. Instead of soccer and basketball, this season it is just soccer.

"I haven't noticed any relief in prices lowering," said Tromburg, a 42-year-old pastor. "Gas prices are a little bit lower. But that hasn't made me say, 'Oh, man, sweet, let's spend more money.'" Housing is by far the biggest monthly expense for U.S. households. In the CPI, **shelter costs** – a measure of **rent and** the **equivalent cost to homeowners**, **as well as lodging away from home and household ins**urance – have **risen** more than **13% in two years**.

When a family's $3,000 rent or mortgage payment jumps 13%, that dings the bank account by about $400 a month.

Some prices are rising owing to factors other than traditional supply and demand. Home-insurance costs for owners in some parts of the U.S. have ballooned partly because of storms and fires. **Utility bills have climbed as companies try to shore up an aging power grid**.

The pace of some price increases is likely to slow down, according to economists. Take cars as an example. Car prices shot up early in the pandemic. It took time for **car-insurance** costs to catch up – but over the past two years they have risen quickly, too.

Brendan Madigan, an accountant in Durham, N.C., and his wife, Alexis Madigan, would like to buy a minivan and move to a house that is bigger than their current three-bedroom.

ABOVE: Left, among the ways Marie and Jake Tromburg have sought to rein in household costs is to downgrade their home-insurance plan and to tell their children to turn off lights during the day; right, Jasmine Moore, here with her son, has switched to discount grocery stores and cut back on visits to out-of-town family.

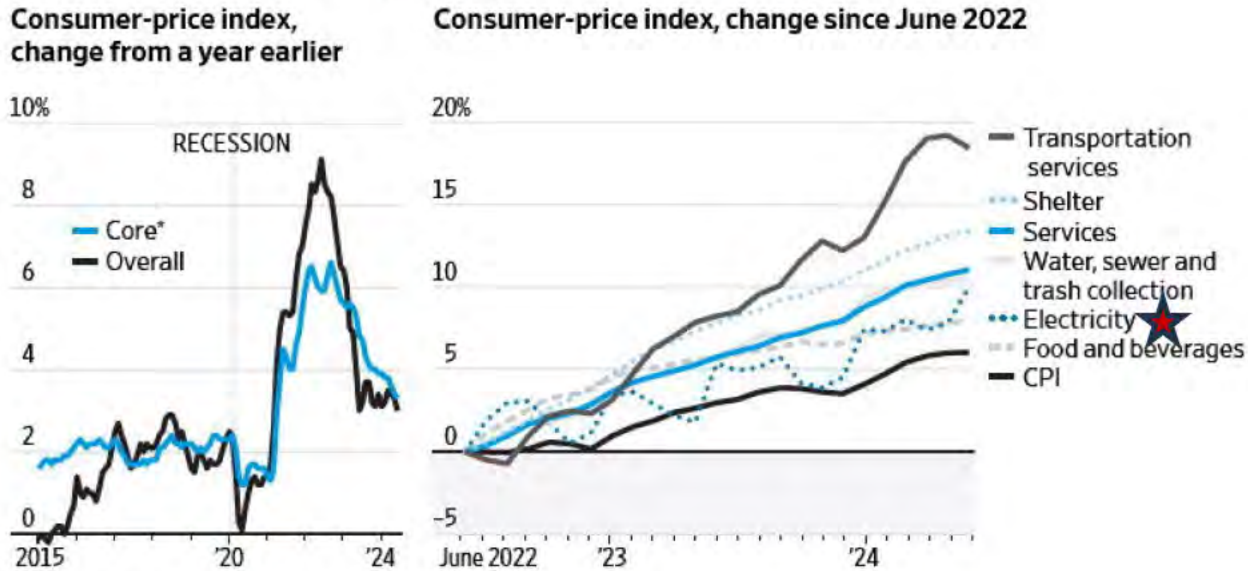
But they have held off because of the rising costs of home insurance, transportation and other expenses. They have also cut restaurants and movie nights out of their budget.

"We were looking for a bigger house and potentially growing our family further in the future. But with the cost so high, we're really pinching pennies," Brendan Madigan said.

Families with young children are also paying higher prices for **child care**. Costs have risen 6.4% over the past two years, in line with the overall CPI. Because daycare bills can be as big as the rent payment or the mortgage, even a relatively small increase can feel like a lot.

In major metro areas, the median price to put an infant in center-based care in 2022 was more than $1,400 a month, according to the Labor Department. A 6.4% increase puts that bill closer to $1,500.

The Madigans' daycare costs have risen much faster. The daycare bill for their older daughter shot up last month to $1,650 a month from $1,200. Daycare for their younger daughter, who starts in two weeks, will be $1,800 a month. They searched for cheaper options but quickly realized that the price was the standard.



*Core excludes food and energy prices.
Sources: Labor Department (change from a year earlier); Labor Department via St. Louis Fed (change since June)

"I would have hoped that where my career path is at, and with my wife working as well, that we would have some financial flexibility," said Madigan, 32 years old.

Households across the country are facing similar struggles. According to the Labor Department, the **prices of essential services** such as water, sewer and trash collection have **jumped** nearly **11% over** the **past two years**, and **electricity** has **climbed 10%.**

The **cost of transportation** services, which includes vehicle insurance and repair, has **jumped** more than **18%** in the **past two years**, according to the CPI. That would slap an extra $55 a month on a $300 budget. An **increasing number** of cash-strapped **Americans** are choosing to **drive without car insurance**.

Jasmine Moore, an operations manager at a social-justice nonprofit, missed a payment on her auto insurance about six months ago. Now her monthly bill has doubled, from $195 to $395. Her bank account is often near overdraft. She also has $80,000 in student debt from college and graduate school.

As a single mom, Moore feels guilty when she has to skimp on things that make her 10-year-old son happy. Part of her feels as though she should focus on him before any other bills. The two have had to cut back on visits to family in Valdosta, Ga., roughly three hours south of their home in the Atlanta suburbs.

Moore also canceled her son's math-tutoring sessions and instead tutors him herself. Instead of Publix, she opts for discount grocery stores and food pantries.

"I have middle-class pay," said Moore, 32. "But I feel like I'm lower income."

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AI Is About to Boost Power Bills

by Jinjoo Lee – WSJ – Aug. 13, 2024

High prices are a windfall for power-plant owners but are starting to raise difficult questions. Power-plant owners are reaping a bonanza, but not without new risks, too.

The **AI-driven**, **energy-hungry data-center boom** was bound to bring up uncomfortable questions: **Will it raise energy bills** and, if so, **who will shoulder** the **costs**? America's largest wholesale power market is starting to see the results.

Rapid data-center build-out is **increasing power demand just as a wave of older power-plant retirements is reducing supply** in PJM Interconnection, the independent system operator that manages the wholesale power market spanning 13 states including Virginia, Pennsylvania and Illinois. It said two weeks ago that its latest capacity auction yielded prices of $269.92 per megawatt-day for most of its footprint, about nine times the clearing price a year ago. A contributing factor was a tweak in PJM's modeling to better plan for extreme weather conditions. Skyrocketing capacity prices are a clear signal that the grid needs new power plants.

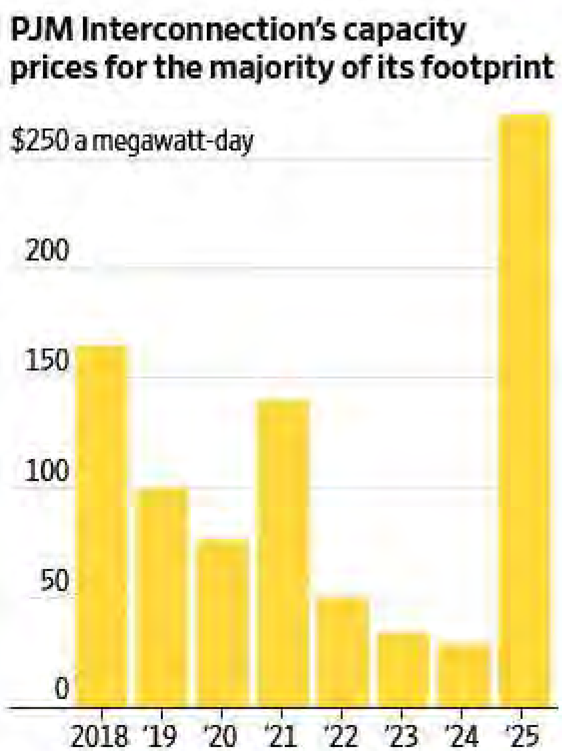
This is a **windfall for independent power producers** such as Talen Energy, Constellation Energy Group and Vistra, all of which own a sizable number of power plants that cleared the latest auction. Constellation's shares jumped 10% since the company reported last week that its earnings would get a healthy boost from high capacity prices. If they remain high in 2026, the company expects that to boost profit by 14% compared with analysts' earnings expectations before the auction results.

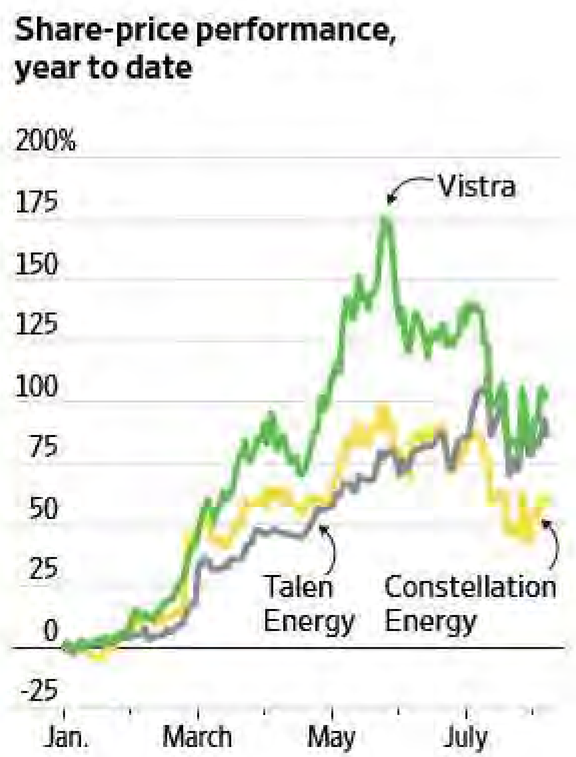
Vistra last Thursday raised the midpoint of its 2025 guidance for earnings before interest, taxes, depreciation and amortization by $200 million, or about 4%, partly as a result of higher capacity prices. Its shares have gained 5.4% since its earnings call.

High prices should encourage more companies to build new power plants, but they can take up to five years if built from scratch, notes Hugh Wynne, co-head of utilities and renewable energy research at SSR.

"What we're seeing in the [latest] capacity auction is the tip of the iceberg," said Wynne, referring to future capacity needs. This means the capacity price windfall could last a few more years for companies such as Constellation and Vistra.

But high prices come with **risk of political backlash and court challenges**, said Steve Fleishman, equity analyst at Wolfe Research. The **utilities that purchase electricity from these producers have signaled that bills will rise**: Chicago utility Exelon said in its latest earnings call that rates will increase by a double-digit percentage in some of its jurisdictions as a result of higher capacity prices. PPL, whose service territory includes Pennsylvania, Kentucky and Virginia, said higher capacity prices would increase utility bills by $10 to $15 a month starting next year.





Sources: PJM Interconnection (capacity); FactSet (performance)

Skyrocketing capacity prices are a clear signal that the grid needs new power plants. A control room at a Constellation nuclear station in Scriba, N.Y.

The strains could reshape the industry. **Utilities in certain states aren't allowed to own power plants**, but some are hinting that they will push for legislation to change that. PPL said during its latest earnings call that it would advocate for legislative changes in Pennsylvania that would allow it to do so. Similarly, FirstEnergy floated the idea that some states might change their rules to allow utilities to invest in their own generation.

Another point of conflict came up earlier this summer, when utilities – including Exelon and American Electric Power – pushed back on an aspect of Talen Energy's agreement to sell nuclear power to an adjacent Amazon.com data center in Pennsylvania, arguing that the **power plant** would **benefit from** the **transmission system without paying for it**. They estimated that as much as $140 million of costs could shift to other customers as a result.

The Federal Energy Regulatory Commission sought more information about that agreement earlier this month, and analysts at energy research firm ClearView Energy Partners think Talen can get the green light from FERC. The overhang could nevertheless create some delays for companies like Constellation and Vistra, which are vying for long-term, high-price contracts similar to the one that Talen set. Constellation was said to be nearing a deal with Amazon Web Services, as The Wall Street Journal reported.

Vistra said on Thursday it was talking to potential data-center customers but didn't give a timeline on when a deal might be reached. FERC is also set to hold a conference this fall to discuss broader issues related to co-locating large loads near power plants.

Also worth watching are states' changing stances toward data centers. While many have pushed forward incentives to lure the facilities, some are having misgivings. Georgia earlier this year passed a bill that would have halted the state's tax incentives for new data centers for two years, though that was ultimately vetoed by the governor in May.

Virginia, which also **has tax breaks for data centers**, is conducting a legislative study to examine how they are affecting electric reliability and affordability.

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CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2411

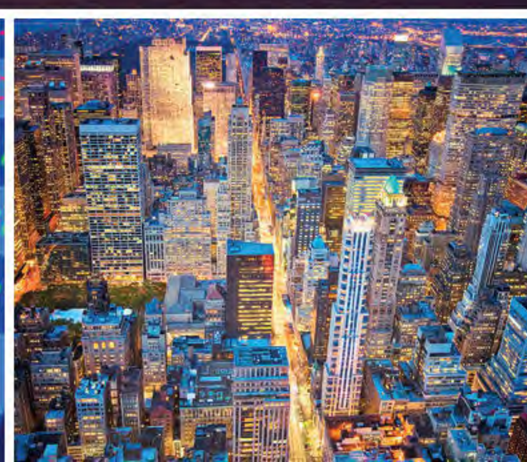
EEI Financial Review

August 16, 2024

Edison Electric INSTITUTE

2023 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry



Edison Electric INSTITUTE

2023 FINANCIAL REVIEW

ANNUAL REPORT OF THE U.S. INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

About EEI and the Financial Review

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the U.S. and contributes 5 percent to the nation's GDP. The 2023 Financial Review is a comprehensive source for critical financial data covering 39 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The report also includes data on five additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States. These 44 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 78 for a list of these companies.

Contents

Highlights of 2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2023	2022r	% Change
Total Operating Revenues	$411,173	$412,757	(0.4%)
Utility Plant (Net)	$1,507,915	$1,407,967	7.1%
Total Capitalization	$1,455,785	$1,363,510	6.8%
Earnings Excluding Non-Recurring and Extraordinary Items	$61,265	$49,871	22.8%
Dividends Paid, Common Stock	$32,980	$31,016	6.3%

Note: r = revised. Percent changes may reflect rounding.

Abbreviations and Acronyms

AFUDC	Allowance for Funds Used During Construction
BTU	British Thermal Unit
CFTC	Commodity Futures Trading Commission
CPI	Consumer Price Index
DOE	Department of Energy
DOJ	Department of Justice
DPS	Dividends per share
EEI	Edison Electric Institute
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Independent Transmission Company
kWh	Kilowatt-hour
M&A	Mergers & Acquisitions
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
NOAA	National Oceanic & Atmospheric Administration
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
PSC	Public Service Commission
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution

Company Categories

Two categories are used throughout this publication that group companies based on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

Regulated: 80% or more of total assets are regulated.

Mostly Regulated: Less than 80% of total assets are regulated.

Note: In prior editions of the Financial Review, a "Diversified" category was included for companies with less than 50% of total assets that are regulated. Some tables with historical data therefore include a "Diversified" category.

President's Letter

2023 Financial Review

For more than 90 years, EEI has represented America's investor-owned electric companies, and we are proud of their steadfast commitment to delivering reliable, affordable, and resilient clean energy to the customers and communities they serve. Today, electricity demand is growing significantly across our nation's economy, and the work that our members do has perhaps never been more significant than it is today.

In January of this year, I was honored to assume the critical role of EEI president and CEO. My predecessor, Tom Kuhn, held this role with distinction for more than 30 years, establishing EEI as one of the most respected energy institutes in the world. I am committed to building on the successes of the past, while adding a new perspective and experience to critical policy debates that will shape the industry's future.

After years of flat demand growth, the Federal Energy Regulatory Commission recently revised its five-year growth projection up to 4.7 percent from 2.6 percent. Grid planners now are preparing for the challenge of meeting peak demand growth of up to 38 gigawatts by 2028. That is an enormous amount of electricity that is going to come on the energy grid in a relatively short amount of time. What we do in the next several years as an organization and as an industry will ultimately determine our country's path for decades to come.

Thanks largely to the leadership of our member companies, we can chart a course for an American energy future that is secure, resilient, and affordable, using cleaner sources of generation in the process. Carbon emissions from the U.S. electric power sector today are as low as they were nearly 50 years ago, while demand for electricity has doubled and continues to grow.

We lead the world in reducing carbon emissions and are enabling the clean energy transition: More than 40 percent of U.S. electricity generation now comes from clean, carbon-free sources. And, since 2005, our sector's carbon emissions are down more than 41 percent.

It's more important than ever that we are able to use all the tools in the energy toolbox to meet demand growth and customer needs, preserving both our nuclear fleet and our ability to utilize natural gas as a partner to integrate renewable energy resources reliably and affordably.

And, we must build new energy infrastructure of all kinds. EEI and our member companies remain focused on the implementation of the 2021 Bipartisan Infrastructure Law and the 2022 Inflation Reduction Act—which included nearly $272 billion in clean energy tax credits. Together with the siting and permitting provisions included in the 2023 Fiscal Responsibility Act, this legislation is spurring critical infrastructure investments and technological innovation.

As an industry, we face a growing number of threats, and we continue to work across the sector and with our government and private-sector partners on several fronts, including to enhance our cyber and physical security posture and to strengthen our capabilities for managing weather and wildfire risks. Through our work with the CEO-led Task Force on Wildfires and the CEO-led Electricity Subsector Coordinating Council, industry leaders are partnering with the highest levels of government to enhance our industry's collective capability to mitigate and manage risk.

Over the past decade, EEI member companies have invested more than

> *"Energy security is at the core of everything we do as an industry. We cannot have a robust, prosperous economy without it. We must do all that we can to ensure that the electricity we provide is there when and where our customers need it—and that the infrastructure delivering electricity to homes and businesses across the country is modern, resilient, and secure.*

$1 trillion to make the energy grid smarter, stronger, cleaner, more dynamic, and more secure. Last year alone, more than $170 billion was invested, with more than $30 billion of that in adaptation, hardening, and resilience projects to strengthen the nation's transmission and distribution infrastructure for all customers.

Energy security is at the core of everything we do as an industry. We cannot have a robust, prosperous economy without it. We must do all that we can to ensure that the electricity we provide is there when and where our customers need it—and that the infrastructure delivering electricity to homes and businesses across the country is modern, resilient, and secure.

EEI continues our advocacy for stable, constructive policies that support our member companies' infrastructure investments. Related to this, we are asking the U.S. Treasury Department to implement the Corporate Alternative Minimum Tax without unduly impacting electricity customers or undermining needed investment in grid infrastructure.

And, as you will see in the Financial Review, EEI's member companies have continued to build upon a strong financial foundation. In 2023, the industry's average credit rating at the parent company level remained at BBB+ for the tenth straight year, having increased from BBB in 2014. This improved credit quality continues to support the electric power industry as the most capital-intensive industry in the country. Total industry capital expenditures were $171.9 billion in 2023, a record high for the 12th consecutive year.

Our industry extended its long-term trend of widespread and consistent dividend increases last year, with 87 percent of EEI member companies increasing their dividend rate. That percentage aligns with 2022's performance and the 82 percent to 93 percent range seen from 2015 through 2021. As of December 31, 2023, 38 of the 39 companies in the EEI Index were paying a common stock dividend.

We find ourselves at a truly transformational moment in this industry, and I have no doubt that we are up to the challenges that lie before us.

It has never been more important for America to maintain its position of leadership as the world enters an increasingly electric and energy-intensive era. The U.S. economy, and, indeed, the global economy, are counting on our industry to meet rising demand. Customer expectations for a resilient clean energy future are higher than ever before.

We truly value the partnership that we share with the financial community and the role that you all play in helping us deliver the future of energy.

Dan Brouillette

President and CEO
Edison Electric Institute

Capital Markets

Stock Performance

Major market indices extended Q3's weakness into late October when the S&P 500's year-to-date gain had eroded to just 7%. But Federal Reserve Chairman Jerome Powell's comments at the Fed's November 1 policy meeting—the second-straight with no rate increase—hinted rate hikes were over. Markets surged in November and December. The S&P 500 gained 11.7% in Q4 to end 2023 with a 26.3% return. The Dow Jones Industrials jumped 13.1% to finish 2023 with a 16.2% return. The red-hot Nasdaq surged 13.4% in the year's last quarter to close the year up 43.3%.

Few market watchers expected anything like this when the year began; recession calls were then widespread while fears that "something will break" from the Fed's rate hikes also kept outlooks muted. The sole bullish theme through much of 2023 was investors' enthusiasm for the commercialization potential of artificial intelligence (AI). Market strength was focused in the so-called "Magnificent Seven" large-cap tech companies—Google, Amazon, Apple, Meta (Facebook), Microsoft, AI chip maker Nvidia and Tesla—along with others seen as agents or

2023 Index Comparison

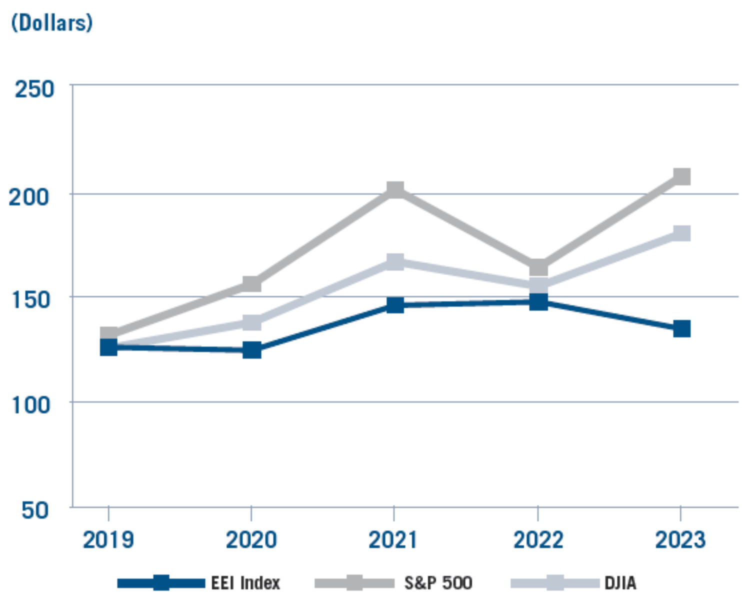
EEI Index	**(8.7)**
Dow Jones Industrial Average	16.2
S&P 500	26.3
Nasdaq Composite*	43.3

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and S&P Global Market Intelligence.

Comparison of the EEI Index, S&P 500, and DJIA Total Return

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2018.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Top 10 Performers
Twelve-month period ending 12/31/2023

Company	Total Return %	Category
Otter Tail Corporation	48.0%	R
Edison International	17.4%	R
PG&E Corporation	10.9%	R
Unitil Corporation	5.7%	R
MGE Energy, Inc.	5.0%	R
Public Service Enterprise Group Inc.	3.6%	R
Southern Company	2.2%	R
NiSource Inc.	0.5%	R
Sempra Energy	0.0%	R
ALLETE, Inc.	-0.7%	MR

Note: Return figures include capital gains and dividends.
Source: EEI Finance Department.

Sector Total Shareholder Return 2023

Sector	Total Return %
Technology	65.1%
Consumer Services	34.1%
Industrials	19.8%
Financials	16.1%
Consumer Goods	13.9%
Basic Materials	11.0%
Telecommunications	3.5%
Healthcare	1.9%
Oil & Gas	-1.0%
Utilities	-7.2%
EEI Index	**-8.7%**

Source: EEI Finance Dept., Dow Jones & Company.

beneficiaries of AI-driven innovation. Absent those seven names, the S&P 500 would have been 3% lower for the year by late October. But November and December's market gains were broad-based.

The EEI Index returned 8.0% in Q4, lifted by a sudden fall in interest rates and roughly matching the broader Utilities' sector's 8.6% return. However, neither index could fight rising interest rates through most of 2023 or compete with the AI optimism of the "Magnificent Seven", and the EEI index finished the year down about 9%.

Economic Strength Thwarts Recession Fears

Recession fears that colored economic outlooks as the year began melted in the face of surprisingly strong data as 2023 evolved. Estimated Q1 real gross domestic product (GDP) rose from a first estimate of 1.1% to a final reading of 2.2%. Q2 produced 2.1% growth. But it was late October's Q3 GDP report at 4.9% that fueled the bullish spirits spurred by Fed Chairman Powell's perceived pivot.

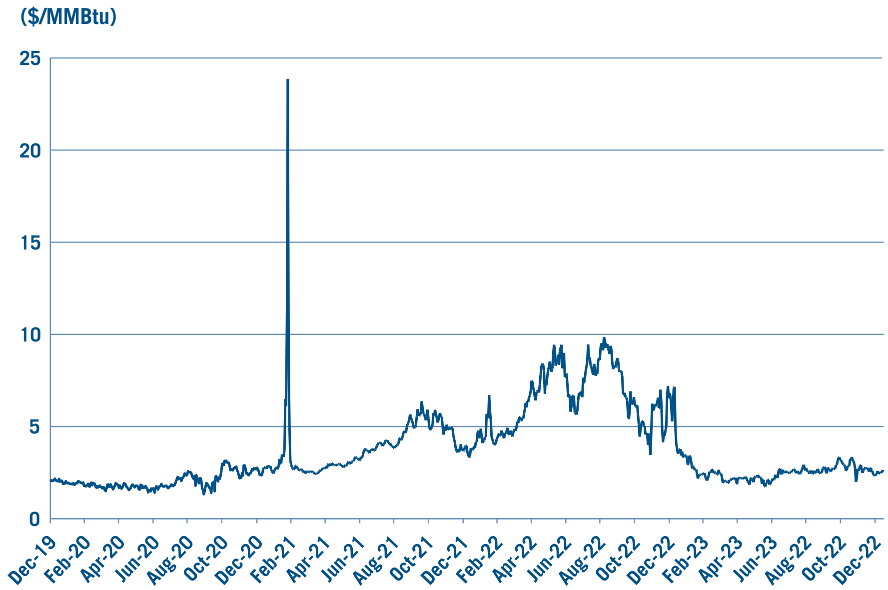
Economic bears missed their 2023 recession call but took analytical solace in what proved to be an earnings recession. Corporate profits for all S&P 500 companies (according to data compiled by Zacks Investment Research) declined 2.3% year-to-year in Q1 and 6.7% in Q2, marking three quarters of negative comparisons (including Q4 2022's 5.5% decline). As Q4 ended, full-year 2023 earnings were pegged to be unchanged from 2022. Optimism returned to 2024 and 2025 with projected 10%+ growth. While individual companies and pockets of the market showed good earnings gains, the aggregate picture imbues 2023's market advance with a macro-driven and thematic quality that broad fundamentals don't quite substantiate.

Interest Rates Drop

Utility shares have faced the headwind of rising interest rates since 2020, when the 10-year Treasury yield reached a record low 0.6%. Starting 2023 at 3.7%, the 10-year yield rose to nearly 5% by late October, causing much of utilities' 2023 negative return. In addition to Fed rate hikes, Wall Street pundits in

Natural Gas Spot Prices - Henry Hub

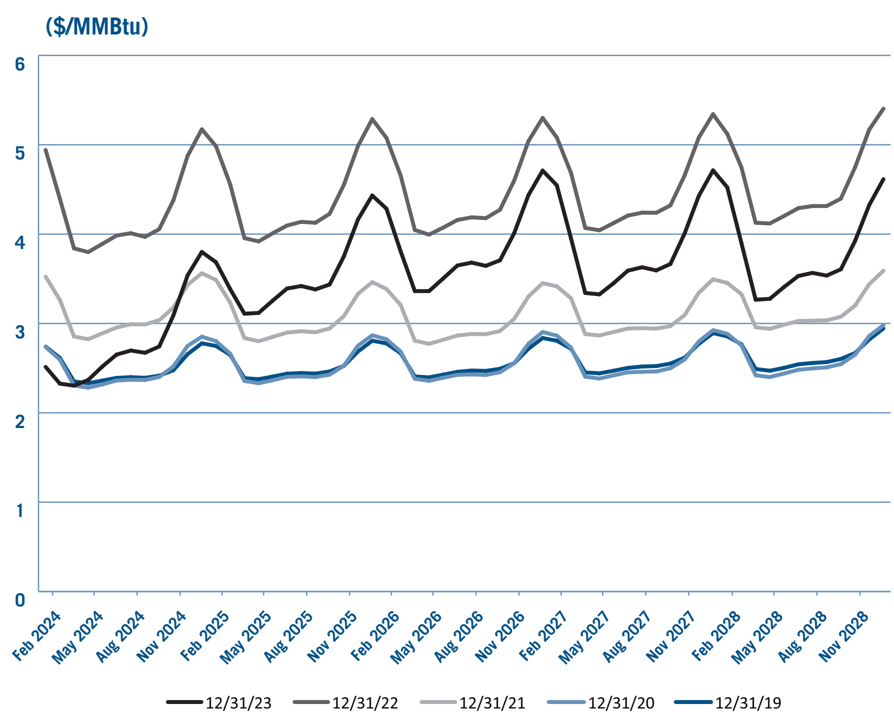
12/31/19 through 12/31/23



Source: S&P Global Market Intelligence.

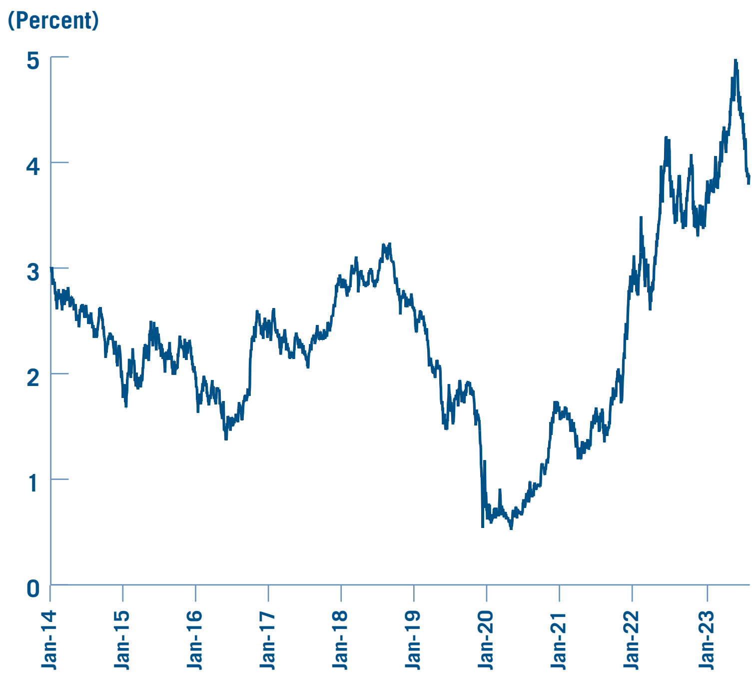
NYMEX Natural Gas Futures

February 2024 through December 2028



Source: S&P Global Market Intelligence.

10-Year Treasury Yield



Source: U.S. Federal Reserve.

Q3 attributed rising yields to bond investors' newfound exhaustion at Washington's big deficits and rising debt, which seem likely to rise further when the economy weakens. Yet after the Fed's November meeting, rates fell steadily from late October's 5.0% to 3.8% as December ended, driving the EEI Index's 8.0% Q4 gain. Interest rates also took direction from inflation data; monthly CPI inflation held in a narrow range of 3.0% to 3.2% through Q4, the lowest levels of the year and down from 5% readings through May.

Fundamental Concerns Color Thinking

During much of 2023, Wall Street's utility research grappled with several factors that weighed on utility stocks in addition to the share price impact of higher interest rates.

Cost of Capital. Analyst research noted some utilities face the prospect of refinancing maturing debt over the next few years at what may be much higher interest costs. Lower share prices also raise the equity cost of capital for utilities.

Wildfires. Wildfire risk was typically seen as a concern for California utilities. But Hawaii's August fires made headlines and Wall Street's Q3 research noted similar risks in Oregon and Colorado.

Inflation. If inflation raises renewable build-out costs and threatens long-term capex planning, utility growth plans may suffer. Related supply chain bottlenecks may also delay construction.

Regulation. Analysts cited scattered regulatory outcomes in 2023 that disappointed investors. With electric bills rising due to higher capex, Wall Street closely watched rate reviews for signs of waning support for utility investment.

Presentations Convey Steady Outlooks

Wall Street's worry over threats to the industry's fundamental picture took a back seat to parsing the Q3 earnings reports and investor presentations that occurred during Q4.

Utilities release Q3 earnings in October and November each year and hold conference calls with investors to review outlooks. Wall Street's published research in Q4 generally saw Q3 earnings as on target, with several utilities slightly raising earnings guidance. Utilities' Q3 conference call presentations, taken as a whole, presented a cautiously optimistic picture. Several utilities formally raised 5-year capex projections while others noted opportunities not yet included in current outlooks. A few raised load growth forecasts due to economic development in service territories along with record-setting peak loads in 2023. Many noted demand boosts from data centers (one facet of utility exposure to AI-driven innovation) and the "re-shoring" of industrial production. Several Q3 earnings presentations cited favorable regulatory support for clean energy investment. Wall Street said utilities appear to be successfully managing rising interest costs and the impact of inflation on company operations and capex planning. Many companies cited room for additional operations & maintenance (O&M) cost efficiencies, in some cases from deployment of AI-driven approaches to system monitoring.

EEI's Financial Conference in November, along with other industry conferences, added news flow that Wall Street research analyzed and reported. Constructive themes that were extended from Q3 earnings calls included steady or rising capex outlooks, boosts to demand growth at some utilities, and maintenance of the mid-single-digit, five-year earnings growth forecasts that have been a constant for much of the industry in recent years.

Yet Wall Street is paid, in part, to be critical thinkers; analysts also noted industry balance sheets are a bit stretched from aggressive capex financing and remained wary that state regulation may turn less supportive of capex—especially if the economy turns down. For the time being, Wall Street appears in agreement with utilities' general view that state commissions and ratepayers will tolerate 2% to 4% bill inflation, given that's required to fund the nation's clean energy transition and the jobs and local economic development that come with it. But the multi-year trend back to nearly a fully regulated focus makes state-by-state regulatory relations an ever-present Wall Street concern.

Wall Street Turns More Positive on Valuation

Utility stocks have fought rising interest rates since mid-2020 and have lagged a surging, albeit volatile, stock market in four of the last five years. Will utilities get any respect in 2024? If industry news stays positive and outlooks steady the answer likely depends on interest rates, although company-specific regulatory outcomes can override macro forces and shape stock moves on a company-by-company basis. Wall Street broadly sees utilities as cheaper than they've been in years and set up to shine should rates fall and earnings outlooks remain steady. In 2023, the Nasdaq 100 had its best year since the 1999 tech bubble. The broader Nasdaq peaked in March 2000 then collapsed; it took 15 years to recover. It's hard to be a bear in a bull market, but long-term investors have reason to like utility stocks in early 2024. The next five years may be very different than the past five.

2023 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	(2.9)	(3.0)	(10.3)	8.0
Dow Jones Industrial Average	0.9	4.0	(2.1)	13.1
S&P 500	7.5	8.7	(3.3)	11.7
Nasdaq Composite*	16.8	12.8	(4.1)	13.4
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	(0.5)	(2.7)	(10.5)	8.1
Regulated	(0.0)	(2.5)	(8.7)	8.0
Mostly Regulated	(3.8)	(3.9)	(23.3)	9.2

* Price gain/loss only. Other indices show total return.
For the Category comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).

Source: EEI Finance Department, S&P Global Market Intelligence.

2023 Category Comparison

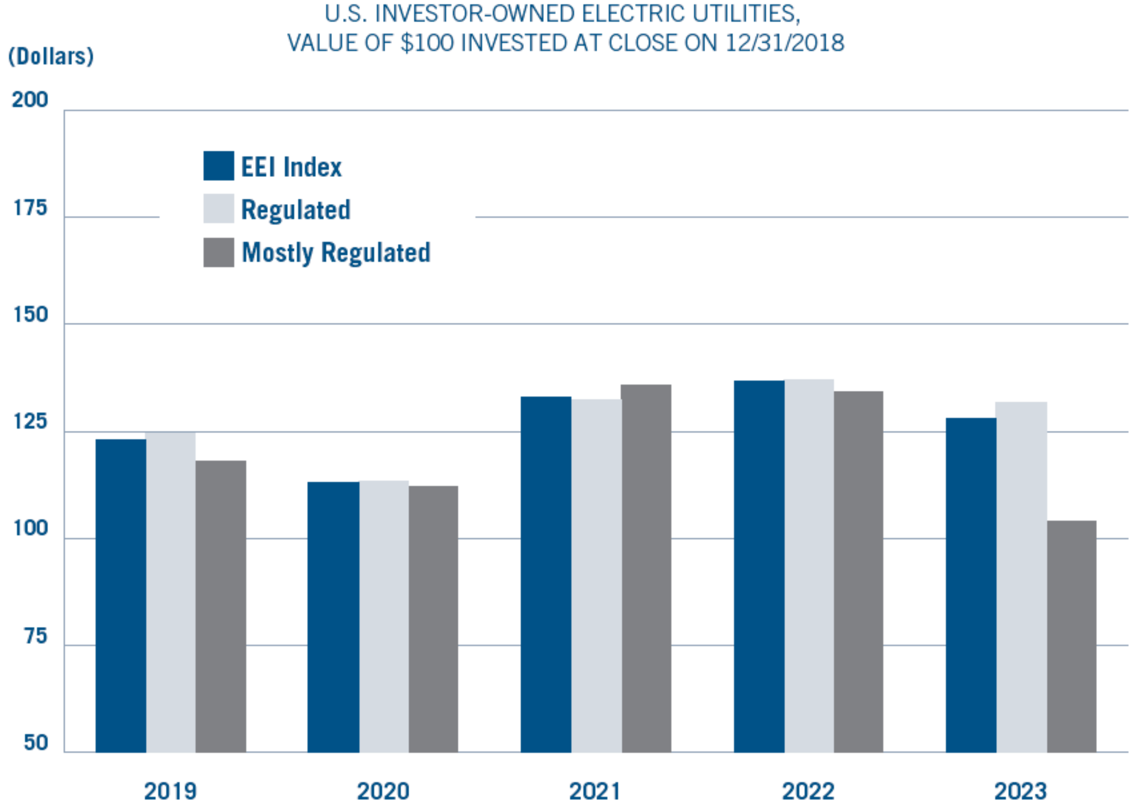
Category	Return (%)
EEI Index	**(6.3)**
Regulated	(3.9)
Mostly Regulated	(22.5)

Regulated: 80% or more of total assets are regulated.
Mostly Regulated: Less than 80% of total assets are regulated.

Note: For the Category Comparison, straight, equal-weight averages are used (i.e., not market-capitalization-weighted).

Source: EEI Finance Dept., S&P Global Market Intelligence, company reports

Comparative Category Total Annual Returns



	2019	2020	2021	2022	2023
EEI Index Annual Return (%)	23.06	(8.07)	17.62	2.74	(6.30)
EEI Index Cumulative Return ($)	123.06	113.12	133.05	136.69	128.08
Regulated EEI Index Annual Return	24.56	(9.01)	16.72	3.59	(3.92)
Regulated EEI Index Cumulative Return	124.56	113.33	132.28	137.03	131.67
Mostly Regulated EEI Index Annual Return	17.87	(4.95)	21.09	(1.15)	(22.50)
Mostly Regulated EEI Index Cumulative Return	117.87	112.04	135.67	134.12	103.94

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2018.

Source: EEI Finance Dept., S&P Global Market Intelligence

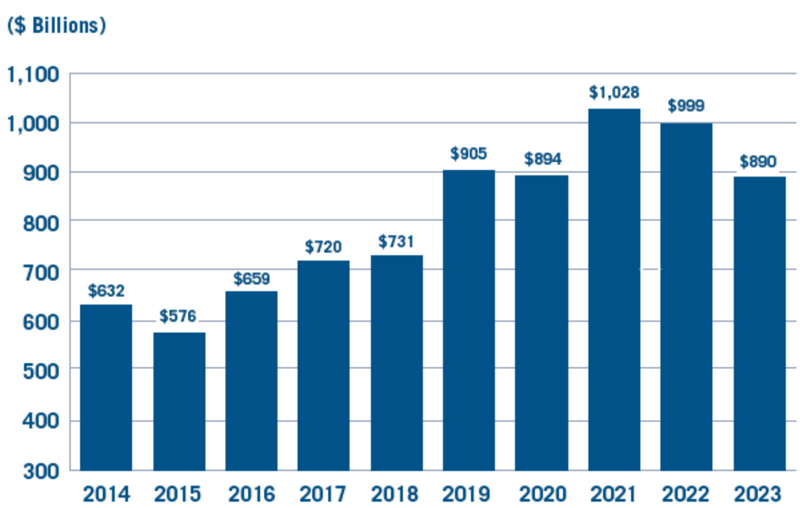
Market Capitalization at December 31, 2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Ticker	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	123,381	13.86%
Southern Company	SO	76,571	8.60%
Duke Energy Corporation	DUK	74,818	8.41%
Sempra Energy	SRE	47,083	5.29%
American Electric Power Company, Inc.	AEP	42,272	4.75%
Dominion Energy, Inc.	D	39,330	4.42%
PG&E Corporation	PCG	38,061	4.28%
Exelon Corporation	EXC	35,756	4.02%
Xcel Energy Inc.	XEL	34,174	3.84%
Consolidated Edison, Inc.	ED	31,385	3.53%
Public Service Enterprise Group Inc.	PEG	30,453	3.42%
Edison International	EIX	27,381	3.08%
WEC Energy Group, Inc.	WEC	26,547	2.98%
DTE Energy Company	DTE	22,714	2.55%
Eversource Energy	ES	21,584	2.43%
Entergy Corporation	ETR	21,398	2.40%
FirstEnergy Corp.	FE	21,006	2.36%
PPL Corporation	PPL	19,976	2.24%
Ameren Corporation	AEE	19,011	2.14%
CenterPoint Energy, Inc.	CNP	18,033	2.03%
CMS Energy Corporation	CMS	16,898	1.90%
Alliant Energy Corporation	LNT	13,005	1.46%
AVANGRID, Inc.	AGR	12,538	1.41%
Evergy, Inc.	EVRG	12,011	1.35%
NiSource Inc.	NI	10,978	1.23%
Pinnacle West Capital Corporation	PNW	8,151	0.92%
OGE Energy Corp.	OGE	6,996	0.79%
IDACORP, Inc.	IDA	4,987	0.56%
Portland General Electric Company	POR	4,371	0.49%
MDU Resources Group, Inc.	MDU	4,032	0.45%
Black Hills Corporation	BKH	3,632	0.41%
PNM Resources, Inc.	PNM	3,581	0.40%
Otter Tail Corporation	OTTR	3,542	0.40%
ALLETE, Inc.	ALE	3,511	0.39%
NorthWestern Energy	NWE	3,076	0.35%
Avista Corporation	AVA	2,742	0.31%
MGE Energy, Inc.	MGEE	2,615	0.29%
Hawaiian Electric Industries, Inc.	HE	1,557	0.17%
Unitil Corporation	UTL	846	0.10%
Total Industry		**890,003**	**100%**

Source: EEI Finance Department and S&P Global Market Intelligence. All dollar amounts presented in millions.

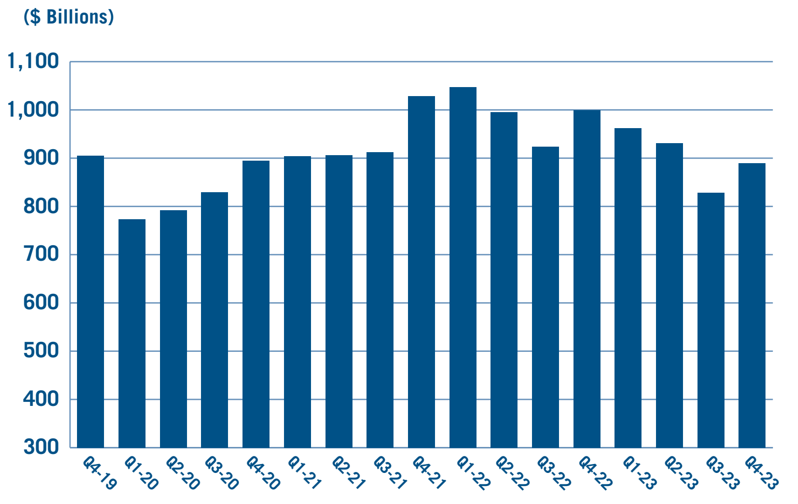
EEI Index Market Capitalization



Note: Results are as of December 31 of each year.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization by Quarter



Source: EEI Finance Department and S&P Global Market Intelligence.

Dividends

The investor-owned electric utility industry continued its long-term trend of widespread dividend increases in 2023. A total of 34 companies increased or reinstated their dividend for the second straight year; this compares to 32 in 2021, 34 in 2020, 37 in 2019, 39 in 2018 and 36 to 40 companies annually from 2012 through 2017. One company suspended its dividend in 2023. One company reduced its dividend in 2022, zero did so in 2021 and two did in 2020.

The percentage of companies that raised or reinstated their dividend in 2023 was 87% for the second straight year. This was up from 82% in 2021 and in line with the 85% to

Dividend Patterns 1996–2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Raised	No Change	Lowered	Omitted*	Reinstated	Not Paying	Total	Dividend Payout Ratio
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	–	3	96	84.2%
1998	40	37	7	–	–	5	89	82.1%
1999	29	45	4	–	3	2	83	74.9%
2000	26	39	3	1	–	2	71	63.9%
2001	21	40	3	2	–	3	69	64.1%**
2002	26	27	6	3	–	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	–	–	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	–	–	–	6	64	63.5%
2007	40	15	–	–	3	3	61	62.1%
2008	36	20	1	–	1	1	59	66.8%
2009	31	23	3	–	–	1	58	69.6%
2010	34	22	–	–	–	1	57	62.0%
2011	31	22	–	1	1	–	55	62.8%
2012	36	14	–	–	1	–	51	64.2%
2013	36	12	1	–	–	–	49	61.5%
2014	38	9	1	–	–	–	48	60.4%
2015	39	7	–	–	–	–	46	67.0%
2016	40	4	–	–	–	–	44	62.9%
2017	38	4	–	1	–	–	43	64.0%
2018	39	1	1	–	–	1	42	63.9%
2019	37	2	–	–	–	1	40	62.6%
2020	34	2	2	–	–	1	39	65.3%
2021	32	6	–	–	–	1	39	62.7%
2022	34	3	1	–	–	1	39	70.8%
2023	33	4	–	1	1	–	39	63.7%

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Average of the Increased Dividend Actions***	5.7%	5.8%	5.6%	5.6%	5.7%	5.1%	5.1%	4.8%	5.2%	5.1%
Average of the Declining Dividend Actions***	(34.5%)	NA	NA	NA	(79.8%)	NA	(40.6%)	NA	(51.8%)	(100.0%)

* Omitted in current year. This number is not included in the Not Paying column.

** * Prior to 2000: Total industry dividends/total industry earnings. Starting in 2000: Average of all companies paying dividend.

*** Excludes companies that omitted or reinstated dividends.

2022 current year figures reflect dividend changes (raised, lowered, etc.) through 12/31/2022 and earnings and dividends through 12/31/2022 (payout ratio).

Source: S&P Global Market Intelligence and EEI Finance Department

93% range from 2015 through 2020. By contrast, only 27 of the 65 utilities tracked by EEI increased their dividend in 2003, just prior to the passage of legislation that reduced dividend tax rates. The percentages noted above are drawn from a dataset that begins in 1988. Mergers and acquisitions reduced the number of publicly traded utilities included in the EEI Index from 65 in 2003 to 39 at year-end 2023.

As shown in the Dividend Patterns table, 38 of the 39 publicly traded utilities in the EEI Index were paying a common stock dividend as of December 31, 2023. Each company is limited to one action per year in the table. For example, if a company raised its dividend twice during a year that counts as one in the Raised column. Electric utilities generally use the same quarter each year for dividend changes, with Q1 the most common.

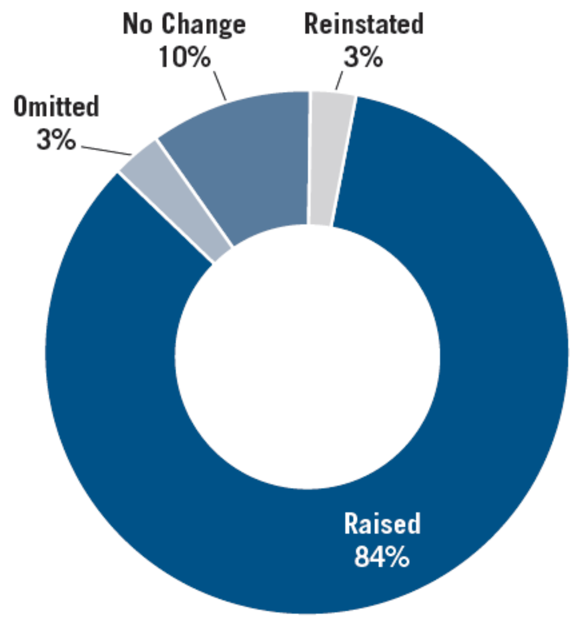
2023 Increases Average 5.1%

The average dividend increase in 2023 was 5.1%, with a range of 1.0% to 10.0% and a median increase of 5.4%. NextEra Energy (+10.0% in Q1), WEC Energy (+7.2% in Q1), DTE Energy (+7.1% in Q4), Ameren (+6.8% in Q1), Xcel Energy (+6.7% in Q1), PPL Corporation (+6.7% in Q1) and Exelon (+6.7% in Q1) posted the largest percentage increases.

NextEra Energy, headquartered in Juno Beach, Florida, increased its quarterly dividend from $0.425 to $0.4675 per share during the first quarter. The increase is consistent with its plan, announced in 2022, to target roughly 10% annual growth in its per-share dividend through at

2023 Dividend Patterns

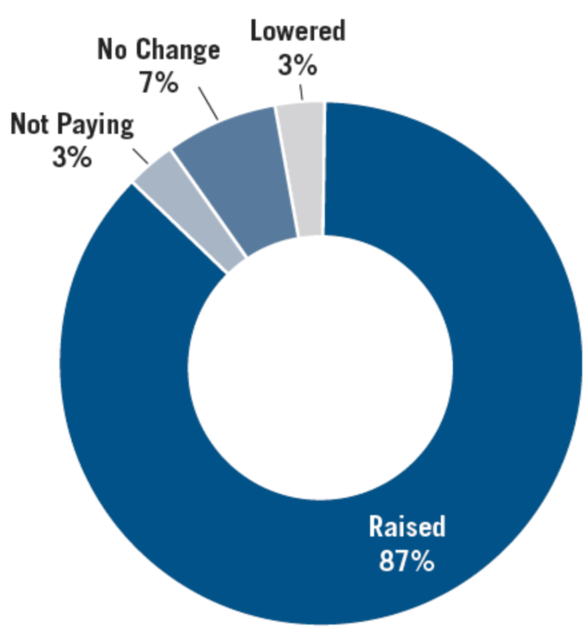
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2022 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

least 2024, off a 2022 base. NextEra recorded the industry's highest percentage increases in 2022 (+10.4%), 2021 (+10.0%), 2020 (+12.0%) and 2019 (+12.6%), which followed the second-highest percentage increase in 2018 (+13.0%) and the largest percentage increases in both 2017 (+12.9%) and 2016 (+13.0%, along with Edison International and DTE Energy).

WEC Energy Group, based in Milwaukee, Wisconsin, raised its quarterly dividend from $0.7275 to $0.78 in the first quarter. This marked its 322nd consecutive quarterly common stock dividend, dating back to 1942, and the 20th straight year with a dividend increase. WEC Energy continues to target a dividend payout ratio of 65 to 70 percent of earnings.

DTE Energy, headquartered in Detroit, Michigan, increased its quarterly dividend from $0.9525 to $1.02 per share during the fourth quarter. The company noted the move continues its more than 100-year history of issuing a cash dividend.

Ameren, based in St. Louis, Missouri, raised its quarterly dividend from $0.59 to $0.63 per share in Q1, marking the tenth consecutive annual increase. The company anticipates dividend growth will be in line with the company's long-term earnings-per-share growth expectations and within a payout ratio of 55% to 70%.

Xcel Energy, headquartered in Minneapolis, Minnesota, increased its quarterly dividend from $0.4875 to $0.52 per share during Q1. Since increasing its dividend growth objective in 2015 to a range of 5% to 7% annually, Xcel has delivered average annual dividend increases above 6%.

PPL Corporation, based in Allentown, Pennsylvania, raised its quarterly dividend from $0.225 to $0.24 per share in Q1. The company reaffirmed expectations of 6% to 8% annual EPS and dividend growth through at least 2026.

Exelon, headquartered in Chicago, Illinois, increased its quarterly dividend from $0.3375 to $0.36 per share during Q1. In February 2022, the company completed the separation of Constellation Energy, Exelon's former power generation and competitive energy business, with Exelon continuing as the parent company for its fully regulated transmission and distribution utilities.

Hawaiian Electric announced in August 2023 that it would suspend its dividend effective Q4 2023 due to the impact from the Maui wildfires. The company's quarterly dividend rate had been $0.36 per share. Prior to the dividend suspension, Hawaiian Electric's last dividend increase occurred in Q1 2023.

The industry's average and median increases have been relatively consistent in recent years. The average was 5.2% in 2022, 4.8% in 2021, and ranged between 5.1% and 5.7% from 2016 through 2020. The median increase was 5.6% in 2022 and ranged between 4.8% and 5.5% from 2017 through 2021.

PG&E Reinstates Dividend

PG&E in Q4 declared a cash dividend on its common stock for the first time since 2017. The company stated that "reinstating the common dividend reflects Pacific Gas and Electric Company's substantial progress in becoming a safe and stable utility that can now attract more long-term investors. Since 2017, we have reinvested the vast majority of our earnings back into our system and will continue to do so. Our earnings have gone directly into infrastructure projects focused on improving safety and reliability for our customers." The reinstated dividend was set initially at an annual rate of $0.04 per share.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 62.2% for the twelve months ended December 31, 2023, exceeding all other U.S. business sectors. The industry's payout ratio was 63.7% when measured as an un-weighted average of individual company ratios; 62.2% represents an aggregate figure. From 2000 through 2022, the industry's annual payout ratio ranged from 60.4% to 70.8%.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.
3. Companies with a payout ratio in excess of 200% are eliminated.

Sector Comparison Dividend Payout Ratio
For 12-month period ending 12/31/23

Sector	Payout Ratio (%)
EEI Index Companies*	**62.2%**
Utilities	59.8%
Consumer Staples	53.8%
Materials	39.6%
Energy	39.4%
Industrial	34.1%
Health Care	33.5%
Financial	27.2%
Technology	25.3%
Consumer Discretionary	21.9%

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

Assumptions:
1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2023E.

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence, and EEI Finance Department.

Sector Comparison, Dividend Yield
As of December 31, 2023

Sector	Dividend Yield (%)
EEI Index Companies	**3.8%**
Energy	3.6%
Utilities	3.5%
Consumer Staples	2.7%
Materials	2.0%
Financial	1.8%
Health Care	1.6%
Industrial	1.5%
Technology	0.9%
Consumer Discretionary	0.8%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2023); S&P sector yields based on 2023E cash dividends (estimates as of 12/31/2023).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence and EEI Finance Department.

The industry's average dividend yield was 3.8% on December 31, 2023, leading all U.S. business sectors. The industry's average dividend yield was 3.4% at year-end 2022, 3.3% at year-end 2021, 3.6% at year-end 2020, 3.0% for 2019 and 3.4% at each of the three previous year-ends. An overall decline in utility stock prices along with strong dividend activity resulted in a higher yield at year-end 2023; the market cap weighted EEI Index returned -8.7% for the year. We calculate the industry's average dividend yield using an un-weighted average of the yields of EEI Index companies paying a dividend.

Business Category Comparison

The Regulated category's dividend payout ratio was 62.9% for the twelve months ended December 31, 2023, compared to 68.5% for the Mostly Regulated category. The Regulated group produced the higher annual payout ratio in 2020, 2017, 2015, 2011, 2010 and in each year from 2003 through 2008.

The Regulated and Mostly Regulated average dividend yields were 3.8% and 3.9%, respectively on December 31, 2023, compared to 3.4% and 3.3% at year-end 2022, 3.3% and 3.0% at year-end 2021, 3.6% and 3.4% at year-end 2020 and 3.0 and 3.1% at year-end 2019. The dividend yields for both categories at year-end 2018 and 2017 were 3.4%.

Electric Utilities' History of Strong Dividends

The electric utility sector has long been known as a leading dividend payer among U.S. business sectors. This reputation is founded on:

Category Comparison, Dividend Payout Ratio

Category	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023*
EEI Index	**60.4**	**67.0**	**62.9**	**64.0**	**63.9**	**62.6**	**65.3**	**61.6**	**70.8**	**63.7**
Regulated	59.4	68.7	61.1	68.7	60.1	62.1	65.3	59.5	69.2	62.9
Mostly Regulated	63.8	62.6	68.0	53.3	72.8	64.1	65.2	69.0	77.4	68.5
Diversified	56.4	64.9	64.6	–	–	–	–	–	–	–

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Diversified: Prior to 2017, less than 50% of total assets are regulated

*2023 figures reflect earnings and dividends through 12/31/2023.

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department

- A steady stream of income from a product that is universally needed and with low elasticity of demand.
- A mostly regulated industry that provides reasonable returns on investment and relatively low investment risk.
- A mature industry comprised of companies with very long track records of maintaining and/or steadily increasing their dividends over time.

Category Comparison, Dividend Yield
As of December 31, 2023

Category	Dividend Yield
EEI Index	**3.8%**
Regulated	3.8%
Mostly Regulated	3.9%

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Source: S&P Global Market Intelligence, company reports and EEI Finance Department

These characteristics are especially attractive to an aging population of investors who seek a combination of growth and income. A typical total return model for electric utilities is approximately 4% to 6% annual earnings growth and a 3% to 4% dividend yield, producing highly visible and relatively stable 7% to 10% annualized long-term total return potential.

Dividend Tax Rates

The top tax rate for dividends and capital gains in 2023 was 20%, applied at income thresholds of $553,850 for couples and $492,300 for individuals. Below these thresholds, dividends and capital gains are each taxed at rates of 15% or 0%, depending on the filer's income. A 3.8% Medicare tax that was included in 2010 health care legislation is also applied to all investment income for couples earning more than $250,000 ($200,000 for singles).

The Tax Cuts and Jobs Act (TCJA), signed into law in December 2017, maintained the pre-existing and equal tax rates for dividends and capital gains. This parity is crucial to avoid a capital raising disadvantage for companies, such as electric utilities, that rely on a strong dividend to attract investors and finance capital spending.

Dividend Summary

As of December 31, 2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	MR	$2.71	86.9%	4.4%	Raised	$2.71	$2.60	2023 Q1
Alliant Energy Corporation	LNT	R	$1.81	64.9%	3.5%	Raised	$1.81	$1.71	2023 Q1
Ameren Corporation	AEE	R	$2.52	57.2%	3.5%	Raised	$2.52	$2.36	2023 Q1
American Electric Power Company, Inc.	AEP	R	$3.52	73.0%	4.3%	Raised	$3.52	$3.32	2023 Q4
AVANGRID, Inc.	AGR	MR	$1.76	100.6%	5.4%	Raised	$1.76	$1.73	2018 Q3
Avista Corporation	AVA	R	$1.84	82.3%	5.1%	Raised	$1.84	$1.76	2023 Q1
Black Hills Corporation	BKH	R	$2.50	62.7%	4.6%	Raised	$2.50	$2.38	2022 Q4
CenterPoint Energy, Inc.	CNP	R	$0.80	52.2%	2.8%	Raised	$0.80	$0.76	2023 Q3
CMS Energy Corporation	CMS	R	$1.95	84.2%	3.4%	Raised	$1.95	$1.84	2023 Q1
Consolidated Edison, Inc.	ED	R	$3.24	66.4%	3.6%	Raised	$3.24	$3.16	2023 Q1
Dominion Resources, Inc.	D	R	$2.67	77.3%	5.7%	Raised	$2.67	$2.52	2022 Q1
DTE Energy Company	DTE	R	$4.08	53.2%	3.7%	Raised	$4.08	$3.81	2023 Q4
Duke Energy Corporation	DUK	R	$4.10	69.9%	4.2%	Raised	$4.10	$4.02	2023 Q3
Edison International	EIX	R	$3.12	48.2%	4.4%	Raised	$3.12	$2.95	2023 Q4
Entergy Corporation	ETR	R	$4.52	38.2%	4.5%	Raised	$4.52	$4.28	2023 Q4
Evergy, Inc.	EVRG	R	$2.57	76.6%	4.9%	Raised	$2.57	$2.45	2023 Q4
Eversource Energy	ES	R	$2.70	52.8%	4.4%	Raised	$2.70	$2.55	2023 Q1
Exelon Corporation	EXC	R	$1.44	59.9%	4.0%	Raised	$1.44	$1.35	2023 Q1
FirstEnergy Corp.	FE	R	$1.64	73.5%	4.5%	Raised	$1.64	$1.56	2023 Q3
Hawaiian Electric Industries, Inc.	HE	MR	$0.00	52.1%	0.0%	Lowered	$0.00	$1.44	2023 Q4
IDACORP, Inc.	IDA	R	$3.32	62.4%	3.4%	Raised	$3.32	$3.16	2023 Q4
MDU Resources Group, Inc.	MDU	MR	$0.50	37.1%	2.5%	Raised	$0.50	$0.49	2022 Q4
MGE Energy, Inc.	MGEE	R	$1.71	51.3%	2.4%	Raised	$1.71	$1.63	2023 Q3
NextEra Energy, Inc.	NEE	MR	$1.87	65.8%	3.1%	Raised	$1.87	$1.70	2023 Q1
NiSource Inc.	NI	R	$1.00	61.1%	3.8%	Raised	$1.00	$0.94	2023 Q1
NorthWestern Energy	NWE	R	$2.56	79.4%	5.0%	Raised	$2.56	$2.52	2023 Q1
OGE Energy Corp.	OGE	R	$1.67	79.9%	4.8%	Raised	$1.67	$1.66	2023 Q3
Otter Tail Corporation	OTTR	R	$1.75	24.8%	2.1%	Raised	$1.75	$1.65	2023 Q1
PG&E Corporation	PCG	R	$0.04	0.0%	0.2%	Raised	$0.04	$0.00	2023 Q4
Pinnacle West Capital Corporation	PNW	R	$3.52	75.4%	4.9%	Raised	$3.52	$3.46	2023 Q4
PNM Resources, Inc.	PNM	R	$1.55	69.8%	3.7%	Raised	$1.55	$1.47	2023 Q4
Portland General Electric Company	POR	R	$1.90	78.5%	4.4%	Raised	$1.90	$1.81	2023 Q2
PPL Corporation	PPL	R	$0.96	54.2%	3.5%	Raised	$0.96	$0.90	2023 Q1
Public Service Enterprise Group Inc.	PEG	R	$2.28	44.2%	3.7%	Raised	$2.28	$2.16	2023 Q1
Sempra Energy	SRE	R	$2.38	41.0%	3.2%	Raised	$2.38	$2.29	2023 Q1
Southern Company	SO	R	$2.80	81.1%	4.0%	Raised	$2.80	$2.72	2023 Q2
Unitil Corporation	UTL	R	$1.62	58.0%	3.1%	Raised	$1.62	$1.56	2023 Q1
WEC Energy Group, Inc.	WEC	R	$3.12	65.2%	3.7%	Raised	$3.12	$2.91	2023 Q1
Xcel Energy Inc.	XEL	R	$2.08	58.1%	3.4%	Raised	$2.08	$1.95	2023 Q1
Industry Average				**63.7%**	**3.8%**				

NOTES
Business Segmentation: Assets as of 12/31/2022
R = Regulated: 80% or more of total assets are regulated. **MR = Mostly Regulated:** Less than 80% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2023.
Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2023 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2023. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.
"NM" applies to companies with negative earnings or payout ratios greater than 200%.
Dividend Yield: Annualized Dividends Per Share at 12/31/2023 divided by stock price at market close on 12/31/2023.
By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.

Source: EEI Finance Department and S&P Global Market Intelligence.

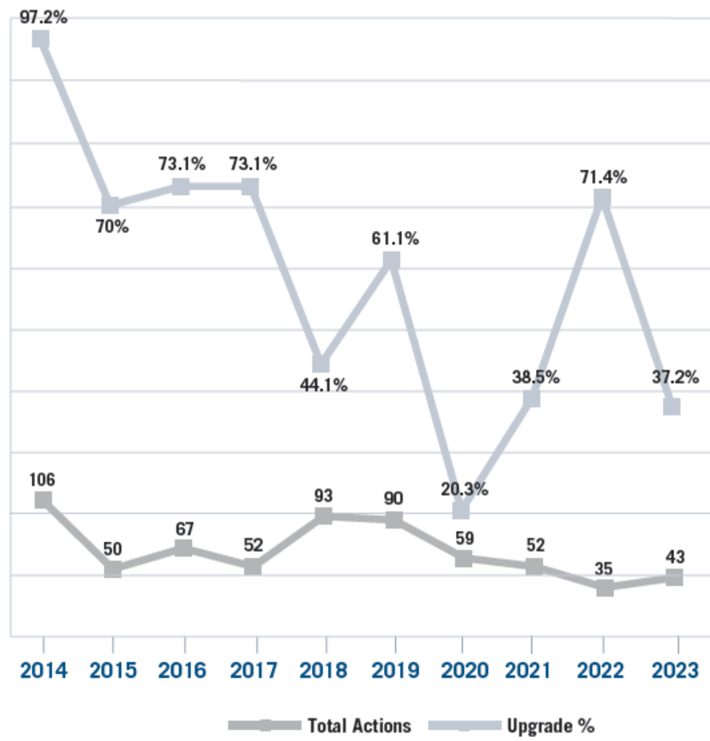
Credit Ratings

The industry's average parent company credit rating in 2023 remained at BBB+ for the tenth straight year, although four parent-level downgrades caused a weakening in aggregate holding company credit quality. There were only 43 total actions—16 upgrades and 27 downgrades—affecting both parents and subsidiaries. This pace was far below the 68-action annual average of the previous ten calendar years and is the second-lowest annual total in our historical dataset (back to 2000).

On December 31, 2023, 68% of parent company ratings outlooks were "stable" and 16% were "positive" or "watch-positive". Only 16% of outlooks were "negative" or "watch-negative"; this is an increase over the 11% at year-end 2022, which was the lowest negative share since 2013.

Direction of Rating Actions

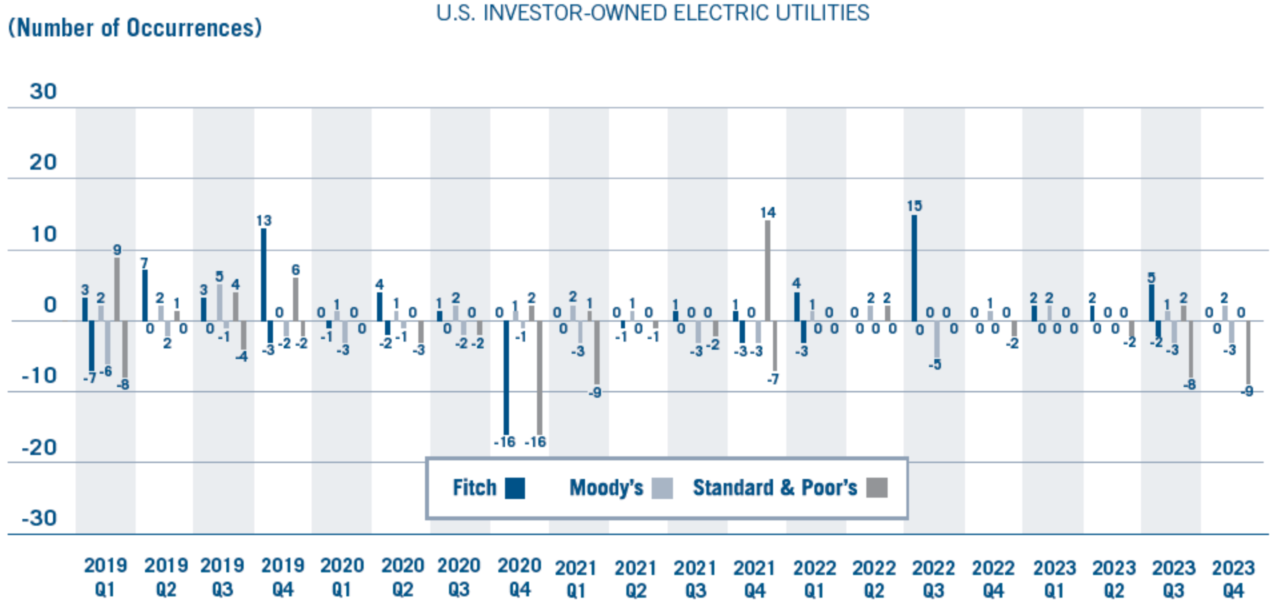
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades

	2019 Total Upgrades	2019 Total Downgrades	2020 Total Upgrades	2020 Total Downgrades	2021 Total Upgrades	2021 Total Downgrades	2022 Total Upgrades	2022 Total Downgrades	2023 Total Upgrades	2023 Total Downgrades
Fitch										
Q1	3	(7)	0	(1)	0	0	4	(3)	2	0
Q2	7	0	4	(2)	0	(1)	0	0	2	0
Q3	3	0	1	0	1	0	15	0	5	(2)
Q4	13	(3)	0	(16)	1	(3)	0	0	0	0
Total	**26**	**(10)**	**5**	**(19)**	**2**	**(4)**	**19**	**(3)**	**9**	**(2)**
Moody's										
Q1	2	(6)	1	(3)	2	(3)	1	0	2	0
Q2	2	(2)	1	(1)	1	0	2	0	0	0
Q3	5	(1)	2	(2)	0	(3)	0	(5)	1	(3)
Q4	0	(2)	1	(1)	0	(3)	1	0	2	(3)
Total	**9**	**(11)**	**5**	**(7)**	**3**	**(9)**	**4**	**(5)**	**5**	**(6)**
S&P										
Q1	9	(8)	0	0	1	(9)	0	0	0	0
Q2	1	0	0	(3)	0	(1)	2	0	0	(2)
Q3	4	(4)	0	(2)	0	(2)	0	0	2	(8)
Q4	3	(2)	2	(16)	14	(7)	0	(2)	0	(9)
Total	**26**	**(11)**	**2**	**(21)**	**15**	**(19)**	**2**	**(2)**	**2**	**(19)**

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.
Source: Fitch Ratings, Moody's, and Standard & Poor's.

Electric utility industry credit quality has generally improved over the past decade. The industry's average parent-level rating has held at BBB+ since increasing from BBB in 2014. Upgrades have outnumbered downgrades in six of the past ten calendar years with an annual average upgrade percentage of 59% over the decade.

EEI captures upgrades and downgrades at both the parent and subsidiary levels. The industry's average credit rating and outlook are the unweighted averages of all Standard & Poor's (S&P) parent holding company ratings and outlooks. However, our upgrade/downgrade totals reflect all actions by the three major ratings agencies affecting parent holding companies as well as individual subsidiaries. Our universe of 44 U.S. parent company electric utilities on December 31, 2023 included 39 that are publicly traded and five that are either a subsidiary of an independent power producer, a subsidiary of a foreign owned company, or owned by an investment firm.

Credit Actions at Parent Level

The only parent-level ratings actions in 2023 by S&P were four downgrades. By comparison, there was one downgrade and no upgrades in 2022, three downgrades and one upgrade in 2021, and three downgrades, one upgrade and one reinstatement in 2020.

On August 15, S&P Global Ratings downgraded Hawaiian Electric Industries (HE) to BB- from BBB-. Subsidiaries Hawaiian Electric, Maui Electric, and Hawaii Electric Light were also downgraded to BB- from BBB. The downgrades resulted from the worst wildfires in Hawaii's history, predominantly on the island of Maui, with over 2,200 structures destroyed and many fatalities. S&P noted that the severity of the fires showed that wildfire risk for the utilities was higher than previously expected, and that class action lawsuits related to the event would significantly increase uncertainty and financial risk going forward.

On August 24, S&P Global Ratings again downgraded HE to B- from BB- following the announcement that its dividend would be suspended beginning in Q3 as a result of the wildfires. Subsidiaries Hawaiian Electric, Maui Electric, and Hawaii Electric Light were also downgraded to B- from BB-. S&P cited growing concern about the company's access to capital markets due to class action lawsuits.

On November 8, S&P Global Ratings downgraded MDU Resources Group (MDU) to BBB from BBB+ after MDU completed a strategic review and announced the divestiture of its construction services business by year-end 2024. MDU completed a spinoff of its construction materials business, Knife River, in 2023. S&P said the November 8 downgrade reflected the fact that MDU Resources will no longer have the diversification benefit of multiple uncorrelated business lines.

On November 29, S&P Global Ratings downgraded Evergy (EVRG) to BBB+ from A-. Subsidiaries Evergy Kansas Central, Evergy Kansas South, and Evergy Missouri West were also downgraded to BBB+ from A-, while subsidiary Evergy Metro was downgraded to A- from A. S&P cited two recent rate review settlements in Kansas as the primary cause of the downgrades; these were the first rate review decisions in Kansas since the merger between Great Plains Energy and Westar Energy in 2018.

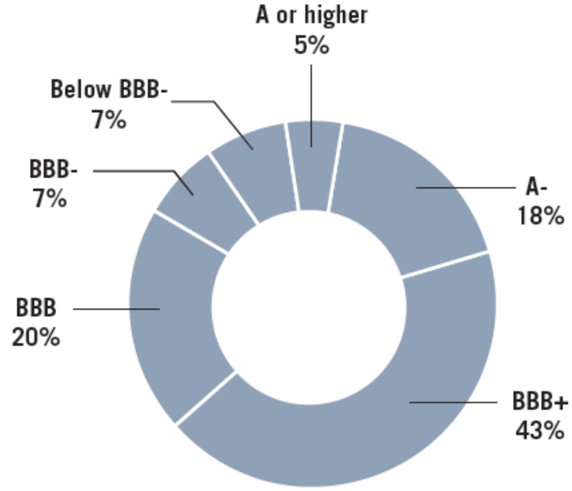
Ratings Activity Remained Slow in 2023

The 43 ratings actions during 2023 (upgrades and downgrades) was the second-lowest total for any year since our dataset's inception in 2000. By comparison, there were 35 actions in 2022, 52 actions in 2021, 59 actions in 2020, and an annual average of 68 over the last decade.

The industry's 16 upgrades in 2023 versus 27 downgrades produced an upgrade percentage of 37.2%, down from 71.4% in 2022 and 38.5% in 2021. Upgrades outnumbered down-

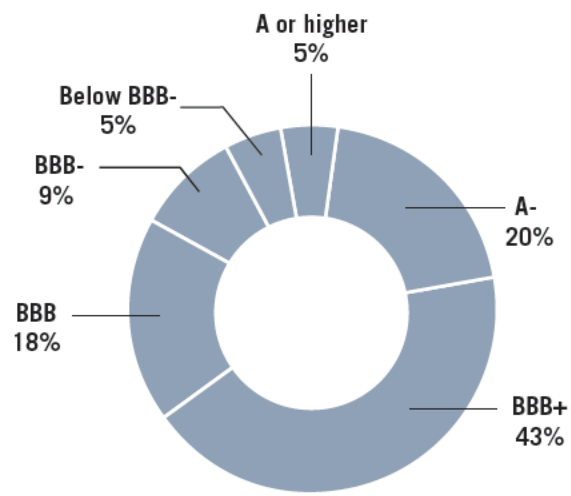
Bond Ratings December 31, 2023
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



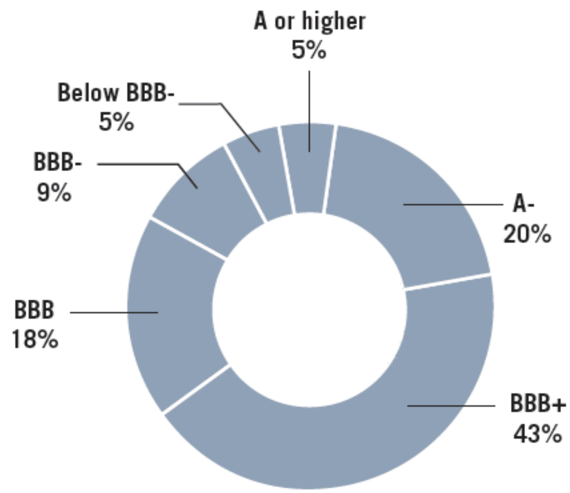
Bond Ratings December 31, 2022
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



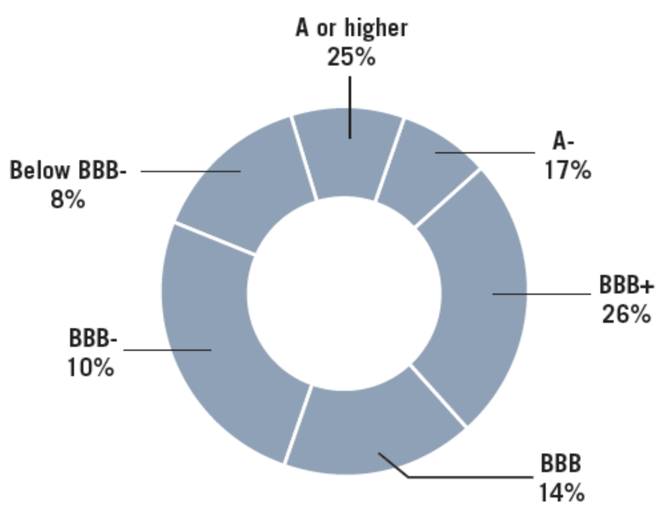
Bond Ratings December 31, 2021
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2001
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



grades in six of the past ten calendar years, with an annual average upgrade percentage of 59%.

The Credit Rating Agency Upgrades and Downgrades table presents quarterly activity by all three ratings agencies. Following are full-year totals for 2023:

Fitch (9 upgrades, 2 downgrades)

Moody's (5 upgrades, 6 downgrades)

Standard & Poor's (2 upgrades, 19 downgrades)

Upgrades in 2023

Many of the year's upgrades cited reduced financial uncertainty and reduced regulatory lag due to a more predictable regulatory framework. Other upgrades were driven by improved metrics related to wildfire risk in California, with a significant decline in the number of wildfires linked to utility equipment in the state.

On February 23, Moody's upgraded Edison International (EIX) to Baa2 from Baa3 and its Southern California Edison subsidiary to Baa1 from Baa2. Moody's noted the progress made by Southern California Edison to address wildfire risk, combined with its access to the state's wildfire fund and the legislative reform of the wildfire cost recovery process, has materially improved overall credit quality.

On March 20, Fitch upgraded PG&E (PCG) to BB+ from BB and upgraded subsidiary Pacific Gas & Electric to BB+ from BB. Fitch cited as primary catalyst for the upgrades the significant decline in the number

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fitch	14	11	16	15	33	36	24	6	22	11
Moody's	85	12	13	12	23	20	12	12	9	11
Standard & Poor's	7	27	38	25	37	34	23	34	4	21
Total	**106**	**50**	**67**	**52**	**93**	**90**	**59**	**52**	**35**	**43**

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

of wildfires involving PG&E equipment during 2019–2022 compared with 2017–2018, along with lower related liabilities. The upgrades were also driven by California's wildfire-related legislative reforms, by PG&E's ongoing management efforts to reduce wildfire risk, and by Fitch's expectation that credit metrics at the utilities will improve.

On April 28, Fitch upgraded Edison International (EIX) to BBB from BBB- and upgraded subsidiary Southern California Edison to BBB from BBB-. The upgrades mostly reflect the significant decline in wildfires linked to Southern California Edison's equipment after 2018 despite elevated wildfire activity in California in 2020 and 2021, as well as ongoing efforts to enhance system resilience. With the large majority of 2017/2018 wildfire liabilities resolved, Fitch also said it expects EIX's 2023-2026 credit metrics to improve significantly.

On July 24, S&P Global Ratings upgraded Xcel Energy subsidiary Northern States Power to A from A-. The move followed a final order by the Minnesota Public Utility Commission authorizing a $306 million aggregate rate increase for 2022-2024. S&P Global Ratings cited constructive regulation in Minnesota that includes a multi-year ratemaking framework for electric rates based on forecasted rate-base estimates. The agency noted this reduces regulatory lag, cash flow volatility and uncertainty for the utility and its stakeholders.

On July 26, S&P Global Ratings upgraded Exelon subsidiary Commonwealth Edison to A- from BBB+ due to an improved assessment of governance. The U.S. District Court for the Northern District of Illinois dismissed a bribery charge against the utility following completion of a three-year deferred prosecution agreement that required increased oversight and training related to internal controls.

On July 28, prior to the wildfires in Maui, Fitch upgraded Hawaiian Electric Industries (HE) to BBB+ from BBB and upgraded subsidiary Hawaiian Electric to A- from BBB+. Fitch cited a more predictable regulatory framework implemented in 2021 as the primary reason; regulatory adjustments have improved stability of earnings and cash flow and will moderate the impact of inflation. Fitch also expected Hawaiian Electric to narrow the gap between allowed and earned ROEs over the next few years.

On September 1, Fitch upgraded Southern Company subsidiary Georgia Power to BBB+ from BBB due to the successful start of commercial operation at Vogtle Unit 3. The nuclear unit was placed into service on July 31, 2023. The upgrade also reflects a constructive agreement with the Georgia Public Service Commission (PSC) and other intervenors that allows Georgia Power to recover $7.6 billion of capital costs and $1.0 billion of capitalized financing costs associated with construction of the two Vogtle nuclear units.

On September 22, Fitch upgraded utility parent company Otter Tail (OTTR) to BBB from BBB- and upgraded subsidiary Otter Tail Power to BBB+ from BBB. Fitch cited the predictable earnings and cash flow from the company's regulated operations and strong performance at its non-utility manufacturing and plastics business segments. Fitch expects the regulatory environment to remain supportive of credit quality across the company's three state jurisdictions (Minnesota, North Dakota and South Dakota).

On September 26, Moody's upgraded Southern Company subsidiary Mississippi Power to A3 from Baa1 based on an improved Mississippi regulatory environment. Moody's cited the consistency and predictability shown by the Mississippi PSC during the last few years as it approved rate orders in several Mississippi Power regulatory proceedings.

On November 20, Moody's upgraded Consolidated Edison (ED) to Baa1 from Baa2 and upgraded subsidiary Consolidated Edison (CECONY) to A3 from Baa1. Moody's noted better regulatory support as the primary reason, citing recent decisions by the New York PSC that resulted in revenue increases and improved financial metrics. Moody's stated that stakeholder relationships have improved since the last rate order in 2020, with increased political support, more predictable regulatory outcomes and better cost recovery.

Downgrades in 2023

Many of the year's downgrades were related to the Maui wildfires in August 2023. Additional downgrades were related to a terminated acquisition, increased wildfire risk in Oregon, and increased debt from capital investment.

On April 20, S&P Global Ratings downgraded AEP subsidiary Kentucky Power to BBB from BBB+ following cancellation of the planned sale of Kentucky Power to Liberty Utilities. The downgrade was driven by weakening stand-alone financial measures at Kentucky Power. In 2021 and 2022, Kentucky Power's FFO to debt was 11.6% and 11.4%, respectively, significantly below S&P's downgrade threshold of 15%.

On June 20, S&P Global Ratings downgraded Berkshire Hathaway Energy subsidiary PacifiCorp to BBB+ from A following a negative decision in a class action lawsuit related to four Oregon wildfires in 2020. In S&P's view, the verdict that the company contributed to the wildfires significantly increases operating risk for PacifiCorp. S&P also noted that the jury award on a per-plaintiff basis was materially above base-case assumptions. The jury also found that a broader absent class affected by the fires could bring more claims against the company.

On August 11, Moody's downgraded DPL to Ba2 from Ba1 and downgraded subsidiary Dayton Power & Light (DP&L) to Baa3 from Baa2. Moody's observed that the pace of DP&L's investments in transmission, distribution and smart-grid improvements is driving a significant increase in debt, which will more than double between 2021 and 2024. While DP&L's Energy Security Plan IV recently became effective in Ohio, allowing it to implement a delayed base-rate increase, Moody's noted DP&L's agreement to not pursue decoupling exposes its cash flow to more volatility.

On August 18, Moody's downgraded Hawaiian Electric Industries subsidiary Hawaiian Electric Company to Ba3 from Baa1 due to the Maui wildfires. Moody's expects significant financial liabilities if the utility is found to be at fault once investigations are complete. Moody's also noted the future regulatory risk related to cost recovery for system rebuilding.

On August 21, Fitch downgraded Hawaiian Electric Industries to B from BBB+ and downgraded subsidiary Hawaiian Electric to B from A-. Fitch also assigned first-time ratings of B to Hawaiian Electric Company's subsidiaries Maui Electric and Hawaii Electric Light. If investigations find that utility equipment caused the August wildfires and the utility is deemed by a court to be negligent, Fitch believes the companies may be subject to large third-party liabilities in a process that could take several years.

On October 27, Moody's downgraded Eversource Energy (ES) to Baa2 from Baa1 and downgraded subsidiary NSTAR Electric to A2 from A1. Moody's cited heightened uncertainty related to the company's pending offshore wind project sale and concerns that additional balance sheet actions would be needed to offset the challenges associated with the wind project transaction. Moody's also noted a challenging regulatory environment in Connecticut.

On November 20, S&P Global Ratings downgraded Berkshire Hathaway Energy (BHE) subsidiaries MidAmerican Energy, Nevada Power, and Sierra Pacific Power to A- from A. The downgrades were driven by an assessment that BHE will not provide extraordinary support to its subsidiaries under all foreseeable circumstances. S&P said it now ex-

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2019		2020		2021		2022		2023	
	#	%	#	%	#	%	#	%	#	%
Regulated										
A or higher	1	3%	1	3%	1	3%	1	3%	1	3%
A-	11	31%	11	32%	8	23%	8	22%	7	18%
BBB+	11	31%	10	29%	14	40%	15	42%	18	47%
BBB	8	23%	7	21%	7	20%	7	19%	7	18%
BBB-	2	6%	2	6%	3	9%	3	8%	3	8%
Below BBB-	2	6%	3	9%	2	6%	2	6%	2	5%
Total	35	100%	34	100%	35	100%	36	100%	38	100%
Mostly Regulated										
A or higher	1	10%	1	10%	1	11%	1	13%	1	17%
A-	1	10%	1	10%	1	11%	1	13%	1	17%
BBB+	7	70%	6	60%	5	56%	4	50%	1	17%
BBB	0	0%	1	10%	1	11%	1	13%	2	33%
BBB-	1	10%	1	10%	1	11%	1	13%	0	0%
Below BBB-	0	0%	0	0%	0	0%	0	0%	1	17%
Total	10	100%	10	100%	9	100%	8	100%	6	100%

Note: Totals may not equal 100.0% due to rounding.
Refer to page v for category descriptions.
Source: Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

pects BHE's extraordinary support for subsidiary PacifiCorp would be limited should PacifiCorp receive further adverse outcomes in a class action lawsuit related to wildfires.

On December 11, Moody's downgraded Alliant Energy subsidiary Wisconsin Power and Light to Baa1 from A3. Moody's stated that WPL's financial metrics have been weak since 2018 largely due to a three-year base rate freeze associated with the 2017 Tax Cuts and Jobs Act and the coronavirus pandemic, additional debt issuance to help finance higher capital expenditures, and under-recovered fuel costs.

Ratings by Company Category

The S&P Utility Credit Ratings Distribution by Company Category table presents the distribution of credit ratings over time by company category (Regulated and Mostly Regulated) for the investor-owned electric utilities. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. On December 31, 2023, the average rating for the Regulated category was BBB+ and the average rating for the Mostly Regulated category was BBB.

Rating Agency Credit Outlooks

The three major ratings agencies held divergent utility industry credit outlooks as 2024 began. S&P maintained a stable outlook for regulated utilities. Moody's maintained the stable outlook for regulated utilities that it had revised from negative in late 2023. Fitch retained its deteriorating outlook for North American utilities. The agencies cited increased physical risks to utility infrastructure, elevated capital expenditures and related customer bill impacts, and stability of financial metrics as key themes they are watching. We note that the groups of underlying companies vary slightly across the three rating agency outlooks.

Standard & Poor's (S&P)

Published in January 2024, S&P's report "Industry Credit Outlook 2024—North America Regulated

Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Moody's	Standard & Poor's	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-

	Moody's	Standard & Poor's	Fitch
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C

	Moody's	Standard & Poor's	Fitch
Default	C	D	D

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Utilities" maintained the agency's stable industry outlook. However, the report observed that downgrades outpaced upgrades for the fourth consecutive year in 2023. And, given that 28% of the industry has a negative outlook versus 14% with a positive outlook, the agency said it's possible that downgrades may outpace upgrades once again in 2024.

S&P's base case assumes that industry credit quality will remain challenged in 2024. For many utilities, the physical risk to system infrastructure is growing as climate change increases the frequency of extreme weather events such as wildfires. S&P cited industry initiatives that are addressing wildfire risk, including detailed wildfire mitigation plans, system hardening, improved weather forecasting using machine learning, implementation of public safety power shutoffs (PSPS) programs, and vegetation management. S&P also noted that, while the industry's robust capital spending represents necessary investment in safety, reliability, and the nation's energy transition, it is also leading to rising leverage. Consistent access to the capital markets will be necessary for the industry to fund its debt maturities and cash flow deficits.

S&P noted that effective management of regulatory risk will be key to maintaining the industry's credit quality going forward. This will require constructive rate case orders, minimized regulatory lag, and management of customer bill impacts. Timely recovery of capital expenditures and operation and maintenance costs will also be necessary for the industry to maintain credit quality.

Moody's

In its "Outlook—Regulated Electric and Gas Utilities—US" (published in September 2023), Moody's revised its outlook for the sector to stable from negative. Moody's noted that sustained lower natural gas prices, moderating inflation, and continued regulatory support for the recovery of fuel and purchased power costs will improve credit metrics for the industry. The significant decline in natural gas prices since mid-2022 has provided relief to utilities and has eased both affordability pressures and regulatory risk.

The report also stated that interest rates and capital spending will continue to pressure holding company credit metrics. Although the pace and magnitude of interest rate increases have slowed, increased debt and debt refinancing costs will pressure parent company metrics. Moody's expects utilities to maintain high levels of capital spending as they focus on reducing carbon emissions and investing in system resilience and reliability. Moody's noted that, despite many challenges, aggregate sector FFO metrics have been remarkably steady and are likely to remain so. The sector's aggregate industry funds from operations (FFO) to debt ratio will likely stabilize at 14% in 2024, according to the report.

Moody's listed several factors that could change its outlook back to negative: 1) if there is a sustained decline in regulatory support for timely cost recovery, 2) if capital market access becomes less certain or the availability of bank credit facilities becomes constrained, or 3) if the sector's aggregate FFO-to-debt ratio dips materially below 14%. Factors that could change its outlook to positive were: 1) if the regulatory and political environment turns even more credit supportive, and 2) if the sector's aggregate FFO-to-debt ratio rises to around 18% on a sustainable basis.

Fitch Ratings

In its "North American Utilities, Power & Gas Outlook 2024" (released December 2023), Fitch Ratings maintained its deteriorating outlook for the sector. Fitch stated that macroeconomic headwinds, elevated capital expenditures, and higher funding costs will continue to pressure utility credit metrics. Fitch noted that customer affordability concerns will persist despite reductions in natural gas prices and inflation. However, with 90% of companies at a stable ratings outlook, Fitch expects little ratings movement in 2024. Fitch expects median leverage metrics for the sector to improve in 2024, driven by the recovery of deferred fuel balances.

Fitch also cited the catastrophic wildfires in Maui to highlight the heightened physical risks faced by electric utilities as a result of climate change. The agency explained that California provides a roadmap for other states to follow regarding the development of comprehensive plans to prevent, mitigate and respond to wildfires. Some other states have begun to address this issue, and Fitch believes that progress on these initiatives could improve utility credit risk.

The report also noted positive tailwinds for the industry. Several electric utilities have begun to see sales growth from data centers, expansion of manufacturing facilities, and electrification trends in oil and gas drilling. Fitch expects weather-normalized total retail sales to be 0.5%–1.0% higher in 2024 compared with 2023. Fitch also expects authorized ROEs to start trending up with the increase in interest rates, although with a lag that could be longer than in previous cycles. Fitch stated that the gap between authorized and earned ROEs continues to narrow. Fitch also views the Inflation Reduction Act as a positive for credit quality since its tax incentives for clean generation will help offset inflationary bill pressures.

Business Strategies

Business Segmentation

The industry's regulated business segments—regulated electric and natural gas distribution—grew their combined assets by $81.3 billion, or 4.6%, in 2023, extending a multi-year trend and driving a $95.7 billion, or 4.7%, increase in total industry assets. Regulated assets were 84.9% of the industry total at year-end, unchanged from the same 84.9% total at year-end 2022. The Regulated Electric segment's share of total industry assets increased to 71.9% from 70.9% at year-end 2022; that segment's total assets grew $91.4 billion, or 6.2%. Natural Gas Distribution assets decreased by $10.2 billion, or 3.5%, and Competitive Energy assets increased $6.5 billion, or 4.0%. Assets for the relatively small Natural Gas Pipeline segment decreased by $182 million, or 0.5%. A record-high $171.9 billion of capital expenditures in 2023 and generally constructive regulatory relations supported the significant growth in Regulated assets.

Nationwide power demand in 2023 declined 1.6% from 2022's total due to mild weather, and natural gas prices fell sharply from 2022's elevated levels. As a result, the Regulated Electric business segment's revenue increased by only $1.3 billion, or 0.4%. Natural Gas Distribution revenue decreased $5.9 billion, or 8.7%. Competitive Energy revenue decreased $2.0 billion, or 6.1%. Natural Gas Pipeline revenue decreased by $1.7 billion, or 26.8%. Total industry revenue was $415.5 billion in 2023, a decline of $8.9 billion, or 2.1%, versus 2022's $424.4 billion.

2023 Revenue by Segment

Regulated Electric revenue increased by $1.3 billion, or 0.4%, to $311.1 billion from $309.7 billion in 2022. The segment's share of total industry revenue rose to 73.1% from 71.3% in 2022, remaining well above its level at the start of the industry's

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2023	2022	$ Change	% Change
Regulated Electric	311,077	309,739	1,337	0.4%
Competitive Energy	30,498	32,480	(1,982)	(6.1%)
Natural Gas Distribution	61,542	67,426	(5,884)	(8.7%)
Natural Gas Pipeline	4,772	6,518	(1,745)	(26.8%)
Other	17,439	18,128	(689)	(3.8%)
Discontinued Operations	111	0	111	0.0%
Eliminations/Reconciling Items	(9,943)	(9,863)	(80)	0.8%
Total Revenues	**415,495**	**424,428**	**(8,933)**	**(2.1%)**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/23	12/31/22	$ Change	% Change
Regulated Electric	1,567,683	1,476,245	91,438	6.2%
Competitive Energy	167,982	161,501	6,481	4.0%
Natural Gas Distribution	281,268	291,443	(10,175)	(3.5%)
Natural Gas Pipeline	35,191	35,373	(182)	(0.5%)
Other	126,905	117,516	9,389	8.0%
Eliminations/Reconciling Items	(64,516)	(63,257)	(1,259)	2.0%
Total Assets	**2,114,512**	**2,018,820**	**95,691**	**4.7%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

two-decade-long migration back to a regulated focus (Regulated Electric's share was only 51.9% in 2005).

Natural Gas Distribution revenue fell $5.9 billion, or 8.7%, to $61.5 billion from $67.4 billion in 2022. Volatile natural gas prices drove revenue gains of 26.1% in 2022 and 18.0% in 2021 for this segment, a decrease of 3.3% in 2020, and increases of 4.4% in 2019, 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016. Revenue growth in 2016 and 2017 was also due to completion in 2016 of four large acquisitions of natural gas distribution businesses.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — decreased by $4.5 billion, or 1.2%, to $372.6 billion in 2023. The industry's focus on state-regulated operations has driven a steady growth in these business segments' share of industry revenue in recent years. Regulated revenue accounted for 87.6% of total industry revenue in 2023 compared to 86.8% in 2022, totals well above 2005's 65.3% share.

Eliminations and reconciling items are added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2023 and Revenue Breakdown 2022*.

2023 Assets by Segment

Regulated Electric assets increased $91.4 billion, or 6.2%, during 2023. The segment's share of total industry assets was 71.9% at year-end, above its 70.9% share at year-end 2022. Natural Gas Distribution assets decreased by $10.1 billion, or 3.5%, while Competitive Energy assets increased by $6.5 billion, or 4.0%. The Natural Gas Pipeline segment's relatively small asset total declined slightly, falling by $182 million, or 0.5%, to $35.2 billion at year-end 2023 and representing 1.6% of industry assets.

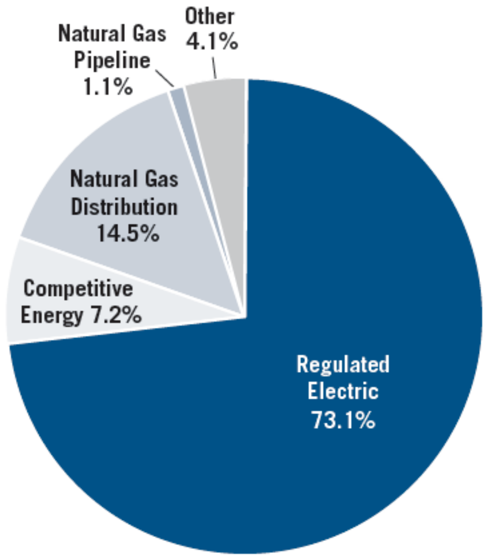
Total regulated assets (Regulated Electric and Natural Gas Distribution) grew $81.3 billion, or 4.6% in 2023 for a 84.9% share of total industry assets at year-end; this is identical to the 84.9% share at year-end 2022. This aggregate share measure has risen steadily from 61.6% at year-end 2002, underscoring the significant regulated rate base growth and widespread divestitures of non-core businesses over that 21-year period. Twenty-seven of the industry's 44 constituent companies (61%) either increased regulated assets as a percent of total assets or maintained a 100% regulated structure in 2023.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of

Revenue Breakdown 2023

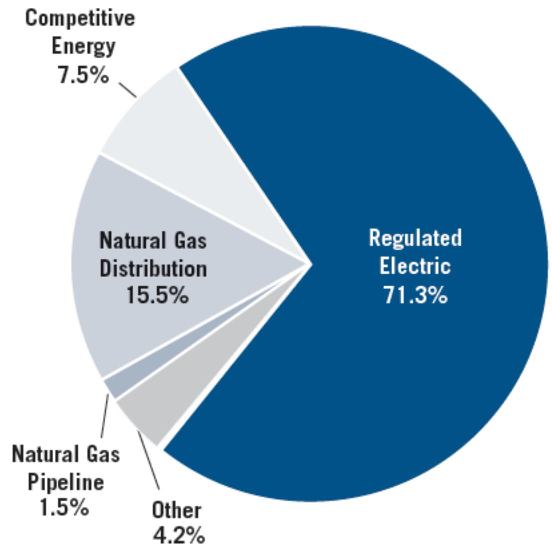
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2022

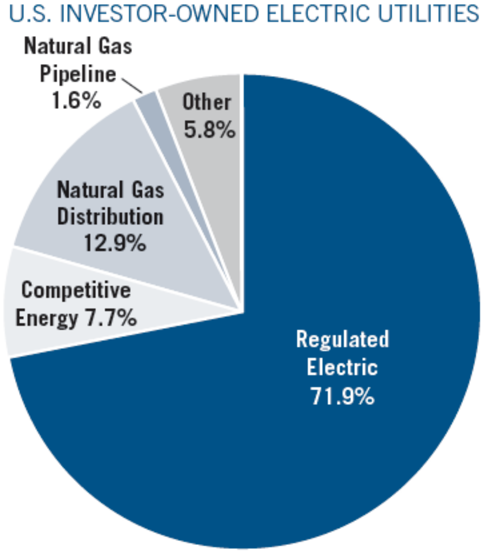
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown As of December 31, 2023

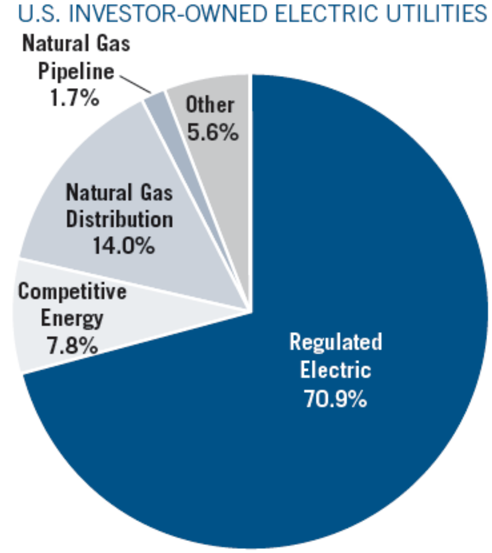
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown As of December 31, 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

electricity under state regulation for residential, commercial and industrial customers. Regulated Electric revenue increased slightly in 2023, rising $1.3 billion, or 0.4%. Twenty-one companies, or 48% of the industry, had higher Regulated Electric revenue in 2023 than in the prior year. Regulated Electric revenue increased by 14.1% in 2022 and 8.0% in 2021, fell by 0.8% in 2020 and by 0.5% in 2019, was unchanged in 2018, and grew by 0.8% in 2017.

Total nationwide electric output decreased 1.6% in 2023 after rising 2.8% in 2022 and in 2021. On a weather-adjusted basis, electric output rose 1.4% in 2023. Electric output has risen in only eight of the past sixteen years. Prior to this period, a year-to-year output decline was a rare event in an industry that typically experienced low single-digit percent demand growth. Energy efficiency initiatives, demand-side management programs, and the off-shoring of formerly U.S.-based manufacturing and heavy industry are all forces that have suppressed the growth of electricity demand since the late 20th century.

Regulated Electric assets increased by $91.4 billion, or 6.2%, in 2023, representing the largest asset growth in dollar terms of all business segments. The industry's record-high $171.9 billion of capital expenditures in 2023 and generally constructive regulatory relations supported the increase in regulated assets. The 2023 capital expenditure total was the twelfth consecutive annual record high, with the expansion well represented across the industry's Regulated Electric and Natural Gas Distribution segments over this period. Asset growth is also evident in the industry's net property, plant, and equipment in service, which rose 6.4% from year-end 2022 and 21.6% over the level five years earlier, at year-end 2018. Such robust growth in assets reflects the size of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure, and other capital projects in recent years.

Competitive Energy

Competitive Energy assets increased by $6.5 billion, or 4.0%, to $168.0 billion at year-end 2023 from $161.5 billion at year-end 2022. Competitive Energy assets fell $47.4 billion, or 22.7%, in 2022 relative to 2021 due to the spin-off of Constellation Energy, Exelon's power generation and competitive energy business, in February 2022. Competitive Energy revenue decreased by $2.0 billion, or 6.1%, to $30.5 billion from $32.5 billion in 2022. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically regional power pools, large industrial customers, and electric utilities looking to supplement generation capacity. Competitive Energy also includes the trading and marketing of natural gas. Of the 16 companies that maintain Competitive Energy operations, seven (44%) grew these assets during 2023 and six (38%) had revenue gains from this segment.

Natural Gas

Natural Gas Distribution assets decreased by $10.2 billion, or 3.5%, to $281.3 billion at year-end 2023 from $291.4 billion at year-end 2022. The segment's revenue decreased by $5.9 billion, or 8.7%, to $61.5 billion from $67.4 billion in 2022 as natural gas prices declined from elevated 2022 levels. Revenue grew 26.1% in 2022 and 18.0% in 2021, as natural gas prices surged. Only eight of the 27 companies that report gas distribution revenue showed a year-to-year increase in 2023 after all companies did in both 2022 and 2021. This followed increases at 26%, 70%, 86% and 93% of reporting companies in 2020, 2019, 2018 and 2017, respectfully. Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States.

Natural Gas Pipeline assets decreased by $182 million, or 0.5%, to $35.2 billion at year-end 2023 from $35.4 billion at year-end 2022. Three of the six companies that report this segment showed asset growth. This segment's revenue decreased by $1.7 billion, or 26.8%, to $4.8 billion in 2023 from $6.5 billion in 2022, which was somewhat impacted by lower natural gas prices. The Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers.

Added together, the Natural Gas Distribution and Natural Gas Pipeline segments decreased assets by $10.4 billion, or 3.2%, in 2023 and produced revenue of $66.3 billion, down from $73.9 billion in 2022. The contribution to total industry revenue from these two natural gas activities decreased to 15.6% in 2023 from 17.0% in 2022.

Strategic Moves Completed in 2023

Several companies completed strategic transactions in 2023 that notably affected their business segmentation reporting.

- Dominion Energy sold its remaining 50% stake in the Cove Point LNG facility to Berkshire Hathaway Energy for $3.3 billion. As a result, Berkshire Hathaway Energy increased its stake in the terminal operator to 75%, with the remaining 25% held by a subsidiary of Brookfield Infrastructure Partners.
- Con Edison completed the divestiture of its renewables business to RWE Renewables Americas for $6.8 billion. Con Edison said it will focus on its core utility business and the investments needed to lead New York's clean energy transition.
- NextEra Energy finalized the sale of its Texas Natural Gas Pipeline portfolio to Kinder Morgan for $1.8 billion.

Strategic Announcements in 2023

In addition to 2023's completed transactions, several announcements were made that, if completed, will impact business segment reporting in 2024 and beyond.

- Dominion intends to sell three gas utilities to Enbridge for $14.0 billion; these include East Ohio Gas, Public Service Company of North Carolina, and Questar Gas (which distributes gas in Utah, Wyoming, and Idaho). Dominion said it would use after-tax proceeds of $8.7 billion to reduce parent-company debt.
- Cleco announced the intent to sell its competitive electric business, Cleco Cajun, to private investor group Atlas Capital Resources for $600 million. Cleco expects to complete the transaction in June 2024.
- FirstEnergy announced an additional 30% divestiture of its transmission business, FirstEnergy Transmission, to Brookfield Partners for $3.5 billion. In 2022, FirstEnergy sold a 19.9% stake to Brookfield for $2.4 billion.

2023 Year-End List of Companies by Category

Early each calendar year, EEI updates our list of investor-owned electric utility holding companies organized by business category. The list is based on the prior year-end business segmentation data presented in 10Ks. Our two categories are Regulated (80% or more of holding company assets are regulated) and Mostly Regulated (less than 80% of holding company assets are regulated).

We use assets rather than revenue for determining category membership because we believe assets provide a clearer picture of strategic trends; fluctuating commodity prices for natural gas and power can impact revenue so greatly that a company's strategic approach to business segmentation may be distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and shows the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

There was only one company that migrated across categories in 2023; Otter Tail Corporation moved to the Mostly Regulated category. The company began the year just above the 80% threshold and fell just below this percentage by year-end. Otter Tail is split between its larger regulated Electric segment and its unregulated Manufacturing segment, which includes a metal fabrication company, a custom plastics parts manufacturer, and two PVC pipe manufacturing companies.

The number of parent companies in the EEI universe remained at 44, the same as the year-end 2022 total. (See List of Companies by Category on December 31, 2023).

List of Companies by Category at December 31, 2023

Regulated (37)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
CenterPoint Energy, Inc.
*Cleco Corporate Holdings LLC**
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
*DPL Inc.**
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
IDACORP, Inc.
*IPALCO Enterprises, Inc.**
NiSource Inc.
NorthWestern Energy
MGE Energy, Inc.
OGE Energy Corp.
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
*Puget Energy, Inc.**
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Mostly Regulated (7)

ALLETE, Inc.
AVANGRID, Inc.
*Berkshire Hathaway Energy**
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.
Otter Tail Corporation

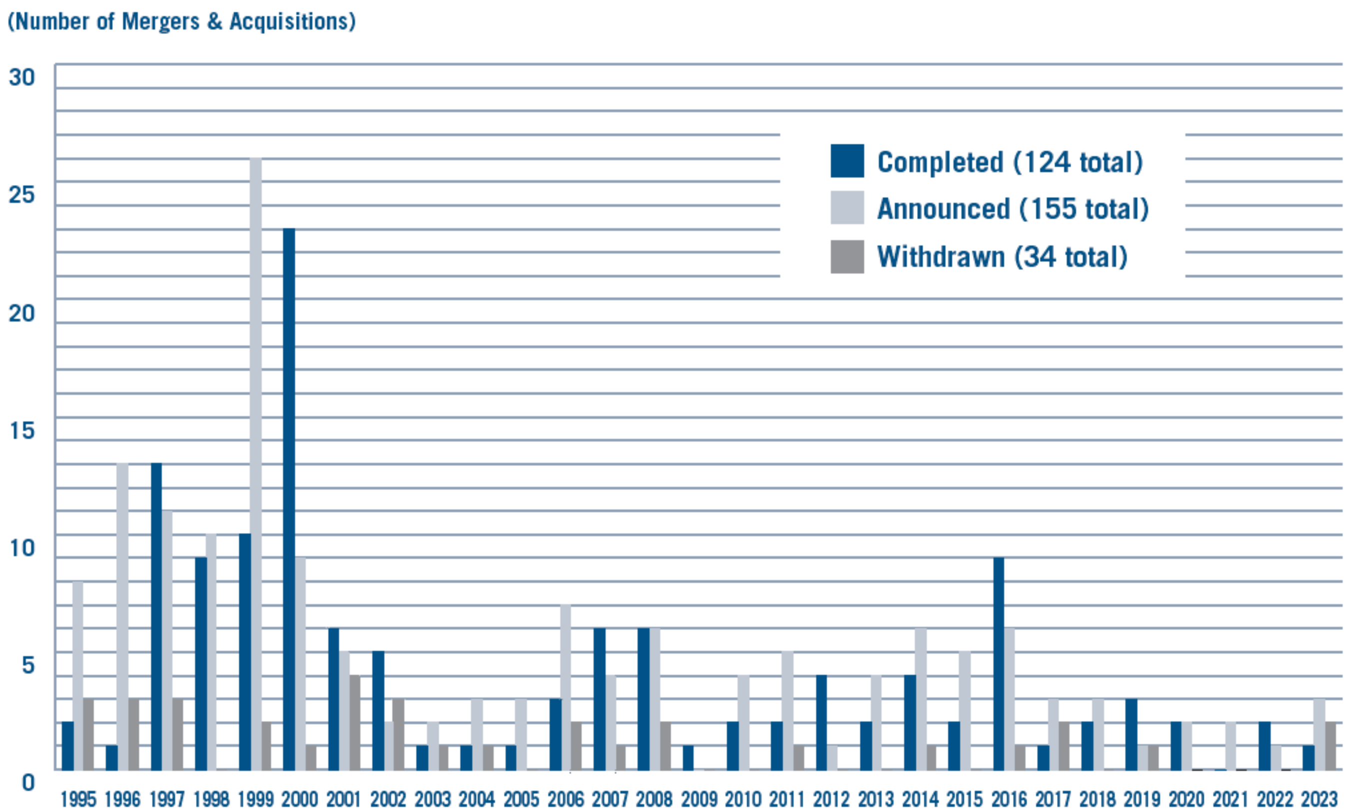
Note:* Non-publicly traded companies.

Mergers & Acquisitions

Utility merger and acquisition (M&A) activity involving whole operating companies with regulated service territories remained slow in 2023. The year's three new announcements were Dominion's move to sell its natural gas distribution utilities to diversified energy company Enbridge, NextEra's sale of Florida City Gas to Chesapeake Utilities, and Entergy's announced sale of its Louisiana natural gas distribution business to a Baton Rouge-based private equity firm. The number of utilities tracked by EEI remained at 39 for the fourth straight year. By contrast, consolidation from the mid-1990s through 2019 reduced the number of holding companies by more than half, from 98 to 40. The reduced number of holding companies alone constrains the opportunity set for new M&A. But industry fundamentals do as well. Most utilities are focused on ambitious investment programs that seek internal growth through expansion of regulated electric rate base focused on clean energy infrastructure. And the Inflation Reduction Act (IRA), passed in August 2022, provides a strong public policy tailwind for clean energy investment, already incentivized by state renewable portfolio standards, carbon mitigation programs and support from state regulators and the public. Most of the now-smaller group of utilities don't see M&A as a priority, particularly given the well-known challenges steering deals through a complex state and federal regulatory approval process. These challenges were clear in the termination of the two deals pending when 2023 began: AVANGRID cancelled its bid to buy New Mexico-based PNM Resources while AEP and Canadian utility

Status of Mergers & Acquisitions 1995–2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

Algonquin ended their plan to shift ownership of AEP's Kentucky operations to the Canadian utility.

Strategic activity in 2023 focused again on asset sales rather than M&A. The last few years have been active on this front as companies look to simplify corporate structures — generally around regulated utility operations — and reduce risk through the exit of merchant generation and other non-core businesses. Sale proceeds have strengthened balance sheets and reduced the need for external equity, which has become more expensive given the industry's discounted share prices in a world of higher interest rates. Private equity buyers continued to step up in 2023 as a natural home for the merchant renewable generation portfolios regulated utilities sought to sell, and as minority stake venture partners with utilities engaged in aggressive clean power capex programs.

Status of Mergers & Acquisitions 1995–2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1995	2	8	3
1996	1	13	3
1997	13	11	3
1998	9	10	–
1999	10	26	2
2000	23	9	1
2001	6	5	4
2002	5	2	3
2003	1	2	1
2004	1	3	1
2005	1	3	–
2006	3	7	2
2007	6	4	1
2008	6	6	2
2009	1	–	–
2010	2	4	–
2011	2	5	1
2012	4	1	–
2013	2	4	–
2014	4	6	1
2015	2	5	–
2016	9	6	1
2017	1	3	2
2018	2	3	–
2019	3	1	1
2020	2	2	–
2021	–	2	–
2022	2	1	–
2023	1	3	2
Totals	**124**	**155**	**34**

Source: EEI Finance Department.

Announced Transactions

Dominion Energy to Sell Natural Gas Businesses

On September 5, 2023, Virginia-based Dominion Energy said it agreed to sell its three natural gas local distribution companies (LDCs) to Canadian diversified energy company Enbridge for $9.4 billion cash plus debt in a transaction valued at $14 billion. The three LDCs — East Ohio Gas, Public Service Company of North Carolina, and Questar Gas (with subsidiary Wexpro) — serve three million homes and businesses in Ohio, North Carolina, Utah, Wyoming, and Idaho. Dominion noted the move came from its internal strategic review process, announced in November 2022, which looks to better position the utility to create maximum long-term value for shareholders. Dominion said sale proceeds will be used to reduce debt and strengthen its credit position. The utility is focusing its growth strategy on state-regulated electric infrastructure, noting that data center expansion, bolstered by artificial intelligence (AI), along with electrification and general economic activity in its service territories are driving the most significant electric demand growth in the company's history. It said this demand growth will require considerable regulated capital investment to ensure reliable energy for its nearly 3.5 million electric utility customers.

NextEra Energy Sells Florida City Gas

NextEra Energy on September 26, 2023 said its regulated utility subsidiary Florida Power & Light (FPL) would sell FPL's gas distribution subsidiary Florida City Gas (FCG) to Chesapeake Utilities in a transaction valued at $923 million, including $145 million of intercompany debt. NextEra, as the nation's largest utility focused on development of renewable energy infrastructure, noted the transaction supports its strategy of redeploying capital into its core renewables businesses. Chesapeake Utilities, conversely, is a diversified energy company with a commitment to natural gas transmission and distribution. Chesapeake said FCG, which serves about 120,000 residential and commercial natural gas customers, would expand its footprint in the high-growth Florida market. Chesapeake noted Florida offers considerable investment opportunities for natural gas pipeline replacement, expansions to support customer growth, and increased gas transmission capabilities to reach new developments and support increased demand. The transaction was completed on December 1.

Entergy to Sell Gas Distribution Business

On October 30, 2023, Entergy said it agreed to sell its gas distribution business to Bernhard Capital Partners, an infrastructure-focused private equity management firm, for approximately $484 million in cash. Entergy Louisiana's gas business serves about 200,000 homes and businesses in the Baton Rouge and New Orleans regions. Entergy said net proceeds from the transaction, if it's approved, will be used to strengthen Entergy's credit through the repayment of debt and to support investment needs in its growing electric utility business.

Withdrawn Transactions

AEP/Algonquin Cancel Plan to Sell Kentucky Power

On April 17, 2023, AEP and Algonquin Power & Utilities jointly agreed to end plans to sell AEP's Kentucky operations to Liberty Utilities, a subsidiary of the Canadian utility holding company. Announced in April 2021, the planned sale came after AEP said it would conduct a strategic review of its Kentucky operations. AEP said it planned to use the expected $1.45 billion cash proceeds to eliminate equity needs and boost investment in regulated renewable energy infrastructure. The deal ran into resistance from the Federal Energy Regulatory Commission (FERC), which rejected the merger in late 2022. The deal also faced resistance from Kentucky state regulators. AEP said it would pursue a renewed strategy for Kentucky that is consistent with the goals of the Kentucky commission, including filing a new base rate review, right-sizing Kentucky's rate base and encouraging economic development in the region.

Avangrid Terminates Plan to Acquire PNM Resources

While not technically a 2023 termination, on January 2, 2024, AVANGRID said it would end its three-year-long effort to buy New Mexico-based PNM Resources. When announced, AVANGRID said the transaction would support its U.S. growth strategy focused on regulated businesses and renewables. PNM, which operates regulated utilities in Texas and New Mexico, called the move a strategic fit that would help the utility invest in clean energy distribution and transmission and expand its position in renewables. Despite widespread stakeholder support and approvals by PNM shareholders, Texas regulators and the FERC, the New Mexico Public Regulation Commission rejected the merger on December 8, 2021. The deal remained in limbo throughout 2022 after media reports said PNM and AVANGRID had appealed the rejection to the New Mexico Supreme Court. In early 2023, news reports said the New Mexico Public Regulation Commission had joined PNM and AVANGRID in requesting the Supreme Court to send the case back to the commission for a "rehearing and reconsideration" following a move by the state's governor to replace the previous five-member commission with a new three-member body. The companies' merger agreement was extended through December 31, 2023, while awaiting a decision from the New Mexico Supreme Court.

Utilities Exit Commercial Renewable Generation

Con Edison completed the sale of its commercial renewables business on March 1, 2023. In October 2022, Con Edison announced it would sell its wholly owned commercial renewables subsidiary, Con

Edison Clean Energy Businesses, to RWE Renewables Americas for $6.8 billion. RWE Renewables Americas is owned by German multinational energy giant RWE AG. Con Edison said it would cancel plans to issue up to $850 million of common equity in 2022 and focus on its core utility businesses and the investments needed to lead New York's ambitious clean energy transition.

On June 12, 2023, Duke Energy announced it would sell its unregulated utility scale commercial renewables business to Brookfield Renewable, one of the world's largest owners and operators of renewable power assets, for an enterprise value of approximately $2.8 billion, including non-controlling tax equity interests and the assumption of debt. Duke Energy said it would use the net proceeds to strengthen its balance sheet and avoid more holding company debt issuance. It said this will allow it to focus on investment opportunities in its regulated businesses, including grid reliability and integration of 30,000 megawatts of regulated renewable energy into its system by 2035. Duke said the sale's completion on October 25 marked the last step in its transition to a fully regulated utility.

On February 22, 2023, American Electric Power said it agreed to sell its 1,365-megawatt (MW) unregulated, contracted renewables portfolio to IRG Acquisition Holdings (a partnership owned by Invenergy, CDPQ and funds managed by Blackstone Infrastructure) for an enterprise value of $1.5 billion including project debt. AEP said it was committed to

Merger Impacts 1995–2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	–
12/31/96	98	–
12/31/97	91	(7.14%)
12/31/98	86	(5.49%)
12/31/99	83	(8.79%)
12/31/00	71	(14.46%)
12/31/01	69	(2.82%)
12/31/02	65	(5.80%)
12/31/03	65	–
12/31/04	65	–
12/31/05	65	–
12/31/06	64	(1.54%)
12/31/07	61	(4.69%)
12/31/08	59	(3.28%)
12/31/09	58	(1.69%)
12/31/10	56	(3.45%)
12/31/11	55	(1.79%)
12/31/12	51	(7.27%)
12/31/13	49	(3.92%)
12/31/14	48	(2.04%)
12/31/15	47	(2.08%)
12/31/16	44	(6.38%)
12/31/17	43	(2.27%)
12/31/18	42	(2.33%)
12/31/19	40	(4.76%)
12/31/20	39	(2.50%)
12/31/21	39	–
12/31/22	39	–
12/31/23	39	–

Number of Companies Declined by 60% since Dec.'95

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department.

Mergers & Acquisitions Announcements (2000–2023)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Completed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
10/30/23	Bernhard Capital Partners	Entergy Louisiana (Gas) / Entergy New Orleans (Gas)	Pending				PG	$484 million in cash to acquire two gas distribution companies from Entergy	484.0
9/26/23	Chesapeake Utilities	Florida City Gas	Completed		12/1/23	3	GG	$923 million in cash to acquire Florida City Gas from NextEra Energy	923.0
9/5/23	Enbridge	East Ohio Gas / PSNC Gas / Questar Gas	Pending				GG	$9.4 billion cash + $4.6 billion debt to acquire three gas distribution companies from Dominion Energy	14,000.0
2/11/22	Ullico Inc.	Hope Gas, Inc.	Completed		8/31/22	6	EG	Ullico Inc. paid $690 million in cash to acquire Hope Gas Inc. (parent company Dominion Energy)	690.0
10/26/21	Algonquin Power & Utilities Corp	Kentucky Power Company & AEP Kentucky Transmission Company Inc	Withdrawn		4/17/23		EE	$1.221 billion debt + $1.625 billion cash (valuation multiple of 1.3x rate base)	2,846.0
3/18/21	PPL Energy Holdings, LLC	Narragansett Electric Company	Completed		5/25/22	14	EG	$1.5 billion debt + 3.8 billion cash (valuation multiple of 1.7x rate base)	5,270.0
10/21/20	AVANGRID	PNM Resources	Withdrawn		12/31/23		EE	AGR to pay $50.30/share in cash (roughly 10% premium) for PNM common stock	4,300.0
7/5/20	Berkshire Hathaway Energy	Dominion Energy Natural Gas Transportation and Storage	Completed		11/1/20	4	EG	$5.7 billion debt + $4.0 billion cash	9,700.0
6/3/19	JP Morgan Investment Management	El Paso Electric	Completed		7/29/20	13	EE	JPMorgan pays $68.25/share in cash for each share of El Paso Electric Co. common stock	4,285.7
5/21/18	NextEra Energy, Inc.	Gulf Power Company	Completed		1/1/19	7	EE	NEE to pay $4.35 billion in cash to acquire Gulf Power Company from Southern Company	4,350.0
4/23/18	CenterPoint Energy	Vectren Corporation	Completed		2/1/19	10	EG	CNP pays $72.00/share in cash for each share of Vectren common stock	6,000.0
1/3/18	Dominion Energy, Inc.	SCANA Corporation	Completed		1/1/19	12	EE	$6.7B debt + $7.9 stock (per share value of $55.35, roughly 31% premium)	14,600.0
8/21/17	Sempra Energy	Oncor Electric Delivery Co	Completed		3/8/18	6	EE	$9.5B cash	9,450.0
7/19/17	Hydro One Limited	Avista Corporation	Withdrawn		1/23/19			$5.3B cash (per share value of $53.00, roughly 24% premium)	5,300.0
7/7/17	Berkshire Hathaway Inc.	Oncor Electric Delivery Co	Withdrawn		8/21/17			$9.0B cash	9,000.0
9/28/16	DTE Energy	Appalachia Gathering System / Stonewall Gas Gathering	Completed		10/20/16	1	EG	Undisclosed	1,300.0
7/29/16	NextEra Energy, Inc.	Oncor Electric Delivery Co	Withdrawn		10/31/17			$6.8B debt + $4.4B cash	11,178.0
5/31/16	Great Plains Energy	Westar Resources	Completed	Evergy, Inc.	6/5/18	24	EE	$3.6B debt + $8.6 stock and cash (per share value of $60.00)	12,200.0
2/9/16	Fortis Inc.	ITC Holdings Corp.	Completed		10/14/16	8	EE	$4.4B debt + $6.9B common shares and cash (per share value of $44.90, roughly 33% premium)	11,300.0
2/9/16	Algonquin Power & Utilities	Empire District Electric Co	Completed		1/1/17	11	EE	$1.6B debt + additional debt and equity (per share value of $34.00, roughly 21% premium)	2,400.0
2/1/16	Dominion Resources, Inc.	Questar Corporation	Completed		9/16/16	8	EG	$1.5B debt + $2.4B cash + $500M equity (per share value of $25.00, roughly 30% premium)	4,400.0
10/26/15	Duke Energy	Piedmont Natural Gas	Completed		10/3/16	12	EG	$3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium)	4,900.0
9/4/15	Emera	TECO Energy, Inc.	Completed		7/1/16	10	EE	$6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium)	10,400.0
8/24/15	Southern Company	AGL Resources	Completed		7/1/16	10	EG	$4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium)	12,060.4
7/12/15	Black Hills Corporation	SourceGas Holdings	Completed		2/12/16	10	GG	$760M debt + $1.13B cash	1,890.0
2/25/15	Iberdrola USA	UIL Holdings	Completed	AVANGRID, Inc.	12/16/15	10	EE	$1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash)	4,756.0
12/3/14	NextEra Energy, Inc.	Hawaiian Electric	Withdrawn		7/18/16		EE	NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares)	3,963.0
10/20/14	Macquarie-led Consortium	Cleco	Completed		4/13/16	18	EE	$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt	4,700.0
6/23/14	Wisconsin Energy	Integrys	Completed	WEC Energy Group	6/30/15	12	EE	WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/14	Berkshire Hathaway Energy	AltaLink (Canadian)	Completed		12/1/14	7	ET	BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/14	Exelon	Pepco	Completed		3/23/16	24	EE	EXC to acquire POM for $6.8B in cash ($27.25 per POM share)	12,327.0
3/3/14	UIL Holdings	Philadelphia Gas Works	Withdrawn		12/4/14		EG	UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash	1,860.0
12/12/13	Fortis Inc.	UNS Energy	Completed		8/15/14	8	EE	Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/13	Avista	Alaska Energy & Resources Company	Completed		7/1/14	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169.5
5/29/13	MidAmerican Energy Holdings Co.	NV Energy	Completed	Berkshire Hathaway Energy	12/19/13	7	EE	MidAmerican pays $23.75 / share + assume $4.8 billion debt	10,494.3
5/25/13	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	Completed		9/2/14	15	EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/12	Fortis Inc.	CH Energy Group	Completed		6/27/13	16	EE	Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt.	1,609.7
5/27/11	Fortis Inc.	Central Vermont Public Service Corp	Withdrawn		7/11/11		EE	Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt.	701.6
1/8/11	Duke Energy	Progress Energy	Completed		7/3/12	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt.	32,000.0
7/11/11	Gaz Metro LP	Central Vermont Public Service Corp	Completed		6/27/12	12	GE	Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt.	704.2
10/16/10	Northeast Utilities	NSTAR	Completed		4/10/12	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/11	Exelon Corp.	Constellation Energy Group Inc.	Completed		3/12/12	11	EE	CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt	10,623.2
4/19/11	AES Corporation	DPL Inc.	Completed		11/28/11	7	EE	AES pays 30.00/share cash & assumes approx $1.1 billion of net debt	4,613.2
4/28/10	PPL Corp.	E.ON U.S.	Completed		11/1/10	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/10	Emera Inc	Maine & Maritimes	Completed		12/21/10	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/10	FirstEnergy	Allegheny Energy	Completed		2/25/11	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/08	Berkshire Hathaway	Constellation Energy Group Inc.	Withdrawn		12/17/08		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5

7/25/08	Sempra Energy	EnergySouth Inc.	Completed		10/1/08	3	EG	$499 million cash + 283 million debt	771.9
7/1/08	MDU Resources Group, Inc.	Intermountain Gas Co.	Completed		10/1/08	3	EG	$245 million cash + $82 million debt	327.0
6/25/08	Duke Energy	Catamount Energy Corp.	Completed		9/15/08	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/08	Unitil Corp.	Northen Utilities / Granite State Gas Transmission	Completed		12/1/08	10	EG	$160 million cash	160.0
1/12/08	PNM Resources, Inc.	Cap Rock Holding Corp.	Withdrawn		7/22/08		EE	$202.5 million	202.5
10/26/07	Macquarie Consortium	Puget Energy	Completed		2/6/09	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/07	Iberdrola S.A.	Energy East Corp.	Completed		9/16/08	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/07	KKR & Texas Pacific Group	TXU Corp.[1]	Completed	Energy Future Holdings Corp.	10/10/07	8	PE	$31.8 billion cash + $12.1 billion net debt	43,8[illegible]2.0
2/7/07	Black Hills Corp. / Great Plains Energy Inc.[2]	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	Completed		7/14/08	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/06	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	Completed		7/2/07	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/06	WPS Resources Corporation	Peoples Energy Corporation	Completed	Integrys Energy Group	2/21/07	7	EG	$2.47 billion	2,472.4
7/5/06	Macquarie Consortium	Duquesne Light Holdings	Completed		5/31/07	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/06	Gaz Metro LP	Green Mountain Power Corp.	Completed		4/12/07	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	2[illegible].5
5/11/06	ITC Holdings Corp	Michigan Electric Transmission Co.	Completed		10/10/06	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/06	Babcock and Brown Infrastructure	NorthWestern Corp.	Withdrawn		7/24/07		EE	$2.2 billion cash	2,200.0
2/27/06	National Grid	KeySpan Corp.	Completed		8/24/07	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/05	FPL Group Inc.	Constellation Energy Inc.	Withdrawn		10/25/06		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/05	MidAmerican Energy Holdings Co.	Pacificorp	Completed		3/21/06	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/05	Duke Energy Corp.	Cinergy Corp.	Completed		4/3/06	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/04	Exelon Corp.	Public Service Enterprise Group	Withdrawn		9/14/06		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/04	PNM Resources	TNP Enterprises	Completed		6/6/05	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/04	Ameren Corp	Illinois Power[3]	Completed		10/1/04	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/03	Saguaro Utility Group L.P.	UniSource Energy	Withdrawn		12/30/04		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/03	Exelon Corp.	Illinois Power	Withdrawn		11/22/03		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/02	Aquila Inc	Cogentrix Energy Inc	Withdrawn		8/2/02		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/02	Ameren Corp	CILCORP[4]	Completed		1/31/03	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/01	Northwest Natural Gas	Portland General	Withdrawn		5/16/02		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/01	Duke Energy	Westcoast Energy	Completed		3/14/02	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/01	Dominion Resources	Louis Dreyfus Natural Gas	Completed		11/1/01	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/01	Energy East	RGS Energy	Completed		6/28/02	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/01	Pepco	Conectiv	Completed		8/1/02	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/00	PNM	Western Resources[5]	Withdrawn		1/8/02		EE	Stock transfer	4,442.0
10/2/00	NorthWestern	Montana Power[6]	Completed		2/15/02	16	EE	$1.1 billion in cash	1,100.0
9/5/00	National Grid Group	Niagara Mohawk	Completed		1/31/02	16	EE	$19 per share	8,900.0
8/8/00	FirstEnergy	GPU Inc.	Completed		11/7/01	15	EE	$35.60 per share	12,000.0
7/31/00	FPL Group	Entergy	Withdrawn		4/2/01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/00	AES Corporation	IPALCO	Completed		3/27/01	8	IPPE	$25 per share	3,040.0
6/30/00	NS Power	Bangor Hydro	Completed	Emera	10/10/01	16	EE	$26.50 per share	206.0
5/30/00	WPS Resources	Wisconsin Fuel and Light	Completed		4/2/01	11	EG	1.73 shares of WPSR	55.0
2/28/00	PowerGen plc	LG&E	Completed		12/11/00	10	EE	$24.85 per share	5,400.0
8/8/00	FirstEnergy	GPU Inc.	Completed		11/7/01	15	EE	$35.60 per share	12,000.0
7/31/00	FPL Group	Entergy	Withdrawn		4/2/01		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/00	AES Corporation	IPALCO	Completed		3/27/01	8	IPPE	$25 per share	3,040.0
6/30/00	NS Power	Bangor Hydro	Completed	Emera	10/10/01	16	EE	$26.50 per share	206.0
5/30/00	WPS Resources	Wisconsin Fuel and Light	Completed		4/2/01	11	EG	1.73 shares of WPSR	55.0
2/28/00	PowerGen plc	LG&E	Completed		12/11/00	10	EE	$24.85 per share	5,400.0

[1] TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007. TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

[2] Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

[3] Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

[4] Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

[5] PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

[6] NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

General Note: sum of Announced, Completed, Withdrawn, and Pending may not total due to inclusion of transactions announced prior to the 1994 window (e.g., a transaction announced in 1993 and completed in 1994 is included as a completion, but not as an announcement).

C = Completed	E = Electric
W = Withdrawn	G = Gas
PN = Pending	O = Oil
	IPP = Independent Power Producer
	P = Privatized

Source: EEI Finance Department, SNL Financial de-risking the company and prioritizing investments in its core regulated businesses. AEP said net sale proceeds of approximately $1.2 billion will fund opportunities to develop clean energy infrastructure. In 2022, AEP announced it would divest unregulated commercial renewables businesses over the next two years and focus on transmission and regulated renewable investments.

Divestitures To Fund Regulated Electric Capital Expenditures

On July 10, 2023, Dominion Energy said it agreed to sell its 50% interest in the Cove Point liquified natural gas (LNG) export facility to its operator, Berkshire Hathaway, in a transaction valued at $3.5 billion. Cove Point is an LNG shipping terminal on Maryland's Chesapeake Bay. Consistent with its overall strategic review, Dominion called the Cove Point investment non-core to Dominion Energy and said the sale shows its commitment to a strong credit profile as it focuses on state-regulated electric utility operations. The sale was completed on September 1.

On February 2, 2023, FirstEnergy said it would sell an additional 30% ownership interest in its FirstEnergy Transmission (FET) business to Brookfield Super-Core Infrastructure Partners (Brookfield). FirstEnergy said proceeds from the $3.5 billion all-cash deal will strengthen its financial position and support additional smart grid and clean energy investments in its regulated transmission and distribution businesses. In May 2022, FirstEnergy completed the sale of a 19.9% non-controlling interest in FET to Brookfield. FirstEnergy noted it will remain the majority owner of FET and FirstEnergy's workforce will continue to run the business.

On June 20, 2023, NiSource said it agreed to sell a 19.9% interest in its Indiana electric and gas utility NIPSCO to infrastructure investor Blackstone Group for $2.15 billion. NiSource called the transaction a highly attractive and efficient form of equity financing. NiSource said it will use the capital infusion to support NIPSCO's growth, de-lever its balance sheet and fund the renewable generation transition underway. Through 2030, NIPSCO expects to invest $3.5 billion in electric generation transition investments, with this investment primarily focused on installing new renewable generation to replace coal-fired generation.

At year-end 2023, most industry analysts expected whole company M&A to remain slow. The lower stock prices, as of December 31, 2023, made equity currencies less valuable and the industry's focus on strengthening balance sheets to fund internal capex makes uncertain regulatory approval a risky proposition. Yet, by its nature, M&A is hard to predict, and a changing macro landscape combined with company-specific nuance may allow even larger deals to make sense. Time will tell if the EEI list of utilities remains at 39 at year-end 2024 for a fifth straight year.

Construction

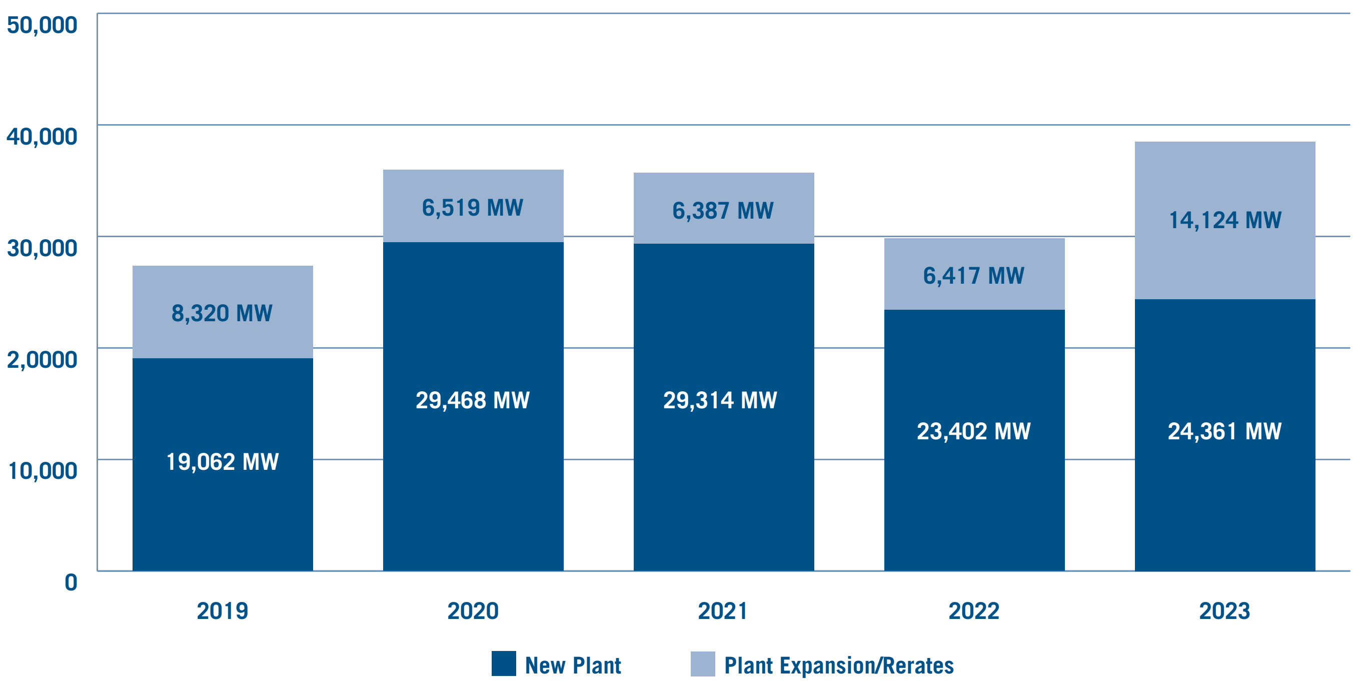
The industry brought 46,003 MW (38,484 MW generation and 7,518 MW storage) of new capacity online in 2023, 35% more than the 34,148 MW in 2022. The increase from 2022 to 2023 was primarily driven by expansions in solar, natural gas, and storage capacity.

Solar installations increased 58%, from 12,279 MW in 2022 to 19,438 MW in 2023. New natural gas capacity brought online increased from 6,978 MW in 2022 to 11,109 MW in 2023. New wind capacity was the only fuel type that declined, from 10,148 MW in 2022 to 6,340 MW in 2023. Wind as a generation source may be maturing after decades of rapid growth. Energy storage installations increased 74%, from 4,329 MW in 2022 to 7,518 MW in 2023.

New power plants comprised 63% of 2023's total new generation capacity (excluding energy storage), lower than 2022's 78% share. Expansions and rerates in 2023 ac-

New Capacity Online (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY



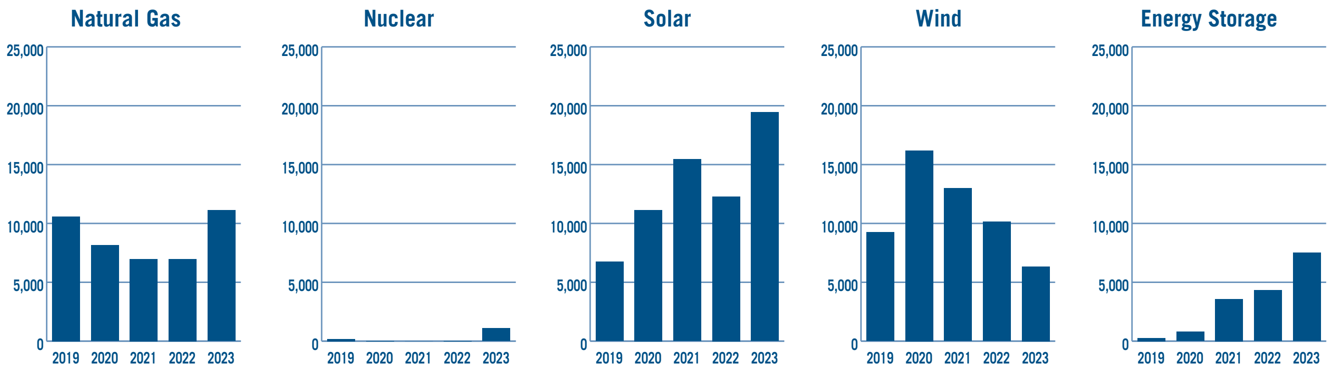
	2019	2020	2021	2022	2023
New Plant	19,062	29,468	29,314	23,402	24,361
Plant Expansion/Rerates	8,320	6,519	6,387	6,417	14,124
Total	**27,382**	**35,987**	**35,701**	**29,819**	**38,484**
Energy Storage	274	790	3,572	4,329	7,518

Notes: Includes all new capacity placed on the grid by U.S. investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

New Capacity Online by Fuel Type (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY



Fuel Type	2019	2020	2021	2022	2023
Coal	–	–	–	–	–
Natural Gas	10,597	8,146	6,976	6,978	11,109
Nuclear	175	20	-	17	1,100
Solar	6,741	11,144	15,463	12,279	19,438
Wind	9,242	16,194	12,988	10,148	6,340
Other	627	483	274	396	498
Total	**27,382**	**35,987**	**35,701**	**29,819**	**38,484**
Energy Storage	274	790	3,572	4,329	7,518

Note: Includes all new capacity placed on the grid by U.S. investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, and wood. All Other includes Coal, Nuclear, and Other. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

counted for the remaining 37%, an increase from 22% in 2022.

Renewables accounted for 67% of new generation capacity in 2023 versus 75% in 2022. Supported by continually declining costs, wind and solar have powered more than half of the new capacity added in each of the last five years. Investor-owned utilities that brought the most new renewable capacity online were NextEra Energy (1,687 MW of wind, 3,128 MW of solar), AES (238 MW of wind, 525 MW of solar), Alliant Energy (639 MW of solar), WEC Energy Group (351 MW of wind), Duke Energy (316 MW of solar), National Grid (274 MW of solar), TECO Energy (230 MW of solar), and Berkshire Hathaway (202 MW of wind).

Natural gas accounted for 29% of generation capacity added in 2023. Combined cycle technology accounted for 71% of this new natural gas capacity compared with 51% in 2022. New plants represented 15% of the natural gas total, expansions accounted for 79%, and the remaining 6% were rerates. Tennessee Valley Authority led natural gas additions with 1,500 MW. Southern Company was second with 846

New Capacity Online by Region (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY

	New Plant and Expansion/Rerates					Energy Storage				
Region	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
ASCC	33	11	9	8	15	1	–	–	47	–
ERCOT	5,317	5,869	8,912	6,706	6,134	14	139	642	1,364	1,745
HCC	187	60	17	42	66	34	–	46	39	156
MRO	3,321	4,870	2,918	2,386	1,934	–	–	6	12	4
NPCC	2,206	1,665	1,477	1,129	1,566	98	121	165	150	124
RFC	4,023	2,794	6,153	5,576	7,096	31	11	21	6	62
SERC	7,308	8,964	7,422	5,474	12,439	16	22	562	91	128
SPP	1,119	3,367	2,745	2,708	1,757	24	–	–	–	–
WECC	3,869	8,388	6,047	5,789	7,478	57	497	2,129	2,621	5,299
Total	**27,382**	**35,987**	**35,701**	**29,819**	**38,484**	**274**	**790**	**3,572**	**4,329**	**7,518**

Notes: Data includes new plants, rerates, and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

Announced New Capacity by Region and Fuel Type in 2023 (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY

Fuel Type	Alaska Systems Coordinating Council	Electric Reliability Council of Texas	Hawaiian Coordinating Council	Midwest Reliability Organization	Northeast Power Coordinating Council	Reliability First	SERC Reliability Corp	Southwest Power Pool Inc.	Western Electricity Coordinating Council
Coal	–	–	–	–	–	–	–	–	–
Natural Gas	–	2,215	–	588	–	120	4,628	454	627
Nuclear	–	-	–	–	–	135	–	–	–
Solar	8	691	3	715	3,391	4,890	9,927	477	7,301
Wind	–	258	–	56	4,009	937	–	–	4,426
Hydro	–	–	–	–	–	–	–	–	–
Other	–	–	–	4	–	17	728	4	466
Total	**8**	**3,164**	**3**	**1,363**	**7,401**	**6,099**	**15,283**	**936**	**12,820**
Energy Storage	0	2,592	0	179	15,556	1,352	1,162	0	9,090

Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, and wood. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

MW. TECO Energy was third with 494 MW of gas turbine expansions.

A total of 7,518 MW of energy storage was brought online in 2023, a 74% increase from 2022. Investor-owned utilities that brought the most energy storage capacity online included NextEra Energy (1,535 MW), Consolidated Edison (258 MW), Berkshire Hathaway (200 MW), Hawaiian Electric (120 MW), and AES Corporation (100 MW).

New Capacity Online by Region

The SERC Reliability Corporation brought the most new generation capacity online of any region in 2023; the 12,439 MW total (excluding energy storage) was more than double 2022's 5,474 MW. An increase in new solar generation, from 3,819 MW to 5,061 MW, and in natural gas generation, from 1,509 MW to 5,359 MW, were the primary contributors to the increase. The Western Electricity Coordinating Council (WECC) also increased new capacity, rising from 5,789 MW in 2022 to 7,478 MW in 2023; this was primarily driven by an increase in solar generation, from 3,327 MW to 5,946 MW. The Reliability First Corporation (RFC) had an increase of 1,520 MW, from 5,576 MW in 2022 to 7,096 MW in 2023, with new solar generation rising from 1,196 MW to 2,465 MW. The Southwest Power Pool (SPP) had the largest absolute decrease in new generation added, from 2,708 MW in 2022 to 1,757 MW in 2023; the decline resulted from reduced additions of wind (2,672 MW to 1,452 MW).

WECC brought the most energy storage capacity online of any region at 5,299 MW in 2023 compared to 2,621 MW in 2022. ERCOT was second with 1,745 MW in 2023 compared to 1,364 MW in 2022. Together, both regions accounted for 94% of energy storage capacity additions in 2023; this was primarily due to the high penetration of wind and solar generation in each region.

Announcements by Region and Fuel Type

New generation capacity (excluding energy storage) announced in 2023 totaled 47,077 MW. Renewable capacity accounted for 79% of the total, with solar at 58% and wind at 21%. Natural gas accounted for 18%. The remaining 3% was nuclear and other. No new coal capacity was announced in 2023.

New solar announcements declined 26%, from 37,089 MW in 2022 to 27,404 MW in 2023. New wind generation capacity announcements fell 16%, from 11,484 MW in 2022 to 9,687 MW in 2023. Higher interest rates and interconnection queue challenges may have contributed to lower renewable capacity announcements.

Announced new natural gas capacity rose for the first time since 2020, increasing from 1,337 MW in 2022 to 8,632 MW in 2023. SERC Reliability Corporation (SERC) and Electric Reliability Council of Texas (ERCOT) together accounted for 79%, or 6,844 MW, of the total new natural gas generation capacity announcements.

SERC Reliability Corporation (SERC) saw the most announced new generation of any region in 2023, at 15,283 MW, with 65% solar, 30% natural gas, and 5% other. The Western Electricity Coordinating Council (WECC) region had the second-highest amount of any region, at 12,820 MW, with 57% solar, 35% wind, 5% natural gas, and 4% other.

Energy storage produced the strongest year-to-year growth in announced new capacity, with 29,931 MW in 2023 compared to 22,522 MW announced in 2022. Northeast Power Coordinating Council (NPCC), Western Electricity Coordinating Council (WECC), and Electric Reliability Council of Texas (ERCOT) together accounted for 91%, or 27,238 MW, of the total new energy storage capacity announcements in 2023.

Projected Capacity Additions

As of April 2024, new generation capacity (excluding energy storage) expected to come online from 2024 through 2028 totaled 370,041 MW. Renewable capacity accounted for most of the total, with solar representing 63% and wind 26%. The third-largest category was natural gas, at 9%, followed by nuclear at 1% and other at 1%. Of the 370,041 MW total, 50% was in the proposal stage, with only 15% under construction and 4% in the testing stage.

Separately, new energy storage capacity expected to come online from 2024 through 2028 totaled 130,188 MW. Approximately 49% was in the proposal state, with 10% under construction and 2% in the testing stage.

Retirements

From 2024 through 2028, 111,997 MW of capacity is scheduled to be retired. Coal continues to

Stage of Announced Capacity Additions (MW) 2024-2028

U.S. ELECTRIC UTILITY AND NON-UTILITY

Fuel Type	Testing	Under Construction	Site Prep	Permitted	Application Pending	Feasibility	Proposed	Total
Natural Gas	665	5,349	–	6,871	7,916	171	13,705	34,677
Nuclear	1,100	–	–	–	–	–	1,693	2,793
Solar	9,414	36,259	–	43,339	34,268	–	109,378	232,658
Wind	2,178	12,019	–	10,887	10,359	3,270	57,070	95,782
Other	7	1,287	–	316	71	1,343	1,107	4,131
Total	**13,364**	**54,913**	**–**	**61,412**	**52,614**	**4,784**	**182,953**	**370,041**
Energy Storage	2,925	12,556	–	15,400	31,473	4,526	63,308	130,188

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, hydroelectric turbines, wood. Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates. Data includes projects with an expected online date up to 2028.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

lead projected retirements, accounting for 52% of the total. Natural gas ranked second and fuel oil third in terms of projected retirements over the full five-year period.

Natural gas retirements are expected to peak in 2025 at 17,786 MW. Wind and solar retirements remain minimal, together accounting for only a combined 0.13% of total projected retirements from 2024 through 2028. Nuclear retirements peaked in 2020, at 2,031 MW, with the shutdowns of the Duane Arnold Energy Center in Iowa (660 MW) and Indian Point Unit 2 in New York (1,371 MW). There were no nuclear retirements in 2023 and no nuclear capacity is expected to retire over the next five years due to the cancelled shutdown of the 2,323 MW Diablo Canyon Power Plant in California.

Energy Storage

Energy storage continues to be a fast-growing area for the industry. At year-end 2023, utilities owned or operated 40,215 MW of storage capacity, or about 93% of all energy storage in the United States. Since 2018, total installed energy storage capacity nationwide owned or operated by utilities has increased by 71%.

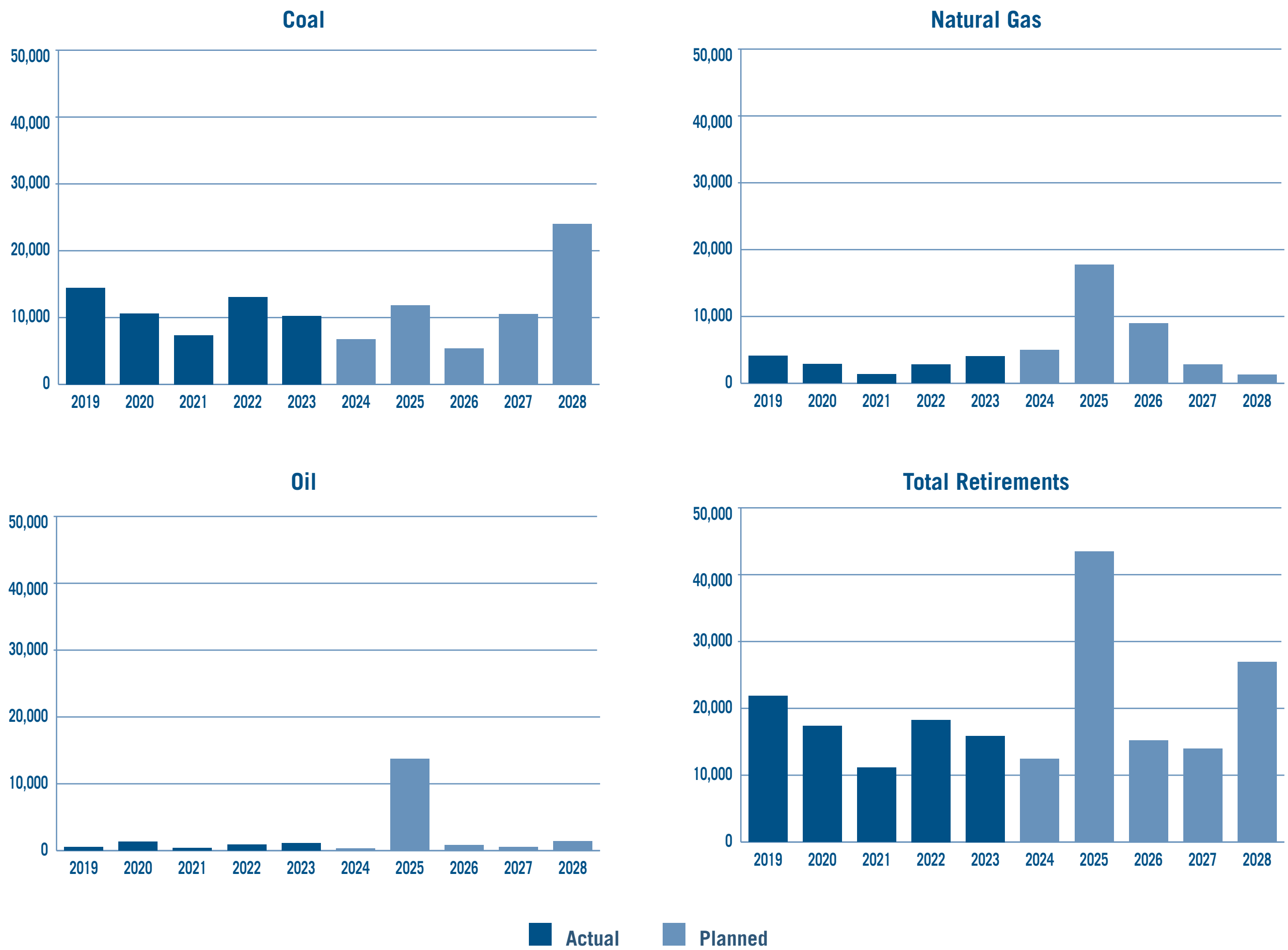
Pumped hydro accounted for 51%, or 21,992 MW, of the total energy storage capacity owned by both U.S. investor-owned utilities and non-utilities. Battery storage is the fastest-growing storage technology in terms of capacity, with the total deployed up more than ten times from 2,118 MW in 2019 to 20,623 MW in 2023. Between 2019 and 2023, battery storage grew from 8.6% of total energy storage capacity to 47.5%.

The fast-paced growth of battery storage is likely to continue; 72,788 MW of battery capacity is expected to come online from 2024 through 2028. Utilities will continue to lead battery storage deployment, accounting for 59,472 MW or 82% of this expected increase in battery storage capacity.

Energy storage capacity driven by other technology is also expected to increase during this time period, including 14,705 MW of additional pumped hydro. Three rerate projects will drive 865 MW of new hydro capacity: Salina by Grand River Dam Authority in Oklahoma (197 MW), Lewiston Niagara by the New York Power Authority (20 MW), and Bad Creek by Duke Energy in South Carolina (648 MW). One expansion project accounts for 1,000 MW of new hydro capacity, the Swan Lake North Hydro Pumped Storage Project in Oregon. A large compressed air energy storage project is also expected to enter operation. The Rosamond CASE project (500 MW) in California is expected to come online in 2024.

Actual 2019-2023 and Planned 2024-2028 Retirements (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY



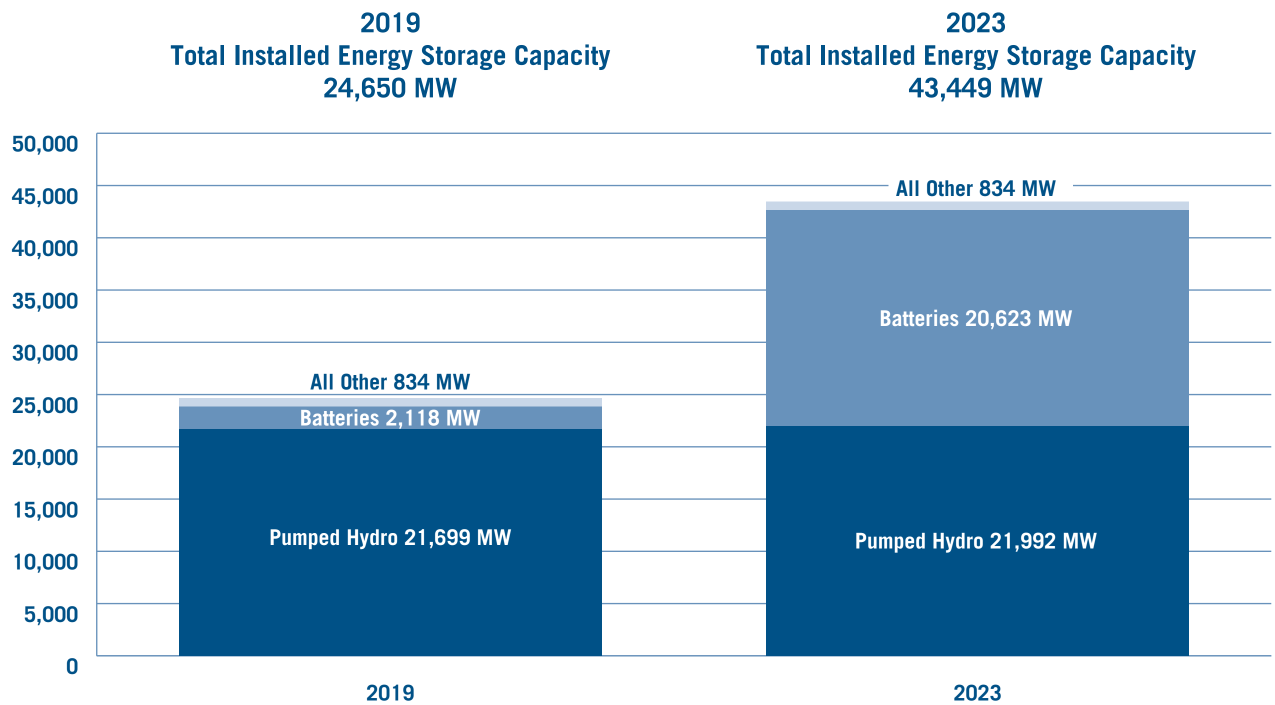
	Actual					Planned				
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Coal	14,460	10,648	7,361	13,097	10,250	6,800	11,834	5,396	10,546	24,015
Natural Gas	4,111	2,858	1,381	2,821	4,055	4,988	17,786	8,949	2,815	1,294
Nuclear	1,641	2,031	1,074	823	-	-	-	-	-	-
Oil	546	1,366	397	903	1,137	345	13,757	849	522	1,421
Solar	8	-	275	4	3	-	-	2	4	7
Wind	210	259	303	294	99	139	1	-	-	-
Hydro	170	15	6	12	35	2	17	3	24	-
Other	740	211	345	326	303	173	43	-	52	213
Total	**21,887**	**17,388**	**11,141**	**18,278**	**15,882**	**12,449**	**43,437**	**15,199**	**13,963**	**26,950**

Notes: 2019-2023 is actual plants retired. 2024-2028 is projected based on announced or expected retirements. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, wood, and energy storage. All Other includes Coal, Nuclear, and Other.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

Total Installed Energy Storage Capacity by Technology (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY



Notes: All other includes Thermal, CAES, and Flywheel
Sources: The Velocity Suite, Hitachi Energy; Wood Mackenzie Energy Storage Database; U.S. Department of Energy Sandia Energy Storage Dataset, EEI Energy Supply and Finance Department, March 2024

Fuel Sources

Net Generation and Electricity Sales

Electric power industry net generation in 2023 totaled 4,251,790 gigawatt hours (GWh), a decrease of 0.9% versus 2022. Nationwide retail electricity sales declined 1.7%, with lower totals across 38 states and the District of Columbia, after rising 2.7% in 2022. The states with the largest year-to-year percentage increases in retail electricity sales in 2023 were North Dakota (+12.8%), New Mexico (+5.7%), Texas (+2.4%) and Wyoming (+2.0). Kentucky (-7.2%), California (-5.4%), Maine (-5.4%) and New Jersey (-5.4%) had the largest percentage declines.

Total electricity sales to commercial customers decreased 1.1% in 2023 after two consecutive annual increases. Commercial sales rose 3.4% in 2022 and 2.9% in 2021 as business activity recovered from 2020's pandemic-related shutdowns. Most states experienced a decrease in commercial sales in 2023, with Kentucky (-4.8%), New Jersey (-4.6%) and Pennsylvania (-4.5%) experiencing the largest declines. However, commercial sales rose in a few states with North Dakota (+14.6%), South Carolina (+4.9%) and Mississippi (+4.8%) producing the largest percentage gains.

Total electricity sales to industrial customers increased 0.4% compared to 2022, showing year-to-year gains in 14 states. The nationwide gain was lower than 2022's 0.7% and 2021's 2.9% , which were likely driven by the resumption and expansion of industrial activity after states relaxed COVID-19 protocols. North Dakota (+18.7%) and Texas (+15.3%) had the highest percentage increases. Texas showed the highest increase in absolute terms, at 22,049 GWh. Most states experienced a decrease in industrial sales in 2023, with Oregon (-13.3%), Maine (-12.4%), California (-11.6%) and New Jersey (-10.0%) showing the largest percentage declines.

Total electricity sales to residential customers decreased 3.6% after rising 3.5% in 2022. Louisiana (+1.5%), Arizona (+1.2%) and New Mexico (+1.0%) were among the few states with growth. Louisiana also experienced the highest growth in absolute terms, at 481 GWh. On the other hand, 44 states and the District of Columbia saw residential electricity sales decrease in 2023. West Virginia (-8.1%), California (-7.3%) and Pennsylvania (-7.0%) had the largest percentage declines.

The significant reduction in year-to-year residential sales across states may indicate that fewer people worked from home in 2023 compared to 2022. Increases in each of the two previous years resulted in part from progressive easing of the protocols put in place during the Covid-19 pandemic.

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2022r	2023
Coal	19.4%	15.9%
Natural Gas	39.3%	42.4%
Nuclear	18.0%	18.2%
Hydro	5.9%	5.6%
Renewables	16.5%	17.1%
Biomass	1.2%	1.1%
Geothermal	0.4%	0.4%
Solar	4.8%	5.6%
Wind	10.1%	10.0%
Other Fuels	0.9%	0.8%
Total	100.0%	100.0%

Notes: r = revised. Other fuels include: Pumped hydro, other gases, and diesel/fuel oil. Totals may reflect rounding.

U.S. Electric Utility: Owns and/or operates facilities within the U.S., its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

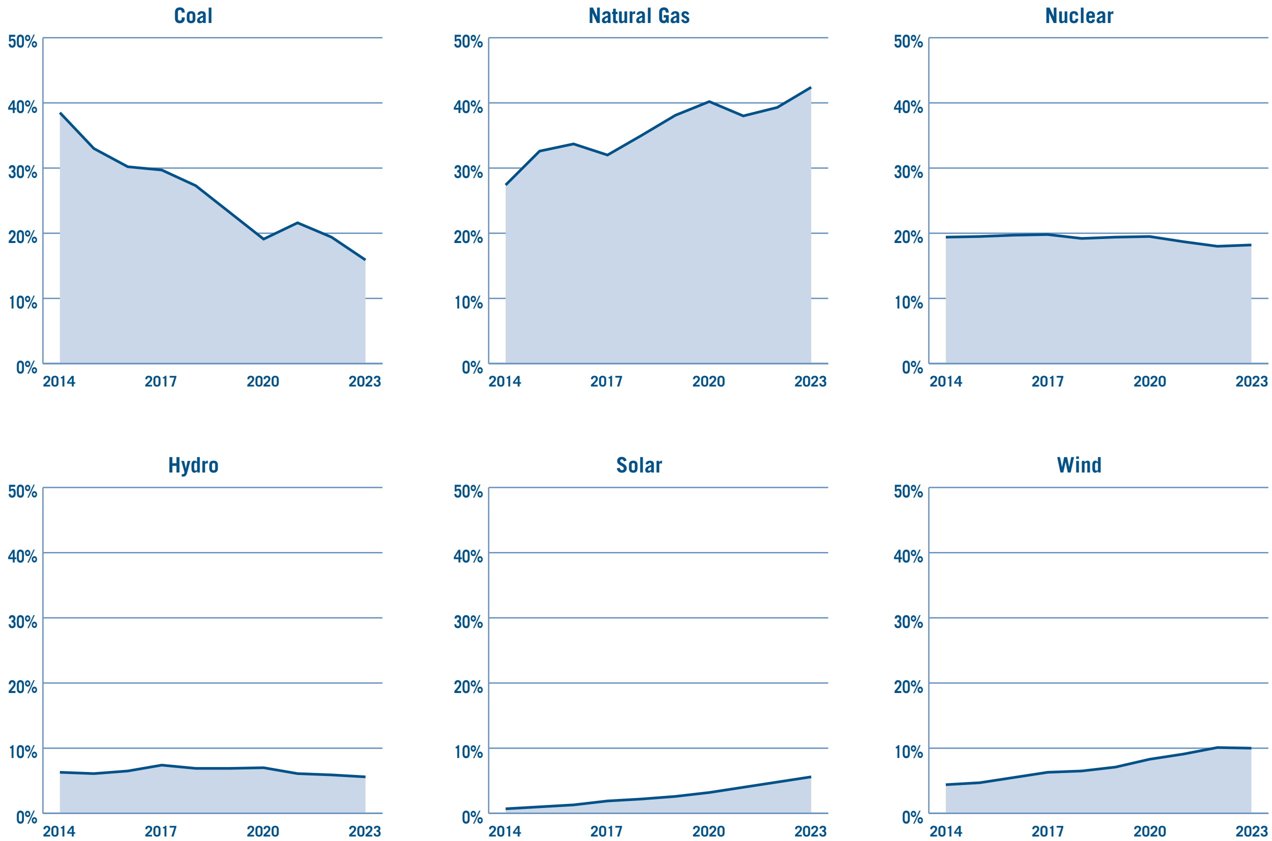
Non-Utility Power Producer: Includes qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) withouta designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA), EEI Energy Supply and Finance Dept, April 2024

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

Percent of Total U.S. Electric Generation



	2014	2015	2016	2017	2018	2019	2020	2021	2022r	2023
Coal	38.5%	33.0%	30.2%	29.7%	27.3%	23.2%	19.1%	21.6%	19.4%	15.9%
Natural Gas	27.4%	32.6%	33.7%	32.0%	35.0%	38.1%	40.2%	38.0%	39.3%	42.4%
Nuclear	19.4%	19.5%	19.7%	19.8%	19.2%	19.4%	19.5%	18.7%	18.0%	18.2%
Hydro	6.3%	6.1%	6.5%	7.4%	6.9%	6.9%	7.0%	6.1%	5.9%	5.6%
Solar	0.7%	1.0%	1.3%	1.9%	2.2%	2.6%	3.2%	4.0%	4.8%	5.6%
Wind	4.4%	4.7%	5.5%	6.3%	6.5%	7.1%	8.3%	9.1%	10.1%	10.0%
Other Fuels	3.2%	3.2%	3.0%	2.9%	2.9%	2.7%	2.6%	2.6%	2.5%	2.3%

Notes: r = revised.

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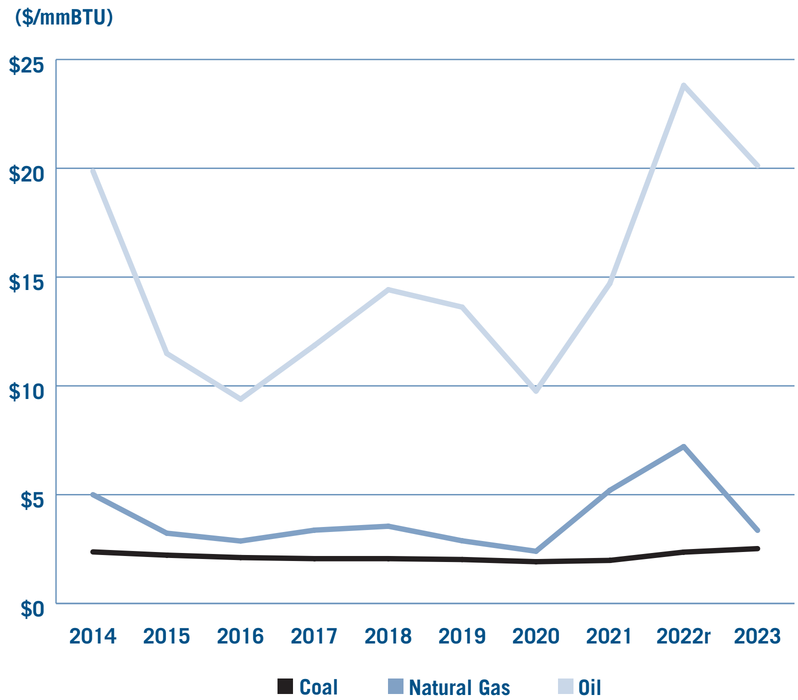
Source: Energy Information Administration (EIA), U.S. Department of Energy; EEI Energy Supply and Finance Department, April 2024

Average Cost of Fossil Fuels

U.S. ELECTRIC UTILITY AND NON-UTILITY



Notes: r = revised.

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Source: Energy Information Administration (EIA), U.S. Department of Energy; EEI Energy Supply and Finance Department, April 2024

Coal

Generation from coal-fired plants decreased in 2023, with coal accounting for 15.9% of total electricity generation nationwide. Coal's 675,264 GWh of generation placed it third, behind natural gas and nuclear, among the fuels that contributed to total nationwide generation. The coal fleet's capacity factor decreased from 48% in 2022 to 42% in 2023.

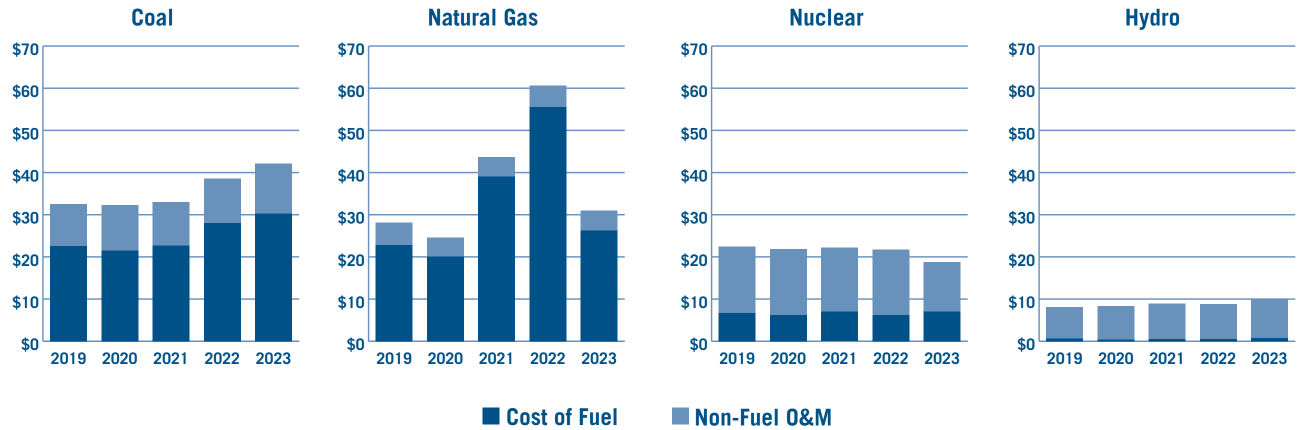
The price of coal combined with operations and maintenance costs for coal plants increased 9.1%, from $38.56/MWh in 2022 to $42.08/MWh in 2023. The average price of coal for electricity generation increased by 6.8%, from $2.36 per million British Thermal Units (MMBtu) in 2022 to $2.52 MMBtu in 2023. At the same time, average total operations and maintenance expense for coal increased by 11.2%, from $10.56/MWh in 2022 to $11.74/MWh in 2023. Given the small increase in overall generation cost for coal in 2023, along with a substantial decrease in natural gas fuel prices, coal was the most expensive fuel for electricity generation for the first time since 2020.

Natural Gas

Natural gas accounted for 42.4% of total generation from utility-scale

Average Cost to Produce Electricity ($/MWh)

U.S. ELECTRIC UTILITY AND NON-UTILITY



	Cost of Fuel					Non-Fuel O&M				
	2019	2020	2021	2022r	2023	2019	2020	2021	2022r	2023
Coal	$22.53	$21.52	$22.64	$28.00	$30.34	$10.00	$10.72	$10.30	$10.56	$11.74
Natural Gas	$22.72	$20.05	$39.04	$55.58	$26.21	$5.37	$4.51	$4.70	$5.07	$4.78
Nuclear	$6.69	$6.26	$6.98	$6.23	$7.04	$15.72	$15.55	$15.24	$15.42	$11.66
Hydro	$0.66	$0.45	$0.48	$0.48	$0.76	$7.44	$7.91	$8.53	$8.29	$9.36

Notes: r = revised. 2023 results are preliminary.

U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2024

facilities in 2023, more than any other fuel type. Its share increased 3.1 percentage points from the 2022 level to a historical high. The average cost of natural gas for electricity generation fell dramatically, decreasing 53% from $7.21/MMBtu in 2022 to $3.36/MMBtu in 2023. As a result, the overall average cost to produce electricity from natural gas declined by 49% in 2023 versus 2022, and was 26% lower than the average cost to produce electricity from coal.

Renewables

The industry continues to add record amounts of renewable capacity. As a result, electric generation from carbon-free sources increased to 1,742,483 MWh in 2023, representing 41% of the electric power industry's total generation. Generation from all renewable sources was 967,136 MWh, or 22.7% of the total in 2023 compared with 962,100 MWh, or 22.4%, in 2022.

Generation from wind power decreased 2.1%, from 434,297 MWh in 2022 to 425,235 MWh in 2023 and accounted for 10% of total electricity generation. Solar generation increased 16.1%, from 205,079 MWh in 2022 to 238,121 MWh in 2023, reaching 5.6% of total electricity generation. Conventional hydroelectric generation declined to 239,855 MWh, a 5.9% reduction from 254,789 MWh in 2022. It accounted for 5.6% of electricity generation.

Nuclear

Nuclear generation increased 0.5% in 2023 and accounted for 18.2% of total electric power generation, up from 18% in 2022. The increase occurred despite recent nuclear plant retirements. From 2019 through 2023, 5,570 MW of nuclear capacity was retired. The most recent retirement was 823 MW at Palisades nuclear power plant in Michigan. Nuclear generators had an average capacity factor of 93% in 2023 compared to average capacity factors of 42% for coal and 39% for natural gas.

Nuclear fuel costs increased 13%, from $6.23/MWh in 2022 to $7.04/MWh in 2023. However, non-fuel operations and maintenance costs decreased 24%, from $15.42/MWh in 2022 to $11.66/MWh in 2023.

Industry Financial Performance

Income Statement

- Energy Operating Revenues declined 0.4% versus last year. U.S. electric output fell 1.6% as mild weather reduced the need for both winter heating and summer cooling. Total nationwide heating degree days were 9% lower than last year and total cooling degree days fell 11%. Eight of the nine U.S. power regions saw output declines, which ranged from -0.8% to -4.1%. The South Central region's 2.8% gain was the only year-to-year increase. Energy operating revenue was also constrained by a sharp decline in the cost of natural gas. These forces were partially offset by a 2.9% increase in the average retail price of electricity nationwide.

- While fuel price inflation drove Total Energy Operating Expenses sharply higher in 2021 and in 2022, the trend reversed in 2023. This line item decreased 14.0% as its two constituents each showed large year-to-year declines. Total Electrical Generation Cost fell 11.6% as the average cost of natural gas for electricity generation declined 53% year-to-year. A 6.3% rise in the average cost of coal for electricity generation only partially offset the impact of lower natural gas prices. Higher output from renewable generation (where fuel cost is zero) also constrained industry aggregate fuel costs. Gas Cost—which tracks fuel cost for the industry's natural gas distribution business segment—declined 24.5%.

- Operations and Maintenance (O&M) costs rose 2.2% over the 2022 total, a pace well below last year's 7.9% gain and 2021's 4.6% rise. O&M cost inflation was only 1.0% to 1.5% annually from 2018 through 2020. Utilities' O&M spending is benefitting from productivity gains resulting from smart-grid investment, and the industry worked hard to constrain O&M expenses during the pandemic to address revenue declines. Yet O&M spending is also driven by essential reliability needs. O&M costs rose, or were equal to last year, at 29 of the 43 utilities that report this line item. These costs declined at only 14 utilities.

- Depreciation & Amortization (D&A) expenses rose 5.8%. This metric increased for 38 of the 44 constituent companies, reflecting the industry's ongoing widespread and diverse investments in new clean generation, transmission, distribution, reliability, and grid modernization.

- Operating Income rose $14.4 billion, or 19.7%, versus 2022. Slightly lower energy operating revenues were offset by even lower electrical generation and gas costs, overcoming rising O&M and depreciation expenses. While most utilities are focused on state-regulated operations, enough variety remains in individual corporate structures and business models to make broad generalizations difficult. So does the variety of costs that can affect operating income. Despite the industry's aggregate increase, operating income was flat to lower at 15 utilities and rose at 29.

- Total Other Recurring Revenue rose $5.0 billion, or 66.9%, due almost entirely to a $5.8 billion jump in Other Revenue. This in turn resulted from accounting treatment for energy operations at just a few of the 44 underlying utilities and does not reflect a broad industry trend. In fact, one company contributed half the industry's aggregate gain.

- Interest Expense rose by 34.4%, reflecting the sharp rise in interest rates during 2022 and 2023 and widespread debt issuance to fund the clean energy capex programs seen across the industry. In a rare display of consistency between aggregate industry figures and individual company reports, this line item increased for all but one of the industry's 44 constituent companies.

- Net Income Before Taxes increased $9.8 billion or 20.8%. Net Income rose $8.9 billion or 20.4%. These figures are driven by the industry's largest companies and mask a wide variation in company-specific results. Pre-tax income rose at 25 companies and was unchanged or lower at 19. Net income rose at 26 and was unchanged or declined at 18. The year-to-year change in both metrics showed considerable variation across companies.
- The industry's aggregate Common Dividends payments rose 6.3% versus 2022, to $33.0 billion from $31.0 billion, although the average percentage dividend increase was 5.1%. Nearly all utilities raised their dividend in 2023. Income-oriented and risk-averse investors continue to benefit from the industry's reliable and growing stock dividends.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

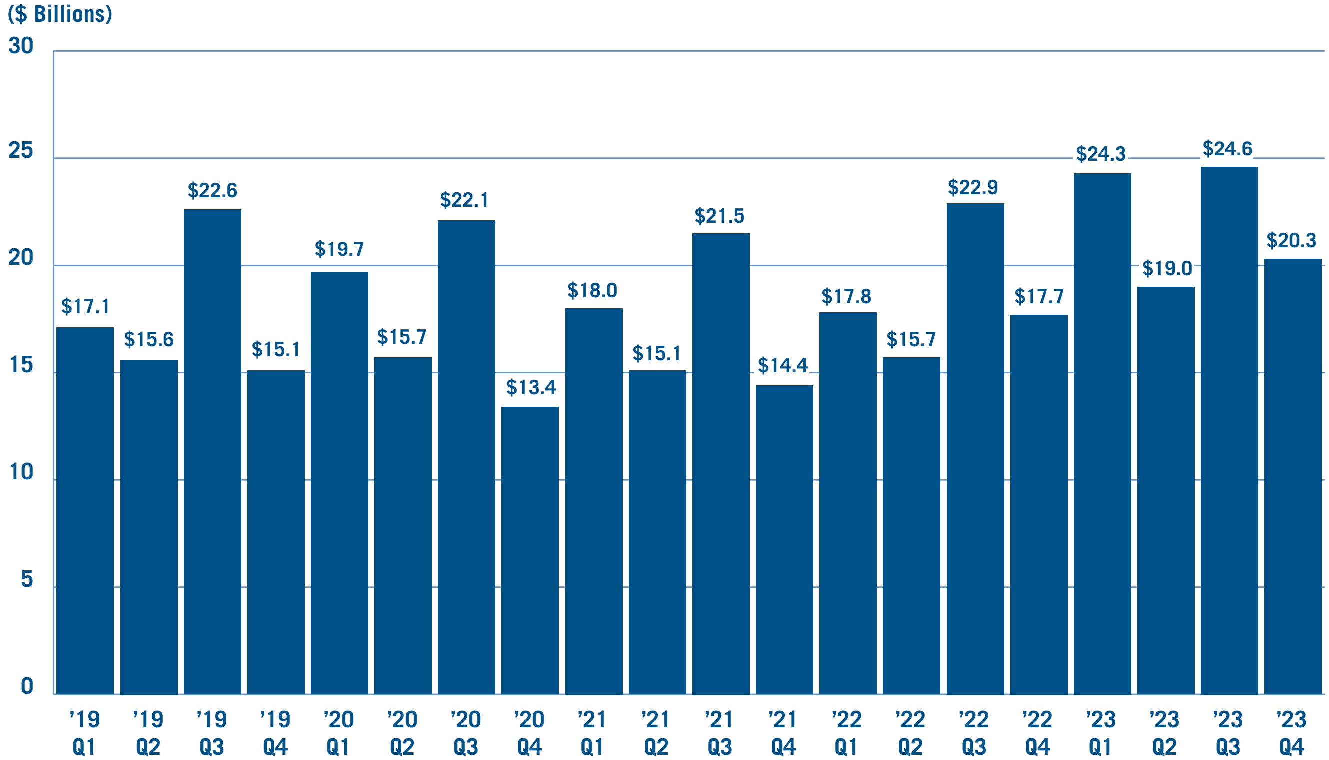
	12 Months Ended		
($ Millions)	**12/31/2023**	**12/31/2022r**	**% Change**
Energy Operating Revenues	$411,173	$412,757	(0.4%)
Energy Operating Expenses			
Total Electrical Generation Cost	106,348	120,305	(11.6%)
Gas Cost	20,653	27,341	(24.5%)
Total Energy Operating Expenses	**127,002**	**147,645**	**(14.0%)**
Revenues less energy operating expenses	**284,171**	**265,112**	**7.2%**
Other Operating Expenses			
Operations & maintenance	100,349	98,185	2.2%
Depreciation & Amortization	64,404	60,882	5.8%
Taxes (not income) - Total	23,518	22,986	2.3%
Other Operating Expenses	12,536	15,060	(16.8%)
Total Operating Expenses	**327,809**	**344,759**	**(4.9%)**
Operating Income	**87,686**	**73,267**	**19.7%**
Other Recurring Revenue			
Partnership Income	1,388	2,666	(47.9%)
Allowance for Equity Funds Used for Construction	2,761	2,279	21.1%
Other Revenue	8,319	2,523	229.7%
Total Other Recurring Revenue	**12,467**	**7,468**	**66.9%**
Non-Recurring Revenue			
Gain on Sale of Assets	1,501	441	240.8%
Other Non-Recurring Revenue	123	319	(61.5%)
Total Non-Recurring Revenue	**1,624**	**760**	**113.8%**
Interest expense	36,253	26,978	34.4%
Other expenses	187	822	(77.2%)
Asset Writedowns	2,905	2,489	16.7%
Other Non-Recurring Expenses	5,456	4,050	34.7%
Total Non-Recurring Expenses	8,361	6,540	27.8%
Net Income Before Taxes	**56,977**	**47,155**	**20.8%**
Provision for Taxes	2,448	3,064	(20.1%)
Dividends on Preferred Stock of Subsidiary	-	-	NM
Other Minority Interest Expense	-	-	NM
Minority Interest Expense	-	-	NM
Trust Preferred Security Payments	-	-	NM
Other After-tax Items	-	-	NM
Total Minority Interest and Other After-tax Items	-	-	NM
Net Income Before Extraordinary Items	**54,529**	**44,091**	**23.7%**
Discontinued Operations	(1,689)	(194)	772.4%
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	(1,689)	(194)	772.4%
Net Income	**52,840**	**43,897**	**20.4%**
Preferred Dividends Declared	455	508	(10.5%)
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	2	(6)	(133.3%)
Net Income Attributable to Noncontrolling Interests	(266)	(513)	(48.1%)
Net Income Available to Common	**52,641**	**43,894**	**19.9%**
Common Dividends	**32,980**	**31,016**	**6.3%**

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Net Operating Income

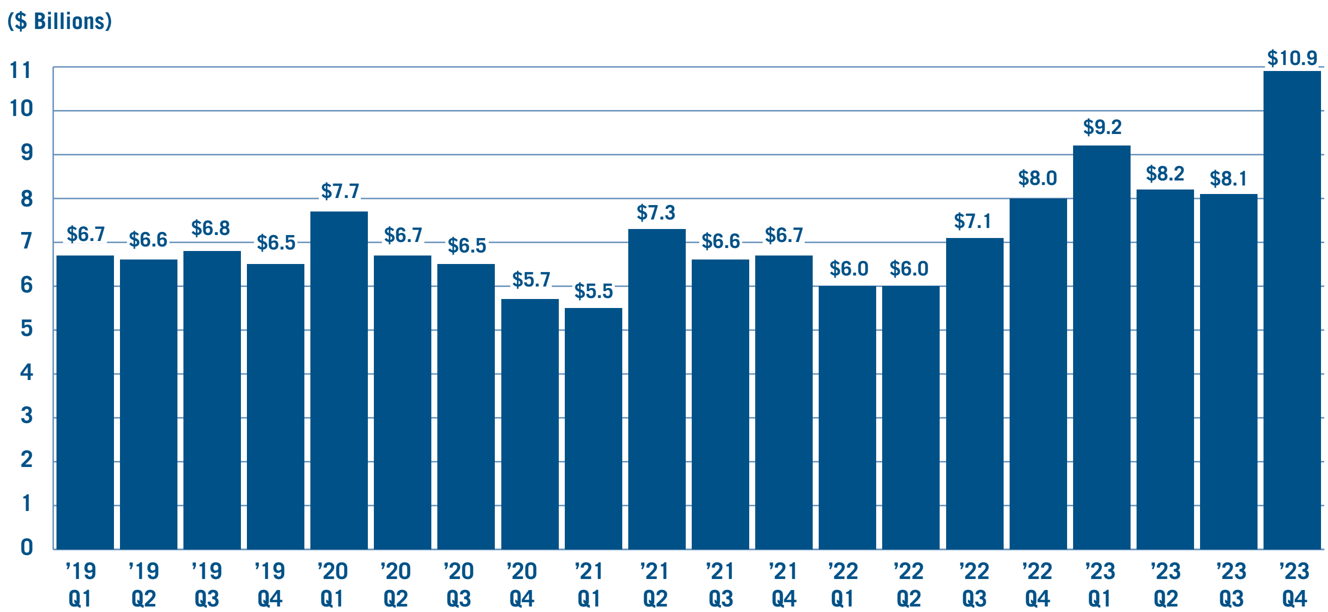
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Individual Non-Recurring and Extraordinary Items

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022r	2023
Net Gain (Loss) on Sale of Assets	996	789	767	1,012	5,272	3,049	(398)	(1,902)	441	1,501
Other Non-Recurring Revenue	296	(4)	888	493	131	117	–	471	319	123
Total Non-Recurring Revenue	**1,292**	**785**	**1,655**	**1,505**	**5,403**	**3,167**	**(398)**	**(1,430)**	**760**	**1,624**
Asset Writedowns	(8,762)	(5,189)	(17,487)	(4,166)	(4,121)	(3,470)	6,704	1,199	2,489	2,905
Other Non-Recurring Charges	(2,675)	(1,764)	(3,109)	(5,630)	(17,841)	(13,034)	8,504	7,221	4,050	5,456
Total Non-Recurring Charges	**(11,437)**	**(6,953)**	**(20,596)**	**(9,796)**	**(21,962)**	**(16,504)**	**15,208**	**8,421**	**6,540**	**8,361**
Discontinued Operations	295	(1,148)	(732)	(1,554)	602	1,243	17	793	(194)	(1,689)
Change in Accounting Principles	–	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	–	–	–	–	–	–	–	–	–	–
Total Extraordinary Items	**295**	**(1,148)**	**(732)**	**(1,554)**	**602**	**1,243**	**17**	**793**	**(194)**	**(1,689)**
Total Non-Recurring and Extraordinary Items	**(9,850)**	**(7,316)**	**(19,674)**	**(9,844)**	**(15,957)**	**(12,094)**	**(15,589)**	**(9,058)**	**(5,974)**	**(8,425)**

r = revised Note: Figures represent net industry totals. Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Top Net Non-Recurring and Extraordinary Gains (Losses) 2023

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

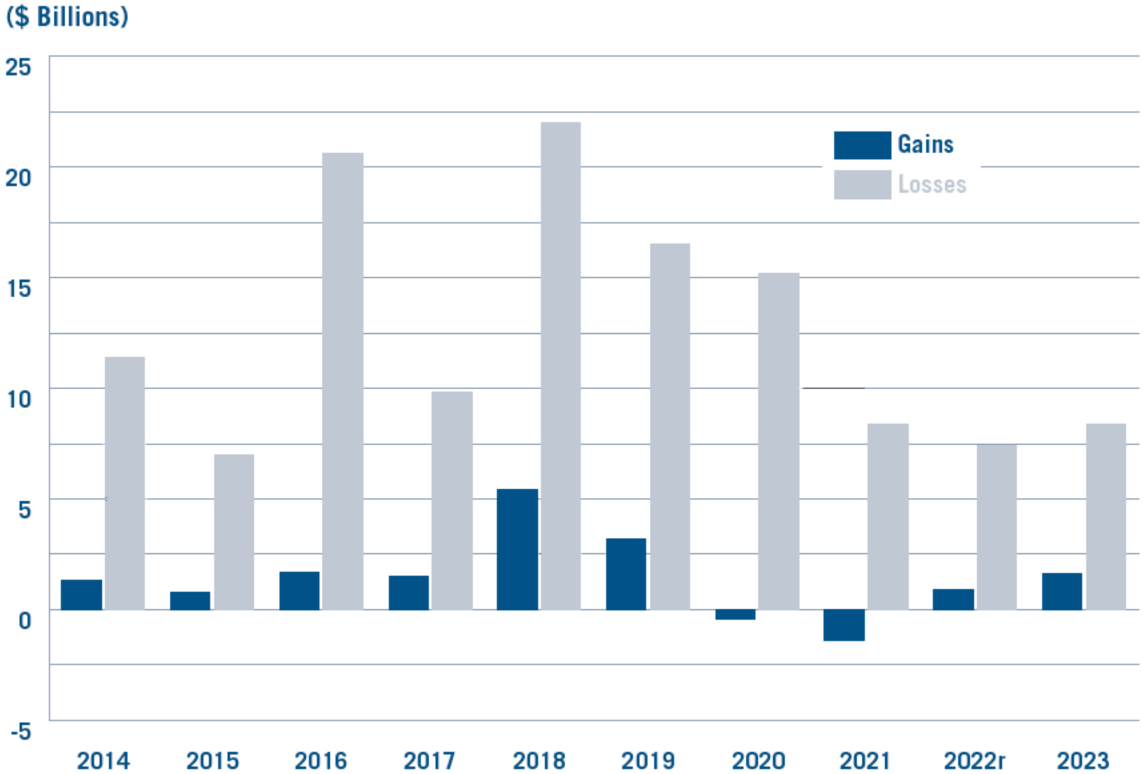
($ Millions)

Company	Gains	Losses	Net Total
Eversource Energy	–	2,174	2,174
PG&E Corp	–	1,898	1,898
Berkshire Hathaway Energy	–	1,677	1,677
Edison International	–	898	898
Consolidated Edison	865	–	865
PPL Corp	(12)	547	559
NextEra Energy	530	–	530
Dominion Energy	27	307	280
American Electric Power	–	197	197
WEC Energy Group	–	179	179

Source: S&P Global Market Intelligence and EEI Finance Department.

Aggregate Non-Recurring and Extraordinary Items

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



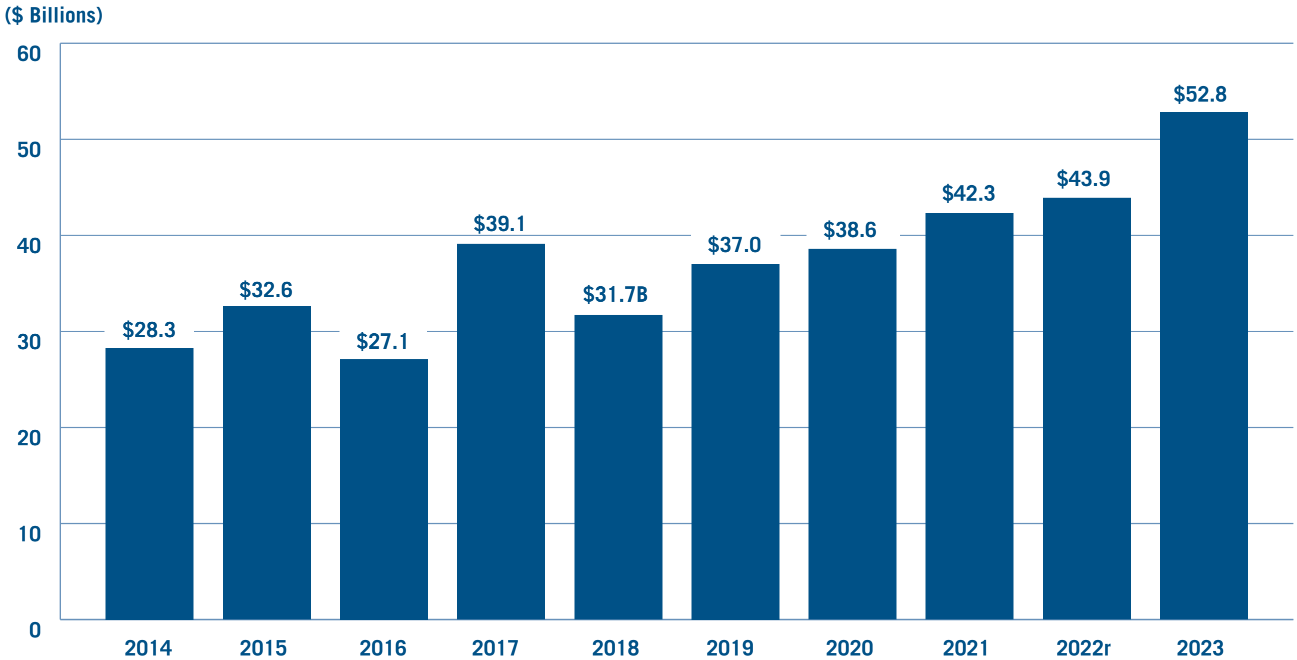
	2014	2015	2016	2017	2018	2019	2020	2021	2022r	2023
Gains	1.3	0.8	1.7	1.5	5.4	3.2	(0.4)	(1.4)	0.8	1.6
Losses	11.4	7.0	20.6	9.8	22.0	16.5	15.2	8.4	6.5	8.4

r = revised   Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

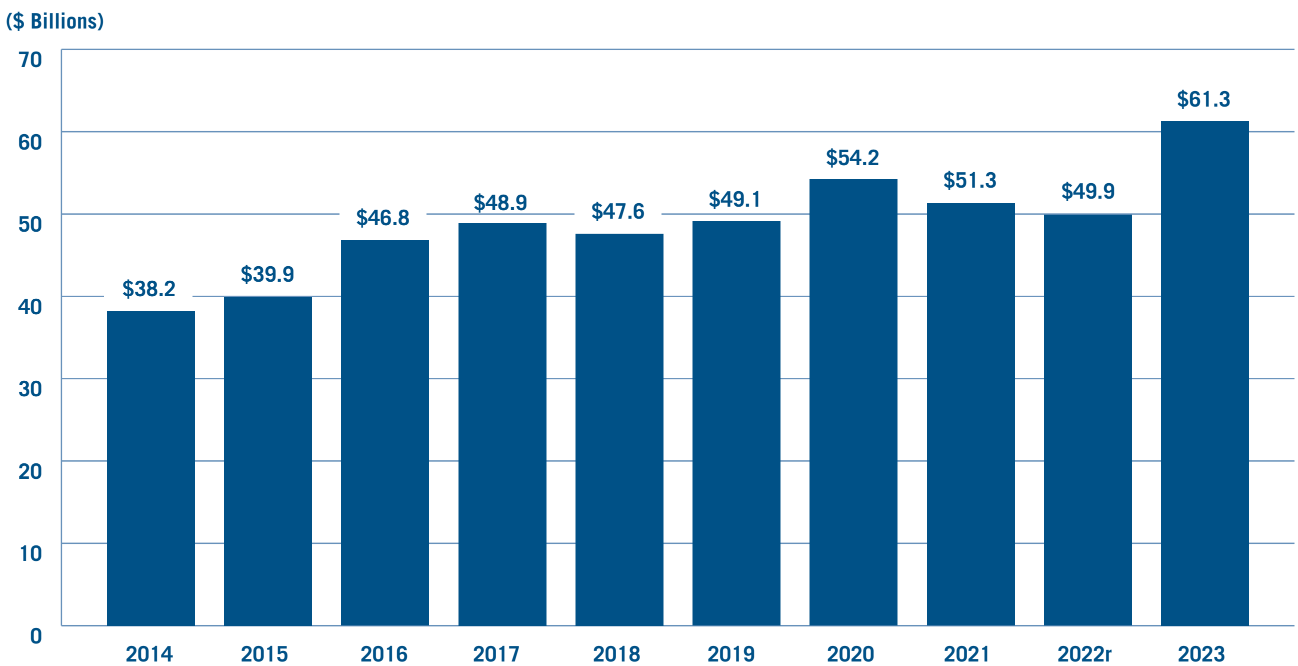


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

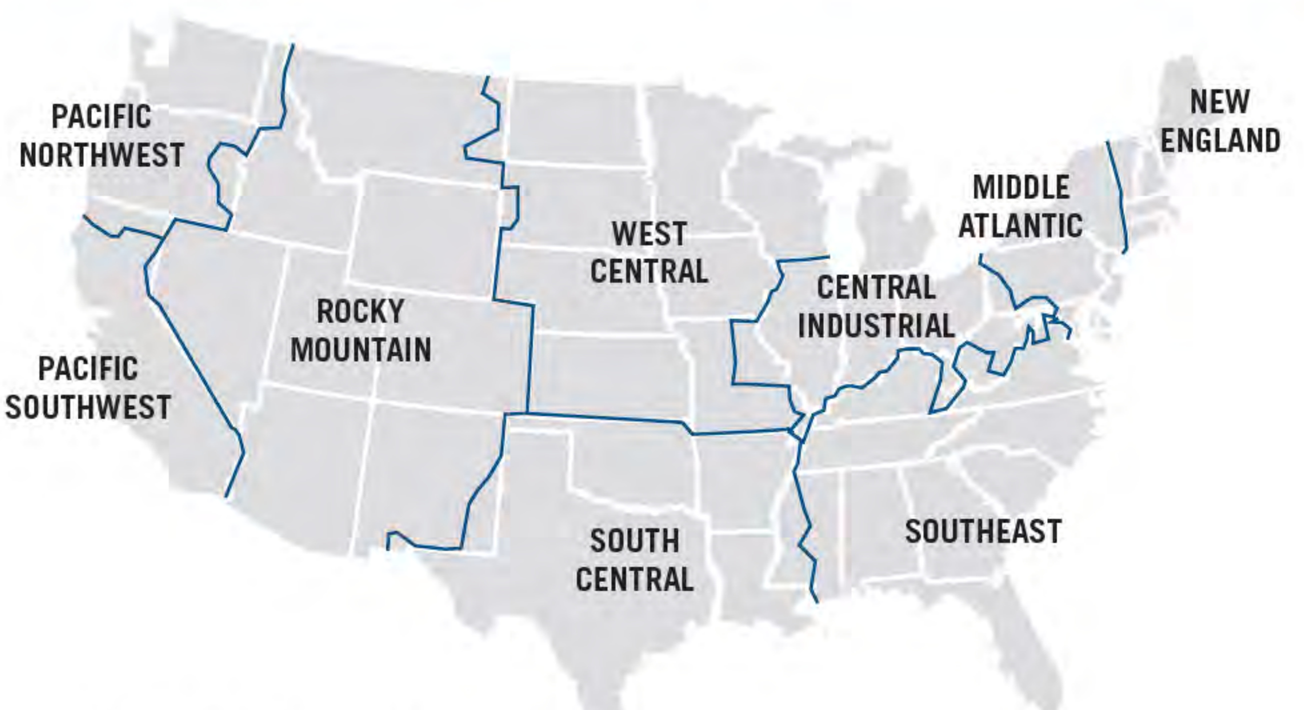
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2022	2021	% Change
Central Industrial	635,658	657,622	(3.3%)
Mid-Atlantic	402,544	419,466	(4.0%)
New England	111,002	115,781	(4.1%)
Pacific Northwest	158,794	161,364	(1.6%)
Pacific Southwest	267,566	273,602	(2.2%)
Rocky Mountain	293,697	296,141	(0.8%)
South Central	864,046	840,535	2.8%
Southeast	1,005,533	1,036,554	(3.0%)
West Central	337,306	341,836	(1.3%)
Total United States	**4,076,145**	**4,142,901**	**(1.6%)**

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Analytics.

EEI U.S. Electric Output – Regions



Source: EEI Business Analytics.

U.S. Weather
January – December 2023

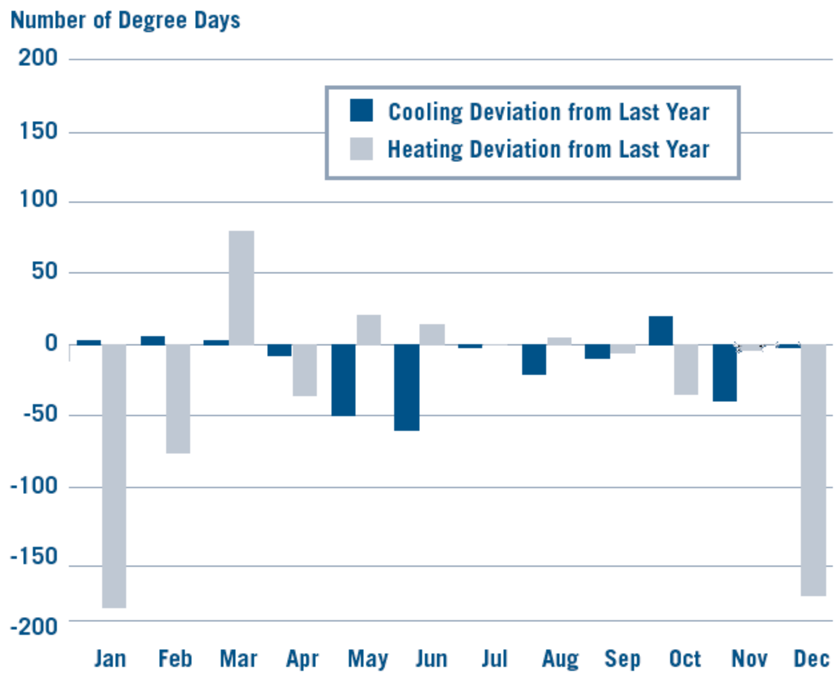
	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	550	133	32%	(136)	(20%)
Mid-Atlantic	698	42	6%	(281)	(29%)
East North Central	663	(45)	(6%)	(184)	(22%)
West North Central	1,057	129	14%	(34)	(3%)
South Atlantic	2,052	88	4%	(153)	(7%)
East South Central	1,632	84	5%	(94)	(5%)
West South Central	2,942	493	20%	16	1%
Mountain	1,253	10	1%	(154)	(11%)
Pacific	695	(9)	(1%)	(281)	(29%)
United States	**1,305**	**89**	**7%**	**(165)**	**(11%)**
Heating Degree Days					
New England	5,723	(888)	(13%)	(397)	(6%)
Mid-Atlantic	5,004	(907)	(15%)	(609)	(11%)
East North Central	5,561	(936)	(14%)	(795)	(13%)
West North Central	6,038	(712)	(11%)	(911)	(13%)
South Atlantic	2,318	(535)	(19%)	(388)	(14%)
East South Central	2,897	(707)	(20%)	(591)	(17%)
West South Central	1,970	(317)	(14%)	(399)	(17%)
Mountain	5,221	12	0%	22	0%
Pacific	3,412	184	6%	300	10%
United States	**4,001**	**(523)**	**(12%)**	**(401)**	**(9%)**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

2023 Weather Compared to 2022

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



Source: National Oceanic and Atmospheric Administration and National Weather Service.

	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	2	(185)
Feb	5	(76)
Mar	2	79
Apr	(8)	(36)
May	(50)	20
Jun	(60)	14
Jul	(2)	0
Aug	(21)	4
Sep	(10)	(6)
Oct	19	(35)
Nov	(40)	(4)
Dec	(2)	(176)
Total	**(165)**	**(401)**

Heating and Cooling Degree Days and Percent Changes

January—December 2023

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan	8	(1)	2	742	(175)	(185)	(11.1%)	33.3%	(19.1%)	(20.0%)
Feb	13	5	5	649	(83)	(76)	62.5%	62.5%	(11.3%)	(10.5%)
Mar	21	3	2	617	24	79	16.7%	10.5%	4.0%	14.7%
First Quarter	**42**	**7**	**9**	**2,008**	**(234)**	**(182)**	**20.0%**	**27.3%**	**(10.4%)**	**(8.3%)**
Apr	35	5	(8)	320	(25)	(36)	16.7%	(18.6%)	(7.2%)	(10.1%)
May	90	(7)	(50)	146	(13)	20	(7.2%)	(35.7%)	(8.2%)	15.9%
Jun	189	(24)	(60)	41	2	14	(11.3%)	(24.1%)	5.1%	51.9%
Second Quarter	**314**	**(26)**	**(118)**	**507**	**(36)**	**(2)**	**(7.6%)**	**(27.3%)**	**(6.6%)**	**(0.4%)**
Jul	371	50	(2)	3	(6)	0	15.6%	(0.5%)	(66.7%)	0.0%
Aug	319	29	(21)	8	(7)	4	10.0%	(6.2%)	(46.7%)	100.0%
Sep	179	24	(10)	53	(24)	(6)	15.5%	(5.3%)	(31.2%)	(10.2%)
Third Quarter	**869**	**103**	**(33)**	**64**	**(37)**	**(2)**	**13.4%**	**(3.7%)**	**(36.6%)**	**(3.0%)**
Oct	62	9	19	237	(45)	(35)	17.0%	44.2%	(16.0%)	(12.9%)
Nov	13	(2)	(40)	524	(15)	(4)	(13.3%)	(75.5%)	(2.8%)	(0.8%)
Dec	5	(2)	(2)	661	(156)	(176)	(28.6%)	(28.6%)	(19.1%)	(21.0%)
Fourth Quarter	**80**	**5**	**(23)**	**1,422**	**(216)**	**(215)**	**6.7%**	**(22.3%)**	**(13.2%)**	**(13.1%)**
Full Year	**1,305**	**89**	**(165)**	**4,001**	**(523)**	**(401)**	**7.3%**	**(11.2%)**	**(11.6%)**	**(9.1%)**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service.

Balance Sheet

- The U.S. economy in 2023 defied recession fears and rebounded steadily from late 2022's weakness. Real gross domestic product (GDP) grew 1.7% year-over-year in Q1 and 2.4% in Q2. Then growth strengthened to 2.9% in Q3 and 3.1% in Q4. Full-year 2023 real GDP growth was 2.5%.

- The Federal Reserve hiked short-term rates four times during the year's first half, raising the target Fed Funds rate to a range of 5.25% to 5.50%. Inflation eased from 2022's 7% to 9% monthly readings, falling from 6.4% in January to 3.1% in June. The Fed held rates steady in the year's second half, hoping the lag effects of its year-long tightening campaign would be enough to drive inflation lower. But inflation throughout 2023's second half remained above 3%, higher than the Fed's 2% policy goal.

- Inflation data and concerns over Washington's deficit spending lifted the 10-year Treasury yield from 3.5% in the year's first half to 5% by October before easing into year end. But economic confidence drove credit risk premia steadily lower throughout 2023. As a result, investment-grade corporates (Moody's Baa rating) could borrow long-term for less than 6% for most of the year.

- The industry's financial condition remained strong in 2023. Balance-sheet leverage appropriate for a lower risk profile has accompanied the multi-year trend toward increased state-regulated operations. Balance sheet leverage, in aggregate, increased slightly in 2023. However, aggregate figures convey only broad, long-term trends and emphasize large holding companies. Balance sheet structures vary widely across the industry. Leverage increased more than one percentage point at 21 utilities. Leverage was reduced by more than one percentage point or was largely unchanged at the remaining 23.

- The industry's consolidated total debt rose in 2023, a natural consequence of financing the aggressive build-out of clean-energy infrastructure. Rising interest rates since early 2022 have increased utilities' borrowing costs. Yet most have managed balance sheet ratios and cash flows to maintain investment-grade credit ratings. Most utilities increased long-term debt in 2023. Short-term debt rose at 24 companies and decreased or was largely unchanged at the remaining 20.

- Common equity issuance in 2023 declined from 2022's total, remaining well below its level from 2018 through 2020. This metric increased in 2023 at only 13 utilities. Many have sought to fund capex without significant equity dilution, in some cases with proceeds from asset sales. Equity issuance was strong in both 2020 and 2019 as companies augmented balance sheets and addressed the impact of tax reform. Equity issuance was also strong in 2018 as utilities took advantage of high price-earnings ratios and welcoming capital markets to fund capex and offset debt issuance.

- Property, plant and equipment in service (PPE in Service, net) rose 7.1% from its year-end 2022 level. This metric grew at nearly all 44 utilities which constitute EEI's consolidated data. Such broad growth shows the size and scope of the industry's build-out of new renewable generation, new transmission, reliability-related infrastructure and other capital projects that support the nation's clean energy transition. Construction work in progress (CWIP), a part of the PPE in Service total, jumped more than 18% from 2022's year-end total. CWIP accounts for capital investment in utility infrastructure still under construction and not yet in service. The growth in CWIP offers another view of the industry's rising clean energy capex.

- The debt-to-capitalization ratio by category data shows the dominance of state-regulated operations in the industry. EEI's "Regulated" group numbered 37 utility holding companies at year-end 2023. The remaining eight utilities constituted the "Mostly Regulated" group.

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2023	12/31/2022r	% Change	$ Change
PP&E in service, gross	1,899,012	1,788,991	6.1%	110,021
Accumulated depreciation	541,724	512,896	5.6%	28,828
PP&E in service, net	1,357,288	1,276,095	6.4%	81,193
Construction work in progress	122,475	103,611	18.2%	18,864
Net nuclear fuel	13,189	12,933	2.0%	256
Other property	14,963	15,328	(2.4%)	(365)
PP&E, net	1,507,915	1,407,967	7.1%	99,948
Cash & cash equivalents	14,182	13,331	6.4%	852
Accounts receivable	55,013	55,591	(1.0%)	(578)
Inventories	32,115	29,025	10.6%	3,090
Other current assets	81,539	80,311	1.5%	1,229
Total current assets	182,850	178,257	2.6%	4,592
Total investments	103,073	99,385	3.7%	3,688
Other assets	320,674	333,697	(3.9%)	(13,022)
Total Assets	**2,114,512**	**2,019,305**	**4.7%**	**95,207**
Common equity	566,924	539,386	5.1%	27,537
Preferred equity	8,332	10,287	(19.0%)	(1,955)
Noncontrolling interests	29,659	28,036	5.8%	1,623
Total equity	604,915	577,709	4.7%	27,205
Short-term debt	54,446	49,464	10.1%	4,983
Current portion of long-term debt	51,390	50,895	1.0%	495
Short-term and current long-term debt	105,836	100,359	5.5%	5,477
Accounts payable	86,980	90,908	(4.3%)	(3,928)
Other current liabilities	62,052	60,128	3.2%	1,923
Current liabilities	254,867	251,396	1.4%	3,472
Deferred taxes	122,845	116,561	5.4%	6,284
Non-current portion of long-term debt	799,481	734,906	8.8%	64,575
Other liabilities	330,684	337,154	(1.9%)	(6,470)
Total liabilities	1,507,877	1,440,016	4.7%	67,861
Subsidiary preferred	421	421	(0.0%)	(0)
Other mezzanine	1,299	1,159	12.1%	140
Total mezzanine level	1,720	1,580	8.9%	140
Total Liabilities and Owner's Equity	**2,114,512**	**2,019,305**	**4.7%**	**95,207**

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

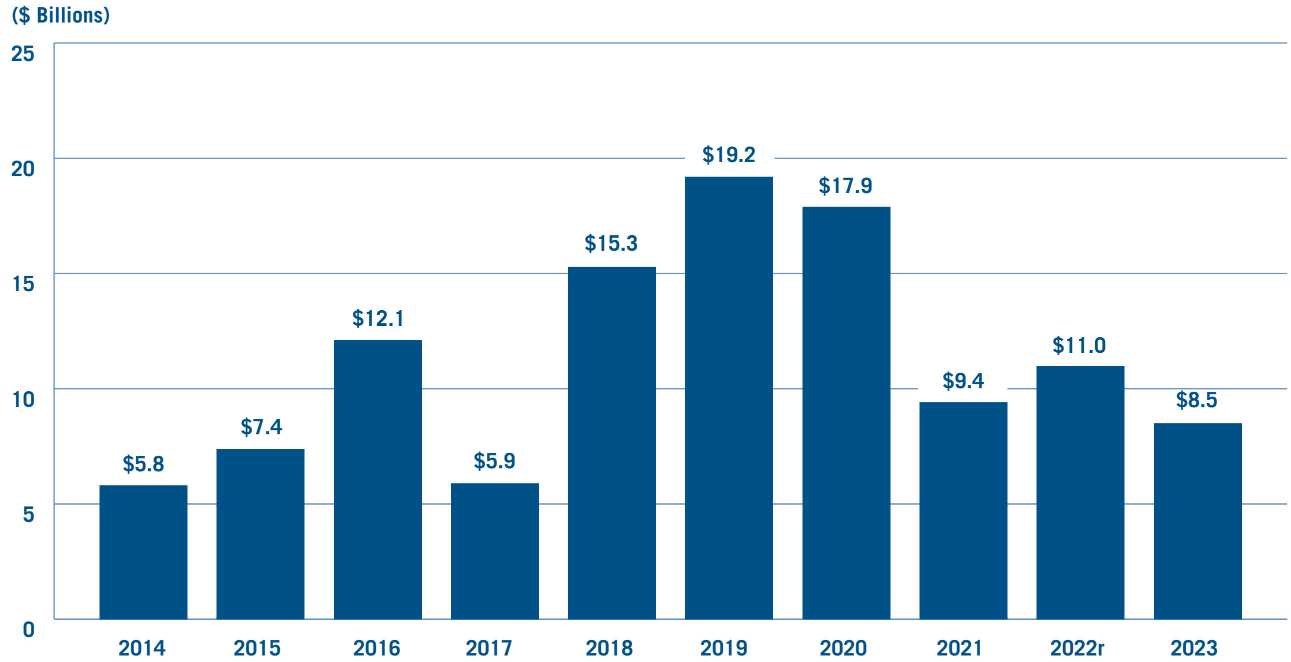
Capitalization Structure ($M)	12/31/2023	12/31/2022r	Change
Common Equity	566,924	539,386	27,537
Noncontrolling Interests & Preferred Equity	37,991	38,323	(332)
Long-term Debt (current & non-current)*	850,871	785,801	65,070
Total	**1,455,785**	**1,363,510**	**92,275**
Common Equity %	38.9%	39.6%	-0.6%
Noncontrolling Interests & Preferred Equity %	2.6%	2.8%	-0.2%
Long-Term Debt (current & non-current)* %	58.4%	57.6%	0.8%
Total	**100.0%**	**100.0%**	**–**

r = revised
Long-term debt not adjusted for (i.e., includes) securitization bonds.
Source: S&P Global Market Intelligence and EEI Finance Department.

- The tendency toward slightly higher balance sheet leverage at the consolidated industry level is not so clear when measured by individual company totals. Only 18 of the 37 "Regulated" holding companies meaningfully increased leverage in 2023. Leverage increased at three of the six "Mostly Regulated" companies.
- The dispersion across companies in both categories—with some showing higher, some lower and others no change in leverage—shows why individual company strategies are just as meaningful as consolidated totals when assessing industry trends.
- Regulated companies as a group continued to report higher balance sheet leverage than their Mostly Regulated peers. This is to be expected given their lower business risk profile.

Proceeds from Issuance of Common Equity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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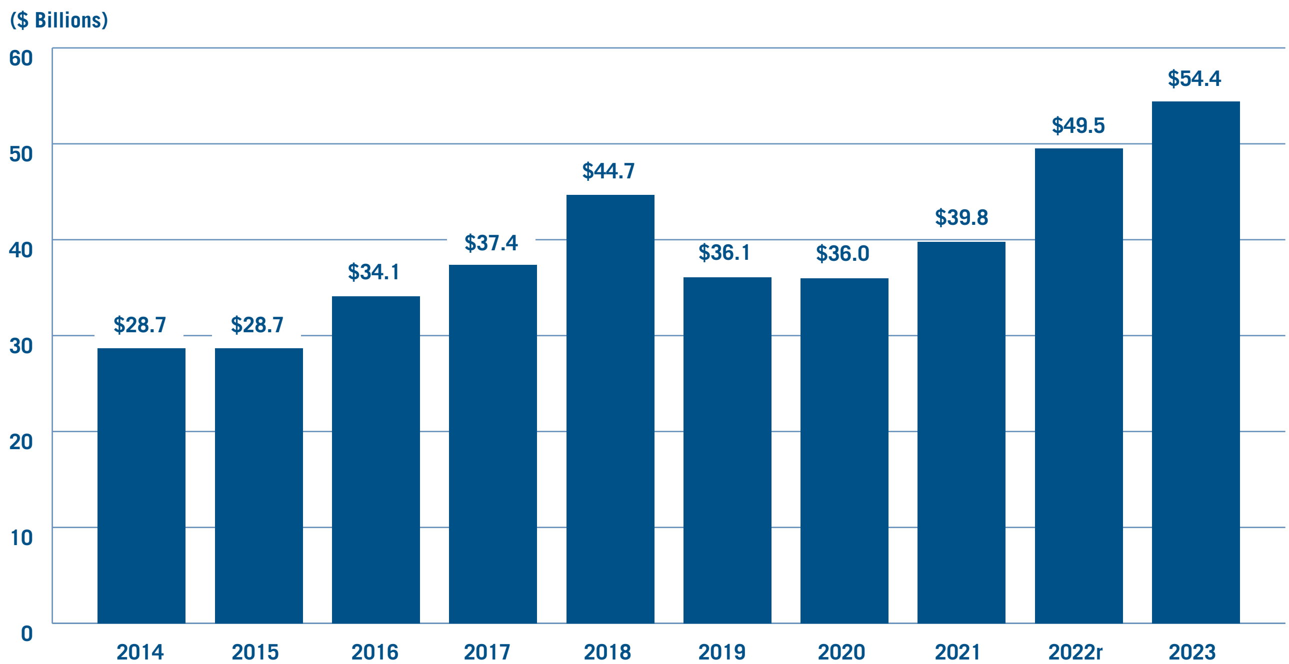
Source: S&P Global Market Intelligence and EEI Finance Department.

Short-term Debt

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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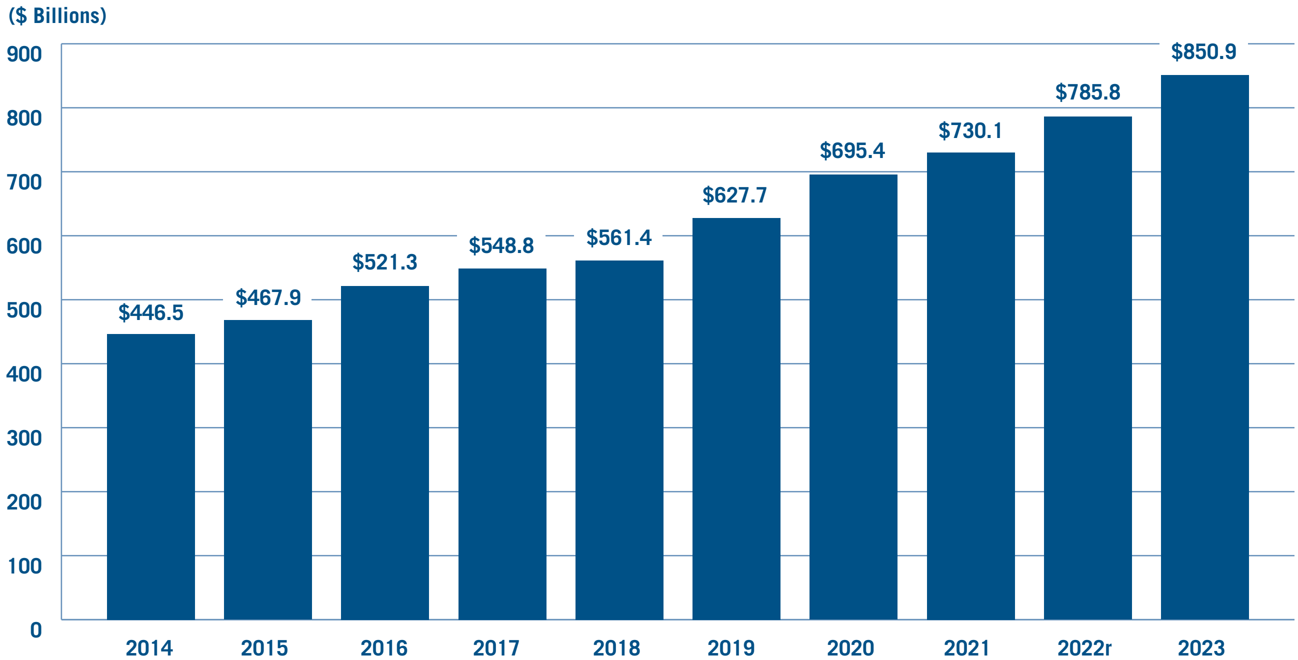
Source: S&P Global Market Intelligence and EEI Finance Department.

Long-term Debt

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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Source: S&P Global Market Intelligence and EEI Finance Department.

Debt-to-Cap Ratio by Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Total Industry	
	Number	%	Number	%	Number	%
Lower	8	21.1%	2	33.3%	10	22.7%
No Change*	12	31.6%	1	16.7%	13	29.5%
Higher	18	47.4%	3	50.0%	21	47.7%
Total	**38**	**100.0%**	**6**	**100.0%**	**44**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2023 vs. December 31, 2022. Refer to page v for category descriptions.

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure by Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated			Mostly Regulated		
	2023	2022r	Change	2023	2022r	Change
Common Equity ($M)	443,314	426,314	17,000	123,610	113,073	10,537
Total Preferred Equity	24,760	22,950	1,809	13,231	15,372	(2,141)
Long-term Debt (current & non-current)*	710,215	654,636	55,579	140,656	131,165	9,491
Total Capitalization	1,178,289	1,103,900	74,389	277,497	259,610	17,886
Common Equity %	37.6%	38.6%	-1.0%	44.5%	43.6%	1.0%
Preferred Equity %	2.1%	2.1%	0.0%	4.8%	5.9%	-1.2%
Long-Term Debt %	60.3%	59.3%	1.0%	50.7%	50.5%	0.2%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised
Refer to page v for category descriptions.
Note: Long-term debt not adjusted for (i.e., includes) securitization bonds.
Source: S&P Global Market Intelligence and EEI Finance Department.

PP&E In Service, Net

Date	PP&E in Service, Net ($M)	% Change from 12/31/2019
12/31/2023	1,357,288	20.1%
12/31/2022r	1,276,095	12.9%
12/31/21	1,221,089	8.1%
12/31/20	1,196,315	5.9%
12/31/19	1,129,880	

Source: S&P Global Market Intelligence and EEI Finance Department.

Cash Flow Statement

- Net Cash Provided by Operating Activities increased by $24.8 billion, or 26.9%, to $117.2 billion. Cash provided by Depreciation and Amortization (D&A), a non-cash charge on the income statement, increased by $4.1 billion, or 6.5%, at the consolidated industry level. D&A increased at 38 of the 44 utility holding companies that comprise EEI's data set; widespread increases are to be expected given the industry's aggressive clean energy infrastructure buildout.

- Cash provided by Deferred Taxes & Investment Credits increased to $3.5 billion from $3.0 billion in 2022. This metric ranged from $9.3 billion to $16.5 billion annually from 2010 through 2017, which were historically high levels due to elevated capex and use of bonus depreciation. The Tax Cuts & Jobs Act (TCJA), passed in late 2017, significantly reduced deferred taxes due to the reduction in the corporate income tax rate from 35% to 21% and the elimination of bonus depreciation. Since then, the aggregate industry total has been much lower.

- Change in Working Capital utilized $11.4 billion less cash in 2023 than in 2022. The difference traced mostly to accounting at a few large utility holding companies. Other Operating Changes in Cash remained small and was little changed.

- Net Cash Used in Investing Activities increased by $13.4 billion, or 9.0%. The industry's capital spending—by far the largest component of this metric—increased 16.4% to $171.9 billion from $147.7 billion in 2022. Industry capex has reached a new record high in each of the past ten years. EEI member companies continue to invest in clean energy resources and the infrastructure necessary to make the power grid more modernized, resilient, and secure for all customers. Spending on transmission and distribution continues to increase relative to recent years, as EEI member companies expand their focus on adaptation, hardening, and resilience (AHR) initiatives. Investment in generation continues to be driven by the development of renewable energy and natural gas generation.

- Cash provided by Asset Sales increased $8.8 billion, or 37.7%, from $23.5 billion in 2022 to $32.3 billion in 2023. Utilities continue to utilize asset sales to exit non-regulated operations while raising equity to avoid dilutive stock offerings and fund clean energy capex. This metric is typically driven by activity at a few large utilities; 2023 was no exception as six companies accounted for more than 90% of the industry's 2023 total.

- Net Cash Provided by Financing Activities decreased by $9.6 billion, or 17.5%. The decline resulted primarily from a nearly equal reduction, at $8.2 billion, in the use of long-term debt financing. That metric fell in aggregate from $67.5 billion in 2022 to $59.3 billion in 2023 and was tied to divestiture activity and balance sheet management at just a few large utilities. Debt issuance is routine in the normal course of financing operations for such a capital-intensive industry, and just over half the 44 underlying utilities tracked by EEI increased their use of long-term debt in 2023.

- Dividends Paid to Common Shareholders rose 4.8% to $32.9 billion. Investors that supply equity capital are attracted to steady and growing dividends. The industry raised its aggregate dividend payout during the 2008/2009 financial crisis and the more recent Covid-19 pandemic.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

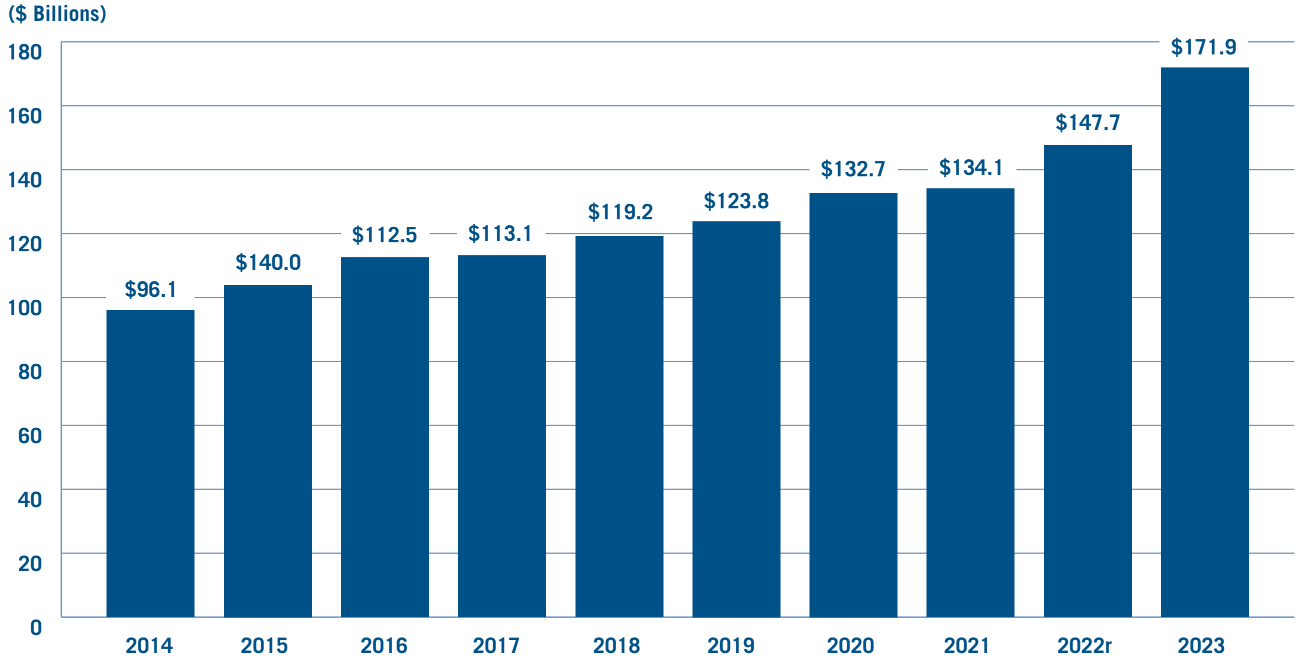
$ Millions	12 Months Ended		
	12/31/2023	12/31/2022r	% Change
Net Income	$52,840	$43,897	20.4%
Depreciation and Amortization	67,289	63,156	6.5%
Deferred Taxes and Investment Credits	3,548	2,894	22.6%
Operating Changes in AFUDC	(1,989)	(1,599)	24.4%
Change in Working Capital	(1,057)	(12,454)	(91.5%)
Other Operating Changes in Cash	(3,378)	(3,463)	(2.4%)
Net Cash Provided by Operating Activities	**117,252**	**92,431**	**26.9%**
Capital Expenditures	(171,918)	(147,662)	16.4%
Asset Sales	32,296	23,454	37.7%
Asset Purchases	(18,144)	(19,681)	(7.8%)
Net Non-Operating Asset Sales and Purchases	14,146	3,769	275.3%
Change in Nuclear Decommissioning Trust	(1,112)	(698)	59.3%
Investing Changes in AFUDC	55	45	22.6%
Other Investing Changes in Cash	(4,131)	(5,015)	(17.6%)
Net Cash Used in Investing Activities	**(162,954)**	**(149,557)**	**9.0%**
Net Change in Short-term Debt	11,203	8,013	39.8%
Net Change in Long-term Debt	59,269	67,472	(12.2%)
Proceeds from Issuance of Preferred Equity	542	–	NM
Preferred Share Repurchases	(2,339)	(2,768)	(15.5%)
Net Change in Prefered Issues	(1,797)	(2,768)	(35.1%)
Proceeds from Issuance of Common Equity	8,505	10,957	(22.4%)
Common Share Repurchases	(1,095)	(2,036)	(46.2%)
Net Change in Common Issues	7,410	8,921	(16.9%)
Dividends Paid to Common Shareholders	(32,925)	(31,409)	4.8%
Dividends Paid to Preferred Shareholders	(322)	(335)	(4.0%)
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(33,247)	(31,744)	4.7%
Other Financing Changes in Cash	2,577	5,123	(49.7%)
Net Cash (Used in) Provided by Financing Activities	**45,414**	**55,016**	**(17.5%)**
Other Changes in Cash	13	(38)	NM
Net increase (decrease) in cash and cash equivalents	($275)	($2,148)	(87.2%)
Cash and cash equivalents at beginning of period	$14,457	$15,478	(6.6%)
Cash and cash equivalents at end of period	$14,182	$13,331	6.4%

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Capital Expenditures

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

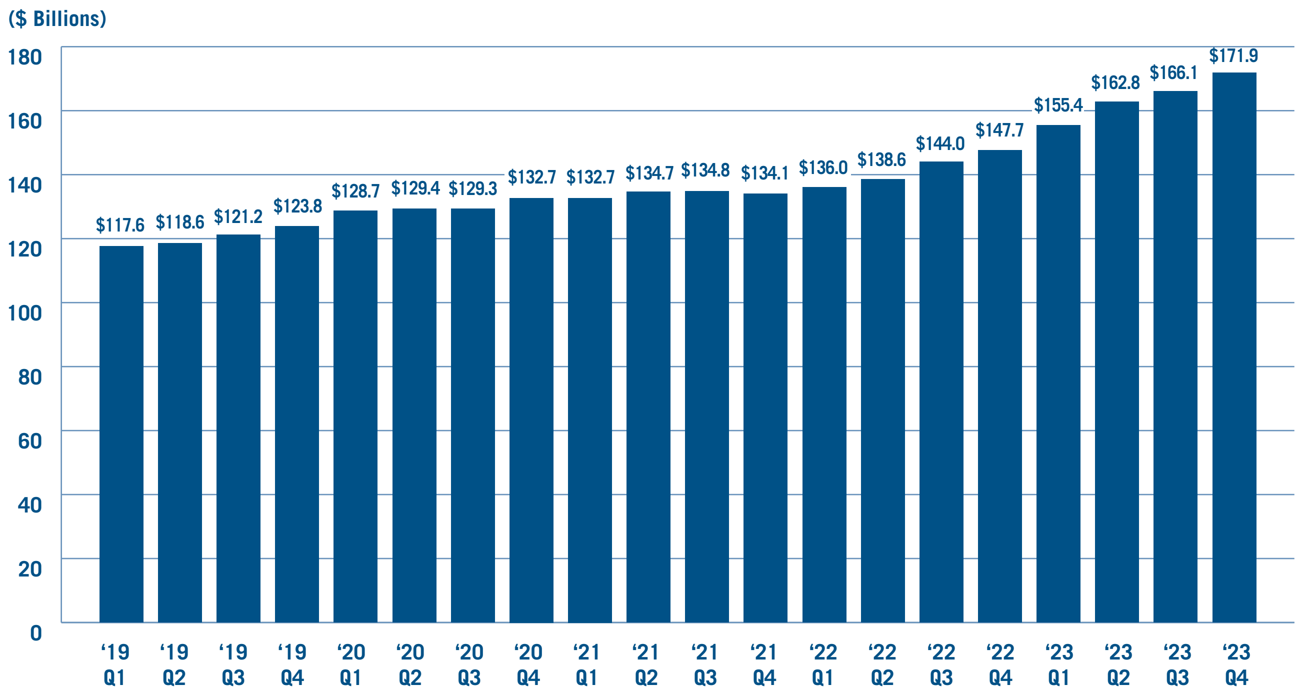


r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Expenditures—Trailing 12 Months

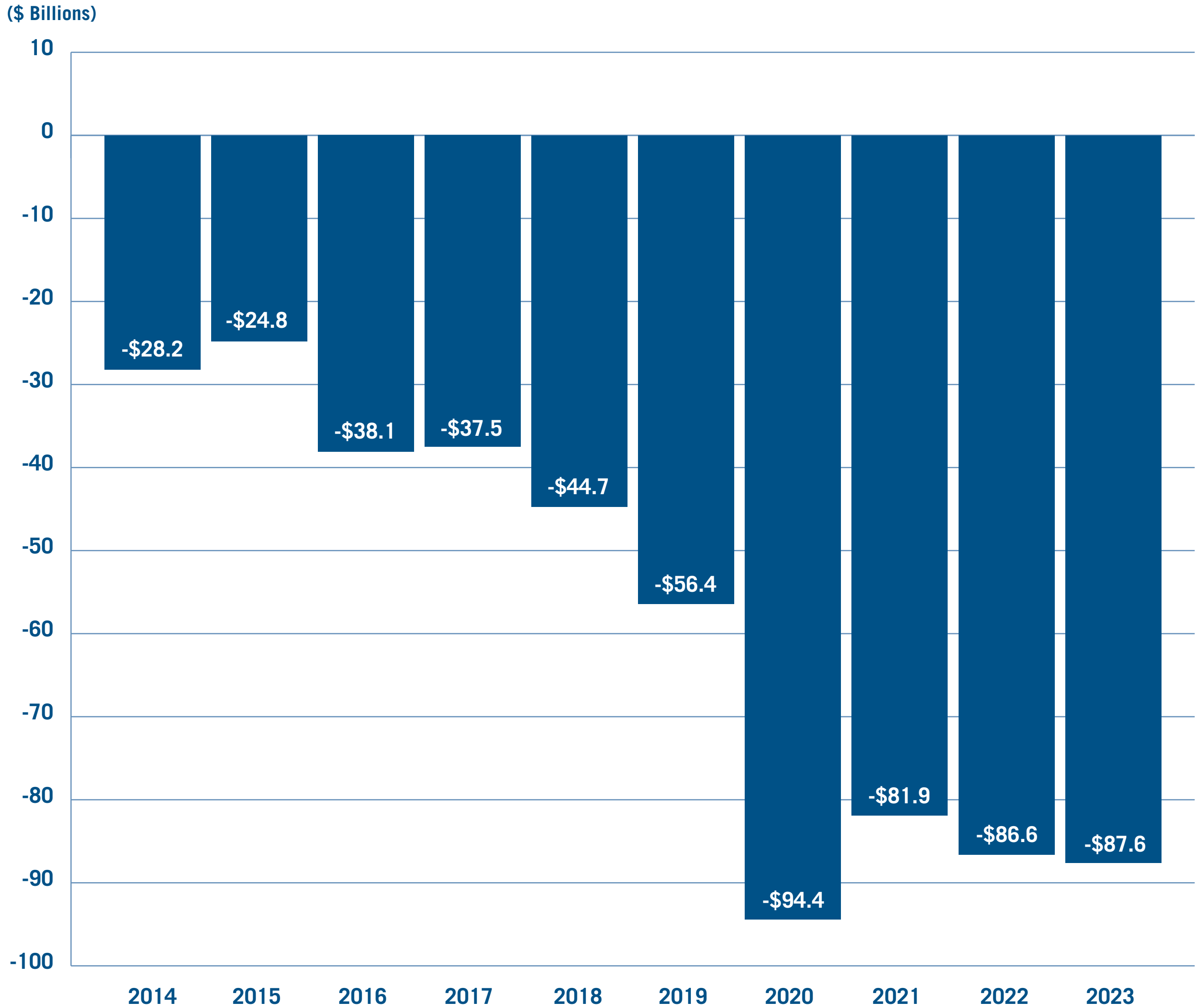
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Free Cash Flow (FCF)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



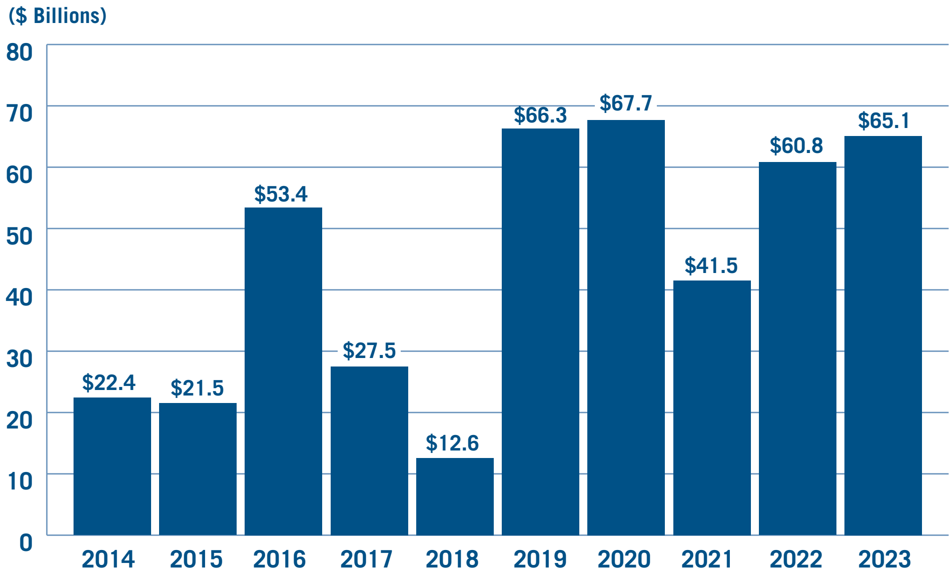
($ Billions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Net Cash Provided by Operating Activities	89.0	101.6	98.3	101.2	100.1	95.3	67.7	82.4	92.4	117.3
Capital Expenditures	(96.1)	(104.0)	(112.5)	(113.1)	(119.2)	(123.8)	(132.7)	(134.1)	(147.7)	(171.9)
Dividends Paid to Common Shareholders	(21.1)	(22.5)	(23.8)	(25.5)	(25.6)	(27.9)	(29.3)	(30.3)	(31.4)	(32.9)
Free Cash Flow	**(28.2)**	**(24.8)**	**(38.1)**	**(37.5)**	**(44.7)**	**(56.4)**	**(94.4)**	**(81.9)**	**(86.6)**	**(87.6)**

r = revised

Note: Totals may not equal sum of components due to rounding.
Source: S&P Global Market Intelligence and EEI Finance Department.

Net Change in Long-term Debt

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Note: Based on data from industry's consolidated balance sheet.

Source: S&P Global Market Intelligence and EEI Finance Department.

Rate Review Summary

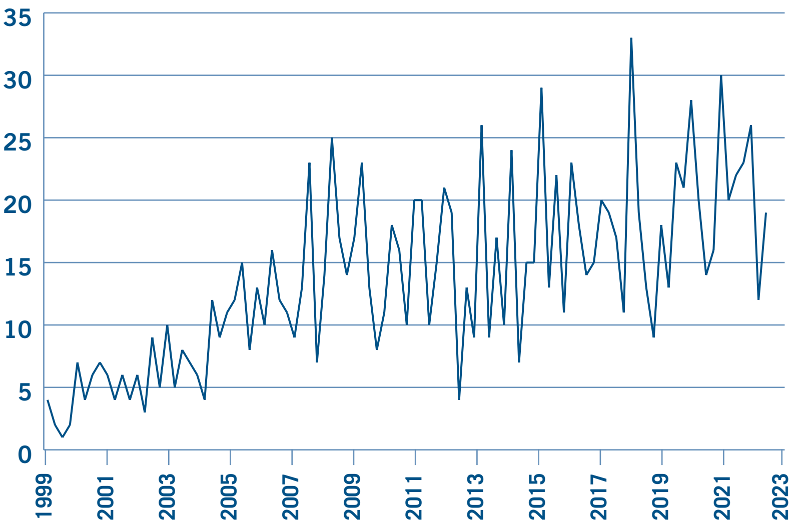
- There were 80 rate reviews filed in 2023, with 91 rate reviews decided. This is notably more than the 59 rate reviews filed and the 81 rate reviews decided in 2022.
- Of the decided filings, electric companies requested revenue increases of approximately $17 billion in 2023; with approximately $9.3 billion approved.
- The average awarded ROE was 9.58 percent, a slight rebound of 11 basis points from 2022 which had an average awarded ROE of 9.47 percent. The average awarded ROE for distribution-only companies was 9.24 percent compared to 9.80 percent for vertically integrated companies.
- Regulatory lag hovered around 8.51 months, which is longer than it has been in the last couple years at 8.01 months in 2022 and 8.41 months in 2021.

State Regulatory Highlights from 2023

- Infrastructure Investment & Jobs Act (IIJA) and Inflation Reduction Act (IRA) – More than two dozen states have opened proceedings for electric companies to provide information related to their efforts to obtain federal grants or other benefits under IIJA and IRA. Many of these proceedings also look to quantify the benefits to customers, explore potential challenges for electric companies in receiving the grants, and information gathering/reporting. As of year-end 2023, 22 member companies

Number of Rate Reviews Filed

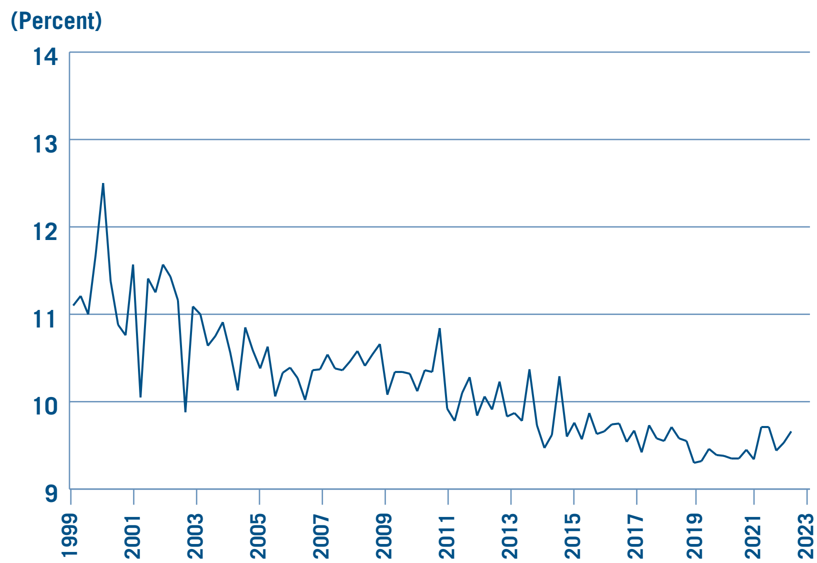
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Average Awarded ROE

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



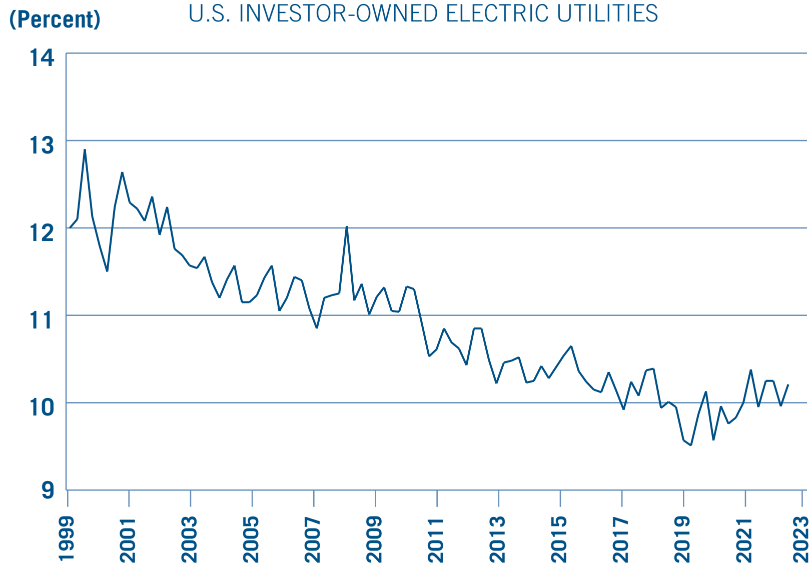
Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

have received over $1 billion in Grid Resilience and Innovation Partnerships (GRIP) awards.

- Rate Design – The convergence of numerous industry pressures including the clean energy transition, affordability, ambitious state policies, and unprecedented load growth have brought rate design to the forefront in several states. Rate design helps to determine who pays, how much they will pay, and how they will pay and is currently being examined by stakeholders as a potential tool to help address the pressures listed above. For example, in California, the commission opened a docket, as required by legislation passed in 2022, to implement an income-graduated fixed charge to protect low-income customers. Missouri was also the latest state to make time-of-use rates the default option for residential customers, while a similar proceeding is currently under consideration in Hawaii.

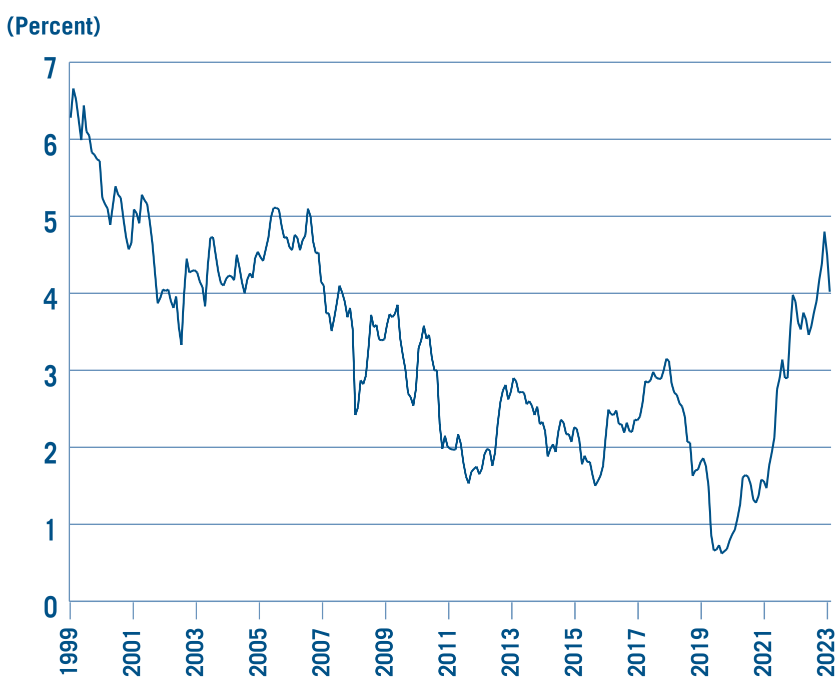
- Affordability – The topic of affordability continues to play a significant role in state regulatory activity and is a key consideration in many of the areas mentioned above. Several states are considering wide-ranging action to support low- to moderate-income (LMI) customers. This includes expanding electric company credits or bill discounts, including an LMI carveout for community solar programs like those in Maryland and New Jersey, and/or how to stack various state, electric company, and federal programs to ensure the customers most in need receive the biggest benefit.

Average Requested ROE



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

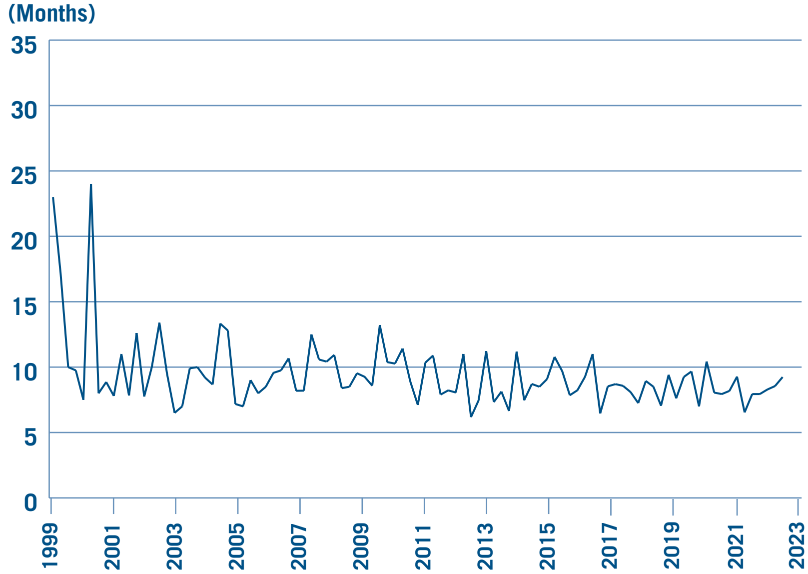
10-Year Treasury Yield



Source: U.S. Federal Reserve.

Average Regulatory Lag

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Finance, Accounting, and Investor Relations

The Finance, Accounting, and Investor Relations teams are part of EEI's Business Operations Group. This division provides leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, and budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Finance, Accounting, or Investor Relations staff member. Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

Publications

Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly Financial Update (QFU) reports include stock performance, dividends, credit ratings, and rate review summary.

Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry including the QFU topics mentioned above as well as the industry's consolidated financial statements. The report also includes an analysis in the areas of business segmentation, mergers & acquisitions, construction, and fuel use by electric utilities.

EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The EEI index, which measures total return and provides company rankings for year to date and trailing one-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples.

Conference Highlights

Financial Conference

This three-day conference is the premier industry gathering of electric company c-suite officers, investors, and the financial community. This annual conference provides a unique opportunity for delegates to network and discuss issues impacting electric companies, investors, customers, and key stakeholders. This exclusive event fosters an engaging setting for delegates, speakers, and sponsors. The meeting features general session presentations, breakout company visit rooms, and entertaining receptions. Contact Jacob Moshel for more information.

Chief Financial Officers' Forum

This forum is held once a year in the fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is open to member company chief financial officers only. Contact Aaron Cope for more information.

Finance Committee Meeting

This day and a half meeting is held in the spring or summer. The meeting covers current and emerging industry issues critical to the electric power industry. It also provides an opportunity for utility financial officers to identify best practices and share management skills that contribute to financial performance. Contact Aaron Cope for more information.

Investor Relations Meeting

This one-day meeting is held in the spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Jacob Moshel for more information.

Treasury Group Meeting

Half day meetings are held in the spring and the fall annually. Discussion is focused on pension funding, capital markets and economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. Contact Jacob Moshel for more information.

ESG/Sustainability Committee Forum

The committee forum convenes in-person biannually and virtually as needed to discuss existing and emerging ESG issues in the power sector. The two-day forum is open to the financial community, ESG stakeholders, and members on day one and is closed to members only on day two. Attendees hear industry and expert perspectives on key ESG trends that have implications on the power sector. The forum also allows attendees to discuss best practices and develop collaborative industry solutions to address various ESG issues and increasing disclosure mandates. Contact Aaron Cope for more information.

Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Beginning in 2024, the EEI Accounting Standards Committee joined this conference. Contact Dave Dougher for more information.

Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Internal Auditing Committee and other employees of EEI/ AGA member companies designated by the CAE. Contact Dave Dougher for more information.

Spring Accounting Conference

Hosted by the EEI Accounting, Reporting, & Automation Committee, the Property Accounting & Valuation Committee, the Budgeting & Financial Forecasting Committee and the AGA Corporate Accounting and Property Accounting Committees, this conference provides a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries. The meeting is open to members of the Committees and other employees of EEI/AGA member companies. Contact Dave Dougher for more information.

Taxation Committee Meeting

This three-day meeting is held every June and November, providing an opportunity for member company tax personnel to discuss technical information on utility tax issues. In addition to information exchange, members are briefed on current developments concerning major tax issues through presentations by committee members, outside tax specialists, and EEI staff. Contact Mark Agnew for more information.

Tax School

Hosted by the EEI Taxation Committee, this training is held every year as a virtual meeting done over 2-3 days. The program is designed for tax managers and tax staff with two-plus years of tax experience or for financial accounting supervisors with tax responsibilities. The school is taught by a faculty of outstanding speakers from the accounting and legal professions as well as others from within the industry. The EEI Tax School will rotate in alternate years between an intermediate-level focus and a beginner-level focus. The 2024 EEI Tax School will be held in September and have an intermediate-level focus. Contact Mark Agnew for more information.

Accounting Courses

Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Dave Dougher for more information.

Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect EEI member companies. Contact Dave Dougher for more information.

Property Accounting & Depreciation Training Seminar

The content from this seminar has been incorporated into the public utility accounting training courses described above and is no longer offered as a separate seminar. Contact Dave Dougher for more information.

Utility Internal Auditor's Training

Provides utility staff auditors, managers, and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA—convenes for two and one-half days. Contact Dave Dougher for more information.

Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Accounting for Energy Derivatives and FERC Accounting. Contact Dave Dougher for more information.

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Schedule of Upcoming Meetings

To assist in planning your schedule, here are upcoming meetings related to finance and accounting that may be of interest.

July 22-23, 2024
EEI/AGA Accounting Liaison Committee Meeting with FERC Staff
Edison Electric Institute
Washington, DC

August 27-29, 2024
EEI/AGA Utility Internal Auditor's Training Courses
Loews Atlanta Hotel
Atlanta, Georgia

August 27-30, 2024
EEI-AGA Introduction to Public Utility Accounting and Advanced Public Utility Accounting Training Courses
Loews Atlanta Hotel
Atlanta, Georgia

September 9 and 11, 2024
EEI Tax School
Virtual Meeting

November 3-6, 2024
EEI/AGA Taxation Committee Meeting
Marco Island, Florida

November 10-12, 2024
EEI Financial Conference
Diplomat Beach Resort
Hollywood, Florida

November 10, 2024
EEI Treasury Group Meeting
(Closed meeting, admittance by invitation only)
Diplomat Beach Resort
Hollywood, Florida

November 10, 2024
Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Diplomat Beach Resort
Hollywood, Florida

December 2024
Investor Relations Planning Group Meeting
(Closed meeting, admittance by invitation only)
New York, New York

December 2024
Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
New York, New York

May 2025
EEI/AGA Spring Accounting Conference
TBD

June 2025
EEI/AGA Accounting Leadership and Chief Audit Executives Conferences
TBD

U.S. Investor-Owned Electric Utilities

(At 12/31/2023)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
Berkshire Hathaway Energy
Black Hills Corporation
CenterPoint Energy, Inc.
Cleco Corporate Holdings LLC
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Energy
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Inc.
Puget Energy, Inc.
Sempra Energy
Southern Company
The AES Corporation *
DPL Inc.
IPALCO Enterprises, Inc.
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Note: This list includes 39 publicly traded U.S. electric utility holding companies plus an additional five electric utilities (shown in italics) that are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States.

* The AES Corporation is not included in the count of 39, but rather its two U.S. electric utility subsidiaries are included in the group of five italicized companies.

Other EEI Member Companies

American Transmission Company
Central Hudson Gas & Electric Corp.
Duquesne Light Company
El Paso Electric
Florida Public Utilities
Green Mountain Power
ITC Holdings Corp.
Liberty Utilities
Mt. Carmel Public Utility Company
National Grid
Ohio Valley Electric Corporation
Sharyland Utilities
Tampa Electric an Emera Company
UGI Corporation
UNS Energy Corporation
Upper Peninsula Power Company
Vermont Electric Power Company

Note: These companies are not included in the EEI Financial Review data sets for one of the following reasons: they do not provide retail electric distribution service (i.e., transmission-only), they are subsidiaries of foreign-owned companies, they are not traded on a major U.S. stock exchange, or they are owned by a non-utility holding company and the granularity of publicly available financial data is insufficient.

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. EEI also has dozens of international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Safe, reliable, affordable, and increasingly clean energy enhances the lives of all Americans and powers the economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States and contributes 5 percent to the nation's GDP.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at **www.eei.org**.

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CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2412

Major Energy Rate Case Decisions
January to June 2024
Regulatory Research Associates (RRA)
(Affiliate Standard and Poor's Global Market Intelligence)
[July 29 2024 Edition]

August 16, 2024

Major energy rate case decisions in the US

January–June 2024

Quarterly update on decided rate cases

Lisa Fontanella, Research Director

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Majda Shabbir

For detailed data

Access the RRA's electric and gas rate case decisions as of June 30, 2024, data tables.

An overview of state-level electric and gas rate case decisions in the US through the first half of 2024 and select historical data.

Table of Contents

Executive Summary

Introduction

The average electric and gas authorized returns on equity are trending modestly upward.

As per calculations from Regulatory Research Associates, the average return on equity (ROE) authorized electric utilities was 9.68% in rate cases decided in the first half of 2024, above the 9.60% average for full year 2023. There were 21 electric ROE authorizations in January–June 2024 versus 63 in full-year 2023.

The average ROE authorized gas utilities was 9.83% in rate cases decided in the first half of 2024, above the 9.64% average for full year 2023. There were 10 gas ROE authorizations in January–June 2024 versus 43 in full year 2023.

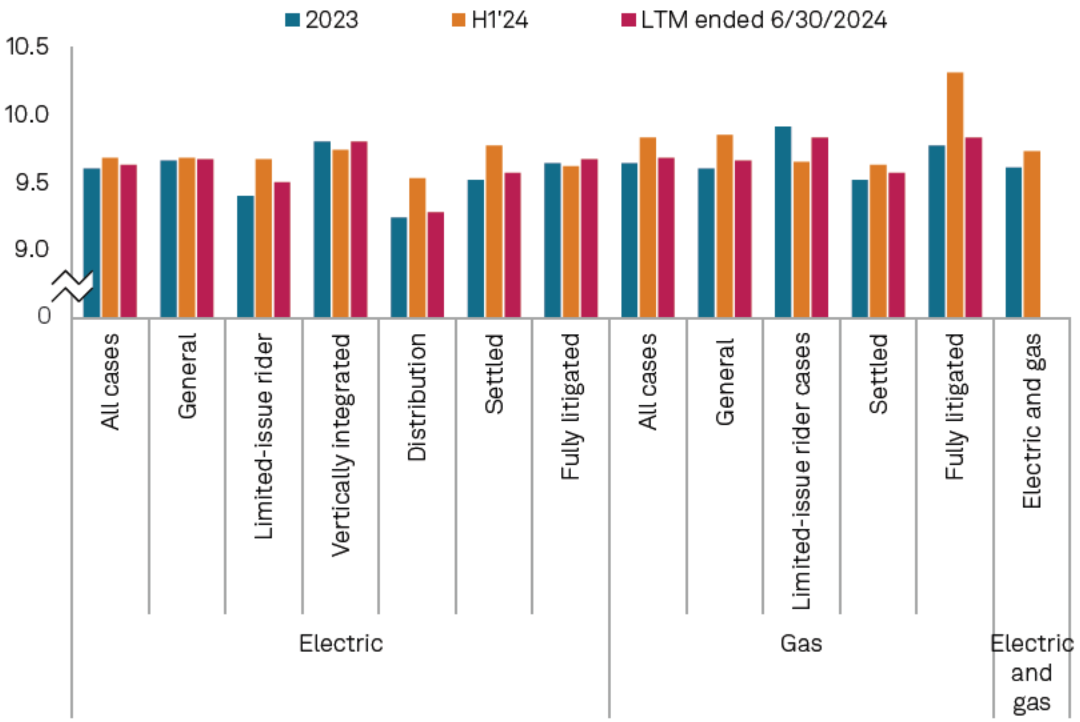
Rate case activity reached record-high levels in 2023, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems; build new natural gas, solar and wind generation; and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost-of-capital parameters, the impact of broader economic and sectorwide forces on operations, recovery of storm and severe-weather-related costs , regulatory approval for alternative regulatory mechanisms, and the need to address rate treatment to be accorded generation facilities being retired prior to the end of their planned service lives due to the energy transition.

About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during the first half of 2024 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, which is available on the S&P Capital IQ Pro platform. RRA endeavors to follow all “major” rate cases for investor-owned utilities nationwide, with “major” defined as a case in which the utility’s request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA’s coverage.

Average authorized ROE (%)



	2023	H1'24	LTM ended 6/30/2024
Electric averages			
All cases	9.60	9.68	9.63
General rate cases	9.66	9.68	9.67
Limited-issue rider cases	9.40	9.67	9.50
Vertically integrated cases	9.80	9.74	9.80
Distribution cases	9.24	9.53	9.28
Settled cases	9.52	9.77	9.57
Fully litigated cases	9.64	9.62	9.67
Gas averages			
All cases	9.64	9.83	9.68
General rate cases	9.60	9.85	9.66
Limited-issue rider cases	9.91	9.65	9.83
Settled cases	9.52	9.63	9.57
Fully litigated cases	9.77	10.31	9.83
Composite electric and gas averages			
Electric and gas	9.61	9.73	9.65
US Treasury			
30-year bond yield	4.09	4.46	4.44

Data compiled July 23, 2024.

ROE = return on equity; LTM = last 12 months.

Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

The Take

Averages calculated for the first half of 2024 show that electric and gas authorized ROEs are trending modestly higher, as the high-interest-rate environment begins to impact authorized ROEs. The effect of interest rate increases on authorized returns is not proportional, however, as regulators are slower to adjust ROEs upward than downward, and affordability concerns persist as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing almost 165 decisions in 2023. With higher interest rates, elevated inflation and accelerating capital spending to address public policy goals, particularly the energy transition, RRA anticipates that the flurry of rate case activity will continue.

Overview of electric and gas authorizations

Both the electric and gas average authorized ROEs in the first half of 2024 inched gently higher than the averages for full year 2023.

The average ROE authorized for electric utilities was 9.68% for rate cases decided in the first half of 2024, above the 9.60% average observed in full year 2023. There were 21 electric ROE determinations reflected in the calculations for January–June 2024 versus 63 in full year 2023.

The average ROE authorized for gas utilities was 9.83% for cases decided in the first half of 2024, above the 9.64% average observed in full year 2023. There were 10 ROE determinations reflected in the calculations for January–June2024 versus 43 in full year 2023.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired. Excluding rider cases, the average authorized ROE for electric cases was 9.68% in the first half of 2024, versus 9.66% for full year 2023. There was only one limited-issue rider case with a gas authorized ROE in January–June2024 and a 9.65% ROE was authorized. Excluding the one rider rate case in the first half of 2024 and six rider cases in full year 2023, the average authorized ROE for gas cases was 9.85% in January–June2024 and 9.60% in full year 2023. For the most part, limited-issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

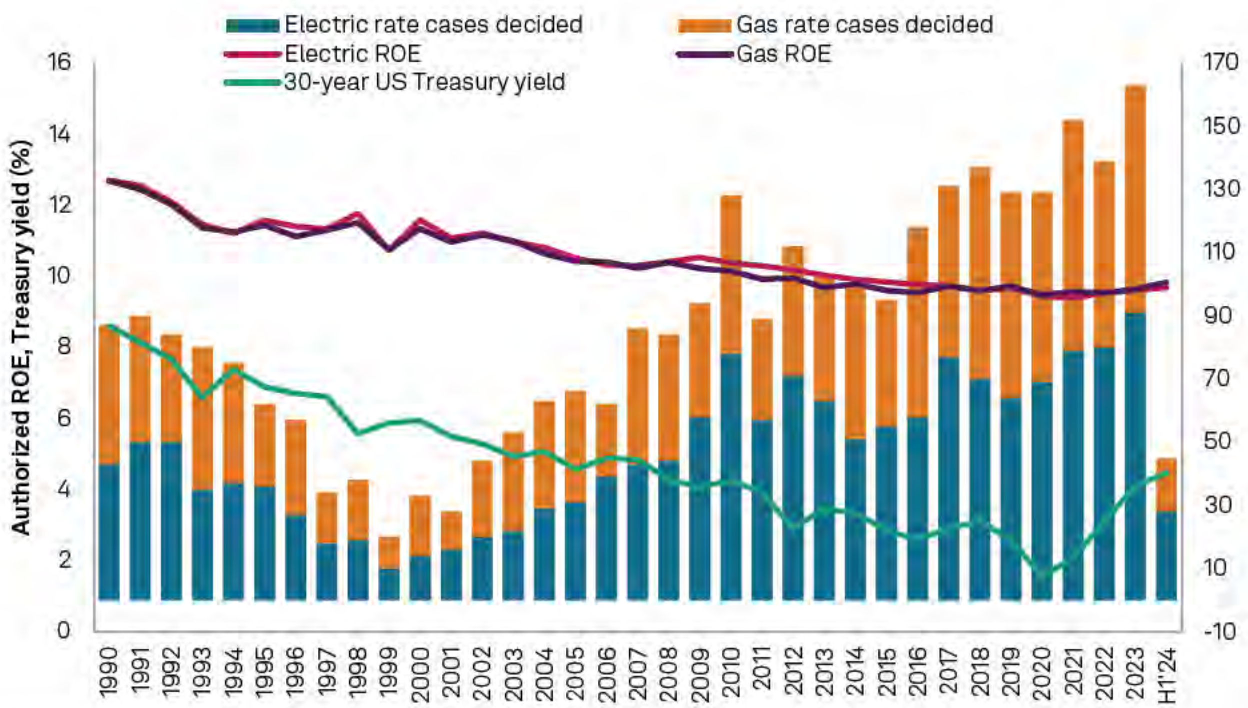
In the first half of 2024, the median ROE authorized in all electric utility rate cases was 9.70% versus 9.50% in full year 2023; for gas utilities, the metric was 9.68% in the first half of 2024 and 9.60% in full year 2023.

Looking at the last 12 months ended June 30, 2024, the average ROE authorized in all electric utility rate cases was 9.63% and the median was 9.60%. For gas utilities in the 12-month period ending June 30, 2024, the average was 9.68% and the median was 9.65%.

Historically, authorized returns have generally tracked the overall direction of interest rates, albeit with two important caveats to keep in mind — the magnitude of the change in authorized ROEs may not be as dramatic as that observed in interest rates, and changes in authorized ROEs may lag changes in interest rates, especially in the upward direction.

Interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

Average electric, gas authorized ROEs; number of rate cases decided



Data compiled July 23, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 12 of the last 15 calendar years. This count includes electric and gas cases where no ROEs were specified but does not include withdrawn cases. At almost 165 cases decided, rate case activity in 2023 was the most robust observed in any year during the 1990–2023 period, with authorized increases totaling about $12 billion.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasuries somewhat widened over this period — going from a little over 400 basis points in 1990 to a peak of just under 800 basis points in 2020.

The widening spread is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the US Federal Reserve intervention was unusual. Consequently, regulators did not fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023.

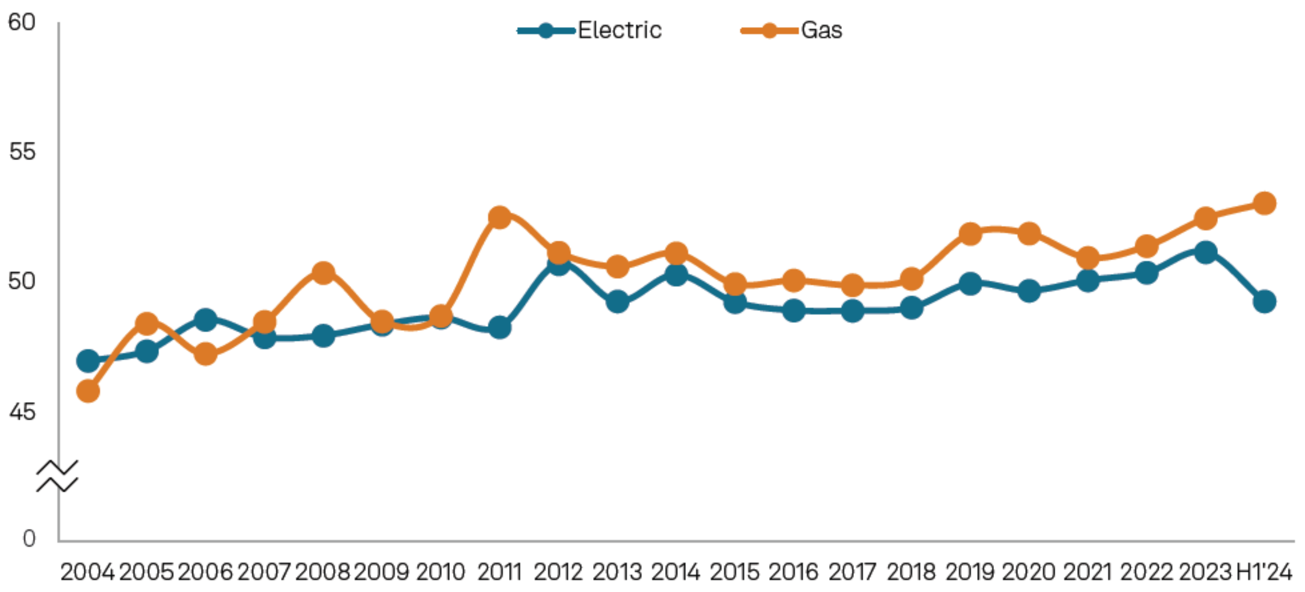
With the myriad factors putting upward pressure on customer bills, the spread may continue to narrow as regulators may become more reluctant to raise authorized returns.

Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

For full years 2023, 2022, 2021, 2020 and 2019, the average equity ratios authorized in electric utility cases were 51.15%, 50.36%, 50.06%, 49.67% and 49.94%, respectively. The average equity ratios authorized gas utilities for these years were 52.45%, 51.38%, 50.94%, 51.87% and 51.86%, respectively.

Average authorized equity ratio (%)



Data compiled July 23, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

In the first half of 2024, the average authorized equity ratio for electric utility cases nationwide was 49.26%. For gas utilities, the average authorized equity ratio nationwide was 53.03%.

From a longer-term perspective, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. In the wake of the 2008 financial crisis, many commissions began approving capital structures that were more equity rich. Authorized equity ratios for gas utilities have been above those of electric utilities for the bulk of the period since 2004.

A more granular look at ROE trends

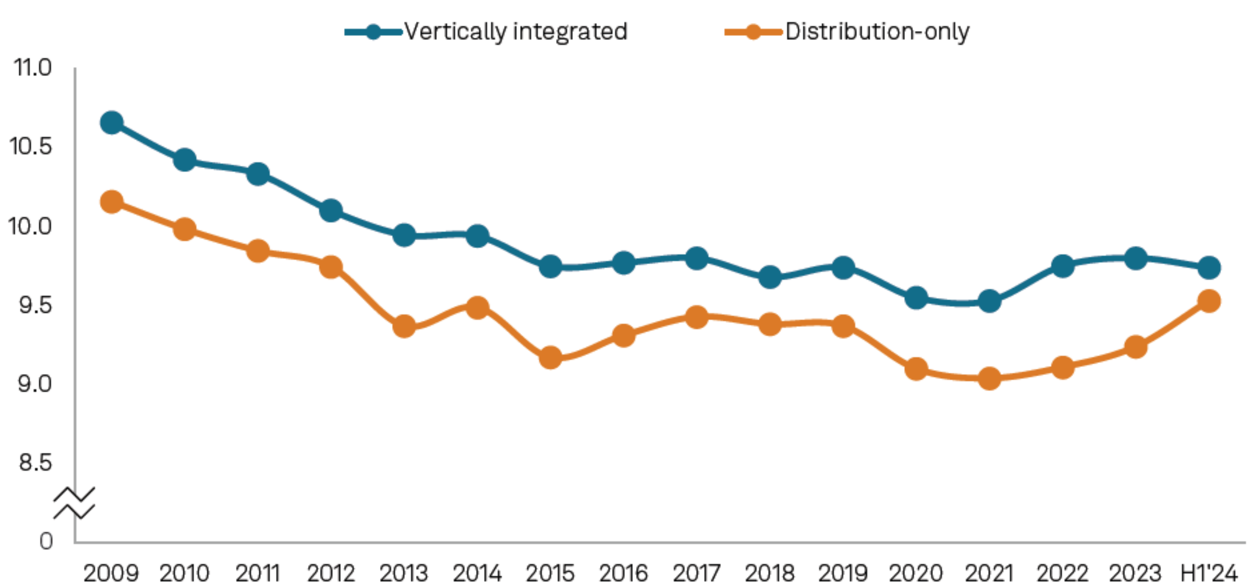
Thus far, the discussion has looked at broad trends in authorized ROEs; the following sections provide a more detailed view.

RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

As a result of the electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

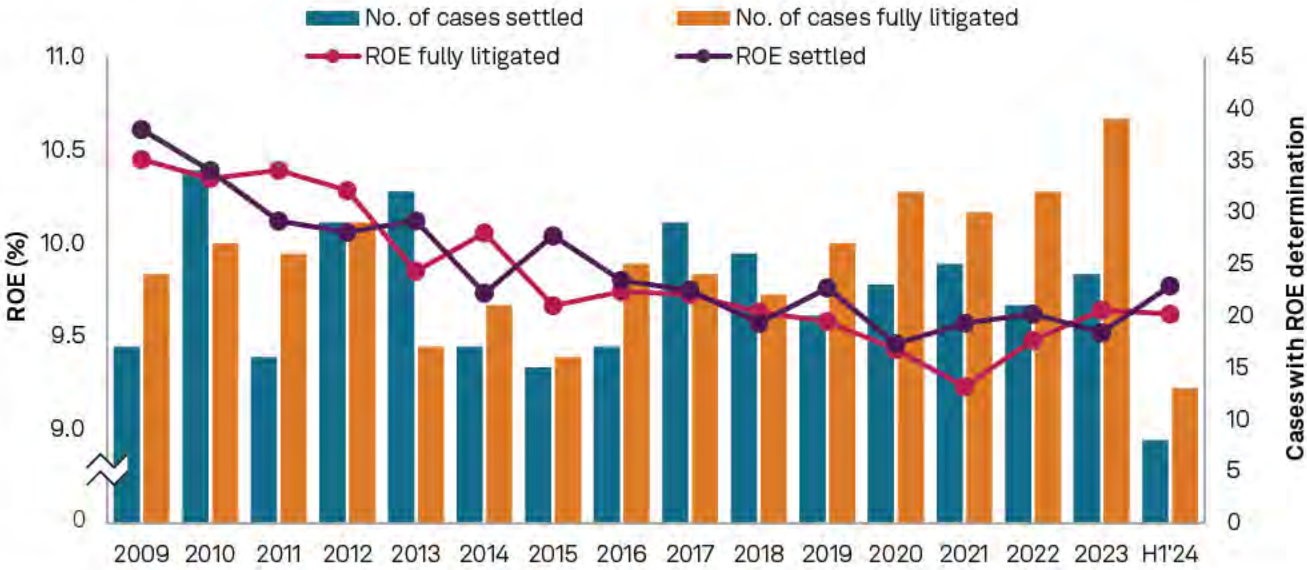
RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation historically have been about 30-65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

Average authorized electric ROEs (%)



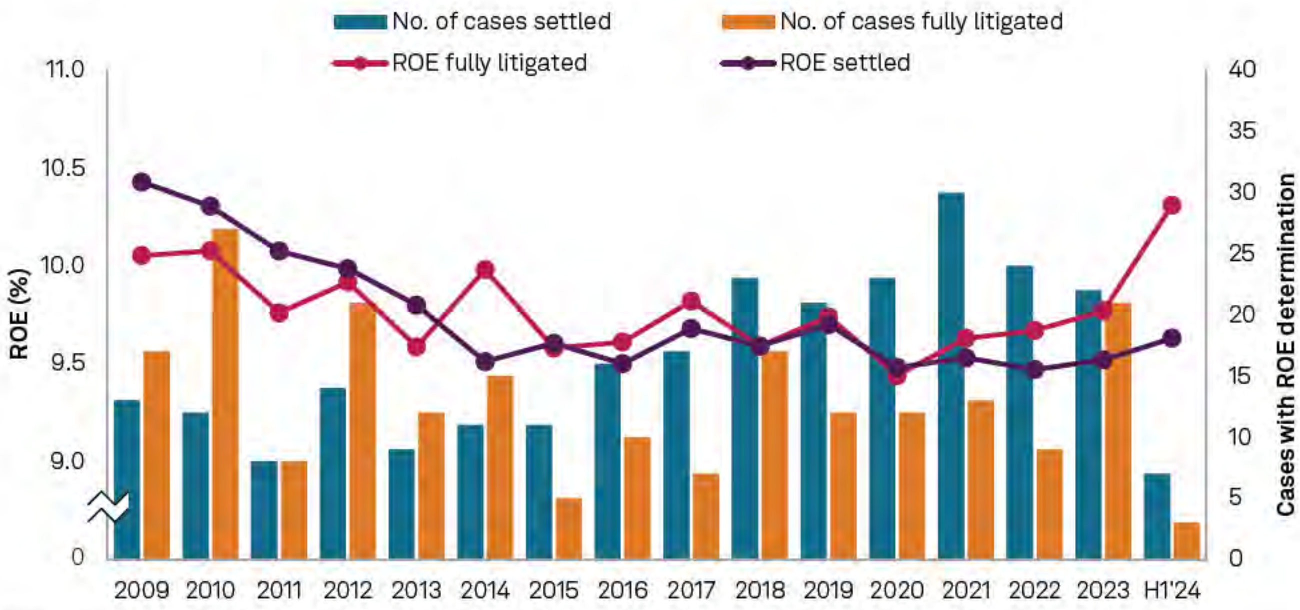
Data compiled July 23, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled July 23, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled July 23, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

The industry average ROE for vertically integrated electric utilities was 9.74% in cases decided in the first half of 2024 versus the 9.80% average in full year 2023. For electric distribution-only cases, the industry average ROE was 9.53% in January–June 2024 versus the 9.24% average in full year 2023.

Settlements have frequently been used to resolve rate cases over the last several years, and many are "black box" settlements that do not specify the ROE or other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, requiring settlements to specify these values, if not the specific adjustments from which these values were derived.

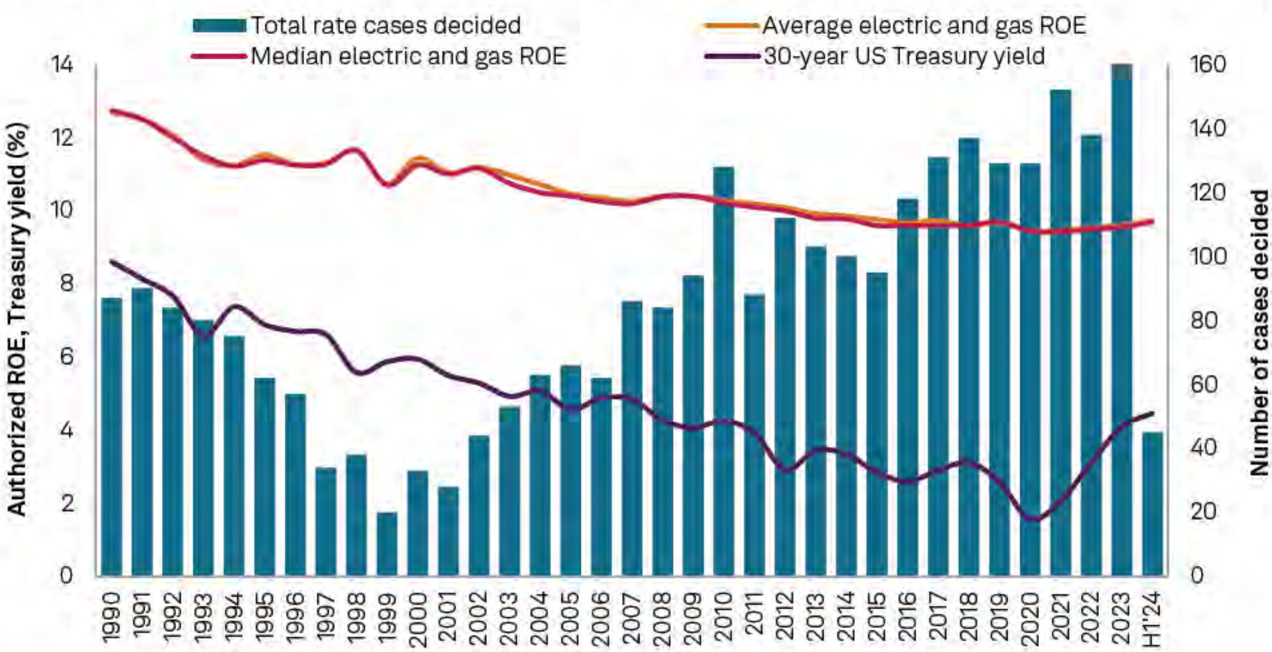
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2019, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

Tables 3 and 4 provide comparisons since 2009 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

Composite electric, gas average authorized ROEs; total number of rate cases



Data compiled July 23, 2024.

ROE = return on equity.

Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

The individual electric and gas cases decided in the first half of 2024 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. This study does not reflect fuel adjustment clause rate changes.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graph below track the average and median equity return authorized for all electric and gas rate cases combined since 1990. As the table indicates, authorized ROEs have generally trended downward since 1990, reflecting the significant decline in interest rates and capital costs over this time frame.

Further Reading

The rate case process: A conduit to enlightenment

Rate base: It's more complicated than it sounds

Frequently Asked Questions

Intro to Water Utilities — Current Trends and Growth Drivers

An Overview of FERC Regulation

FERC Regulatory Review

State Regulatory Evaluations — Energy

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For over 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2413

REDACTED
PacifiCorp's Responses
to Staff Data Requests re: Pensions
(Subject to Protective Order No. 23-132)

August 16, 2024

PacifiCorp's responses to data requests (DR) regarding pension and post-retirement medical expenses, after publication of Staff's Opening Testimony, Aug. 7, 2024.

732. Please provide a narrative and accompanying spreadsheet explaining the distribution of years to retirement, including mean and variance, for recipients or expected recipients of: A) Pensions and B) Post Retirement Medical benefits; and i) how this has changed over the last 5 years; and ii) is expected to change over the next 5 years.

PacifiCorp Response:

Please refer to Attachment OPUC 732-1 and Attachment OPUC 732-2 which summarize the demographics of the subgroups of eligible populations for the PacifiCorp Retirement Plan and the PacifiCorp Retiree Welfare Plan, respectively, over the five most recent actuarial valuations. The populations in both plans will continue to diminish over the next five years with deaths of participants and in both plans, and with some PacifiCorp Retirement Plan Participants electing to take their benefits as a lump sum. **[BEGIN CONFIDENTIAL]**

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[END CONFIDENTIAL]

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733. Please provide a narrative describing the pool of employees who are potentially eligible for each of: A) Pensions and B) Post Retirement Medical benefits and any applicable vesting and other requirements and restrictions for these programs.

PacifiCorp Response:

Eligibility for pension benefits under the PacifiCorp Retirement Plan is available to employees with hire dates prior to January 1, 2006, and other dates no later than April 1, 2010, depending on non-represented status or the union local representing the employees. Vesting is based on three years of service for cash balance benefits and five years of service for final average pay benefits.

Eligibility for post age 65 retiree medical benefits is available to employees with hire dates prior to July 1, 2006, and other dates no later than March 25, 2011, depending on non-represented status or the union local representing the employees. Vesting is based on employment through age 55 and five years of service. Employees with hire dates after the post 65 benefits were frozen are eligible for unsubsidized retiree medical coverage prior to reaching age 65 after age 55 with 10 years of service.

–

734. Please provide narrative explaining the status of each of PacifiCorp's: A) Pensions and B) Post Retirement Medical benefits including:

a. Entry into these programs, or restrictions thereto and how this has changed and is expected to change over time.

b. Number of participants and how this has changed year the last five years

c. How number of participants is expected to change over the next five years.

PacifiCorp Response:

a. Newly hired employees are not eligible for pension benefits or for subsidized retiree medical benefits. The most recent hires who were eligible for pension benefits is a represented group with hire dates before April 1, 2010. The most recent hires who are eligible for subsidized retiree medical benefits is a represented group with hire dates prior to March 25, 2011.

b. The number of pension plan participants has decreased from 6,178 to 5,013 over the past five years. The number of retiree medical plan participants has decreased from 11,159 to 10,713 over the past five years.

c. The number of plan participants in both the pension plan and in the retiree medical plan will continue to decrease as deaths of participants in both plans occur and as a subset of actively employed or deferred vested pension plan participants elect lump sum payments of their accrued pension benefits.

–

735. Please provide a narrative discussing and quantifying whether the expected number of years in retirement are increasing or how this is projected to change over the life of the A) Pensions and B) Post Retirement Medical benefits programs.

PacifiCorp Response:

In general, life expectancy has historically increased through medical advances. In recent years, this trend has reversed primarily due to the opioid crisis and COVID-19 pandemic. Over the long-term, a return to the historic trend of longer life expectancy is probable. This should have a negligible impact on the PacifiCorp Retirement Plan and the PacifiCorp Retiree Medical Plans, as there are no new entrants into the plans, and possible increases in the life span of current participants should be minimal as the vast majority of participants are middle aged or older

Caution regarding **Confidentiality of Retirement Plan Details**:

Despite PacifiCorp's and Staff's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges, or law may have been included in PacifiCorp's responses to these data requests. PacifiCorp and Staff did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp and Staff reserve their rights to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp and Staff immediately if you become aware of any inadvertently disclosed information. Staff choses to treat Company responses to DR 732 returned as Attachments 1 and 2 as Confidential and subject to Commission Protective Order 23-132. That is consistent with Staff efforts to prevent multiple divergent data sets from permitting one to back into personal information.

CASE: UE 433
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2414

“Morningstar Mirage”
WSJ, Oct 25 2017

August 16, 2024

The Morningstar Mirage

by Kirsten Grind, Tom McGinty and Sarah Krouse – WSJ – Oct 25, 2017

Investors everywhere think a 5-star rating from Morningstar means a mutual fund will be a top performer—it doesn't.

Millions of people trust Morningstar Inc. to help them decide where to put their money.

From pension funds to endowments to financial advisers to individuals, investors rely on **Morningstar's star ratings** to help divide $16 trillion among America's mutual funds, in much the way shoppers use Amazon's ratings to pick products. A lot of these investors, and the people paid to guide them, take for granted that the number of stars awarded to a mutual fund is a good guide to its future performance.

By and large, it isn't.

The Wall Street Journal tested Morningstar's ratings by examining the performance of thousands of funds dating back to 2003, shortly after the company began its current system. **Funds that earned high star ratings attracted the vast majority of investor dollars. Most of them failed to perform**.

Of funds awarded a coveted five-star overall rating, only 12% did well enough over the next five years to earn a top rating for that period; 10% performed so poorly they were branded with a rock-bottom one-star rating.

The falloff in performance was even more dramatic for domestic stock funds, the largest category of U.S. funds by assets.

Billions of investor dollars hang in the balance. Nearly every asset manager in the world pays Morningstar for data services. Some 250,000 financial advisers rely on Morningstar's data, services or ratings, according to the firm. That means Morningstar's analysis and ratings influence investment decisions for a vast landscape of retirement plans and brokerage accounts.

Morningstar's reach is so pervasive that the ecosystem for buying and selling mutual funds revolves around it. Fund companies heavily advertise their star ratings. Money typically pours into funds after they receive a five-star rating from Morningstar, the Journal found. It flows out if they lose stars.

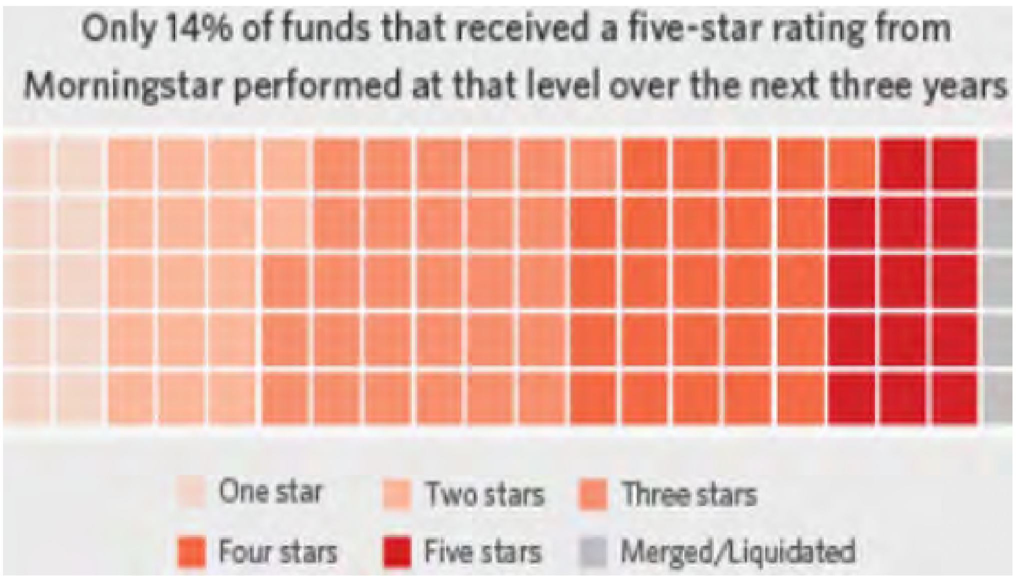
There is **no question** that **Morningstar has greatly improved** the **transparency and rigor of data on mutual funds' holdings and performance**, making it easier for individual investors to compare funds.

Morningstar says it has never claimed its star ratings suggest how funds will perform in the future. The **star system is strictly backward-looking**, assessing past performance, the firm says. "We have always been very clear that it's not intended to predict future performance," the company said in a written statement.

"The star rating works well when it's used as intended: as a first-stage screen that helps identify lower-cost, lower-risk funds with good long-term performance," Morningstar said. "It is not meant to be used in isolation or as a predictive measure. **Reversion to the mean is a powerful force** that can affect any investment vehicle."

How Funds with Different Ratings Compare

Morningstar gives funds one to five stars for past performance, with five the best. Many investors treat the stars as a guide to future performance. But **over time, the performance of funds with different initial star ratings converges**.



How Funds with Different Ratings Compare

Morningstar gives funds one to five stars for past performance, with five the best. Many investors treat the stars as a guide to future performance. But over time, the performance of funds with different initial star ratings converges.

The **firm sends conflicting signals about the star ratings' predictiveness**. A study published by Morningstar last month said the stars point investors to funds "likelier to outperform in the future."

Morningstar founder Joe Mansueto said in an interview that the firm's analysis of past ratings found "some modest predictive value." Chief Executive Kunal Kapoor, in another interview, called the star system "a better predictor than it ever has been."

In its written statement to the Journal, Morningstar said its analysis has found "the Star Rating is moderately predictive," which "conforms to what we'd expect of a backward-looking, entirely quantitative measure."

The Journal's analysis found that most five-star funds perform somewhat better than lower-rated ones, yet on the average, **five-star funds eventually turn into merely ordinary performers**.

Inside Morningstar, some employees have expressed discomfort about how much investors rely on the ratings. Stephen Wendel, head of behavioral science at the

Chicago-based firm, wrote in the June/July issue of Morningstar magazine that part of his job was "examining whether we are contributing to abuses in the industry," and said: "Morningstar's star ratings for funds are clearly used in the industry to imply that funds that performed well in the past will do so in the future."

He added, "That needs to change."

Morningstar's Mr. Mansueto, 61 years old, said the star rating system "is a way to whittle down a big universe into something more manageable." The firm said it has worked to make investors understand the star ratings should be just a starting point for their research.

Since 2011, **Morningstar has had a second rating system**, lesser known and of limited scope, that **includes analysts' opinions**. Unlike the star ratings, it is designed to be **forward-looking**, Morningstar says. **<u>In this system, too, the Journal found the performance of funds rated high, low and in between tended to converge after several years</u>**. In addition, the Journal found **Morningstar only rarely gave funds the lowest analyst rating**, "**negative**."

Mr. Mansueto, growing up in suburban Chicago, sold lemonade by the roadside before moving up to Christmas trees. At the **University of Chicago**, he and a roommate sold chips and soda and advertised by hanging posters for the "Room 607 Soda Service." He also made his first mutual-fund investment, with $250 from a restaurant job.

After college, he and the ex-roommate, Kurt Hanson, started a business that provided market research for radio stations. It surveyed listeners and created a sheet of charts detailing their behavior. Mr. Mansueto then got a job as a financial analyst at Harris Associates LP, a Chicago money manager.

Mutual funds were proliferating, and a few fund managers were becoming stars, such as John Templeton and Peter Lynch. Funds didn't give much information about themselves, and what they provided was opaque to nonprofessionals. Mr. Mansueto told a colleague he wanted to start a **fund newsletter** in the mold of the radio-station fact sheets.

The **colleague, Ralph Wanger, cautioned that financial newsletters didn't have a record of success**. "That turned out to be the **dumbest...thing I ever said**," he recalls. "What I meant to say was, 'Joe, that's the best idea I've ever heard — how about I quit and we go 50-50?' "

"**It's a way to whittle down a big universe into something more manageable**"
Morningstar founder Joe Mansueto on the star ratings

Mr. Mansueto launched Morningstar from his one-bedroom apartment in 1984 with $80,000, taking the name from the ending of Thoreau's "Walden": "The sun is but a morning star."

He later spent $50,000 to hire Paul Rand, the noted designer of IBM's logo, who created a **signature red font** consisting of **tall letters** with an "**O**"

looking like a rising sun. With reports obtained from fund companies, Mr. Mansueto laid out data points so they were easy to read, and advertised his reports in Barron's.

When BusinessWeek later asked him to devise rankings for an issue devoted to mutual funds, Mr. Mansueto began work on what would become his five-star rating system. He toyed with using symbols suggesting little bags of gold before deciding on stars.

Since then, assets invested in U.S.-based mutual funds have multiplied more than forty-fold. Morningstar rode the wave and went public in 2005.

Today, investors descend on Chicago for Morningstar's annual conferences, a pilgrimage for money managers and financial advisers hoping to gather assets. At this year's event in April, shirtless male acrobats cartwheeled and stood on each other's shoulders while financiers sipped cocktails and mingled.

Morningstar groups funds into categories based on their investing style or area, more than 100 groups in all. It **compares funds** not to all other funds, nor to the overall market, but **to other funds with the same investment focus**. The **top 10% of funds in each group receive five stars**, the **bottom 10% get one**, and the rest get two, three or four stars.

The **ratings don't reflect raw performance, but performance adjusted for funds' degree of risk**. To make that calculation, Morningstar uses an algorithm Mr. Mansueto devised that reflects the variation in funds' month-to-month returns.

The firm **rates funds on how they did over three years — plus over five years and 10 years if they're old enough**—and assigns them an overall rating based on the others. **A fund thus could have as many as four ratings from Morningstar, though most investors see only the overall one**. **New** star **ratings come out each month**.

Most mutual funds have multiple "classes," each charging a different expense fee. Since varying expenses spell varying returns, Morningstar rates each class of each fund separately.

Its star ratings covered more than 10,800 mutual funds — and almost 39,000 share classes — during the 14 years studied by the Journal. The only qualification to be rated is being in business three years. The ratings include index funds, which try to mimic the performance of markets.

(The Journal's analysis didn't include exchange-traded funds, or ETFs, which trade throughout the day like a stock and usually mirror an index. Morningstar began rating ETFs alongside ordinary mutual funds late last year, after the period covered by the Journal's analysis.)

Going back to 2003, the Journal examined the rating of every investment class of every fund, in every month, and how these changed over time — some three million records in all.

The Journal also reviewed retirement-plan data, fund ads and regulatory filings, and interviewed dozens of current and former Morningstar employees, fund officials, financial advisers and investors.

For funds that had an overall five-star rating at any point, the Journal found that **their average Morningstar rating for the following five years was three stars**—in other words, halfway between the top and the bottom.

When funds picked up a fifth star for the first time during the period included in the Journal's analysis, half of them held on to it for just three months before their performance and rating weakened.

The findings were especially stark among U.S.-based domestic equity funds. Of those that merited the five-star badge, a mere 10% earned five stars for their performance over the following three years. Only 7% merited five stars for the following five years, and 6% did for 10 years.

For all of the measured periods—three, five and 10 years — five-star domestic equity funds were more likely to turn in a one-star performance than a top one.

That means a **five-star rating for the equity funds was no more an omen of success than it was one of failure**.

Morningstar's ratings of taxable-bond funds, which include corporate bonds and Treasurys, proved a little more indicative of future performance. Of five-star bond funds, about 16% turned in a five-star performance over the next five years.

Still, 8% of the five-star taxable-bond funds performed poorly enough to merit only one star.

Hickory Hills, Ill., not far from Morningstar's Chicago headquarters, has a small pension fund for about 50 active and retired police officers. In 2011, it moved about $2.1 million into the Nuveen Santa Barbara Dividend Growth Fund, which had a five-star Morningstar rating.

The pension board paid close heed to star ratings. "Our brokers thought it was one of the best measurements we had available to decide whether the fund is worth investing in," said board secretary Mary McDonald, referring to brokers from Morgan Stanley.

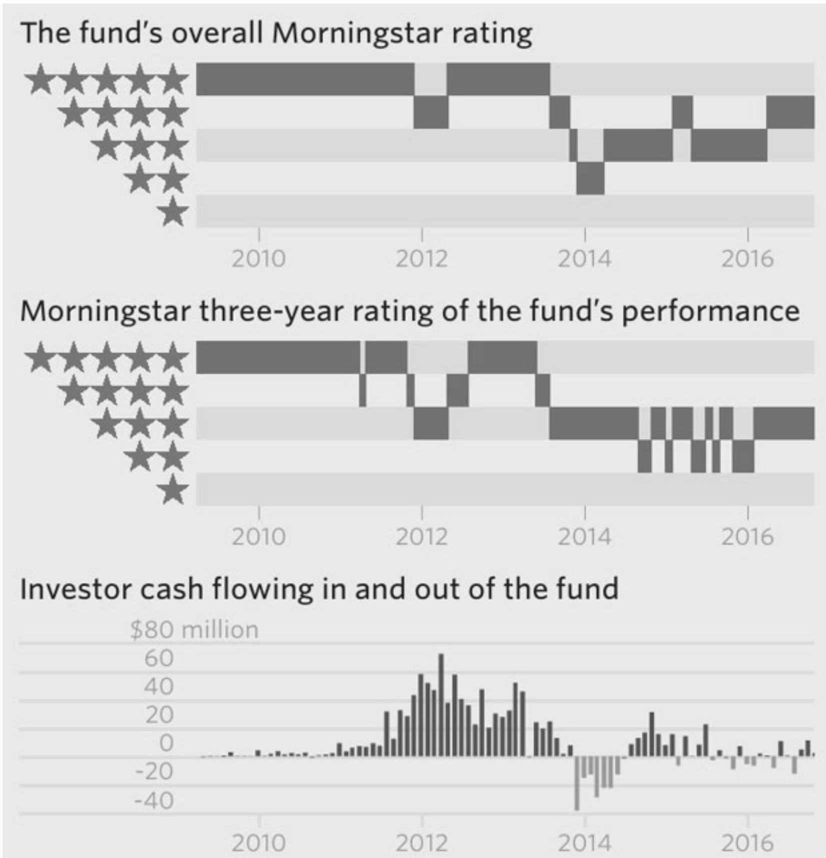
The fund had beaten 95% of others in Morningstar's "large blend" category — funds that buy large-company stocks using a blend of what investors call a "value" strategy and a "growth" strategy.

The following year, the fund beat only 26% of similar funds, and in 2013 just 11%.

Nuveen Santa Barbara – Dividend Growth Fund

A pension fund moved $2.1 million into the Nuveen Santa Barbara Dividend Growth Fund in November 2011, when the fund had a five-star rating.

Notes: Class I share class. Funds rated by Morningstar can have up to four ratings: a three-year rating, a five-year rating, a 10-year rating, and an overall rating that is based on a combination of the others.



The president of the Santa Barbara fund family, John Gomez, attributed the Dividend Growth fund's performance to its focus on stocks with growing dividends, not just the highest-yielding ones.

The Hickory Hills board pulled $1.2 million from the fund in 2014, and in early 2016 it took out $750,000 more. It has since switched to a local broker, in part because of **Morgan Stanley's reliance on Morningstar ratings**, said David Wetherald, a police officer who is also the pension board's president.

The experience was frustrating because "we rely a lot on the financial people. We're not completely blind and naive, but we're smart enough to know that this is what they do," Mr. Wetherald (left) said.

Morgan Stanley declined to comment.

Morningstar said its five-star rating of Nuveen Santa Barbara Dividend Growth in 2011 "was an accurate historical grade on the fund. It was not intended as or presented as a conclusion as to what they should do."

Morningstar also said this type of fund generally did poorly after 2011. The example "presents an underperforming fund in a badly underperforming category as if it's representative of the full rating set, which it's not," the firm said.

The Journal's analysis found that investors put new money into five-star-rated funds in 69% of the months they held that rating, compared with 29% for one-star funds. The Hickory Hills investment was part of $184 million investors put in the Santa Barbara fund in 2011 when it had five stars.

Morningstar acknowledged its ratings can influence demand, though Mr. Mansueto says he believes investors typically move money mainly based on a fund's performance, not its star rating.

Money in Motion

The Journal analyzed how much money flowed into or out of funds over three years based on the overall ratings investors saw and how well the funds actually performed.

Investors pour money into top-rated funds even if their performance declines.

Investors pull money from low-rated funds even if their performance improves

Net flows as a percentage of assets at start of three-year period

Note: Funds rated by Morningstar can have up to four ratings: a three-year rating, a five-year rating, a 10-year rating, and an overall rating that is based on a combination of the others.

The Journal found more than a dozen cases where well-performing funds attracted few investors until they won a fifth Morningstar star.

Tiny Buffalo Emerging Opportunities Fund saw little interest despite beating many similarly focused funds over three years, including gaining 24% in 2012. After it got a fifth star from Morningstar in spring 2013, hundreds of millions came in, quadrupling assets to above $400 million in five months.

The small management team in Mission, Kan., closed the fund to new investors six months later, a step managers sometimes take when given more cash than they feel they can invest. The Journal found many instances of funds closing after an influx that followed a high star rating.

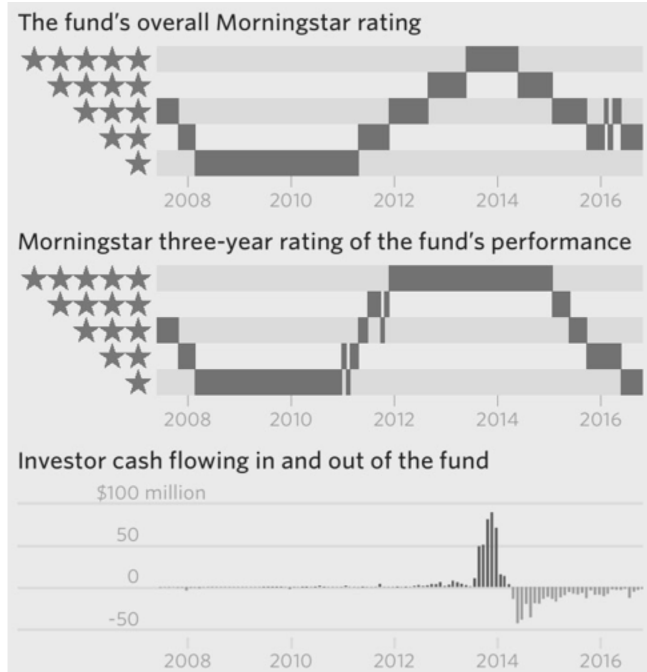
At Buffalo Emerging Opportunities Fund, fortunes soon reversed. In 2014 it lost more than 7% and trailed about 95% of other funds focused on growing small companies. Over the next two years its Morningstar rating fell to two stars and its assets plunged to less than $100 million.

Buffalo Funds declined to comment.

Buffalo Emerging Opportunities Fund

After Morningstar gave the tiny fund five stars in the spring of 2013, investors poured in hundreds of millions of dollars.

Over the next two years its ratings fell.



Inflows sparked by high star ratings are especially important for managers of actively managed funds now that more investors have migrated to passive ones that just try to match an index. On calls with securities analysts, fund-company chiefs often trumpet how much of their asset total is in four- and five-star funds, as a sign of the companies' ability to attract cash.

From his office park in Mechanicsburg, Pa., financial adviser Donald DeMuth starts each workday by logging onto Morningstar Office, which helps him organize client portfolios. He also uses Morningstar data to check on fund performance and details such as how rapidly a fund's portfolio turns over.

Mr. DeMuth, 66, has used Morningstar so long he can't remember when he started. "With rare exception, we would want a fund to have five stars," he said.

Left: Financial adviser **Donald DeMuth**

In early 2012 he put some of his clients' money in a fund called Permanent Portfolio when it had a five-star Morningstar rating. The fund invests across an array of assets, including gold and silver.

Its performance had already started to slip. By the end of 2012, it was 5 percentage points behind its Morningstar category benchmark, the "Morningstar Moderate Target Risk," which is a mix of global bonds and global stocks.

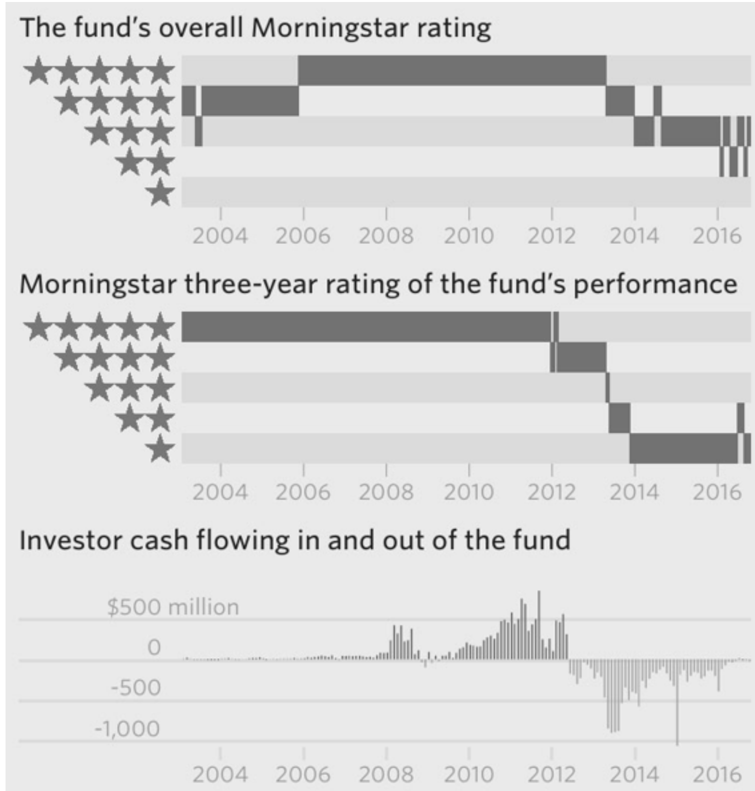
Mr. DeMuth moved his clients out in the fall of 2013, a year when the fund trailed that benchmark by 16 percentage points. At the end of 2013, Morningstar gave the fund a one-star rating for its performance over the prior three years.

Permanent Portfolio

A financial adviser invested clients in Permanent Portfolio in early 2012 when it had five stars, but it quickly started underperforming.

Client David Peterseim, a 55-year-old retired surgeon in Charleston, S.C., said he was relieved the financial adviser got out. He was **disappointed "Morningstar didn't have some semblance to reality**," Dr. Peterseim said.

Michael Cuggino, president of the San Francisco-based family of Permanent funds, said Permanent Portfolio's performance suffered as the price of gold and silver dropped.



Morningstar said Permanent Portfolio was an "outlier" that "was designed as an inflation hedge; when precious metals are in favor, it will score well, and when they're not, this fund won't do well." Major rallies in gold and silver ended in 2011, shortly before Mr. DeMuth invested.

Other industry practices show how much Wall Street's system for buying and selling mutual funds revolves around Morningstar ratings. Brokerage firms recommend high-stars funds to their networks of tens of thousands of financial advisers, and those brokers in turn put clients' money in the funds. Large fund firms such as Fidelity Investments and T. Rowe Price Group Inc. allow investors to filter out funds with low star ratings on their websites.

Current and former Morningstar employees said some advisers use the ratings as a crutch.

"**It's a cover-your-ass type of service**," says Samuel Lee, a former strategist at Morningstar. "**An adviser can say, 'I'm going to put you in this fund, it's a 5-star fund**,' …and if something goes wrong the adviser can shunt blame to Morningstar."

Left: Former Morgan Stanley financial adviser Scott Jennings, on advice he gave

Scott Jennings, a former Morgan Stanley financial adviser, recalled struggling last year to explain to a company's employees which funds they should choose in their retirement plans. He decided to keep it simple and told them,

You only have two funds rated by Morningstar — one's a two-star and one's a four-star. Go with the four-star.

At Morgan Stanley, "Advisers get in trouble when they go against the grain," Mr. Jennings said. "You isolate yourself more if you sell something else rather than just go with what research recommends."

Morningstar said if advisers use the ratings this way, "**this is a fault with the users of the ratings, not the ratings**.... If an advisor wants to do proper due diligence, we provide a robust set of information." The firm's marketing cautions that "a high rating alone is not a sufficient basis for investment decisions."

Morgan Stanley declined to comment.

Fund firms often cite Morningstar ratings in their advertising — at times even out-of-date ones. Alliance Bernstein ran an ad for nine of its funds in a spring edition of Private Wealth magazine, citing star ratings from September 2016. Two of the funds' ratings had fallen by the time the ad ran. Alliance Bernstein ran a similar ad with the September ratings in a Morningstar handout at the research firm's April conference.

A spokesman for Alliance Bernstein said it made a "human error" in two instances out of "hundreds of digital and print ads running that quarter."

Dallas-based Hodges Small Cap Fund's retail share class beat 95% of similar funds in 2010 but had less than $100 million in assets. Late in 2011 Morningstar gave it a fifth star, and everything changed, said Craig Hodges, who manages Hodges Capital Management. Charles Schwab put the fund on its "Schwab Select List." Mr. Hodges and his brother Clark decided to advertise the star rating on a billboard in Dallas/Fort Worth airport.

Hodges Capital paid more than $10,000 to Morningstar for the right to advertise the stars, Craig Hodges said. By the end of 2014, assets in that fund reached about $1.6 billion, according to Morningstar data.

Hodges Small Cap Fund

The Hodges Small Cap Fund had trouble attracting investors until Morningstar gave it five stars.

Investment giants Vanguard Group and Fidelity Investments pay upward of $1 million a year for licensing, data and other tools from Morningstar, said people familiar with the arrangements. It's unclear how much is just for advertising.

Michael Rawson, who was a Morningstar fund analyst for six years until spring 2016, said asset managers who pay to advertise their stars are misrepresenting their funds because the ratings are solely backward-looking.

"We know people misuse it. If we know people misuse it, why don't we do something about it?" Mr. Rawson said.

Morningstar said it publishes the ratings because it believes they have investment merit, not for financial gain. It said its intellectual-property licensing packages, which include the stars, contributed just 4% of revenue in 2016.

Mr. Mansueto said employees are encouraged to debate issues related to its products, but the efficacy of its star ratings no longer comes up internally. "This is not a hot topic or even a cold topic at Morningstar today," he said.

As for the Hodges Small Cap Fund, its performance has since turned down. Its rating has fallen to two stars from five, and assets that had soared after the top rating have dropped by more than half.

Aware of criticism of its star ratings, Morningstar in 2011 launched a second rating system, currently covering 26% of fund share classes, in which the firm's analysts do a more qualitative assessment. Unlike the star system, analysts' ratings often refer to likely future performance. The firm said analysts' ratings reflect its level of conviction that a fund will "outperform its peer group and/or relevant benchmark."

The **analysts** give funds one of three **medals** — **gold, silver or bronze** — or a "neutral" or "negative" rating.

The Journal examined how these funds performed in future years, as measured in their star ratings. It found that five years after having a gold-medal rating from

Morningstar's analysts, funds had an average rating of 3.4 stars for that five-year period.

Silver-medal funds were rated 3.3 stars for their performance over the following five years. Bronze-medal funds had an average rating of 3 stars. In other words, while funds rated highly by the Morningstar analysts did better, the **differences** among the funds **weren't large**.

A Morningstar spokeswoman said there was a mismatch in how the Journal evaluated the performance of analyst-rated funds because it relied on star ratings. She said unlike analysts, the star ratings take into account a "load" — a sales fee —t hat some funds have.

The Journal analysis also found **Morningstar analysts' ratings of funds were overwhelmingly positive**. From November 2011 through August 2017, the firm gave analyst ratings to about 9,200 fund share classes. Just 421, or 5%, received negative reviews. At the end of August, only 1% did.

Mr. Mansueto said analysts tend to choose better funds to examine, since they can't review them all. "Investors want to know what funds they should be investing in," Mr. Mansueto said. "They don't care so much about what the terrible funds are."

Morningstar recently started a third "quantitative ratings" system that it says applies analyst screening to a broader universe of funds. This one is likely to include more negative ratings, executives said.

J.P. Morgan Chase & Co. is among asset managers that regularly send portfolio managers to talk to Morningstar analysts about the merits of their funds. BlackRock Inc. has a team that works to persuade Morningstar analysts of the merits of various funds, according to people familiar with the matter.

They added that BlackRock CEO Laurence Fink met with Morningstar analysts early this year to discuss the firm's ratings. In May, Morningstar upgraded to positive BlackRock's "parent pillar" rating, an evaluation in which analysts are looking for factors including an alignment of interests between fund shareholders and those who manage the funds.

A BlackRock spokesman said its team that works with research providers "is focused on providing transparency, education and information about our products to facilitate informed decisions."

Morningstar said BlackRock had changed how portfolio managers were paid in a way that led to their having more of their own money invested in BlackRock funds. "We followed the same process in evaluating Blackrock's standing as a parent that we do with any other firm," said a Morningstar spokeswoman.

Mr. Kapoor, the Morningstar CEO, said analysts operate independently from fund companies and without influence from management despite frequent angry calls executives must field. "We prize our independence," he said.

Morningstar's application to the Securities and Exchange Commission for permission to launch nine mutual funds of its own has led some critics to cry conflict of interest. The Morningstar spokeswoman said the firm is in a quiet period related to the filing, restricting what it can say, but she said the firm's analysts sit "in a separate entity" from Morningstar Investment Management, which would oversee the company's funds.

The Journal spoke with more than three dozen executives at asset-management firms large and small about Morningstar. Few would go on the record.

Several years ago, some were unhappy when Morningstar changed the way it calculates its "stewardship grade," which is supposed to measure the corporate culture of each fund company. Executives from fund companies viewed the change as the latest example of Morningstar acting unilaterally and without explaining itself.

The money managers drafted a two-page letter to Morningstar that accused the company of "bullying" fund companies and running a monopoly, according to people familiar with the letter.

"The nature of what we do is going to end up alienating some portion of the industry," said Jeffrey Ptak, Morningstar's global director of manager research. "That's not something we relish but it's part of our job."

When the time came for the money-management firms to put their names to the letter, they balked. The letter was never sent.

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How The Wall Street Journal Did Its Analysis of Morningstar Ratings

by Tom McGinty – WSJ – Oct. 25, 2017

Morningstar provided the Wall Street Journal with a list of all U.S. open-end mutual funds that operated at any time from 2003 through October 2016. The list included more than 10,800 funds that together had almost 39,000 share classes that were rated by Morningstar during the period. Share classes within a given fund are all invested in the same securities and differ only in the fees they charge to investors. The funds had been classified into more than 100 investment categories by Morningstar and they invested in a wide range of securities, including domestic and international stock and municipal, government and corporate bonds.

Using complimentary access to Morningstar's data and investment-analysis platform, Morningstar Direct, the Journal pulled monthly performance metrics for each share class for the period spanning from January 2003 through October 2016 (166 months). The metrics the Journal used in its analysis included:

* Overall star rating

* 3-, 5- and 10-year star ratings

* Morningstar analyst ratings

* Monthly net assets

* Estimated monthly net flow (the net of the dollars investors put into and pulled from the share class during the prior month)

The Basics of Morningstar's Star Ratings

Morningstar's star ratings represent how well a given share class performed among all other share classes within its Morningstar-assigned category over a given period. The ratings do not take into account how the share class has performed against the general market in which it invests. To be rated, a share class must have a history of at least three years.

For each share class at the end of every month, Morningstar uses a proprietary algorithm to calculate the "**Morningstar Risk-Adjusted Return**" (**MRAR**) for the prior three years. The risk weighting is generally a measure of how radically the monthly returns moved up and down during the period being studied. For example, two share classes could have identical returns over a three-year period, but if one had large up-and-down swings in its monthly returns while the other saw only small month-to-month variations, the volatile share class would be penalized by the risk-weighting analysis and would earn a lower MRAR score for the three-year period.

Morningstar sorts the share classes within each category by their MRAR scores. The lowest 10% of share classes get a three-year rating of one star; the next 22.5% get two stars; the middle 35% get 3 stars; the next 22.5% get four stars; and the top 10% get five stars.

For share classes with five or more years of history, Morningstar calculates a five-year MRAR and assigns five-year star ratings based on the same percentile cutoffs as the three-year rating. For share classes with at least 10 years of data, the same process is followed to calculate the 10-year MRAR and star rating.

Morningstar's overall star rating — the one most frequently publicized by investment managers — is a weighted distillation of the three-, five- and 10-year ratings. The formula for calculating the overall rating varies depending on how long a share class has existed:

* For share classes with less than five years of history, the overall rating is equal to the three-star rating.
* For share classes with at least five years of history but less than 10 years, the overall rating is based 60% on the five-year rating and 40% on the three-year rating.
* For share classes with at least 10 years of history, the overall rating is based 50% on 10-year rating, 30% on the five-year rating and 20% on the three-year rating.

For example, this table shows the calculation of an overall rating for a share class with a 10-year rating of 4, a five-year rating of 3 and a three-year rating of 3:

Rating period	Stars	Weight	Weighted value (weight x stars)
Three years	3	20%	0.6
Five years	3	30%	0.9
10 years	4	50%	2
Sum of weighted values			3.5
Overall rating (rounded sum of weighted values)			4

With 50% of the overall Morningstar rating predicated on the 10-year performance of a share class, overall ratings tend to move more slowly than the three-year ratings. Put another way, the **overall rating puts more weight on the long-ago performance of a fund than what it has delivered in recent years**.

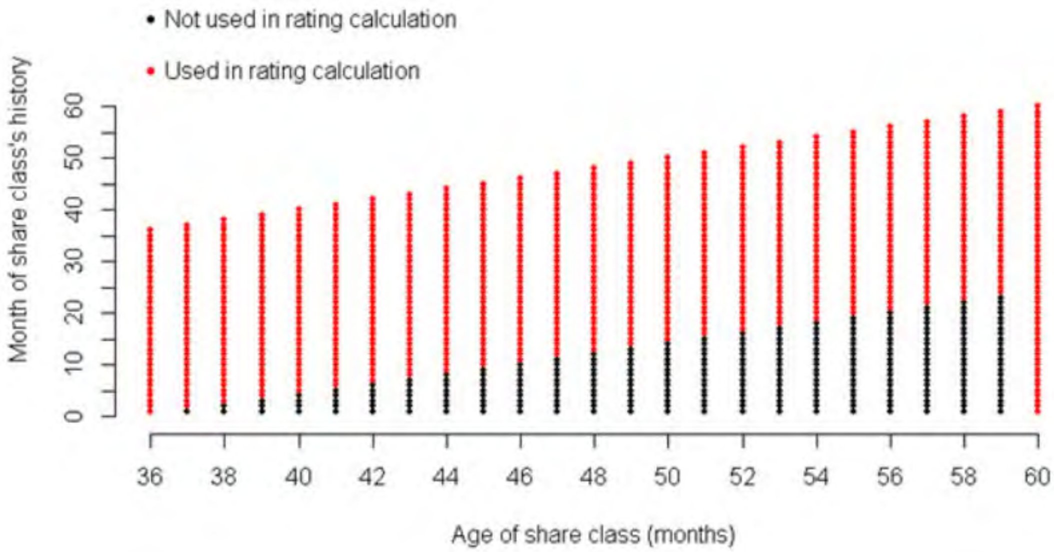
The effects of that weighting become evident when looking at how the overall and three-year ratings of a share class change over time. The Journal's analysis found that the average share class with a five-star overall rating on a given date had an overall rating of 3.7 stars three years later, a decline of 1.3 stars. But those same share classes averaged three-year ratings over the same period of just 3.1, a decline of 1.9 stars.

Note: During the period studied by the Journal, Morningstar's methodology included a provision for altering the weighting used for the overall score for funds that moved from one Morningstar category to another. The Journal found the adjustment affected less than 2% of the overall ratings in its data set. That **adjustment**, which was **meant to account for differences among categories, was discontinued in November 2016**.

A quirk of Morningstar's methodology for its overall rating:

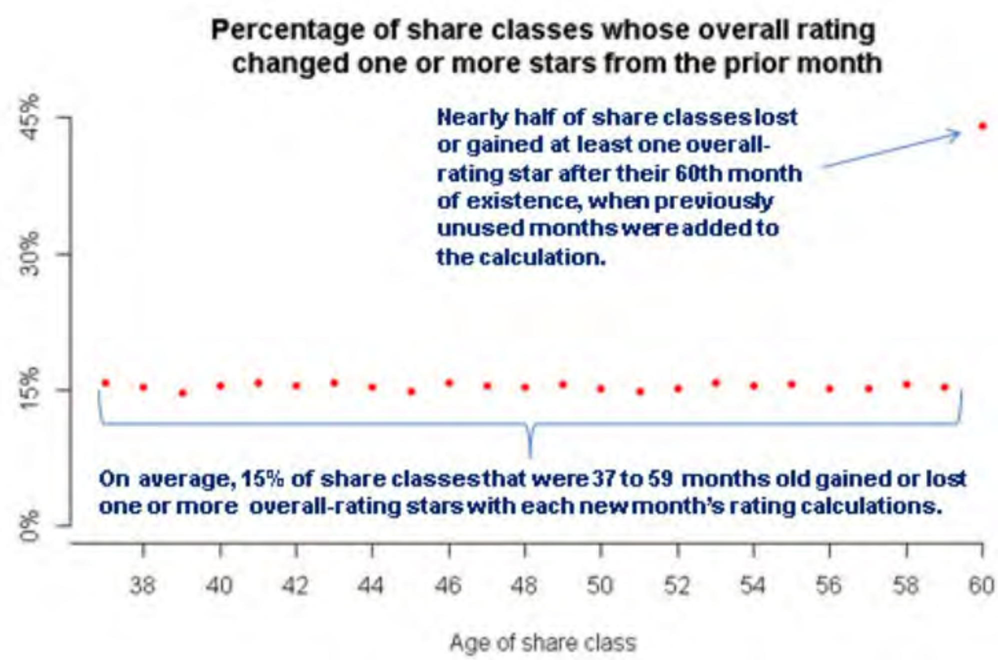
Because of the way the overall rating is calculated, there are many months during a share class's life when its ratings are calculated using only part of the share class's performance history. Later, when those months are added to the calculations, an unusual number of share classes are hit with sudden — sometimes large — changes in their overall ratings.

As noted above, a share class gets its first Morningstar rating after its 36th month of existence. From that point until its 60th month, its three-year rating is calculated using the most recent 36 months of data and its overall rating is equal to the three-year rating. As each new month is added to the three-year calculation, the 37th youngest month is dropped from the calculation. By the time a share class is 59 months old, the first 23 months of its history are left out of the ratings calculations.



After its 60th month, a share class gets a five-year rating for the first time. All 60 months of the share class's history are used to calculate the five-year rating and the most recent 36 months are used to calculate the three-year rating. The overall rating then is derived from those two ratings, with the five-year counting toward 60% of the overall rating and the three-year counting toward 40% of it.

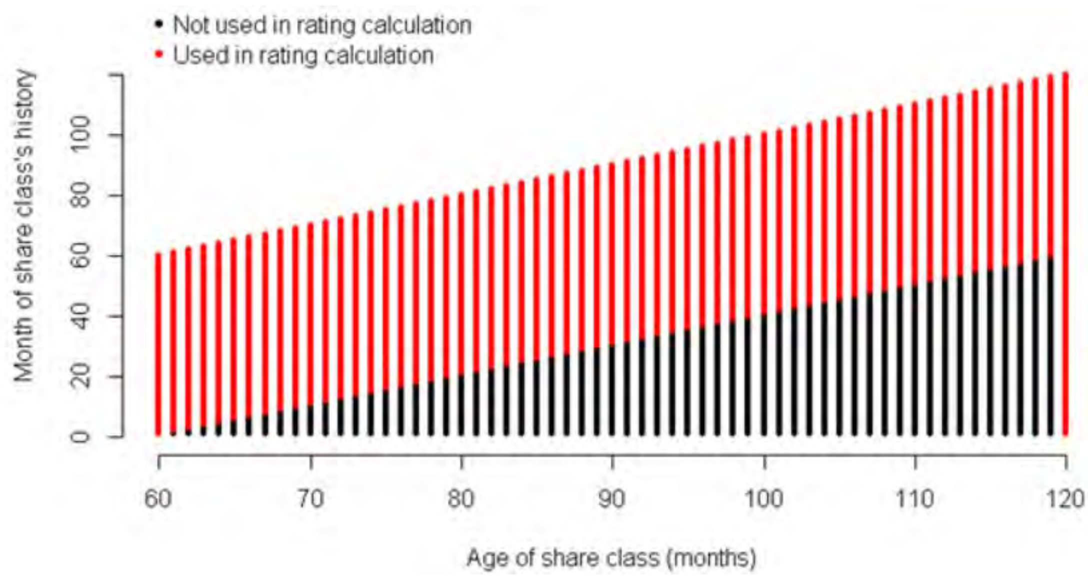
Suddenly adding 23 months of history that were disregarded just one month earlier causes an unusually large number of share classes to see their overall rating change by one star or more.



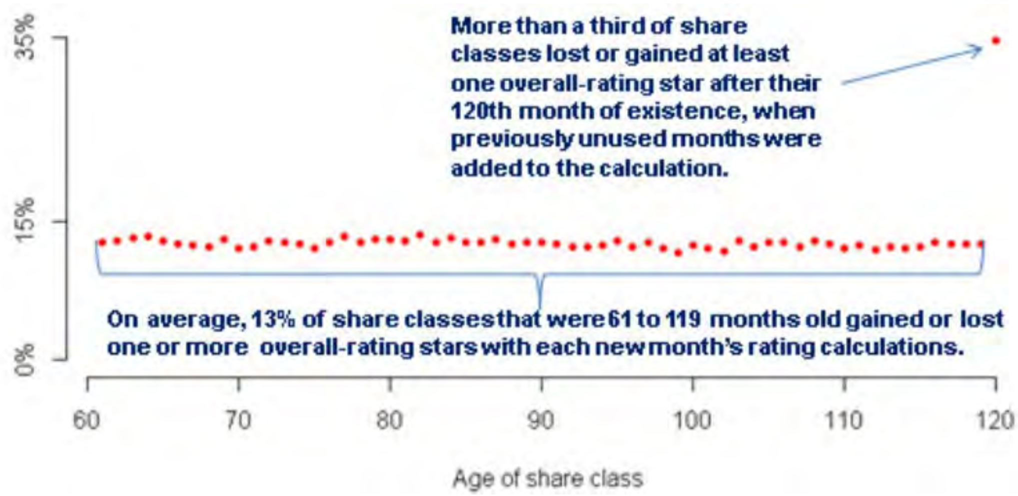
The sudden rating changes may have led to some unpleasant surprises for investors who relied on star ratings of share classes nearing 60 months of age when making investments. More than 800 share classes in the Journal's analysis that had a five-star rating after their 59th month saw a change in their overall rating of one or more stars after their 60th month. In 104 instances, share classes that had an overall rating of five stars after their 59th month fell all the way to three stars when the oldest 23 months of their history were added to the ratings calculations, the Journal's analysis found. In four instances, share classes hitting the 60-month milestone fell from a five-star overall rating to two stars.

More unused months

From the 60th month of a share class's existence through the 119th month, only the most recent 60 months are used in the ratings calculations, with the most recent 60 going into the five-year rating and the most recent 36 used for the three-year rating. Throughout this time, the overall rating is composed 60% of the five-year rating and 40% of the three year. By the time the share class hits the age of 119 months, its oldest 59 months do not factor into the ratings calculations.



After its 120th month, a share class gets a 10-year rating for the first time. All 120 months of the share class's history are used to calculate the 10-year rating; five- and three-year ratings continue to be calculated with the most recent 60 and 36 months, respectively. The newly minted 10-year rating now counts for 50% of the overall rating, while the five-year rating counts for 30% and the three-year 20%.



As happened at the 60-month threshold, the addition of previously excluded months had a pronounced effect on the overall ratings.

After their 120th month, 287 share classes that had five-star overall ratings were downgraded to four stars and 33 were downgraded from five stars to three.

Morningstar said, "We are **aware of this phenomenon** and have explored using unique or rolling periods, but it exponentially increased the complexity of the ratings. The disclosure on thousands of unique peer groups that it would require was a daunting obstacle. It also in general led to very small differences in outcomes. To undermine the simplicity of a starting point — which is all we claimed the stars to be — for minor or nonexistent benefits in outcomes struck us as a poor tradeoff. If we were promoting the stars as a conclusion, we would have pursued such options. As we and our readers knew the stars to be a first-stage screen in the research process, we didn't incorporate this suggestion."

Gauging the predictive powers of Morningstar ratings

Morningstar says its star ratings are backward-looking and not meant to be an indicator of future performance, **but** the company also has described the star ratings as "moderately predictive."

To assess the predictive powers of Morningstar's ratings, the Journal started with the overall rating of each share class on each rating date and looked forward three, five and 10 years to see what ratings it had earned over those periods.

For example, say share class x had an overall rating of 5 stars on Jan. 31, 2003. The performance of the share class over the following three years, relative to all other share classes in its category, could be determined by looking forward 36 months, to Jan. 31, 2006, and examining the 3-year star rating Morningstar assigned to the fund on that date.

How did ratings hold up over three years?

The table below shows the percentage of share classes that started out with a given overall rating and received a given three-year rating 36 months later. (The three-year rating ranks the performance of the fund over the prior three years.)

The overall rating that share classes started out with is labeled down the left side of the table; the 3-year rating they earned 36 months later is across the top of columns two through six. The last two columns contain the percentages of share classes that merged Into other funds or liquidated before the three-year period was completed and thus didn't receive a three-year rating for the period.

For example, the table shows that, among share classes that started out with an overall rating of five stars,14% delivered risk-weighted returns over the following three years that merited a five-star three-year rating, and 10% rated just one star. For funds that started out with a one-star overall rating, just 5% earned five stars after three years and 15% earned just one star.

Note: The Journal's data for its Morningstar analysis runs from January 2003 through October 2016, so the latest starting point for this table was October 2013 to allow for three years of future performance.

	Morningstar rating of next three years of performance						
Starting Overall Rating	1	2	3	4	5	Merged	Liquidated
1	15%	20%	17%	8%	5%	20%	14%
2	11%	24%	25%	12%	4%	15%	9%
3	7%	22%	33%	17%	6%	9%	6%
4	7%	18%	34%	24%	9%	5%	4%
5	10%	17%	29%	25%	14%	2%	3%

How did ratings hold up over five years?

The table below shows the percentage of share classes that started out with a given rating and received a given five-year rating five years later.

Note: The latest starting point for this table was October 2011 to allow for five years of future performance.

	Morningstar rating of next five years of performance						
Starting Overall Rating	1	2	3	4	5	Merged	Liquidated
1	11%	16%	14%	8%	4%	30%	18%
2	9%	20%	22%	10%	4%	24%	13%
3	7%	19%	30%	15%	5%	15%	10%
4	7%	18%	31%	21%	8%	9%	7%
5	10%	18%	28%	22%	12%	5%	5%

How did ratings hold up over 10 years?

The table below shows the percentage of share classes that started out with a given rating and received a given 10-year rating five years later.

Note: The latest starting point for this table had to be October 2006 to allow for 10 years of future performance.

	Morningstar rating of next 10 years of performance						
Starting overall rating	1	2	3	4	5	Merged	Liquidated
1	8%	9%	9%	3%	2%	48%	21%
2	7%	14%	14%	7%	2%	41%	16%
3	6%	14%	22%	11%	3%	30%	14%
4	6%	14%	25%	17%	6%	21%	11%
5	8%	13%	22%	21%	14%	13%	9%

Another way to look at how ratings hold up over time

In addition to determining the percentages of share classes that wound up at each rating level over different periods of time, the Journal calculated the average future ratings of all share classes over three, five and 10 years.

One problem in calculating the average of those future ratings is what experts refer to as "**survivor bias**." The **only share classes that will have ratings three years in the future are those that survived the entire period**. **Funds that merged into other funds or liquidated (shut down and returned money to investors) will not have ratings to include in the averages at the end of the period being studied**.

Morningstar records the dates when share classes disappear and notes whether the disappearance was due to a liquidation or a merger. **Funds that liquidate typically have performed poorly and suffered investor withdrawals**, so the Journal assumed that share classes that liquidated during the periods being studied performed at a one-star level.

Mergers are not as cut and dried. Some funds that merge into others are weak; others have good track records and large amounts of assets. For those reasons, the Journal decided to drop share classes that merged from the analysis rather attempting to classify their performance.

Morningstar's experts said they disagreed with that approach. They would prefer that both merged and liquidated share classes be treated as one-star performers during the time frames in which they drop out of the data. The Journal ran the analysis both ways.

To create the tables below, the Journal examined the starting overall rating of each share class on each rating date and looked forward three, five and 10 years to see what rating Morningstar gave the share class for those periods. For each time frame, the Journal also calculated the average overall rating that share classes received.

Share classes that liquidated during the period being studied were treated as if they had been given a one-star rating for the period. In cases where a share class disappeared before the end of the period due to a merger, the Journal dropped it from the analysis for the article and the tables on the left below. The tables on the right below follow Morningstar's preferred methodology, treating merged funds as if they had been given a one-star rating for the period.

Merged classes dropped from analysis				Merged classes given one star			
Starting overall rating	Three-year rating three years later	Overall rating three years later	Records	Starting overall rating	Three-year rating three years later	Overall rating three years later	Records
1	2.3	1.8	160,795	1	2.0	1.6	201,485
2	2.5	2.3	475,492	2	2.3	2.1	561,277
3	2.8	2.8	743,819	3	2.6	2.6	814,864
4	3.0	3.4	455,493	4	2.9	3.2	479,149
5	3.1	3.7	159,487	5	3.1	3.7	163,635
*Limited to rating dates of 2013-10-31 or earlier				*Limited to rating dates of 2013-10-31 or earlier			

Merged classes dropped from analysis				Merged classes given one star			
Starting overall rating	Five-year rating five years later	Overall rating five years later	Records	Starting overall rating	Five-year rating five years later	Overall rating five years later	Records
1	2.2	2.0	113,495	1	1.8	1.7	161,267
2	2.4	2.3	334,388	2	2.1	2.0	438,502
3	2.7	2.7	534,029	3	2.4	2.5	628,498
4	2.9	3.1	333,491	4	2.7	2.9	368,284
5	3.0	3.4	123,066	5	2.9	3.3	129,931
*Limited to rating dates of 2011-10-31 or earlier				*Limited to rating dates of 2011-10-31 or earlier			

Merged classes dropped from analysis				Merged classes given one star			
Starting overall rating	10-year rating 10 years later	Overall rating 10 years later	Records	Starting overall rating	10-year rating 10 years later	Overall rating 10 years later	Records
1	1.9	1.9	28,846	1	1.4	1.5	55,757
2	2.2	2.3	92,367	2	1.7	1.7	156,853
3	2.5	2.6	154,477	3	2.0	2.1	221,211
4	2.8	2.9	103,065	4	2.4	2.5	130,482
5	3.0	3.1	39,802	5	2.8	2.9	45,704
*Limited to rating dates of 2006-10-31 or earlier				*Limited to rating dates of 2006-10-31 or earlier			

How do analyst ratings hold up in the future?

In **2011**, **Morningstar** introduced a **new rating system**, analyst ratings, in which the firm's analysts provide a more qualitative analysis of funds. That system doesn't have as long a track record to evaluate as the star ratings, but the Journal did look at how the analyst rating on a given date held up over the small number of three- and five-year time frames available, using the same methodology as when the overall star rating was used as the starting point for the tables above. The analysis includes analyst and star ratings from November 2011 through August 2017.

Morningstar's experts object to the way the Journal conducted this analysis. They said they would prefer that the analysis be weighted by the assets of each share class or limited to a single representative share class, such as the oldest share class in a fund, because analysts give funds a single analyst rating rather than rating share classes separately, as star ratings do. Morningstar also said there's a mismatch in how the Journal evaluated analyst ratings because star ratings take into account up-front fees known as loads while analysts' evaluations do not.

The Journal decided to count all share classes equally in the analysis because investors looking at any share class in a given fund would see the same analyst rating and perhaps weigh that rating when deciding where to invest.

These tables show a breakdown of the three- and five-year ratings that analyst-rated share classes received. For example, three years after they had a Gold analyst rating, 14% of share classes received a five-star rating from Morningstar for the three-year period. Just 6%received a one-star rating.

	Three-year rating three years later						
Starting analyst rating	1	2	3	4	5	Merged	Liquidated
Gold	6%	20%	29%	28%	14%	3%	1%
Silver	8%	20%	28%	23%	16%	3%	2%
Bronze	10%	23%	34%	19%	7%	3%	3%
Neutral	8%	24%	37%	17%	6%	4%	3%
Under Review	12%	19%	25%	22%	14%	8%	0%
Negative	7%	23%	21%	15%	5%	2%	28%

	Five-year rating five years later						
analystRating	1	2	3	4	5	Merged	Liquidated
Gold	5%	17%	28%	28%	17%	3%	1%
Silver	8%	16%	27%	27%	18%	2%	2%
Bronze	8%	22%	33%	19%	11%	4%	3%
Neutral	4%	22%	37%	18%	9%	8%	3%
Under Review	16%	16%	22%	23%	14%	8%	2%
Negative	4%	10%	17%	18%	11%	5%	35%

How do the ratings affect decisions of investors and their investment advisers?

Investors and advisers interviewed by the Journal said they used Morningstar's star ratings when deciding which funds to invest in and that they tended to favor funds rated with at least four stars. Morningstar researchers recently noted that "the rating has been used to identify funds that fund selectors expect to perform well in the future." Investors also clearly pay attention to the past returns of funds when making their selections.

The Journal set out to examine the interplay between ratings and returns of funds as investors decided which funds to invest in or pull their money from. For each of the 130 months from January 2003 through October 2013, the Journal started out with all share classes that existed in the given month and survived for the ensuing three years. For each of those share classes, the Journal compiled the following metrics for the three-year period:

- ❖ The net of investor dollars put into or pulled from the share class ("net flow").
- ❖ The net flow over three years divided by the assets of the share class at the beginning of the period (net flow percentage).
- ❖ The three-year rating Morningstar gave the share class at the end of the three years.
- ❖ The average overall rating of the share class during the three years, rounded to a whole number.

Average overall rating	Rounded rating value
1.0 - 1.49	1
1.5 - 2.49	2
2.5 - 3.49	3
3.5 - 4.49	4
4.5 - 5.0	5

The Journal then calculated the averages of those metrics across all 130 three-year periods for each combination of the average overall rating for the three years (rounded to the nearest whole number) and three-year rating share classes were given at the end of the three-year period.

This table shows the average net flow, as a percentage of starting assets, that each combination of average overall rating and three-year rating experienced over the three-year periods studied by the Journal.

For example, it shows that share classes that averaged an overall rating of five stars over the period and received a five-star rating from Morningstar at the end of the period saw average net flows of 107%. In other words, those funds had high overall ratings during the three years, delivered performance that ranked them at the top of the three-year ratings and, on average, they saw their assets more than double over the three years.

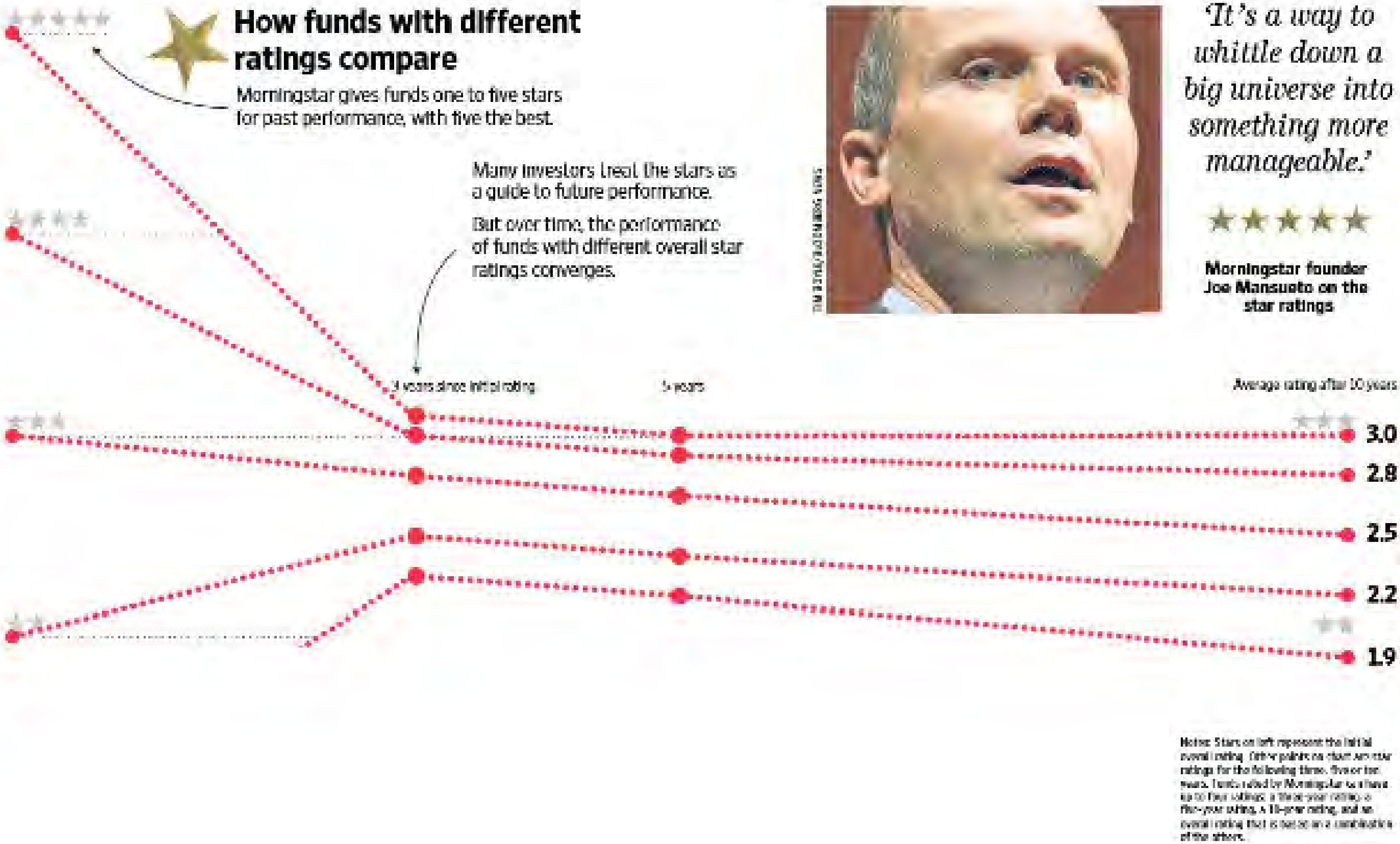
The table also shows that share classes that had an average overall rating of one star during the three years and were given a five-star three-year rating from Morningstar at the end of the three-year period saw their assets decline by about an average of 24% during the three-year periods studied by the Journal.

	Three-year star ratingat end of three years				
Average overall rating over three years	1	2	3	4	5
1	-46%	-43%	-42%	-40%	-24%
2	-42%	-37%	-32%	-29%	-16%
3	-34%	-26%	-16%	-10%	5%
4	-16%	-6%	5%	14%	42%
5	26%	39%	50%	58%	107%

This table shows the average percentage of share classes in each grouping that saw net outflows of investor dollars during the three-year periods studied by the Journal. For example, an average of just 20% of share classes that had an average overall rating of five stars during the three-year periods and earned an overall rating of five stars three years later saw investors pull more money from the fund than they put into it during the three year periods studied by Journal.

The table also shows that, on average, 77% of share classes that averaged an overall one-star rating during the three years saw net outflows of investor dollars even though they had performed at a five-star level over the three-year periods.

	Three-year star rating at end of three years				
Average overall rating over three years	1	2	3	4	5
1	85%	81%	78%	78%	77%
2	83%	79%	73%	69%	60%
3	76%	71%	62%	56%	48%
4	61%	54%	47%	41%	34%
5	45%	38%	31%	27%	20%



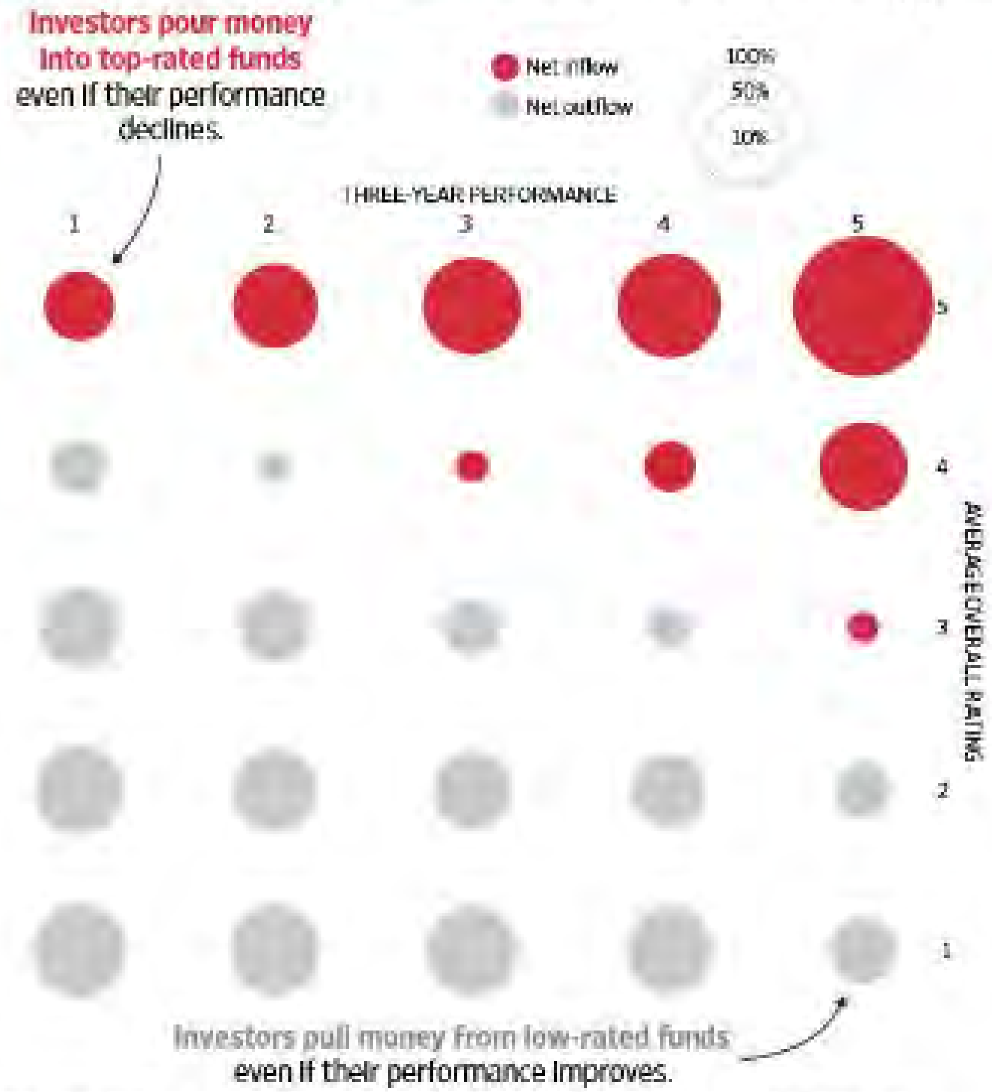
'It's a way to whittle down a big universe into something more manageable.'

★★★★★

Morningstar founder Joe Mansueto on the star ratings

Money In Motion

The Journal analyzed how much money flowed into or out of funds over three yea
based on the overall ratings investors saw and how well the funds actually perforr



Note: Funds rated by Morningstar can have up to four ratings: a three-year rating, a five-year rating, a 10-year rating, and an overall rating that is based on a combination of the others.

Case Studies

Nuveen Santa Barbara Dividend Growth Fund*

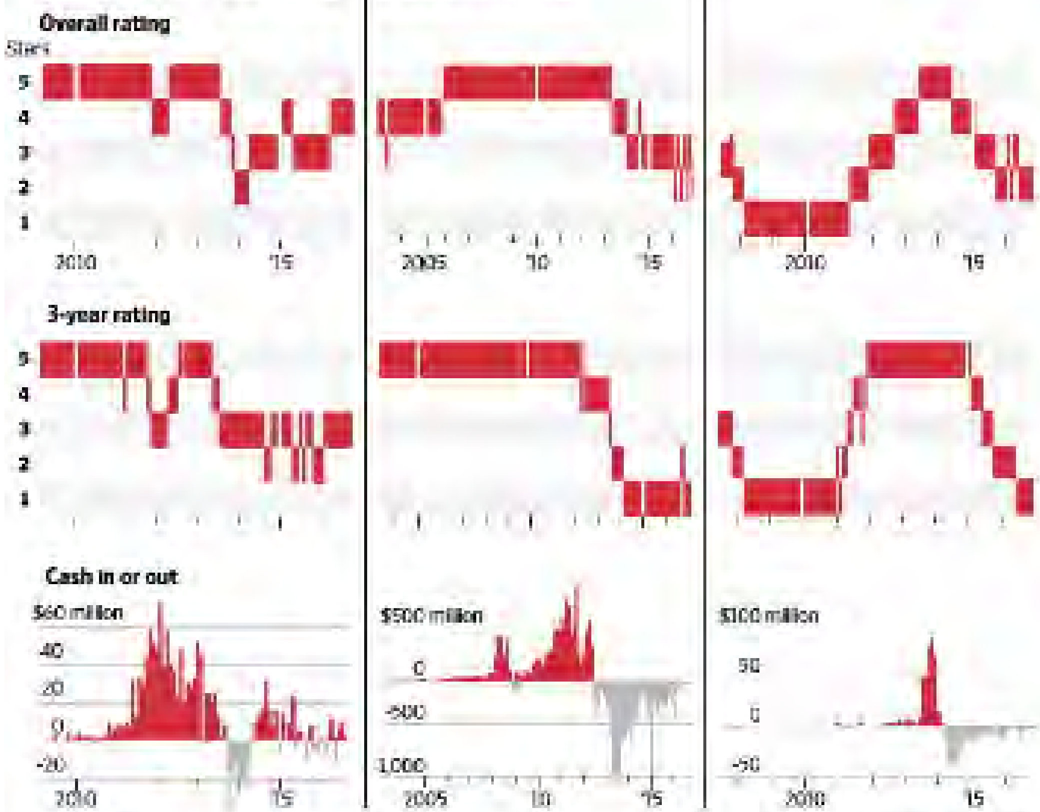
A pension fund moved $2.1 million into the Nuveen Santa Barbara Dividend Growth Fund in November 2011, when the fund had a five-star rating.

Permanent Portfolio*

A financial advisor invested clients in Permanent Portfolio in early 2012 when it had five stars, but it quickly started underperforming.

Buffalo Emerging Opportunities Fund

After Morningstar gave the tiny fund five stars in the spring of 2013, investors poured in hundreds of millions of dollars.



*Share class I

Source: WSJ analysis of Morningstar data

CASE: UE 433
WITNESS: ITAYI CHIPANERA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2500

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Itayi Chipanera. I am a Senior Financial Analyst employed in the Accounting and Finance Section of Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/200 and my Witness Qualifications Statement is provided in Exhibit No. Staff/201.

Q. What is the purpose of your testimony?

A. I am the revenue requirement summary analyst, and the purpose of my testimony is to present changes in revenue requirement associated with Staff's opening position. I also respond to the Company's Reply Testimony regarding my Opening Testimony positions on cash working capital, OPUC fees, and WRAP and COSR Materials fees.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Does the Company agree with any issues that were introduced in your Opening Testimony?

A. Yes. Staff and PacifiCorp agree that the Company should use the new OPUC Fee rate of 0.45 percent for Test Year OPUC fee expenses, the new rate is reflected in the Company's updated revenue requirement. The OPUC fee rate is a revenue sensitive item, and its final value will ultimately depend on the final revenue requirement; therefore, Staff is not proposing an adjustment in this Reply Testimony other than the one necessary to calculate the Company's revenue requirement.

Q. Which issues raised by the Company in its Reply Testimony does Staff agree with?

A. Staff agrees with the Company's correction of errors in its initial filing regarding Test Year amounts for the Western Resource Adequacy Program (WRAP) and Committee of State Regulators (COSR) Materials fees that were uncovered during the discovery process. The Company's updated revenue requirement now reflects the corrected WRAP and COSR fees amounts.

ISSUE 1. REVENUE REQUIREMENT

Q. Please discuss the overall changes to revenue requirement proposed in PacifiCorp's Reply Testimony.

A. The Company reduced its revenue requirement request from $322.3 million requested in its initial filing to $214.5 million in its Reply Testimony.[1] The components of the $214.5 million increase can be disaggregated into

1. A base rate increase of $127.6 million.
2. An Insurance Cost Adjustment of $66.0 million, which reflects $15.5 million of deferred insurance premiums and $50.4 million of on-going insurance premiums.
3. The estimated true-up of $21.2 million for the Wildfire Mitigation Plan (WMP) automatic adjustment clause (AAC).
4. The rebalancing of the Rate Mitigation Adjustment for a reduction of $0.4 million.

Q. What reasons did the Company give in its Reply Testimony for decreasing its initially requested revenue requirement increase of $322.3 million?

A. The Company removed $77.7 million of proposed revenue requirement related to the Catastrophic Fire Fund, as well as a $30 million reduction to base rates.

Q. What are the drivers of the $30 million reduction to base rates?

A. The Company reduced its requested return on equity from 10.3 percent to

[1] PAC/2000, McVee/2.

9.65 percent, resulting in a revenue requirement reduction of $23.5 million. The Company says the proposed reduction in return on equity is a measure to "mitigate the impact of this rate change on its customers".[2] Additionally, PacifiCorp removed $6.3 million of revenue requirement related to a customer service system upgrade due to a delayed in-service date.[3] The Company summarized the proposed $30 million reduction to base rates as shown in the table below.[4]

Table 1.

Adjustments to Initial Base Increase Filed (In $ million)		
ROE Update. 10.30% to 9.65%	$	(23.5)
Cost of Debt Update: 5.18% to 5.28%	$	2.7
Customer Service Project Removal	$	(6.3)
Customer Payment Fees Update	$	(3.4)
Other Corrections and Upates	$	0.5
Total Base Adjustments in Reply Testimony	**$**	**(30.0)**

Q. Has Staff resolved any proposed adjustments to the Company's revenue requirement with PacifiCorp?

A. No. Staff has not resolved any proposed adjustments with the Company.

Q. What is the adjustment to revenue requirement recommended by Staff in this Rebuttal Testimony?

A. Staff proposes to reduce the Company's requested revenue requirement increase based on a range of return on equity (ROE) values. Staff proposes to reduce the requested $214.48 million increase to:

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2 PAC/2000, McVee/3.
3 Id.
4 PAC/3300, Cheung/3.

- $20.655 million, a reduction of $193.826 million when using an 8.77 percent ROE, and
- $43.780 million, a reduction of $170.700 million when using a 9.44 percent ROE.

Q. Summarize Staff's proposed adjustments to the Company's revenue requirement?

A. Staff's adjustments are presented in the table below.

Table 2

PacifiCorp
STAFF ISSUE SUMMARY
Twelve Months Ended December 31, 2025
($000)

Total Incremental Revenue Requirement Initially Filed by the Company	**$ 322,333**	**$ 322,333**
Reply Testimony - Company's Catastrophe Fire Fund Withdrawal	$ (77,789)	$ (77,789)
Reply Testimony - Company's Return on Equity Reduction (10.3% to 9.65%)	$ (23,500)	$ (23,500)
Reply Testimony - Company's Cost of Debt Update (5.18% to 5.28%)	$ 2,700	$ 2,700
Reply Testimony - Company's Customer Service Project Removal	$ (6,300)	$ (6,300)
Reply Testimony - Company's Customer Payment Fees Update	$ (3,400)	$ (3,400)
Reply Testimony - Company's Other Corrections and Updates*	$ 437	$ 437
Total Non-NPC Related Price Change (excludes TAM)	**$ 214,480**	**$ 214,480**

Testimony	Issue No.	Staff	Staff Adjustments	Revenue	Expense	Rate Base	Revenue Requirement Effect @ ROE 8.77%	Revenue Requirement Effect @ ROE 9.44%
2400	ROE	Matt Muldoon	Return on Equity	-	-	-	(32,510)	(8,335)
2400	S-1	Matt Muldoon	Pensions	-	(1,845)	-	(1,906)	(1,906)
2400	S-2	Matt Muldoon	Post Retirement Medical Expense	-	(748)	-	(773)	(773)
3600	COD	Rose Pileggi	Cost of Debt	-	-	-	757	757
2500	S-3	Itayi Chipanera	Interest Expense Synchronization	-	-	-	2,041	2,041
2500	S-4	Itayi Chipanera	Cash Working Capital	-	-	(3,369)	(295)	(310)
2500	S-5	Itayi Chipanera	OPUC Fees	-	-	-	-	-
2800	S-6	Julie Dyck	Fuel Stock	-	-	(13,983)	(1,222)	(1,287)
2800	S-7	Julie Dyck	Juniper Ridge Bend Service Center	-	-	(2,870)	(251)	(264)
2900	S-8	Brett Farrell	Uncollectible Accounts	-	(1,642)	-	(1,696)	(1,696)
2900	S-9	Brett Farrell	Customer Accounts Expense	-	(320)	-	(330)	(330)
3000	S-10	Luz Mondragon	Vehicles	-	-	(3,196)	(279)	(294)
3000	S-11	Luz Mondragon	Routine Vegitation Management Distribution	-	(403)	-	(416)	(416)
3000	S-12	Luz Mondragon	Wildfire Management Distribution	-	(5,274)	-	(5,447)	(5,447)
3000	S-13	Luz Mondragon	Amortization Expense	-	(9,439)	-	(9,748)	(9,748)
3000	S-14	Luz Mondragon	UM 2116 Rate Base-WM Plant	-	-	-	-	-
3000	S-15	Luz Mondragon	UM 2116 Amortization Exp (O&M Deferred)	-	(3.0)	-	(3.1)	(3.1)
3000	S-16	Luz Mondragon	UM 2116 Amortization Exp (Depreciation Exp Deferred)	-	-	-	-	-
3000	S-17	Luz Mondragon	UM 2116 Rate Base	-	-	-	-	-
3000	S-17R	Luz Mondragon	UM 2116 Rate Base	-	-	(9,989)	(873)	(919)
3100	S-18	Mitch Moore	Non-Fuel Materials and Supplies	-	-	(18,902)	(1,653)	(1,739)
3100	S-19	Mitch Moore	Incremental Operation & Maintenace - Jim Bridger	-	(4,585)	-	(4,735)	(4,735)
3100	S-20**	Mitch Moore	CSS Upgrade	-	-	-	-	-
3300	S-21	Sudeshna Pal	Gateway South Management - Disallowance	-	-	(56,387)	(4,930)	(5,188)
3300	S-22	Sudeshna Pal	ROR to MBT Rate for Gateway South	-	-	-	(16,239)	(16,239)
3400	S-23	Ming Peng	Depreciation Expense	-	(13,149)	-	(13,580)	(13,580)
3400	S-24	Ming Peng	Depreciation Reserve	-	-	13,149	1,150	1,210
3400	S-38R	Ming Peng	AFUDC Adjustment - Rate Base	-	-	(8,431)	(737)	(776)
3400	S-39R	Ming Peng	AFUDC Adjustment - Operating Expense	-	843	-	871	871
3500	S-25	Nicola Peterson	Injuries and Damages - Provision	-	(3,149)	-	(3,252)	(3,252)
3500	S-26	Nicola Peterson	Injuries and Damages - Legal Fees	-	(1,708)	-	(1,764)	(1,764)
3500	S-27	Nicola Peterson	Payroll Overhead	-	-	-	-	-
3600	S-28	Rose Pileggi	Fall Creek Hatchery	-	-	(9,800)	(857)	(902)
3700	S-29	Paul Rossow	Memberships Accounts	-	(200)	-	(207)	(207)
3700	S-30	Paul Rossow	Meals and Entertainment	-	(78)	-	(81)	(81)
	S-31**	Stevens\Pileggi\Brewer	Catastrophic Fire Fund	-	-	-	-	-
3800	S-32	Bret Stevens	Base Insurance Cost Adjustment	-	-	-	(50,443)	(50,443)
3800	S-33	Bret Stevens	Liability Insurance Premiums	-	6,403	-	6,613	6,613
3800	S-34	Bret Stevens	Deferred Insurance Premiums	-	-	-	(3,113)	(3,113)
3800	S-35	Bret Stevens	Rate Base - Average of Monthly Averages	-	-	(116,968)	(10,226)	(10,763)
3900	S-36	Stephanie Yamada	Wage and Salaries Operation and Maintenance	-	(782)	-	(808)	(808)
3900	S-37	Stephanie Yamada	Wage and Salaries Capital Adjustment	-	-	(18,842)	(1,647)	(1,734)
4000	S-40R	Madison Bolton	Bridger Mine Reclamation And Depreciation	-	-	-	(35,237)	(35,142)
Total Staff Adjustments							**(193,826)**	**(170,700)**
Staff-Calculated Revenue Requirements Change:							**$ 20,655**	**$ 43,780**

*Adjusted for rounding to match Company Totals
**Issue withdrawn by the Company in its Reply Testimony

ISSUE 2. CASH WORKING CAPITAL

Q. Summarize Staff's Opening Testimony position regarding the Company's Test Year cash working capital amount.

A. Staff proposed to reduce the company's Test Year cash working capital by $10.81 million from $36.52 million to $25.71 million. Staff's Opening Testimony proposal to reduce the Company's cash working capital is based on adjusting the Company's billing lag from 3.32 days to zero. The billing lag is an input into the Company's formula used to calculate cash working capital.

Q. What is Staff's response to the Company's assertion that it is the collection lag and not the billing lag that is driving high net lag days in the Company's operations in Oregon?

A. As explained in Staff's Opening Testimony, the Company calculated its net lag days as:

$$Net\ Lag = Service\ Lag + Billing\ Lag + Collection\ Lag - Expense\ Lag$$

Both the billing lag and collection lag have a direct linear relationship with the net lag. In other words, an increase or decrease of one to either the billing lag or the collection lag results in a similar magnitude change to the net lag. While the collection lag is bigger that the billing lag in magnitude, incremental changes to either the billing lag or the collection lag results in the same incremental change to the net lag. In Staff view's both the billing lag and the collection lag are important drivers of the Company's Test Year cash working capital amount.

Q. What is the Company's response to Staff's proposal to reduce the billing lag?

A. The Company says there is "a necessary processing time when a meter is read to the issuance of an invoice and that timeframe needs to be accounted for".[5] Staff does not disagree with the assertion that the Company needs time to process invoices; however, there is variation in the efficiency of this activity among Oregon utilities, the most efficient ones can get this process done on the same day and some require just one day. The Company cites its unique processes and technology as the driver of why its billing lag is higher than other Oregon utilities.

Q. What is Staff's response to the Company's position that its billing lag requires no adjustment?

A. The Company's lead lag study calculations support a billing lag of 2.32 days; however, the Company manually adds an extra day to the calculation to arrive at 3.32 days.[6] The one-day manual adjustment to the billing lag is arbitrary and is not supported by any data and should therefore not be included as part of the Company's cash working capital calculation. Staff is revising its Opening Testimony billing lag proposal and now proposes to use a billing lag of 2.32 days.

Q. What is Staff's revised adjustment to the Company's Test Year cash working capital amount?

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5 PAC/3300, Cheung/66.
6 2022 Lead Lag Study, Tab 3.2.

A. Staff's proposal to use a billing lag of 2.32 days in the Company's cash working capital calculation results in a Test Year cash working capital amount of $32.992 million compared to $36.361 million as filed in the Company's Reply Testimony. Staff's revised proposal is to reduce the Company's cash working capital by $3.369 million.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: KATE AYRES

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2600

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Kate Ayres. I am an Energy Justice Analyst employed in the Energy Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My opening testimony is found in Exhibit Staff/600 and my Witness Qualification Statement is provided in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. This testimony responds to Intervenor's Opening Testimony and the Company's Reply Testimony. Additionally, it provides further analysis and recommendations regarding the Company's Low-Income Discount (LID), including continuing conversations around the Company's level of disconnections and arrearages and the LID programs' Cost Recovery.

Q. Did you prepare any other exhibits for this testimony?

A. Yes. I prepared Exhibit Staff/2601, PacifiCorp Non-Confidential Responses to Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LOW-INCOME DISCOUNT

Q. Please briefly describe the Company's current Low-Income Discount.

A. PacifiCorp's current Low-Income Discount (LID), approved in 2022 as Schedule 7, is a percentage of bill discount program available to residential customers whose adjusted household income is at or below 60 percent state median income (SMI). The Company currently offers a two-tier discount structure, where customers from 0-20 percent SMI can receive a 40 percent monthly discount to applicable charges on their PacifiCorp bill, and customers from 20-60 percent SMI can receive a 20 percent discount. Customers who previously received Low-Income Home Energy Assistance (LIHEAP) or Oregon Energy Assistance Program (OEAP) funds in the last 12 months may be automatically enrolled, or customers may self-attest to the qualifying household's income and household size. Additionally, the Company offers a 30 percent discount for master metered buildings with 50 percent or greater of individual residential units dedicated to low-income qualifying households and who qualify under Special Condition 10 of Schedule 7.

Q. Please summarize Staff's opening testimony recommendations related to the Low-Income Discount.

A. Staff recommended several proposed program changes to the Company's current LID in opening testimony. The recommendations addressed the Company's lack of program adjustment following a second general rate case filing since the LID's effective date in October 2022. Staff's recommendations from opening testimony included:

- Adding a third tier providing at least a 60 percent discount for customers with an adjusted household income between 0-10 percent SMI.
- The Company monitor, track, and report to the Commission LID participants with usage of more than twice the average monthly residential customer usage and that the Company utilize the reports to refer identified participants to Community Action Agencies (CAA or CAP agencies), Energy Trust of Oregon (ETO) and/or any other known partner agencies administering low-income energy efficiency and weatherization services to environmental justice communities in the Company's service territory.
- The Company engage with CAP agencies to optimize low-barrier and timely enrollment for customers and explore the possibility of a back-end enrollment system that places customers into the proper tier level.
- The Company include a component on the paper LID enrollment form allowing for participants to utilize a third-party to help fill out and submit forms on the customer's behalf.
- The Company file the results of the Energy Burden Assessment (EBA) under Docket No. UM 2211 no later than September 1, 2024.
    - o Based on a timeline coordinated with parties, following the EBA being finalized, PacifiCorp should convene Staff and stakeholders to discuss the findings and consider the need, cost, and feasibility of further near-term refinement of the LID tier structure and discount levels beyond what is adopted in UE 433.

Q. Please summarize CUB's opening testimony recommendations related to the LID.

A. The Oregon Citizens' Utility Board (CUB) recommended that the Commission require PacifiCorp to measure the effectiveness of procedural equity through data and/or the development of Equity Metrics in order to evaluate if PacifiCorp's various modalities for community engagement are effectively targeting procedural justice and translating into measurable improvements to customers.[1] CUB recommended the Company alter its existing program tiers to target households with the lowest SMI to include deeper discounts. CUB also recommended that the Company utilize the July 8 Energy Justice (EJ) Workshop to provide an overview of how various projections of different program tiers and discounts would impact customers' bills and impact LID participant bills.[2]

Additionally, CUB recommends the Company revisit the changes agreed to in UE 433 following the filing of the Company's EBA and if the data shows the need for deeper discounts or a restructuring of tiers, the Company build in flexibility to make these adjustments prior to the January 1, 2025, effective date.[3]

Q. Please provide a brief summary of the Coalition's recommendations regarding the LID.

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1 CUB/200, Wochele-Jenks/22.
2 CUB/200, Wochele-Jenks/39.
3 CUB/200, Wochele-Jenks/40.

A. The Coalition proposed several recommendations to the Commission to change the structure of the Company's LID. First, the Coalition recommends the Company incorporate additional tiers to place PacifiCorp's program on par with other Oregon utilities with tiers being determined following analysis of rate impacts to residential ratepayers.[4] When looking at post-enrollment verification for the LID, the Coalition recommends eliminating the current post-enrollment verification (PEV) process and creating a post-enrollment verification process for master-meter customers if over ten ratepayers are enrolled in the program servicing low-income residential buildings.[5]

Additionally, they recommend requiring the Company to adopt an arrearage forgiveness program offering for households earning at or below 20 percent SMI and evaluate offering arrearage management options for other LID qualified customers following an analysis of ratepayer impacts.[6] The Coalition also recommends providing additional protections by eliminating disconnections for low-income ratepayers in the 0-20 percent SMI range and implementing targeted assistance for households with excessive usage to address energy efficiency and weatherization opportunities.[7] Finally, the Coalition recommends directing PacifiCorp to prioritize delivery of energy efficiency programs to low-income customers and accelerating energy efficiency acquisition in collaboration with Energy Trust of Oregon.[8]

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4 Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 20.
5 Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 24.
6 Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 27.
7 Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 31.
8 Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 48.

Q. Please summarize the Company's response to recommendations on the LID in Reply Testimony.

A. In response to the parties above recommendations, the Company states that any changes made to the LID program should occur after the Company's EBA is completed, which is expected October 1, 2024. The Company explains that "the EBA will assess how effective the current LID is at reducing energy burden, identifying gaps in assistance, and provide recommendations for achieving lower energy burden targets."[9] The Company states that they are committed to continue refining its LID through the UM 2211 process.[10]

Additionally, the Company shares survey responses from two waves of LID participant surveys collected in March 2023 and October/November 2023 to show the data collection being done of LID participants, their reaction to the program following sign-up, and to highlight the participant response indicating that the current program is presently having a significant impact on energy burden.[11]

Regarding post-enrollment verification, the Company states that they are willing to continue discussions with Staff and other parties to determine the best course of action in relation to verification and includes that conversations with the Community Benefits Impact and Advisory Group (CBIAG) has helped shape how post-enrollment verification will roll out.[12]

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9 PAC/2000, McVee/46.
10 PAC/2000, McVee/47.
11 PAC/2000, McVee/48.
12 PAC/3500, Meredith/19.

In response to Staff's recommendation on data reporting for high usage LID customers, the Company responds by pointing to the data landscape analysis and reporting guidance currently underway in Docket No. UM 2211, Staff's HB 2475 implementation process.[13]

The Company also included a response to Staff's recommendation to adjust the LID enrollment form stating that the Company allows agencies to submit forms electronically on the customer's behalf and customers who would like assistance can contact the Company or their energy assistance agency directly.[14]

Q. Were there any other concerns flagged in Staff or other parties' opening testimony regarding low-income issues that PacifiCorp provided a response to?

A. Yes. In response to concerns expressed by parties regarding potential gaps in PacifiCorp's community outreach and engagement, the Company flags collaboration and stakeholder engagement processes as part of the Company's Clean Energy Plan (CEP) process and the utilization of lessons learned from the Company's Distributed System Planning (DSP) engagement.[15] PacifiCorp states that through extensive surveying it identified that costs and potential bill impacts are the primary concerns with the transition to cleaner energy.[16] Additionally, the Company flags the recently established

[13] PAC/3500, Meredith/20.
[14] PAC/3500, Meredith/21.
[15] PAC/2000, McVee/50.
[16] *Id.*

CBIAG, which the Company states focuses on equity and a clean energy future in the state of Oregon as authorized under Oregon House Bill 2021.[17] Following engagement with the CBIAG, PacifiCorp included a Community Benefit Indicator (CBI) within its CEP tracking the number of residential customer disconnections by census tract.[18]

Q. Please describe Staff's concerns with the Company's response in reply testimony related to the LID.

A. While Staff appreciates the Company's interest in ensuring the LID is making changes based off updated data and information, Staff is concerned that the Company did not meaningfully engage with the numerous calls for program adjustments within this proceeding. The Company's approach disregards discussions and potential near-term actions on improvements to the program until the EBA has been completed, or later. Staff remains concerned that further delays on incremental changes to PacifiCorp's LID, particularly given an anticipated increase to rates following the conclusion of this proceeding, will cause significant and disproportionate hardship on the Company's lowest income households. These concerns are reinforced by the level of PacifiCorp's residential arrearages and disconnections observed in discovery.[19] To this end, Staff believes timely LID review and revisions should be included in this proceeding to minimize these potential harms and address the widening gap of affordability. Staff highlights the process documents released in UM 2211

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[17] PAC/2000, McVee/51.
[18] *Id.*
[19] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 691 and 731.

detailing Staff's interest in finding near-term opportunities to adjust interim rate programs within general rate cases in order to provide necessary relief while additional phase 2 implementation processes occur.[20] Staff also points to the draft proposal timeline released in February 2024 in Docket No. UM 2211 that explicitly states that refinement of interim rates will occur in general rate cases.[21]

Additional detailing of this process can be found in Staff's Survey Synthesis and Updates document filed in April 2024 in Docket No. UM 2211 that reiterates an interest in utilizing the currently filed rate cases to increase bill discount amounts.[22] Staff continues to believe that significant adjustments and/or redesigns to the program should be data informed and responsive to analysis and stakeholder engagement on the most current utility and/or community specific information available. Staff also supports more open and inclusive stakeholder engagement on these issues than contested case proceedings typically allow. That said, Staff does not believe that low-income customers will benefit from putting off opportunities to make progress on program adjustments until after the EBA and does not find Staff's recommended incremental changes to be mutually exclusive of additional refinements and engagement outside of this proceeding.

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[20] *In the Matter of Public Utility Commission of Oregon, Implementation of House Bill 2475,* Docket No. UM 2011, Staff's Phase 2 Process Proposal (February 13, 2024).

[21] *Id.*

[22] *In the Matter of Public Utility Commission of Oregon, Implementation of House Bill 2475,* Docket No. UM 2011, Staff's Phase 2 Survey Synthesis and Updates (April 16, 2024).

While the Company states they expect the completed EBA by October 1, 2024, Staff is concerned that the Company does not include an expected filing date for the EBA. Staff appreciates the Company's work on obtaining an EBA in a timely manner and expects the Company to conduct stakeholder engagement following the EBA's filing to review the analysis completed, and to work with stakeholders on potential revisions to the LID. Given this somewhat undefined timeframe and desire for an inclusive and robust engagement process, Staff does not want to miss the opportunity to make progress on program adjustments that can take effect with the UE 433 January 1, 2025 rate changes.

Adopting higher rates in the middle of winter when customers are already struggling to afford their current energy bills will undoubtedly exacerbate energy system disparities and insecurities faced by low-income and environmental justice communities. Providing for some level of timely and corresponding adjustment to the LID as a part of this proceeding can and should be used to mitigate at least a portion of the rate case's disproportionate effects on energy burden and its associated harms for these same communities.

Additionally, Staff has near-term concerns about the cost efficiency of the current tier model which has the potential to provide too little relief for customers who need it most while also resulting in larger overall program costs. As such, Staff continues to recommend that incremental changes in UE 433 include the addition of a third tier with the intent of providing for more meaningful and targeted relief for customers with household incomes in the lowest SMI subsets.

Staff remains supportive of surveying LID participants to collect feedback on how participants are feeling about the discount amounts, ease of enrollment, and additional opportunities that may be available is important to program evaluation, but it should not be the only venue for evaluating the efficacy of the LID. Staff appreciates PacifiCorp highlighting that participants felt satisfied with the program and that the Company sees survey responses to show that the program is having significant impact on energy burden. This is an indication that our collective efforts are moving customer programs in the right direction to provide meaningful relief. However, Staff is not inclined to forgo opportunities for program improvement at this early stage of implementation based on this information alone. First, these results capture seven percent response rate for a program with approximately 50,000 participants. Second, participants were not surveyed on their opinions of the program or sufficiency of discount levels in connection with the rate increase proposed in this docket. Finally, depending on when participants responded to the survey, their satisfaction levels could change as they may feel that during a difficult winter heating month, or a hot summer month, the program leaves more to be desired. Staff looks forward to ongoing opportunities to review direct feedback from a greater number of participants over a longer period of time as we work to evolve these new offerings.

Regarding the Company's post-enrollment verification process, Staff would like to see additional conversations around best practices and ways to conduct verification that focus on advancing the positive impacts of the program and minimizing unnecessary burdens. Staff sees such an approach as more aligned with the equity driven policies advanced through HB 2475 than a traditional audit process for PEV, which can frequently result in customers being unenrolled from programs when unable to provide all the necessary documentation even if they are an eligible and target household. Staff is interested in a human-centered PEV approach for all HB 2475 programs that offer self-attestation. As such, Staff plans to work with stakeholders to develop ways that post-enrollment verification can be implemented with human impacts and program objectives in the foreground rather than defaulting to legacy processes that can have unintended consequences.

Staff flags additional ways to make PEV better for program outcomes. In addition to minimizing harms associated with high barrier audits, PEV should be more intentional with the sample pool and, similar to processes excluding LIHEAP participants from the sample, we can further narrow the pool by using high income indicators. Examples of this can be found in Portland General Electric Company's recently filed EBA which also include participants with high property value, those that own multiple properties, or have high estimated income.[23] Staff flags this work as an area for PacifiCorp to explore, but

[23] *In the Matter of Portland General Electric Company, Request for a General Rate Revision,* PGE's Energy Burden Assessment in Compliance with Order 23-286 (June 28, 2024).

believes that PEV processes should ultimately be designed following collaboration and engagement between the utility and Staff and stakeholders to ensure processes are not ultimately impacting eligible customers by increasing barriers to stay enrolled.

Staff appreciates the Company's desire to align additional monitoring of high-usage LID participants and referral to Energy Trust, Community Action Agencies, and similar organizations with the UM 2211 data landscape process. Staff does not intend to create duplicative data reporting requirements between this and the UM 2211 proceeding or additional ongoing data work occurring in other PUC dockets. Staff is still interested in including a component of monitoring customers with two times the average monthly usage and referring customers to the aforementioned organizations for assistance to their weatherization and energy efficiency needs. Staff hears PacifiCorp's interest in ensuring the data processes do not become duplicative, so Staff includes the following adjustments to our recommendation from opening testimony: should the UM 2211 data workstream result in guidance regarding the metrics and collection of data of the same value and nature as recommended here, the recommendations made here will be superseded by the data requirements in UM 2211.

In addition to referral, PacifiCorp should work with Staff and Energy Trust of Oregon on the possible ways to follow up with these high usage customers and help them navigate available support systems to upgrade their homes to be more energy efficient. Staff adjusts our recommendation from opening testimony to state that this should occur and not be duplicative of the UM 2211 process. This aligns with Staff's goal of additional reporting until we have finalized the UM 2211 data process and evaluated any necessary additional data reporting needs.[24]

Finally, Staff reiterates the importance of including a checkbox to paper LID enrollment forms allowing third parties to submit forms on behalf of LID participants. While Staff appreciates the Company detailing the opportunities available for customers to utilize electronic forms and reach out to the Company or energy assistance agency to help them with navigating the LID application process, that does not solve the concern Staff raised in opening testimony. Including a checkbox to the paper form allows customers who may not have access to the electronic forms, or who cannot easily access or do not feel comfortable connecting with a community action agency to have an accessible way to sign up for the LID program. This enrollment update can be especially important for elderly individuals who cannot easily leave their homes, for households where the account holder speaks another language and requires assistance from a family member or friend to apply, and other customers who may face barriers to participation in the program without this accessibility offer. Relatedly, Staff encourages the Company to listen and work with CAP agencies and other direct service providers on adjustments or

[24] *In the Matter of Public Utility Commission of Oregon, Implementation of House Bill 2475,* Docket No. UM 2011, Staff's Phase 2 Process Proposal (February 13, 2024).

proposals that ease enrollment for low-income and environmental justice communities.

Q. Are there any additional LID components related to the LID Staff would like to flag?

A. Yes. Following further review of the Company's LID tariff, Schedule 7, Staff has concerns around the upcoming re-enrollment process for LID participants who enrolled in the program shortly after it's effective date in October 2022. PacifiCorp's tariff states that re-enrollment in the program will be required every two years.[25] The Company notes that participants receiving LIHEAP/OEAP will be re-enrolled for two years following the receipt of the energy assistance funds.

Staff is concerned that without engagement prior to re-enrollment, and without analyzing a targeted and sensitive approach, the program will see similar effects to traditional PEV processes. Staff's goal in creating interim rate programs was to create low-barrier relief options for customers to more easily begin reaching the gap that current energy assistance sees. Staff is concerned that without proper outreach, follow-up, and communication, we will see customers unenrolled from the LID due to lack of response rather than lack of eligibility. Additionally, if following the cadence of the two years outlined in the Company's tariff, participants will be up for re-enrollment as early as October 2024. Staff is hesitant to begin this process when we are aware that necessary adjustments are needed to the program, and the timeline places the Company

[25] PacifiCorp Oregon Schedule 7, Low Income Discount.

and participants on the cusp of the winter heating and holiday seasons. Staff is concerned that customers will lose needed benefits to help their energy burden during a critical time of the year.

Similar to the PEV process described above, Staff is uninterested in a process that results in customers being unnecessarily removed from their program benefits, especially when lack of response provides no concrete information on whether the customer's economic status has changed in the past two years. Staff is interested in the re-enrollment process advancing the positive impacts of the program and wants to ensure it is created in a way that understands the human impacts this program can have, and the lived experiences many of these customers face when dealing with verification or other processes that can often create barriers, even inadvertently.

It is important that re-enrollment policies are informed by those with expertise in sensitive and impactful programming practices. Therefore, Staff recommends that the Company postpone beginning the re-enrollment process until after stakeholder engagement has occurred with Staff, stakeholders and CBIAG participants to better inform outreach for re-enrollment, or postponement until after the winter heating season has concluded, whichever occurs first.

Q. Please describe additional analysis of Staff's concerns with the Company's LID.

A. As described in Staff's opening testimony, Staff finds the current LID discount structure does not sufficiently offset high energy burden at existing rates, let alone after factoring in the requested rate increase for UE 433. This is especially apparent when looking at the lowest income customer segments. While Staff agrees that larger program adjustments should be informed by data and information collected in the EBA, making incremental adjustments to the LID within the rate case to address known and observable gaps in assistance does not circumvent the post-EBA process. Further, incremental adjustments in UE 433 represent a justifiable energy burden mitigation strategy to provide meaningful assistance to qualified customers on or before the UE 433 rate effective date.

Staff is cognizant that larger discounts can impact cost recovery rates paid by PacifiCorp customers, including residential customers within the LID program, especially after enrollment numbers have been larger than the Company's initial forecasts.[26] With that in mind, Staff investigated the potential impacts of multiple discount levels and tier structures to try and estimate both need and cost implications. In the process of this review, Staff heard from the Company that as of April 26, 2024 approximately 4,985 LID participants fall between the 0-10 percent SMI range.[27] To this end, Staff was able to limit its estimates of near term impacts of changes to roughly 5 thousand participants given our initial focus on the 0-10 percent SMI group. While we expect the program to grow, Staff believes that targeting this narrow group and the even narrower subset, of 0-5 percent SMI provides some measure of scope and

[26] *In the Matter of PacifiCorp's Advice No. 24-006, Schedule 92, LID Cost Recovery Adjustment,* Docket ADV 1603, Staff Report (April 24, 2024).
[27] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 440.

confidence to make additional program adjustments for known areas and levels of need as part of Staff's Reply Testimony recommendations.

Specifically, and in addition to the 60 percent discount for customers earning 6-10 percent SMI. Staff sees the 0-5 percent SMI customer segment as still facing extremely high energy burden even after a 40 percent (current) or 60 percent (Staff proposed in opening testimony) applied. To address this deficiency and align with Staff's objectives for targeted assistance, Staff provides an amended energy burden table updating the originally filed table from Exhibit Staff/600 to include an additional assistance tier of a 80% discount for the 0-5 percent SMI customer segment. As with the Table in Exhibit Staff/600, Table 1 below utilizes the 2023 net residential average yearly residential customer bill of $1,317 to calculate energy burden.[28]

[28] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 555.

Table 1.

% SMI	HH Income	Energy Burden			
		Before Discount	After Current 40% Discount	After Staff's OT proposal 60% discount	After Staff's Proposed 80% Discount
0.10	$9,374.33	14%	8%	6%	
0.09	$8,436.90	16%	9%	6%	
0.08	$7,499.47	18%	11%	7%	
0.07	$6,562.03	20%	12%	8%	
0.06	$5,624.60	23%	14%	9%	
0.05	$4,687.17	28%	17%	11%	6%
0.04	$3,749.73	35%	21%	14%	7%
0.03	$2,812.30	47%	28%	19%	9%
0.02	$1,874.87	70%	42%	28%	14%
0.01	$937.43	140%	84%	56%	28%

Table 1 demonstrates the potential levels of need as customers fall further below the 10 percent SMI category. As in opening testimony, Staff used the average bill data to calculate the percentages, but many customers within this range may have a higher-than-average bill due to inefficient housing stock or unmet weatherization needs. Similarly, a household could have a lower-than-average bill as a result of energy efficiency adoption, square footage, or energy limiting behavior; however, as Staff has observed, when looking at households in the lowest percentages of SMI, energy burden is so profound that these households where even if the customer used only half the monthly average energy as the residential average, their energy burden would still be between 14 to 70 percent absent any discount, or 9 to 42 percent if enrolled in the current LID. This is compared to non-low-income customers paying an average of roughly 2.3 percent of their income to household energy costs.[29] Additionally, Table 1 is not reflective of the requested rate increase proposed by the Company. As such, there are likely customers in each of these percentage groups with higher energy burden than depicted.

Upon this review, Staff believes targeting the 0-5 percent SMI category for deeper discounts is an additional near-term opportunity that can lead to a noticeable and targeted reduction in energy burden with positive effects on arrearages and disconnections. Staff highlights that no one benefits from billing a customer more than they can reasonably be expected to pay and ultimately doing so has a greater cost on the customer, all ratepayers, and the utility, not including the added stress to the customer to manage the unreasonable expenses or the time required to find a workable solution. Staff's approach gets out in front of these situations and tries to find the most efficient solution to a troubling and difficult issue. As such, Staff recommends that the Company add an additional tier to the LID providing a 80 percent discount to monthly billed amounts for residential customers earning an adjusted household income between 0-5 percent SMI.

[29] *How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden across the United States,* Ariel Dreholb, Lauren Ross, and Roxana Ayala, American Council for an Energy-Efficient Economy (ACEEE), September 2020. Available at: 16. ACEEE, How High are Household Energy Burdens.pdf

ISSUE 2. DISCONNECTIONS AND ARREARAGE LEVELS

Q. Please summarize Staff's opening testimony regarding the Company's disconnection and arrearage levels.

A. Staff's focus in opening testimony highlighted the urgent and concerning picture PacifiCorp's arrearage and disconnection data paint for Oregon customers. Staff recommended, at a minimum, the Company should engage Staff, consumer advocates, Community Action Agency partners, and its CBIAG to discuss disconnection rates, past due balances, struggling active and recently disconnected accounts, and any other factors that can be used to inform a crisis mitigation strategy to be brought before the Commission.[30]

Staff also asked the Company to propose, in Reply Testimony, an Arrearage Management Program attached to the LID program for LID participants at or below 5 percent SMI. Additionally, Staff recommended the Company come before the Commission with an analysis of residential customer past due balances, information on disconnections pending or carried out for the same household within a single calendar year, and a proposal that aims to reduce monthly disconnection rates for residential customers and prevent the accumulation of past due balances above a certain amount.[31]

Staff also recommended that any LID participant with a past-due balance over six times the monthly average bill for the account, the utility halt the accumulation of additional debt and pause any anticipated LID account

[30] Staff/300, Scala/7.
[31] Staff/300, Scala/25.

balance referrals to collection agencies in anticipation of relief from the aforementioned proposal.[32] Finally, Staff recommended that the Company work with Staff and stakeholders to discuss the findings of the EBA and consider the need, cost, and feasibility of additional refinements to an AMP program structure or level of relief beyond what is adopted in UE 433.

Q. Please summarize CUB's recommendations regarding disconnections and arrearages.

A. CUB also highlighted concerns around the level of disconnect and arrearage balances and flagged the need for additional data collection and sharing to pinpoint additional efforts to better serve PacifiCorp customers. CUB asked that requirements be put in place for PacifiCorp to do more thorough public-facing data collecting and reporting related to disconnections and arrearages including customer and neighborhood level demographics, both for LID customers and all other customers, including retroactive reporting through at least 2018 where necessary.[33] CUB includes a recommendation that if the Company cannot markedly reduce its disconnections, it should experience a penalty.[34] Additionally, CUB recommended utilizing limitations in Division 21 as opportunities to implement policies that can address gaps in protections for low-income and other vulnerable customer protections, and that the Company

[32] *Id.*
[33] CUB/200, Wochele-Jenks/22
[34] CUB/200, Wochele-Jenks/54.

should begin working immediately with stakeholders on the creation of an Arrearage Forgiveness Program for low-income customers in its territory.[35]

Q. Please summarize the Coalition's recommendations regarding disconnections and arrearages.

A. The Coalition highlights how current disconnection policies and LID program structure are inadequate to protect PacifiCorp's lowest-income customers. The Coalition recommended the Commission require that PacifiCorp implement an arrearage program for the low-income customers in the 0-20 percent SMI range and investigate permanently adopting an arrearage forgiveness program and/or an AMP in connection with all income tiers of the LID program.[36] Additionally, the Coalition encouraged the Commission to require that the Company eliminate disconnections for the LID program enrollees within the 0-20 percent SMI range.[37]

Q. Please summarize the Company's response to these proposals.

A. The Company points to the Commission approved tariffs to detail the disconnection process.[38] PacifiCorp states that the Company "does not include in its tariffs a disconnect charge, which avoids increasing the burden disconnected customers face."[39] When responding to the rising level of disconnections since 2021, the Company states that the number of disconnections is the result of resuming disconnections following the COVID-

[35] CUB/200, Wochele-Jenks/60.
[36] Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 31.
[37] Coalition/100, Fain-Segovia Rodriguez-Daryanani/Page 34.
[38] PAC/2000, McVee/48.
[39] PAC/2000, McVee/49.

19 moratoriums which resulted in arrears significantly increasing.[40] It includes in its response that the Division 21 protections provided additional protection for customers prior to disconnection and made it easier for customers to have their power restored.[41] Additionally, PacifiCorp identified and corrected a system issue that prevented accounts from being identified for disconnection which resulted in a backlog leading to increased numbers in disconnection.[42]

In response to requests for increased data collection around disconnection, the Company flags its already included CBI metrics in the Company's CEP to track disconnections and to track energy burden by census-tract for low-income customers, bill assistance participants and Tribal members.[43] Finally, the Company states that further discussion would be advantageous to try and determine how disconnections can be reduced, and arrearages alleviated, but does not commit to a specific strategy at this time.[44]

Additionally, the Company disagrees with recommendations encouraging halting disconnections for subsections of low-income customers.[45] PacifiCorp states that it provides ample notification for customers in advance of disconnection in order for the customer to contact the Company to enter into or renegotiate payment arrangements.[46]

[40] *Id.*
[41] PAC/3500, Meredith/22.
[42] *Id.*
[43] PAC/2000, McVee/50.
[44] PAC/3500, Meredith/22.
[45] PAC/3500, Meredith/23.
[46] *Id.*

The Company also states that it has seen a rise in arrearages following the COVID-19 moratorium lifting and is hesitant to instate additional moratoriums that may exacerbate the issue.[47] Finally, the Company does not agree with CUB's recommendation that the Company face a penalty if disconnections are not reduced. The Company raises that "unreasonably hampering the Company's efforts to collect from customers who have not paid their bills can raise costs for all customers."[48]

Q. How does Staff respond to the Company's response that the level of disconnection is a result of catching up from the COVID-19 moratorium ending.

A. While Staff acknowledges the unintended impacts the COVID-19 moratorium may have had on the accumulation of arrears on residential accounts, it is inaccurate to conclude that the moratorium is the sole cause of higher rates in residential disconnections for PacifCorp customers. Staff is concerned that pointing to the COVID-19 moratorium obscures the Company's responsibility to recognize and address extreme arrearage trends and its culpability for not mitigating the resulting disconnection activity. Based on a review of customer accounts in the context of past rate increases, the impact of seasonality of monthly bills, and a lack of thoughtful intervention by the Company on past-due accounts, affordability issues and untenable energy burdens are the more likely culprits of non-payment disconnections than moratorium fall-out. To this end,

[47] *Id.*
[48] PAC/3500, Meredith/23.

the Company's reply does not correspond with the urgent need to investigate the many causes of and solutions for these problems.

Q. Please elaborate on Staff's review of arrearages and disconnections relative to the Company's responsibility.

A. As highlighted in Opening Testimony Exhibit, Staff 300, the level of arrears currently seen with PacifiCorp's Oregon customers is alarming with 20,000 LID participants with active arrears balances greater than 30 days past due.[49] Staff reviewed Company data reflecting LID customers arrears levels, and includes the tables below to highlight the average levels seen of LID customers arrears balances, as well as the average payment of customers enrolled in time payment plans (TPP) or equal payment plans (ETP).[50]

Table 2.

LID Participants in Arrears	
Arrears Bucket	**Average arrears amount**
Under $500	$175.8
$500 - $1,000	$678.2
$1,000-$5,000	$1,696.4
$5,000 - $9,999	$6,470
$10,000+	$15,481.6

Table 3.

LID Participants on Payment Plans		
	Equal Payment Plan	Time Payment Plan
Average monthly cost	$117	$55

[49] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 442.
[50] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 731.

Table 2 includes the roughly 22,800 customers enrolled in the LID program are currently in arrears. Of those customers, over 1,400 have balances above $1,000 of that subsection 41 LID participants have arrearage balances over $5,000 and 8 participants have balances over $10,000.[51] While Table 3 includes averages of LID participants enrolled in TPP and EPPs, Staff is especially concerned by the Company reports on the highest TPP and EPP plans currently negotiated with LID participants.

When looking at EPP, there are 10 LID participants with a monthly bill of $500 or more.[52] Equal payment plans are supposed to allow PacifiCorp customers to divide the total account balance into 12 monthly payments and add it to monthly charges to create a payment for a customer that will be the same every month. This is a mechanism that allows customers to better budget for what is expected for energy utility costs throughout the year.

Of LID participants currently participating in a TPP, 40 have a TPP with a bill of $500 or more a month.[53] When reviewing that subset, 7 have balances over $1,000 with one LID participant facing a bill of over $3,800.[54] A Time payment plan similar to an EPP divides an account balance up over a 12

[51] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 442.
[52] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 731.
[53] *Id.*
[54] *Id.*

month period to create a new charge and adds monthly charges on top. Unlike an EPP, the monthly balance will not be the same each month.

Staff is alarmed by the large balances seen with participants in the LID on these payment plan options. Staff is concerned that PacifiCorp is not considering the reality of circumstances for LID customers or the reasonableness of the amounts when negotiating and enrolling customers onto payment plans above $500 per month. This is especially concerning if we compare it to the average monthly residential bill which varied in 2023 from roughly $83 to $136 depending on the heating/cooling month.[55] To enroll a known low-income customer into a monthly payment plan requiring them to pay upwards of 45 times more than the average monthly customer is reckless and inequitable. This would be unsustainable for the average customer, let alone someone who is enrolled in the LID.

Additionally, we see a concerning number of LID participants that show a disconcerting history of cyclical disconnection. Specifically, there are 439 participants with at least five non-payment disconnects between 2016 and the COVID-19 moratorium effective date, and 16 LID participants with 10 or more disconnects on their account in that same time frame.[56] While Staff is elevating these issues among LID participants given the compound and unique challenges associated with higher energy burden, this issue is not exclusive to low-income customers. Based on the Company's reports on counts of

[55] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 555.
[56] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 442.

residential customers with arrears, in 2023, the average number of customers with arrears balances above $1,000 was 5,963, with arrears balances over $5,000 was 552, and with arrears balances over $10,000 was 106.[57]

Q. Please explains Staff's overall concerns with the Company's arrearage and disconnections levels.

Following the review of the Company's data detailed above, Staff is left to question to what level customers were made aware that the COVID-19 moratorium would be ending, and whether or not customers were informed of the risks that would occur if they did not begin paying their bills. Additionally, Staff wonders if customers were aware of how their arrears balances could grow during this COVID-19 moratorium. This is paired with the response from the Company that LID participants with arrears or who are facing disconnection are not offered additional opportunities for support and there is a seemingly underwhelming response to customers in the deepest of arrears.[58] Staff provides additional details in Mr. Farrell's Exhibit Staff 2900 illustrating much of the data Staff has received on the issue thus far. Overall, Staff is concerned with the current processes and handling of customers in arrears and facing disconnect in general but particularly for those who also qualify or are enrolled in the LID program.

The Company's response that the rising level of disconnects is due to the moratorium ending and large numbers of customers being flagged paired with

[57] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 691.
[58] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 443.

the lack of additional avenues for LID participants in arrears is concerning to Staff. Focusing on customer behavior and emergency regulatory protections is problematic as it deflects responsibility from the utility both to intervene and to even truly understand affordability and energy insecurity across the customers it has a duty to serve. The Company's reluctance to expand the LID in this case despite concerning arrearage and disconnection statistics is further evidence that the Company is not making decisions in the interest of its most energy insecure customers. After reviewing the Company's testimony and responses to several DRs on arrearages and disconnections, Staff is concerned with the Company's overall attitude towards the customers in these positions. Staff questions whether the current approach the Company has towards customers facing disconnection and managing arrears is unbalanced in its focus on near-term revenue collection over keeping customers connected and current over the long-term.

Q. Can you please expand on the concern you mention with how the Company is currently handling arrearage accrual.

A. Yes. The Company has stated that it does not conduct any additional outreach efforts or opportunities available for LID participants who are faced with disconnection or high arrears.[59] This is clearly inequitable given Staff's efforts to highlight that these groups are disproportionately burdened by the systems currently in place. While some measure of payment arrangement programs are offered, Staff is concerned that they are insufficient to serve certain types

[59] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 443.

of high energy burden customers. For example, when looking at residential customers with over $5,000 or $10,000 in arrears for customers struggling with energy costs month to month, payment arrangements are not feasible as they inherently *add* to monthly costs. Staff emphasizes that this is an issue disproportionately impacting LID eligible households given their heightened risk to accumulate arrears and limited financial resources and/or security relative to higher income households.

Q. Please explain Staff's concern with how the Company is currently handling disconnections.

While Staff agrees with the Company's assessment that the Division 21 rules have helped customers reconnect and provided additional assistance, Staff is concerned with the number of customers that have already used the two waived reconnection fees this year that Division 21 provides. In 2023, the Company saw a total of 263 customers use the two waived reconnection fees offered by Division 21. In 2024, between January and May, the Company reports that 125 customers have already used the two waived reconnection fees.[60] Staff is concerned that this number has grown in the months since this reporting, and that these customers, and more, are now left without the assistance of a waived reconnection fee and must pay even more to reconnect. Staff flags that there are likely customers who are facing this cycle of disconnection and reconnection that are eligible for the protections but not receiving them for one reason or another.

[60] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 704.

This concern is compounded when looking at the number of customers that have been disconnected the month following reconnection. In 2023, 97 residential customers were disconnected the month following reconnection. In a Company response filed in July 2024, PacifiCorp reports that 228 customers have been disconnected the month following reconnection in 2024.[61] This leads Staff to believe that for some customers they are scraping enough money together to be reconnected, or are utilizing one of their two Division 21 reconnection waivers, and because the balances on their accounts are too large, or their energy bills unaffordable, they are disconnected the following month and left to start the same cycle over again without additional support from the Company. This suspicion was confirmed in conversations Staff had with community action agencies within PacifiCorp's service territory.

Staff relays this information to show a concerning trend of disconnection faced by PacifiCorp's customers, even when enhanced disconnection protections and monthly bill discounts for low-income customers are available. Without additional measures customers may be stuck in a cycle similar to the one described above without additional support or ways to alleviate the additional stress placed on their family due to the situation they have found themselves in. Staff appreciates the Company describing its postcard effort to deploy outreach targeting all customers in arrears. However, it is impossible to know how effective PacifiCorp's outreach was with the available data on the number of postcards sent without knowing how many customers reached out to

[61] Exhibit Staff/2601, PacifiCorp Response to OPUC Data Request 702.

the Company for assistance in response to this communication, which leads Staff to believe that the postcard effort was not enough given the current trend reported in the Company's data.[62] With Staff's level of concern growing following review of the Company's responses, it is clear that more creative solutions are necessary to fully address these disconnection issues. Staff is concerned that PacifiCorp's current process revolves around complying without concerning themselves with whether or not the protections and programs available to customers are having the desired effect, but the Company should have recognized the need to be proactive.

Additionally, Staff continues to encourage PacifiCorp to make better use of its CBIs. Energy burden metrics are not ornamental and, like all CBIs, are expected to actively inform Company planning and programmatic decisions. The Company should have recognized the need to make adjustments to disconnect processes while actively tracking disconnections within the Company's CBI metrics. PacifiCorp should use its own tracking and data to critically inform Company reports, critically evaluate programs, and determine when adjustments are necessary. This is an area that is important for the Company to bring to its CBIAG. Updates on the CBI metrics should be used to inform conversations with the CBIAG and help the Company understand the opportunities that are available to make programmatic changes to address the concerning statistics. Staff offers this as an area for the Company to work with the CBIAG moving forward, but it should not deter near-term action.

Customers need immediate relief paired with an ongoing evaluation and dialogue on how to address disconnections.

Finally, Staff flags the UM 2211 docket update filed on August 6, 2024, detailing Staff's near-term effort to address disconnection and arrearage levels seen with all utilities.[63] Additional discussion, evaluation and program evaluation or creation will take place in the UM 2211 process in collaboration with utilities and stakeholders. Staff expects the Company to fully participate in the process and bring creative options to the table that alleviate energy insecurity and promote system equity in a sustainable manner.

Q. Are there any additional issues in the Company's Reply Testimony that Staff wishes to flag?

A. Yes. Staff is concerned with the Company's overall approach towards energy justice and affordability demonstrated thus far in the rate case proceedings. As was highlighted in Staff Exhibit 300 by Ms. Scala, "considering affordability and energy justice in the context of how this rate case impacts customers is important to informed decision making about the reasonableness of proposed rates."[64] It is important that this is evaluated not only by Staff in a rate case proceeding, but by the Company. Staff is concerned that the response in PacifiCorp's reply testimony looking towards adjusting the current LID program, and overall responses regarding energy justice and affordability ultimately delay any program changes that would result in assistance provided to low-

[63] *In the Matter of Public Utility Commission of Oregon, Implementation of HB 2475,* HB 2475 Implementation of Differential Rates and Programs in Oregon (August 6, 2024).

[64] Exhibit Staff/300, Scala/11.

income and vulnerable communities. The Company seems to dismiss accountability or action towards energy justice concerns related to arrearage and disconnection levels.

Further, Staff held an Energy Justice Workshop on July 8, 2024, as part of the ongoing Procedural Justice process. For background, Staff filed comments in UM 2211 in January 2024 that acknowledged the significant barriers to inclusive participation in rate case processes.[65] Within the document, Staff stated their commitment to addressing the procedural inequities in Commission processes, which will involve ongoing work on the part of the PUC and rate case parties. While the procedural equity process began in response to comments filed by stakeholders in Docket No. UE 426, Idaho Power's General Rate Case, Staff committed to including procedural equity streams in all other general rate cases in 2024. This included a Staff facilitated workshop focused on allowing non-intervenor stakeholders to participate alongside intervenors in a workshop dedicated to reviewing energy justice issues and allowing stakeholders to ask questions of the Company.

While Staff appreciates the Company's participation in in the July workshop, PacifiCorp explained during the workshop that the LID program manager was out on international travel. The Company had not made PUC Staff aware of this and had not sought to reschedule the workshop for a date when they were available, nor make any other utility staff knowledgeable of the

[65] *In the Matter of the Public Utility* Commission *of Oregon, Implementation of House Bill 2475,* Staff's Comments on Procedural Equity (January 9, 2024).

LID program available for the workshop to answer the identified questions that had been sent to the Company prior to the workshop date. While Staff acknowledges that it is difficult to respond to the pre-issued questions in a tight turnaround, Staff felt as though the Company was unprepared and did not invest in collecting information that could be shared with stakeholders in response to the questions.

Additionally, Staff is concerned that the Company has stated on numerous occasions that it "takes seriously its efforts to address affordability concerns and to mitigate customers' energy burden" but offers no adjustments to the LID program or additional identified areas impacting affordability and energy burden for residential customers. As mentioned previously, Staff believes that while tracking metrics and conducting surveys are important evaluation tools, they have little effect if not followed by program adjustments or enhancements based off of the information collected. This includes reviewing currently available programs in consideration of proposed rate increases so as to fully analyze impacts across differently situated customer segments, including but not limited to environmental justice communities.

Staff believes that PacifiCorp is underutilizing the engagement spaces currently available to them. As the Company mentions in its reply testimony, it has conducted extensive surveys which ultimately highlighted that costs and potential bill increases are the primary concerns with the transition to cleaner energy.[66] The Company also states that the CBIAG is the engagement space

[66] PAC/2000, McVee/50.

that the Company utilizes to "assess the most pressing concerns relating to the Company's transition to cleaner energy."[67] Staff finds it concerning that the Company does not state that they have engaged with the CBIAG to evaluate the impacts that UE 433 will have on customers, especially the low-income and environmental justice community members the CBIAG work with and represent.

While the CBIAG was originally set up following the passage of House Bill 2021 and was directly tied to PacifiCorp's CEP process, the statute does not limit the utility from utilizing the CBIAG to help inform other areas of the Company's work. Additionally, the statute states that the biennial report, which should be developed in consultation with the CBIAG, must include a description of energy burden and disconnection for residential customers along with additional equity focused deliverables.[68] With this directive in mind, it is concerning that the utility has not included a narrative around the CBIAG's reaction to the currently filed rate case, or any adjustments that were made to the rate case filing following feedback from the CBIAG.

Q. Based on the discussion above along with what was provided in Opening Testimony, what are Staff's current recommendation?

A. Staff offers the following recommendations as opportunities to provide near-term adjustments to address customers current energy burden and the expected impacts following an additional rate increase. As such, Staff

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[67] *Id.*
[68] O.R.S. § 469A.425.

recommends the Company add a third discount tier providing a 80 percent discount to monthly billed amounts for residential customers earning an adjusted household income between 0-5 percent SMI.

This should be seen as an incremental near-term adjustment to the LID program. Following the conclusion of the Company's 2024 EBA, the Company should engage with parties in UE 433, stakeholders engaged in the UM 2211 docket, and other important organizations to refine the program tier structures and discount level adjustments to better reflect the data identified in the EBA and stakeholder input. Further, Staff reiterates the recommendation in opening testimony asking the Company to include a checkbox on the paper LID enrollment form allowing for LID participants to utilize a third party to help fill out and submit the form on a customer's behalf.

Staff recommends PacifiCorp engage with Staff, stakeholders, and Community Action Agencies in the UM 2211 docket around post-enrollment verification. The Company should analyze the effectiveness of the current program and use such analysis to inform modifications to develop ways that post-enrollment verification can be implemented with human impacts and program objectives in the foreground rather than defaulting to legacy processes that can have unintended consequences. Staff expects PacifiCorp to participate in future UM 2211 conversations around this topic, and recommends the Company engage with stakeholders and Staff in the interim to identify a path forward before implementing a post-enrollment verification strategy.

Staff recommends the Company be required to track LID participants with high usage, defined here as more than twice the average monthly residential customer usage, and provide such report to the Commission. The Company should utilize the reports to refer identified participants to Community Action Agencies, Energy Trust of Oregon, and/or any other known partner organizations administering low-income energy efficiency or weatherization services to environmental justice communities in the Company's service. The Company should follow-up with customers and agencies to explore additional resources as needed if customers face barriers to program connection. The reporting should not be duplicative of and may be superseded by additional reporting requirements that evolve from the data landscape stream led by Staff in Docket No. UM 2211.

In response to the Company's level of arrears and disconnections, Staff recommends the Company be required to create a crisis mitigation program that provides customers between 0-5 percent SMI with arrearage forgiveness up to $1,000. Additionally, the Company should be directed to halt reconnection fees for LID participants until a more permanent arrearage management program has been identified in the UM 2211 process. Staff also expects the Company to fully participate in the upcoming UM 2211 phase two process dedicated to evaluating arrears and disconnections. Staff encourages the Company to bring creative ideas to the table that fund opportunities to address the alarming levels of disconnections without placing unnecessary burdens onto other customers.

Finally, Staff recommends the Company utilize the CBIAG in the creation of customer programs impacting low-income and environmental justice communities. Staff also recommends the Company utilize the CBIAG to help evaluate customer programs and the impacts these programs have on rates.

ISSUE 3. LOW-INCOME DISCOUNT COST RECOVERY

Q. Please summarize the Company's current cost recovery mechanism.

A. The Company's current cost recovery mechanism is implemented as an automatic adjustment clause (AAC). The Company's cost recovery mechanism was adjusted in April 2024, seen below in Table 1, with Staff acknowledgement that cost recovery adjustments would be addressed further in UE 433.[69]

Table 1.

Schedule	Rate
Residential Rate Schedules (4, 5, 6)	$2.64 per month
Nonresidential Rate Schedules	0.278 cents per kWh for the first 5,000,000 kWh per month.

Q. Please summarize Staff's initial recommendations related to the Low-Income Discount Cost Recovery.

A. To better reflect an equitable distribution of costs, particularly with program participation increasing more rapidly than anticipated, Staff explored additional cost recovery structures in Opening Testimony. Staff asked the Company to explore a percentage of bill cost recovery approach, which would remove the applicable kWh cap for non-residential Schedules. Staff asked the Company to provide analysis on how the costs would shift with a percentage of bill recovery that sufficiently covers the cost of the program

69 *In the Matter of PacifiCorp's Advice No. 24-006, Schedule 92, LID Cost Recovery Adjustment,* Docket No. ADV 1603, Staff Report (April 24, 2024).

with no cap and without the fixed residential rate exceeding a reasonable cost to residential customers. To analyze this proposal and the cost impacts, Staff asked the Company to include analysis in Reply Testimony that evaluated costs at the following percentage points: 2.5; 3; 3.5; and 4 percent.

Q. Please summarize the Company's Reply Testimony.

A. The Company did not include LID cost recovery in its Reply Testimony. Staff is left to assume that the Company includes cost recovery as part of the broader narrative the Company paints, focusing on adjusting the LID following the EBA's completion.

Q. In Opening Testimony, Staff requested analysis regarding additional mechanisms for cost recovery of the LID program. What information has the Company provided?

A. The Company failed to respond to Staff's request to provide analysis. As such, Staff is unable to analyze in any detail how this cost recovery mechanism would look when adjusting for reasonable program growth along with the Company's current proposed increase.

Q. Please explain Staff's current recommendation for cost recovery of the Company's LID.

A. Staff is still interested in evaluating a percentage of bill cost recovery as a mechanism to more equitably distribute costs between residential and non-residential rate schedules. As explained in opening testimony, Staff is concerned with the Company's current cost-recovery mechanism, specifically the current cap on non-residential contributions to the bill discount program. The current cost cap creates an inequitable distribution of costs and places a higher burden on residential customers to support the LID program. As the program grows, Staff is concerned that the current cap on non-residential contributions would result in a large increase absorbed by the residential customer rate schedules, which would be compounded by the current requested rate increase and any future general rate increase filings, if left unchanged.

Staff has included the following two figures to demonstrate the concern that the current cap is not equitable for residential customers. Figure 1 represents the Company's current cap of 5 million kWh for Non-residential schedules.[70] This is compared to Figure 2, which shows the distribution of costs if there was no-cap on non-residential schedules.[71]

Figure 1.

[70] ADV 1603 Pacific Power's Advice No. 24-006 Schedule 92 Low-Income Discount Cost Recovery Adjustment.

[71] Exhibit Staff/2601, PacifiCorp Response to Data Request 438.

Pacific Power
State of Oregon
Proposed Residential Low-Income Discount Cost Recovery Adjustment - Schedule 92

Annual Collection Target $ 35,826,925

		Proposed Schedule 92		
Customer Class		Rate		Revenue
Residential Bills	6,162,972	$2.64	per month	$ 16,270,246
Non Residential	MWh			
Total*	9,868,320			
Monthly per Bill MWh Cap	5,000			
MWh Exceeding Cap	2,849,851			
Non Residential MWh Paying Surcharge	7,018,469	0.278	¢ per kWh	$ 19,511,344
Total				$ 35,781,590

*Includes lighting tariff MWh and distribution only MWh.

Figure 2.

Pacific Power
State of Oregon
Proposed Residential Low-Income Discount Cost Recovery Adjustment - Schedule 92

Annual Collection Target $ 35,826,925

		Proposed Schedule 92		
Customer Class		Rate		Revenue
Residential Bills	6,162,972	$2.17	per month	$ 13,373,649
Non Residential	MWh			
Total*	9,868,320			
Monthly per Bill MWh Cap	-			
MWh Exceeding Cap	-			
Non Residential MWh Paying Surcharge	9,868,320	0.228	¢ per kWh	$ 22,499,769
Total				$ 35,873,418

*Includes lighting tariff MWh and distribution only MWh.

As shown when reviewing both tables, the current cost cap which outlined here will only recover costs for the current program at current enrollment rates, which does not factor in adjustments being asked of the Company in this proceeding, or future enrollment growth, require residential customers to pay 47 cents more than the no-cap cost recovery mechanism. While 47 cents does not seem large in comparison to other line items on a bill, Staff expects the overall cost of PacifiCorp's program to increase as enrollment continues to grow, and as adjustments are made. This is especially important when we also look at the crisis AMP program and the upcoming UM 2211 process around additional assistance could change the amount we are collecting from all customers. As we look towards that future, it is important that we are ensuring that the program is aligned with getting the right level of benefits to customers, but also that we are evaluating cost-recovery to align with equitable distributions.

Staff highlights again, that the goals of the program cost recovery are to ensure an equitable distribution of costs that does not overly burden the residential sector for cost recovery, without adjustment to the Company's recovery mechanism currently, Staff believes the burden of costs will continue to be further placed on residential customers to an extent that may see low-income customers and customers on the margins of just about 60 percent SMI and without energy assistance dealing with increases too large to handle. Absent analysis from the Company's Reply Testimony Staff offers a primary and secondary recommendation related to LID cost recovery.

Staff's primary recommendation is that the Company be directed to align the cost recovery mechanism to Portland General Electric's current cost recovery mechanism, with a 20 million kWh cap for non-residential schedules.

Staff recommends that the Company report the requested analysis on a percentage of bill cost recovery mechanism evaluating costs at 2.5, 3, 3.5, and 4 percent to Staff and stakeholders with its EBA results in UM 2211. Further, if this analysis reveals a percentage of bill mechanism to be a the more equitable strategy and it is not unduly burdensome for the Company to implement, the Company should propose a revision to its tariff adopting a percentage of bill approach.

Broader conversations in future UM 2211 phases may lead to changes in design, both with the LID program and the cost-recovery but addressing PacifiCorp's current cost-recovery cap represents needed near-term equity adjustments to the programs current cost-recovery model.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: KATE AYRES

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2601

Exhibits in Support
Of Rebuttal Testimony

August 16, 2024

UE 433 / PacifiCorp
May 9, 2024
OPUC Data Request 438

OPUC Data Request 438

Energy Justice; Community Outreach; Low-Income Discount Program; Arrearages – Other State LIDs& Post Enrollment Verification – Please generate the workbooks submitted in Docket No. ADV 1603 "OR CY 2025 LID adj ee 5-1-2024" and "Projected Low Income Discount Costs" with the following revised cost recovery structures:

(a) No cost recovery cap.
(b) 20,000 MwH cap.

Response to OPUC Data Request 438

Please refer to Attachment OPUC 438.

Two Excel documents from “PacifiCorp’s response to OPUC DR 438” are filed in electronic format

UE 433 / PacifiCorp
July 9, 2024
OPUC Data Request 704

OPUC Data Request 704

For each month in the years 2022, 2023, and the months available for 2024, please provide the number of residential customers that have utilized two waived remote reconnection fees under Division 21 rules for enhanced low-income protections,

Response to OPUC Data Request 704

Please refer to Attachment OPUC 704.

Excel document from

“PacifiCorp’s response to OPUC DR 704”

is filed in electronic format

UE 433 / PacifiCorp
May 9, 2024
OPUC Data Request 440

OPUC Data Request 440

Energy Justice; Community Outreach; Low-Income Discount Program; Arrearages – Other State LIDs& Post Enrollment Verification – Assuming an LID program structure of 20% discount for 60-21% State Median Income (SMI); 40% discount structure for 20-10% SMI; and 80% discount for 9-0% SMI; please provide the following:

(a) Enrolled customer counts, by tier, using current enrollments.

(b) Estimated direct assistance costs, by tier, using current enrollments.
(c) Assuming (1) no cap; and (2) 20,000 MwH cap:

i. Estimated cost recovery in dollars and as a percentage of total costs, by service schedule.

ii. Estimated average per customer cost, by service schedule.

Response to OPUC Data Request 440

(a) Please refer to the Company's response to OPUC Data Request 436 subpart (c). As stated in that response, as of April 26, 2024, there are 49,726 Low-Income Discount (LID) participants. Of these participants, PacifiCorp estimates that 4,985 would fall into a less than 10 percent state median income (SMI) tier, 4,316 customers would fall into a 10 percent to 20 percent SMI tier, and 40,425 customers fall into the greater than 20 percent SMI to 60 percent SMI tier.

(b) At present rates, estimated annual bill discounts for the customers described in the Company's response to subpart (a) above would be $6,861,000 for the less than 10 percent SMI tier, $2,970,000 for the 10 percent to 20 percent SMI tier, and $14,143,000 for the greater than 20 percent SMI to 60 percent SMI tier for a total annual amount of $23,974,000. For comparison, with the current two-tier discount structure the total estimated annual discount would be $20,543,000.

(c) Please refer to the Company's responses to subparts (1) and (2) below:

(1) Assuming the current LID cost recovery rate structure except with no cap on monthly per customer megawatt-hours (MWh), collecting $23,974,000 over one year would result in the following recovery from customer classes:

UE 433 / PacifiCorp
May 9, 2024
OPUC Data Request 440

No MWh/Month Cap						
Description	Sch No.	No. of Cust	LID Cost Recovery ($000)	% of Net Rev	Average Annual Cost/Cust
Residential					
Residential	4	513,581	$8,936	1.1%	$17.40
Total Residential		513,581	$8,936	1.1%	
Commercial & Industrial					
Gen. Svc. < 31 kW	23	86,033	$1,771	1.0%	$21
Gen. Svc. 31 - 200 kW	28	10,658	$3,146	1.3%	$295
Gen. Svc. 201 - 999 kW	30	847	$2,027	1.5%	$2,393
Large General Service >= 1,000 kW	48	177	$7,127	1.9%	$40,266
Partial Req. Svc. >= 1,000 kW	47	6	$66	1.9%	$11,017
Dist. Only Lg Gen Svc >= 1,000 kW	848	1	$511	24.8%	$511,364
Agricultural Pumping Service	41	7,884	$358	1.1%	$45
Total Commercial & Industrial		105,606	$15,007	1.6%	
Lighting					
Outdoor Area Lighting Service	15	5,833	$3	0.3%	$1
Street Lighting Service Comp. Owned	51	1,210	$12	0.3%	$10
Street Lighting Service Cust. Owned	53	296	$13	1.7%	$45
Recreational Field Lighting	54	98	$2	1.4%	$21
Total Public Street Lighting		7,437	$31	0.5%	
Total		626,624	$23,974	1.3%	

(2) Assuming the current LID cost recovery rate structure except with a 20,000 monthly per customer MWh cap, collecting $23,974,000 over one year would result in the following recovery from customer classes:

UE 433 / PacifiCorp
May 9, 2024
OPUC Data Request 440

20,000 MWh/Month Cap						
Description	Sch No.	No. of Cust	LID Cost Recovery ($000)	% of Net Rev	Average Annual Cost/Cust
Residential					
Residential	4	513,581	$10,169	1.2%	$19.80
Total Residential		513,581	$10,169	1.2%	
Commercial & Industrial					
Gen. Svc. < 31 kW	23	86,033	$2,018	1.2%	$23
Gen. Svc. 31 - 200 kW	28	10,658	$3,584	1.5%	$336
Gen. Svc. 201 - 999 kW	30	847	$2,309	1.7%	$2,727
Large General Service >= 1,000 kW	48	177	$4,959	1.3%	$28,016
Partial Req. Svc. >= 1,000 kW	47	6	$75	1.3%	$12,551
Dist. Only Lg Gen Svc >= 1,000 kW	848	1	$417	20.2%	$416,652
Agricultural Pumping Service	41	7,884	$408	1.3%	$52
Total Commercial & Industrial		105,606	$13,770	1.4%	
Lighting					
Outdoor Area Lighting Service	15	5,833	$4	0.3%	$1
Street Lighting Service Comp. Owned	51	1,210	$14	0.3%	$11
Street Lighting Service Cust. Owned	53	296	$15	2.0%	$52
Recreational Field Lighting	54	98	$2	1.6%	$24
Total Public Street Lighting		7,437	$35	0.6%	
Total		626,624	$23,974	1.3%	

UE 433 / PacifiCorp
May 9, 2024
OPUC Data Request 442

OPUC Data Request 442

Energy Justice; Community Outreach; Low-Income Discount Program; Arrearages – Arrearages – Please provide the number of LID participants that:

(a) Have active arrearage balances greater than 30 days past due.

(b) Have a history of arrearages greater than 30 days past due at any time following enrollment in the LID.

(c) Average, max and min arrearage balances.

(d) Have been unenrolled as a result of a past-due balance.

Response to OPUC Data Request 442

(a) The number of Oregon low-income discount (LID) customers with active arrearage balances greater than 30 days past due is 21,185.

(b) The number of Oregon LID customers with a history of arrearages greater than 30 days past due at any time following enrollment in the LID is 20,365.

(c) The average, maximum and minimum arrearage balance of Oregon LID customers is $504.46, $24,897.97 and $0.01, respectively.

(d) There have been no customers who have been unenrolled because of past due balances.

UE 433 / PacifiCorp
May 9, 2024
OPUC Data Request 443

OPUC Data Request 443

Energy Justice; Community Outreach; Low-Income Discount Program; Arrearages – Arrearages – What is Pacific Power's process for addressing LID participants that fall into arrears at:

(a) 30 days past due.
(b) 60 days past due.
(c) 90+ days past due.

Response to OPUC Data Request 443

Low-income discount (LID) customers are treated the same as other arrears customers except that LID customers may have additional specific required protections. LID customers receive the following protections (subject to change).

- Deposits and late fees waived for low-income residential customers.

- The first two reconnection fees in a calendar year will be waived for low-income customers.

- The first field visit in a calendar year will be waived for low-income customers.

UE 433 / PacifiCorp
May 23, 2024
OPUC Data Request 555

OPUC Data Request 555

Residential Bills, Usage, Revenues - For each calendar month beginning in January 2014 and concluding with December of the Company's UE 435 Test Year, please provide:

(a) *Gross Average Residential Customer Bill ($)
(b) Net Average Residential Customer Bill ($)
(c) Average Residential Customer Usage (kWh)
(d) Total *Gross Residential Revenues ($)
(e) Total Net Residential Revenues ($)

*gross should reflect amounts prior to the application of the regional power act credit

Please provide actual data for months it is available, and provide forecasted data for months in which actual data is not yet available. Please provide this in an MS Excel file using separate tabs for subparts (a), (b), (c), (d) and (e) displayed in tables based on the following example:

	January	**…**	**December**
2014	Data Value	Data Value	Data Value
…	Data Value	Data Value	Data Value
TY	Data Value	Data Value	Data Value

Response to OPUC Data Request 555

The Company assumes that the reference to "UE 435 Test Year" is intended to be a reference to PacifiCorp's general rate case (GRC) with a 2025 test year, which is docket No. UE-433. Note: docket No. UE-435 is a GRC proceeding of Portland General Electric Company (PGE). Based on the foregoing assumption and correction, the Company responds as follows:

Please refer to Attachment OPUC 555 which provides a Microsoft Excel file with formulas intact with tables showing the requested information as available for customers on residential rate schedules. Note: the Company's databases do not include data prior to 2018. Actual and forecasted information for 2024 has been provided to the extent that it is available. The Company did not prepare a forecast of present revenues for 2024 for this general rate case (GRC) with a 2025 test year. Forecast revenues for the 2025 test year were prepared on an annual basis only. Monthly representations as shown in the attachment are spread based on the monthly load forecast.

UE 433 / PacifiCorp
July 9, 2024
OPUC Data Request 691

OPUC Data Request 691

For each month between January 2021 and May 2024 please provide:

(a) The number of residential customers with an arrearage balance, segmented between 31-60 days, 61-90 days, 90-120 days, 120-365 days, and 365+ days.

(b) The (total or average?) arrearage balance for residential customers, segmented between 31-60 days, 61-90 days, 90-120 days, 120-365 days, and 365+ days.

(c) The number of residential customers who had an arrearage balance which exceeded: $1,000, $5,000, and $10,000.

Response to OPUC Data Request 691

Please refer to Attachment OPUC 691. Note: with regard to the information provided in tab "A", a customer may have arrearage balances in one or more aging bucket. The customers specific billings that have not been paid determines the aging bucket for that billing. The total number of unique customers is provided to show the extent of duplication of results when seeking customer count by aging bucket.

UE 433 / PacifiCorp
July 9, 2024
OPUC Data Request 702

OPUC Data Request 702

What does the Company do for customers who remain in arrears upon reconnection? Has the Company seen customers who have been disconnected the month following a reconnection? If so, how many.

Response to OPUC Data Request 702

Upon reconnection, the Company offers payment arrangements to customers for the remaining balance. The customer is also made aware of the Company's Low-Income Discount (LID) program.

Please refer to the table below which provides the disconnections in the following month from 2018 to 2024:

Year	Number of Disconnections Following Month
2018	125
2019	320
2020	29
2021	7
2022	21
2023	97
2024	228

UE 433 / PacifiCorp
August 8, 2024
OPUC Data Request 731

OPUC Data Request 731

Low-Income Discount Program - In an excel workbook, grouped by zip code and discount tier, please provide an anonymized list of PacifiCorp's LID enrolled customers and for each customer, indicate:

(a) The arrears balance, if any.

(b) Whether the customer is currently enrolled in a time payment arrangement (TPA) and where applicable, the monthly payment associated with the TPA.

(c) Whether the customer received LIHEAP or OEAP in the last 24 months.

(d) The number of completed disconnections associated with the account in each year from 2016 up to the COVID-19 utility disconnection moratorium took effect.

(e) On a separate sheet within the same workbook, using the anonymized customer ID, by month, beginning October 2022 to present, the number of:

- Disconnection processes initiated on the customer account (regardless of ultimate outcome).
- Completed disconnections on the customer account.
- Waived reconnection fees.
- Assessed reconnection fees and dollar amount.

Response to OPUC Data Request 731

(a) Please refer to Attachment OPUC 731, specifically tab "OPUC 731-1". Note: customer data is tracked at a customer agreement and customer account level, which is represented by Anonymized 1 and Anonymized 2.

(b) Please refer to the Company's response to subpart (a) above. The monthly payment plan amount provided in column G is directly associated with the type of payment plan the customer is on. The equal time payment plan amount is the customer's average monthly bill plus the customer's payment plan installment. The time payment plan monthly amount was calculated by taking the customer's balance divided by the number of installments on the customer's time payment plan.

(c) Please refer to the Company's response to subpart (a) above.

(d) Please refer to the Company's response to subpart (a) above.

UE 433 / PacifiCorp
August 8, 2024
OPUC Data Request 731

(e) Please refer to Attachment OPUC 731, specifically tab "OPUC 731-2". Note: there is no waived connection fees. Reconnection fees are assessed by the Company's customer service system (CSS). The Company does not track waived reconnection fees.

CASE: UE 433
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2700

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Curtis Dlouhy. I am the manager of Policy and Economic Analysis in the Energy Rates and Regulatory Strategy Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the Company and intervenors on issues I addressed in my opening testimony, including the Company's very large customer rate design proposals, the Company's proposed Time of Use changes, and the proposed amortization of the UM 2220 deferral.

Q. Did you prepare any other exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. VERY LARGE CUSTOMER PROPOSALS

Q. Please summarize Staff's positions on the Company's suite of proposals for very large customers.

A. In opening testimony, Staff responded to the Company's various proposals that would affect customers with loads of at least 25 MW and largely agreed with the Company's structure for these proposals, highlighting that they seemed to address emerging resource adequacy and stranded asset risks.[1] Staff, however, still had some recommended changes to the Company's proposals in opening testimony.

Staff recommended that the Company's Capacity Reservation Charge not apply to the first 2 MW difference between a very large customer's Estimated Demand and actual peak load, noting that in concert with the Excess Demand Charge, the Company's proposal requires very large customers to perfectly forecast their load.[2] Staff also recommended that the revenues earned from the Capacity Reservation Charge and the Excess Demand Charge be tracked through a deferral and returned to all customers.[3] Staff also pushed back against the Company's proposal to deny load requests if there is insufficient capacity, and instead recommended that the Company complete a customer interconnection study and list other potential interconnection points if there is

1 Staff/700, Dlouhy/4.
2 Staff/700, Dlouhy/4-6.
3 Staff/700, Dlouhy/9.

insufficient near-term capacity at a prospective customer's chosen interconnection point.[4]

Q. Did any other parties write opening testimony in response to the Company's very large customer proposals?

A. Yes. The Citizens' Utility Board (CUB), Data Center Coalition (DCC), Vitesse, and the Alliance of Western Energy Consumers (AWEC) all submitted testimony. CUB's testimony was generally supportive of the Company's changes and in alignment with Staff's opening testimony position. Vitesse, DCC, and AWEC – who all represent very large customers – were opposed to the majority of the proposals brought forth by the Company. Staff will briefly summarize intervenors' positions here and more thoroughly outline parties' responses in its discussion about each of the Company's proposals.

Q. Please summarize CUB's opening testimonies on the Company's very large customer proposals.

A. CUB was generally supportive of the Company's proposals concerning very large customers. In opening testimony, CUB witness John Garrett states that the Company's proposals offer a streamlined approach to incent accurate load projections and fairly assign costs, while also giving very large customers the flexibility to evolve their load.[5] CUB also highlighted similar stranded asset concerns raised by Staff but believes that the proposed changes to the Line Extension Advance tariff may help address these concerns.[6] Much like Staff,

[4] Staff/700, Dlouhy/12.
[5] CUB/300, Garrett/7-8.
[6] CUB/300, Garrett/10.

CUB recommends that the revenues generated from the Excess Demand Charge and Capacity Reservation Charge be tracked through a deferral.[7]

Q. Please summarize the areas in which the intervenors representing very large customers – AWEC, DCC, and Vitesse – are in alignment with Staff's opening testimony on the Company's proposals.

A. At a high level, Staff agrees with these intervenors that the combination of the Capacity Reservation Charge and the Excess Demand Charge as proposed unfairly forces very large customers to forecast their load perfectly.[8,] Like Staff, these groups also disagreed with the Company's proposal that they be allowed to deny a speculative load request if there is insufficient capacity.[9] While there was disagreement over whether these costs should return to all customers or just very large customers, AWEC also supported returning revenues associated with the Capacity Reservation Charge and the Excess Demand Charge to some subset of customers.[10]

Q. Please summarize areas in which intervenors recommend rejecting some or all of the Company's proposals.

A. DCC ultimately recommends rejecting the Company's changes wholesale and that these changes should be analyzed in a transparent setting with interested stakeholders.[11] The primary recommendation from AWEC is to reject the

[7] CUB/300, Garrett/11.
[8] AWEC/200, Kaufman/43; Vitesse/100, Coyle/22.
[9] AWEC/200, Kaufman/49; DCC/100, Cain/100; Vitesse/100, Coyle/42.
[10] AWEC/200, Kaufman/42.
[11] DCC/100, Cain/5.

Capacity Reservation and Excess Demand Charges.[12] AWEC also provides a series of recommendations on the large customer policies should they be approved, including lowering the two charges, treating these charges as indicative for the time being, crediting revenues from these charges to schedules that they are collected from, allowing customers to lower their reserved capacity once per year, expressing reserved capacity in on- and off-peak terms, and facilities paid for by the customer through an LEA would be reserved for the customer without added charges.[13] Vitesse recommends that the Commission reject the Company's recommendation that they be able to deny a load request if there is insufficient capacity and opposes the two new charges as they are currently structured.

<u>**Capacity Reservation Charge**</u>

Q. How do intervenors recommend modifying the Capacity Reservation Charge structure if approved?

A. Many intervenors recommend integrating some leniency for forecasting error into the Capacity Reservation Charge. Noting that no customer has a 100 percent load factor, Vitesse suggests that the Capacity Reservation Charge only apply to customers whose actual peak demand is less than 60 percent of its Reserved Capacity in the previous 12 or 36 months.[14] AWEC recommends a similar level as well.[15]

12 AWEC/200, Kaufman/3.
13 AWEC/200, Kaufman/39.
14 Vitesse/100, Coyle/30.
15 AWEC/200, Kaufman/44.

Vitesse also recommends that the Capacity Reservation Charge be aggregated for all of a customer's sites.[16]

Q. Did the Company modify the structure of the Capacity Reservation Charge in its reply testimony?

A. Yes. In response to issues brought up by Staff, DCC, and AWEC, the Company updates its recommendation to incorporate a five percent buffer.[17]

Q. Does Staff see any reason to modify the Company's Capacity Reservation Charge structure?

A. Yes. Staff agrees that it is unreasonable to expect a very large customer to perfectly forecast its load but still has concerns about stranded asset risk, the possibility of shifting costs onto other customer classes, and spending valuable Company efforts to deploy or acquire scarce resources that may not be optimally deployed due to a large customer's load failing to materialize. However, upon reading other parties' testimonies, Staff believes that its 2-MW buffer recommended in opening testimony and the Company's five percent buffer recommended in reply testimony for the Capacity Reservation Charge may be overly stringent. However, on the other hand, parties' recommendation for a 60 percent buffer is unreasonably lax for very large customers and creates a substantial risk of shifting stranded asset cost to customer classes that had no part in creating them. In order to address large customers' concerns about an overly-stringent forecasting requirement and operational

[16] *Id.*
[17] PAC/3400, DeMers/13.

realities of these large loads while continuing to maintain a fair assignment of costs, Staff modifies its opening testimony position to instead recommend that the Capacity Reservation Charge apply only to customers whose 12- to 36-month peak load is less than 90 percent of their reserved capacity.

Q. Can you demonstrate how a 90 percent threshold adequate balances concerns raised by groups representing very large customers with the stranded asset concerns raised by Staff, CUB, and the Company?

A. Yes. Staff notes that the Capacity Reservation Charge applies to customers that have loads of at least 25 MW, but data centers can have loads up to and possibly in excess of 500 MW. Intervenors have raised concerns that they need some level of operational flexibility to share loads between sites or to ramp up at a different rate.[18] Staff does agree that circumstances outside of a customer's control may warrant giving a customer the ability to adjust to changing circumstances. For the range of customers described above, this would give them wiggle room between 2.5 MW to 50 MW. While this is a far cry from 60 percent threshold suggested by AWEC and Vitesse, Staff notes that 2.5 MW to 50.0 MW of slack may give a *single* very large customer enough load flexibility to power entire residential neighborhoods.

While Staff believes incorporating greater flexibility than suggested by the Company is fair and may enable very large customers to better operate in Oregon, Staff also believes that any slack in excess of 90 percent of the requested load could create an outright dangerous cost shift between

[18] Vitesse/100, Coyle/40.

customers. As an example, the Company received load requests for 13 GW of new, very large customer loads between 2020 and 2023, which was more than their 2023 coincident system peak.[19] If Vitesse and AWEC's suggestion of a 60 percent threshold were applied to this new load and these new, very large customers and these customers only used 60 percent of the reserved capacity, the Company would face approximately 5.2 GW of stranded assets that would need to be recovered through other customer classes. As is, a 90 percent threshold could lead to up to 1.3 GW of stranded assets. Therefore, Staff believes that a 90 percent threshold for the Capacity Reservation Charge achieves a reasonable balance of providing very large customers a workable level of load flexibility while minimizing stranded asset concerns.

Q. Does Staff have any other recommendations regarding the Company's proposed Capacity Reservation and Excess Demand Charges?

A. Yes. Staff also believes it is appropriate to allow some level of customer aggregation between sites, as suggested by Vitesse. In making this recommendation, Staff notes that this should apply only to sites that are served by common generation, transmission, and distribution assets. To demonstrate Staff's reason, suppose that a customer has two sites that each reserved 200 MW of capacity each, but one customer registers a peak load of 210 MW and the other registers 190 MW. If the two sites are served by the same generation, transmission and distribution assets, the Company has likely not incurred any incremental costs to serve this customer than if it were a single,

[19] PAC/3400, DeMers/6.

400 MW customer. Conversely, if the customer's two sites are located far apart within the Company's service territory – Grants Pass and Pendleton for example – the Company likely incurred incremental costs to serve the customer who used 210 MW and under-recovered costs associated with investments to serve the customer that only used 190 MW. Staff welcomes the Company or stakeholders to propose a definition to clearly define which customer sites should be aggregated that address the intent of Staff's recommendation.

Q. How do intervenors recommend modifying the Capacity Reservation Charge rate if approved?

A. AWEC recommends removing the fixed generation component of the Capacity Reservation Charge and reducing the transmission portion used to calculate the charge by half.[20] AWEC also proposes to treat this first rate as merely indicative.

Q. Did the Company update its position after reading intervenors' testimonies?

A. No. The Company notes that serving these customers requires significant generation and transmission assets and that very large customers pose unique planning uncertainty.[21] Further, the Company notes that it plans its bulk transmission across its entire service territory, therefore it is appropriate to base these charges off of its full system costs.[22]

[20] AWEC/200, Kaufman/38-39.
[21] PAC/3400, DeMers/16.
[22] Id.

Q. AWEC states that excess demand has not caused reliability issues or unauthorized use of transmission in support of its modifications to the Excess Demand and Capacity Reservation Charges.[23] Does Staff agree with this?

A. No. Staff notes that unauthorized transmission and reliability issues are not the only manner in which very large customers can cause problems that are socialized across the entire system. As pointed out in opening testimony, Staff expects that the costs to maintain reliability, provide transmission, and provide generation increase as total load increases.[24] Further, Staff reiterates that due to the scale of each customer and relatively small quantity of customers, very large customers pose a unique planning and cost assignment problem that is not as easily addressed by traditional ratemaking.[25]

Q. Does Staff see any reason to modify the Company's Capacity Reservation Charge rate?

A. Yes. While Staff disagrees with stakeholders' assertions that the Company could fully recover its sunk transmission costs by selling transmission rights on a short-term basis and disagrees with removing fixed generation from the Capacity Reservation Charge, Staff believes that the Company's $4.91 per kW charge may be too high. Staff agrees that *some* portion of the transmission costs could be recovered through the sale of short-term transmission rights. Given the new nature of this charge and the inherent difficulties in projecting

23 AWEC/200, Kaufman/36.
24 Staff/700, Dlouhy/9.
25 Staff/700, Dlouhy/7-8.

future forecast errors, Staff believes that it is reasonable to adjust the Company's rate downward by 25 percent rather than engage in a full analysis of the costs and benefits of procuring excess transmission and generation assets. Therefore, Staff recommends that the Company's Capacity Reservation Charge be decreased to $3.68 per kW. Staff invites the Company to perform this calculation in the next round of testimony. If the Company is unable to do so, Staff is interested in quantifying this amount to better calculate the Capacity Reservation Charge to incorporate offsetting revenues from short-term transmission sales in a future proceeding if the charge is adopted.

Excess Demand Charge

Q. How do intervenors recommend modifying the Excess Demand Charge if approved?

A. AWEC recommends that the Excess Demand Charge be 200 percent of the Capacity Reservation Charge[26] while Vitesse recommends that the Excess Demand Charge be only 150 percent of the Capacity Reservation Charge.[27] AWEC recommends that a deadband be applied to 127 percent of the customer's forecasted peak,[28] and Vitesse recommends that a 13 percent margin be used before the Excess Demand Charges apply.[29]

Q. How did the Company respond to intervenors' opening testimonies on the Excess Demand Charge?

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26 PAC/3400, DeMers/12; AWEC/200, Kaufman/39.
27 Vitesse/100, Koyle/50.
28 AWEC/200, Kaufman/44.
29 Vitesse/100, Coyle/34.

A. The Company did not update its recommendation on the Excess Demand Charge from its opening testimony. The Company felt that a rate from 1.5 to 2.0 times the Capacity Reservation Charge is only mildly more than the Capacity Reservation Charge, and therefore not a strong disincentive against exceeding load requests.[30] The Company also disagreed with AWEC's proposal to align the Excess Demand Charge with the OATT, highlighting that retail customers are very different than FERC transmission customers.[31]

Q. After reading intervenors testimonies, does Staff agree that there should be a buffer in the Excess Demand Charge?

A. No. As described in opening testimony, Staff is concerned both about the resource adequacy implications of a very large customer exceeding its forecasted load and the cost shifting that could occur from the Company having to find ways to supply and transmit excess power to these customers.[32] Staff's approach of allowing slack on the Capacity Reservation Charge but not the Excess Demand Charge was meant to integrate the slack that these customers need without compromising system reliability or imposing undue costs to customers.

Q. After reading intervenors testimonies, does Staff agree that the Company's proposal to calculate the Excess Demand Charge as four times the Capacity Reservation Charge is excessive and arbitrary?

30 PAC/3400, DeMers/19-20.
31 PAC/3400, DeMers/19.
32 Staff/700, Dlouhy/7.

A. In part. Staff is compelled by the testimony of AWEC, Vitesse and DCC that there is little theoretical reason that the Excess Capacity Charge needs to be four times the Capacity Reservation Charge and may be excessive. However, Staff holds the Company's concerns about system risk associated with very large customers exceeding their load forecasts and believes that there should be a *strong* disincentive to do so. Therefore, Staff recommends that the Excess Demand Charge be set at a rate that is three times the Capacity Reservation Charge.

Excess Demand and Capacity Reservation Charge Deferral

Q. Staff and CUB recommended that revenues from the Excess Demand Charge and Capacity Reservation Charge be tracked through a deferral. Have any other parties opined on what happens with these revenues?

A. Yes. AWEC recommends that the funds from these charges be used as a credit against the allowable revenue requirement for Schedules 47 and 48 to avoid double charging these customers.[33]

Q. Did the Company respond to intervenors' testimony on how the charges should be collected?

A. No.

Q. Does Staff agree with AWEC's assertion that Schedule 47 and 48 customers would be double charged under the Company's proposal?

[33] AWEC/200, Kaufman/42.

A. Absolutely not. As Staff and the Company have expressed, the intent of these charges are to ensure that other customer classes are not forced to absorb revenue shortfalls attributed to very large customers underpaying. AWEC's proposal essentially refunds all money collected from very large customers through the Excess Demand Charge and Capacity Reservation Charge *back* to many of the same customers that caused these incremental service costs and stranded asset costs. AWEC's proposal does little to change incentives for very large customers to properly forecast their loads.

Q. How do you recommend that the revenues collected from these charges be returned to customers?

A. Staff continues to recommend that these revenues be tracked through a deferral. To further clarify *how* these are returned to customers, Staff recommends that these revenues be returned annually to customers through an automatic adjustment clause (AAC) that is spread among all schedules based on each schedule's weighted share of transmission and distribution cost allocation used to set rates. Within each schedule, Staff recommends that these revenues be allocated on a per kWh basis for simplicity.

Q. Why does Staff recommend that the revenues associated with these charges be spread among all customers based on each schedule's weighted share of transmission and distribution costs?

A. Staff notes that the primary problem that these charges aim to solve is incentivizing very large customers to forecast their loads in a way that allows the Company to correctly invest in transmission and distribution assets.

Therefore, any revenue shortfalls due to stranded assets or cost overruns due to exceeding reserved loads would be unfairly allocated to other customers through base rates associated with transmission and distribution. Thus, Staff finds it to be most fair to return revenues generated from these charges using the same cost allocation.

<u>Speculative Load Requests</u>

Q. Please summarize Staff and intervenors' recommendation regard the Company's request to deny speculative loads.

A. As previously summarized, Staff, DCC, AWEC, and Vitesse oppose the Company's request to deny speculative loads. DCC stated that they find the Company's proposed language discriminatory and points out that the Company's Open Access Transmission Tarriff requires the Company to consider generator interconnections up to ten years in the future.[34] DCC further states that the term "speculative" should be more clearly defined.[35]

Q. Has the Company updated its position on its ability to deny load requests if capacity is not available?

A. No.[36] The Company states that it is not required to provide services at any cost or under any circumstances.[37] The Company does however clarify that it would not deny load requests that entail a reasonable level of investment and that a potential customer still has legal recourse with the Commission if it

[34] Vitesse/100, Coyle/41-43.
[35] DCC/100, Cain/30-31.
[36] PAC/3400, DeMers/23.
[37] *Id.*

disagrees with the Company's denial. The Company opposes creating a more formal definition of "speculative" because it fears that a list of technologies and business types could quickly become outdated if spelled out explicitly in a tariff.[38]

Q. Have the Company's and intervenors' arguments changed Staff's thinking on the issue?

A. No. While the Company correctly points out that it does not need to provide services at *any* cost or under any circumstances, Staff finds that the Company's proposal and lack of willingness to enshrine a process by which the costs and timelines are outlined denies the Commission and potential customers the ability to learn about these costs and possible other interconnection locations in an official setting. Staff reasserts its opening testimony recommendation to require a list of other interconnection points and a cost study for load requests more than five years in the future. In lieu of creating a more formal definition of "speculative loads", Staff believes that this documentation about costs, timelines, and other interconnection points could serve as a valuable data point when new load is requested and give all stakeholders the needed information to argue whether the Company's denial of a speculative load request was proper.

Staff also has concerns about the Company's attitude towards denying customer requests. Rather than suggesting that a customer seek legal action if they disagree with a load request denial, Staff believes that a more productive

[38] PAC/3400, DeMers/23-24.

approach that would minimize legal expenses and maintain Commission bandwidth would be for the Company to proactively collaborate with prospective customers.

Line Extension Advances

Q. How did Staff respond to the Company's proposal to require customers with loads greater than 1,000 kW to pay the entire line extension advance up front?

A. Staff did not oppose this change in opening testimony.[39]

Q. How did intervenors respond to the Company's proposal to require customers with loads greater than 1,000 kW to pay the entire line extension advance up front?

A. DCC disagreed with this change, saying that the 50 percent up front and the remaining after completion provides the Company incentives to finish the projects in a timely manner.[40] AWEC and Vitesse did not address this change directly. CUB is generally supportive of the Company's proposed Rule 13 changes.

Q. How did the Company respond to Staff's and intervenors' opening testimony?

A. The Company states that it already has an incentive to construct a new line extension as quickly as possible due to the potential revenue they expect to receive from timely completion.[41] The Company also notes that these line

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[39] Staff/700, Dlouhy/11.
[40] DCC/100, Cain/30.
[41] PAC/3400, DeMers/25.

extensions are expensive and have material impacts on the Company's overall cash flow.[42]

Q. What is Staff's position on the line extension advance after reading other parties' testimonies?

A. Staff is still supportive of the Company's proposed changes to require the full line extension advance be paid up front. Staff is compelled by the Company's argument that it already has an incentive to complete a line extension as quickly as possible. Based on the nature of the Company's Capacity Reservation Charge proposal and stakeholders' requests to incorporate an inappropriate amount of slack in the charge, Staff is less concerned about the Company being able to complete a line extension in a timely manner than a very large customer not being able to ramp up according to their requested schedule.

Changes to Reserved Capacity

Q. What was Staff's position on the Company's proposal to allow a very large customer to reduce its Requested Load by no more than 10 percent of its total load or 50 MW per year, or by a larger amount if there is mutual agreement between parties?

A. Staff did not take issue with this proposal in opening testimony but also noted that it was interested in hearing the positions from parties' in opening and reply testimony.[43]

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42 Id.
43 Staff/700, Dlouhy/10.

Q. How did intervenors respond to this proposal?

A. While CUB did not respond to this proposal directly, CUB was generally supportive of the Company's changes to Rule 13 as a means to mitigate cost shifting between customer classes. AWEC stated that this limits PacifiCorp's ability to respond to a customer's changing business needs and that the Capacity Reservation Charge is a sufficient enough incentive to induce very large customers to accurately forecast their loads.[44] Although the Company states that it disagrees with Vitesse's conclusion in a response to a data request, Vitesse has concerns that the tariff allows the Company to unilaterally reduce a customer's load by up to 10 percent or 50 MW.[45] DCC highlights a similar concern.[46] DCC believes that this is unfair and detrimental because it incentivizes a customer to hang on to Reserved Capacity even if there is a low probability that it would be used.[47]

Q. How did the Company respond to Staff's and intervenors' opening testimonies?

A. The Company clarified that the proposed tariff language requires the customer to hold onto its reserved capacity but for the customer's annual ability to reduce load by the lesser of 10 percent of the load request or 50 MW.[48] The Company reasserts that the intention of this rule change is to ensure that investments made specifically for a customer are indeed recovered from that customer

44 AWEC/200, Kaufman/46.
45 Vitesse/100, Coyle/39-40.
46 DCC/100, Cain/28-29.
47 DCC/100, Cain/28.
48 PAC/3400, DeMers/20.

instead of being unfairly spread to other customer groups.[49] Finally, the Company clarifies that allowing a customer to reduce its load request more by mutual agreement would have a minimal impact on cost recovery if a customer in the same region is available to use the excess capacity.[50]

Q. Has Staff updated its position after reading the Company's and intervenors' testimonies?

A. Staff continues to find the Company's proposed language to be reasonable. Staff does not believe that the Company has any incentive to unilaterally lower a customer's requested load as highlighted by Vitesse and DCC because all this would accomplish is furthering stranded asset concerns raised by the Company, Staff, and CUB.

Staff is uncompelled by AWEC's argument that the Company's proposal makes it unable to respond to a customer's changing business needs. As Staff sees it, it is the obligation of the very large customer to pay its fair share of costs if the customer requests load and causes the Company to invest in millions of dollars of assets to serve the load. While small deviations in actual load should be expected, – and Staff believes are fairly addressed by the 10 percent buffer in the Capacity Reservation Charge – shifting the risk of large load deviations from very large customers onto the Company's overall customer base unfairly subsidizes very large customers in a time when large and potentially expensive system investments are expected to be the norm.

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49 PAC/3400, DeMers/21.
50 PAC/3400, DeMers/21-22.

Staff also agrees with the Company's clarification that the load request could be lowered by more than the allowable amount by mutual agreement between the Company and the customer. To demonstrate why Staff supports this, suppose a new customer is willing to step in and pay the system costs associated with serving an existing very large customer's requested load that the existing customer does not plan to use. This new customer would be able to pay the previously unpaid fixed system costs to serve the existing customer, thus mitigating Staff's, the Company's, and CUB's stranded asset concerns while flexibly allowing for new customers to be added to the system. Staff believes that both the Company and customers have sufficient incentives to seek out these solutions and ability to implement these solutions quickly under the Company's proposed tariff language.

Stakeholder Process For Large Customer Changes

Q. A number of stakeholders representing very large customers brought up concerns that the Company did not conduct outreach with their organizations prior to proposing these very large customer changes.[51] How did the Company respond?

A. The Company noted that very large customers are not the only relevant stakeholder in the process.[52] While the Company notes that the charges are primarily targeted towards very large customers, the intent of these charges is to prevent any unfair reallocation of costs.[53] Therefore, the Company

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51 Vitesse/100, Coyle/20-21; DCC/100, Cain/34.
52 PAC/3400, DeMers/8.
53 Id.

concluded that a general rate case is the best forum to engage stakeholders from all backgrounds that may be directly or indirectly affected by these charges.

Q. Does Staff believe that the Company could have conducted outreach outside of the general rate case prior to proposing these charges?

A. Possibly. However, it is worth highlighting that Staff's, the Company's, and stakeholders' bandwidth is particularly limited. Further, the Company's reply testimony highlights the urgency with which these cost shifting concerns and forecasting incentives should be addressed. As an example, the Company received load requests for 13 gigawatts (GW) of new, very large customer loads between 2020 and 2023, which was more than their 2023 coincident system peak.[54]

Staff understands the Company's rationale for choosing to include this proposal in this rate case. Staff also agrees with the Company's concerns about load forecasting accuracy and cost shifting and that a general rate case setting is the most time-effective way to engage *all* stakeholders that should engage on these issues. Staff believes that engaging all customers to be of paramount importance because the risk outlined above are likely to disproportionately affect highly energy burdened or energy justice communities that are not represented by large, well-resourced companies.

Q. Please summarize any changes to Staff's recommendation regarding the Company's proposed very large customer policies.

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[54] PAC/3400, DeMers/6.

A. Staff updated its position on the following items in this round of testimony:

- Staff recommends that the Capacity Reservation Charge be lowered to $3.68 per kW.
- Staff recommends that the Excess Demand Charge be set at three times the Capacity Reservation Charge.
- For the purposes of calculating the Capacity Reservation and Excess Demand Charges, Staff recommends that a very large customer with multiple sites served by the same transmission and distribution assets be allowed to aggregate their load.
- Staff recommends that the revenues generated through the Capacity Reservation Charge and Excess Demand Charge be tracked through a deferral and returned to all customers using the same rate spread as the transmission and distribution cost allocation.

ISSUE 2. TIME OF USE RATES

Q. Please describe Staff's position on the Company's residential Time of Use (TOU) rates proposals in opening testimony.

A. In opening testimony, Staff did not oppose the Company's proposal to move its TOU pilots into full programs and did not have any changes to the rate structures at the time.[55] While Staff also highlighted possible concerns about a needle peak or cost shifting if the residential TOU program were to expand significantly, Staff did not feel that this was a pressing concern at the moment.[56] However, Staff also noted that the Company's enrollment significantly lagged the enrollment in Portland General Electric's (PGE) equivalent TOU pilots and recommended that the Company take steps to improve its customer outreach.

Q. Did any other parties write testimony on the Company's TOU proposals?

A. Yes. Klamath Water Users Association (KWUA) testified in favor of the proposed changes to the Schedule 41 TOU option available to irrigators. In particular, KWUA states that the Company's proposal to increase the TOU price differential increases the potential for cost savings to irrigators.[57]

Staff was the only party that responded to the Company's residential TOU proposals.

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55 Staff/700, Dlouhy/32.
56 Staff/700, Dlouhy/29.
57 KWUA/100, Reed/14-15.

Q. How did the Company respond to Staff and intervenors' testimonies on the Company's TOU proposals?

A. The Company only responded to the residential TOU issues raised by Staff. The Company believes that it is improper to compare the enrollment in its TOU pilot program to the enrollment in PGE's TOU pilot program because the service territories are vastly different.[58] The Company goes on to state that it believes that it adequately notified customers and plans to continue promoting the program if it is indeed converted to a permanent program.

The Company shared Staff's concerns about cost shifting and needle peaks if indeed the program grows significantly.[59] The Company also states that if the program reaches a substantial enough size – between five and ten percent of customers – that the program should be placed in a separate cost of service class, as is done in the Company's Idaho service territory.[60]

Q. How does Staff respond to the Company's assertion that the Company's TOU enrollment rate should not be compared to PGE's enrollment rate because the service territories are so different?

A. Staff agrees with the Company that the Oregon service territories of PacifiCorp and PGE are different. Although it would be naïve to assume that enrollment levels should close to mirror each other between the two territories, Staff continues to be concerned at the sheer magnitude of the differences in TOU enrollment rate between Oregon's two largest investor-owned utilities even

58 PAC/3500, Meredith/26.
59 Id.
60 PAC/3500, Meredith/27.

though the two pilot programs began at approximately the same time. Robust and representative participation in pilot programs is crucial to understanding the efficacy and distributional equity, and assessing whether these pilot programs are ready to scale up. While Staff believes that now is a proper time to transition the residential TOU pilot to a full program, Staff expects to see more active engagement and better participation in future Company pilot programs.

Q. Does Staff have any recommendations to address the Company's low TOU program enrollment at this time?

A. No. Like KWUA, Staff is hopeful that the Company's proposed changes to its irrigator TOU rate offering can incentivize better participation. Despite the comparatively low enrollment, Staff still believes that now is the proper time to move the Company's residential TOU pilot into a full program. Staff encourages the Company to work with Staff, stakeholders, and members of the public outside of this rate case to ensure that the move to a full residential TOU program is paired with a strong enrollment bump.

ISSUE 4. DISTRIBUTION SYSTEM PLAN DEFERRAL

Q. Please summarize Staff's position on the Distribution System Plan (DSP) deferral, UM 2220, in opening testimony.

A. In opening testimony, Staff recommended that the Company not be authorized to amortize the $2.1 million in the UM 2220 deferral to date nor be allowed to continue to track costs in UM 2220 because it does not appear to fall outside of regular business operations.[61] Staff noted this deferral was originally filed as an expansive deferral for everything related to the DSP, up to $44.8 million, but that to date, the deferral has only incurred $2.1 million in consulting and Staffing costs.[62]

Staff's recommendation left open the opportunity for the Company to file a future deferral related to certain pilot programs.[63]

Q. How did the Company respond to Staff's opening testimony?

A. The Company states that if the Commission approves amortization of the $2.1 million in expenses incurred in 2022 and 2023, it intends to continue tracking expenses.[64] The Company also states that these costs were in response to a newly-adopted Commission program and that in July 2022, Staff recommended approving these costs for deferral.[65]

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[61] Staff/700, Dlouhy/37.
[62] Staff/700, Dlouhy/34-35.
[63] Staff/700, Dlouhy/36.
[64] PAC/2000, McVee/68.
[65] PAC/2000, McVee/68-69.

Q. Even though the DSP is a relatively new Commission program, does Staff believe that recovering incremental DSP costs is necessarily appropriate?

A. No. As stated in opening testimony, the DSP applies to all three of the of Oregon's regulated utilities, but only PacifiCorp chose to file a deferral for these costs.[66]

Q. Why does Staff believe that these costs should not be amortized even though it approved tracking these costs in July 2022?

A. Staff notes that the Commission merely approved tracking these costs for later ratemaking treatment in Order No. 22-260. At no point in Staff's memo recommending approval does Staff endorse all the costs included in the deferral. In fact, Staff memo states, "Preliminary approval of this does not affect any party's rights to make arguments regarding the deferral's proper scope."[67] To date, Staff is not aware of any parties making arguments about the proper scope of this deferral.

Q. Does Staff believe that recommending that the Commission disallow the recovery of incremental costs is consistent with the leniency recommended in Staff's memo?

A. Yes.

Q. Why does Staff believe it is proper to disallow all costs in this deferral?

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[66] Staff/700, Dlouhy/36.
[67] Order No. 22-260. Appendix A, page 3.

A. As stated in opening testimony, Staff finds the costs proposed for amortization to be trivial and a normal part of regulatory lag.[68] Further, Staff notes that many of the cost categories in the Company's initial application have either been far smaller than projected or failed to materialize at all, as evidenced by Table 3 in Staff's opening testimony on the topic.[69] Further, Staff has testified in other proceedings that it felt that the current use of Automatic Adjustment Clauses (AACs) and deferrals is suboptimal, thereby shifting the risk onto customers and eroding stakeholder bandwidth.[70]

Q. Does this conclude your testimony?

A. Yes.

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68 Staff/700, Dlouhy/35.
69 Staff/700, Dlouhy/34.
70 Docket No. UE 416, Staff/2200, Dlouhy – Muldoon – Scala – Stevens/7 (June 13, 2023).

CASE: UE 433
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2800

REDACTED
Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Julie Dyck. I am a Senior Economist/Utility Analyst employed in the Energy Costs Section of the Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Staff/800 and my witness qualifications statement is provided in Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to issues listed below that were raised in PacifiCorp's Reply Testimony. Specifically, I rebut PacifiCorp's Reply Testimony on Fuel Stock and the Juniper Ridge Bend Service Center.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/2801, consisting of PacifiCorp's non-confidential responses to Staff Data Requests (DRs) and Staff/2802, PacifiCorp's confidential responses to data requests (DRs).

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. FUEL STOCK

Q. Please provide an overview of the Company's fuel stock.

A. Fuel stock represents the inventory of fuel that is kept on hand by PacifiCorp to ensure a reliable fuel supply is available to operate its' generating plants. Working capital deposits are an offset to fuel stock and sometimes included in the total fuel stock value. However, for ease of understanding, I exclude those from my discussion of fuel stock in this rebuttal testimony. In UE 433, PacifiCorp is including coal, natural gas, and oil in its Test Year Request. Both oil and natural gas have not been adjusted from the base period and only comprise 3.67 percent of the Test Year Request, so my adjustments and analysis focused on coal.

Q. Please restate what the Company's fuel stock request is.

A. It is unclear what the exact Test Year Request is from the Company, made at various times. See the testimonies and DRs below which show different answers for the Company's Test Year requests. Note that Staff adjustments are made from the Company's Opening Testimony position to allow for readers of this testimony to track the revenue requirement impacts. However, in Table 1 below, Staff shows the Company's updated request it included in Reply Testimony. It is worth noting that also included in the Company's Reply Testimony was a different figure for its' initial filing than when compared with the figures listed in Cheung's Opening Testimony workpapers.[1]

[1] On PAC/3000, Owen/4, in Confidential Table 2, The total fuel stock inventory (dollars) that they state was in their initial filing is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

TABLE 1: FUEL STOCK VALUES IN THE TEST YEAR REQUEST[2]

	Total Company	Oregon Allocated
Opening Testimony	$145,444,254	$38,308,735
Updated with OPUC DR 200 Correction[3]	$133,738,691	$35,225,593
Response to DR 640[4]	$137,279,899	$36,158,316
Reply Testimony	$166,229,731	$44,689,462

Q. Please state the Company's updated request as stated in its Reply Testimony.

A. The Company is requesting to include $166,229,731 of fuel stock in FERC 151 in its rate base for the Test Year.[5] See Confidential Table 2's far right column for this information disaggregated by plant.

CONFIDENTIAL TABLE 2: FUEL STOCK INVENTORY FORECAST[6]

[BEGIN CONFIDENTIAL]

2 Staff/2801, PacifiCorp's response to DR 645 Supplemental Attach (excel).
3 As stated in response to DR 308 (pdf) included in Staff/802. This is intended to be a preliminary updated Test Year request, but it does not include all of the errors found in the discovery process.
4 Staff/2801, PacifiCorp's response to DR 640 (pdf). This is intended to be the most recent test year request value that should in theory, as it was filed on June 14, and encompass all changes from the errors that were found. However, as you can see from the table above, it does not.
5 See Cheung Public Workpaper 8.14_R Miscellaneous Rate Base.
6 PAC/3000, Owen/4.

[redacted]

[END CONFIDENTIAL]

Q. Did any other intervenors comment on fuel stock?

A. Not to my knowledge, although intervenors did submit testimony on general rate base recommendations.

Q. Did the Company agree in a DR response to correct errors found in the discovery process when Reply Testimony was filed?

A. Yes. The Company agreed to correct errors which would result in a $2,947,161 total Company ($776,256 Oregon allocated) adjustment to FERC Account 151.[7]

Q. In addition to the corrections above, what was Staff's recommended adjustment in Opening Testimony?

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[7] Staff/802, PacifiCorp response to DR 518 Supplemental (pdf), which should be encompassing of all errors identified during discovery. See also Staff/2801, PacifiCorp's supplemental response to DR 645 Attach (excel) for a breakdown of the Oregon allocated and Total Company Impact. See also, PacifiCorp's response to DR 758 (pdf) where the Company confirms that it did make the corrections in its reply filing. As this was corrected in the Company's Reply Testimony values, if Staff were adjusting based off the Company's Reply request, this adjustment would not be included.

A. Staff recommended that the Test Year forecast of coal fuel stock for Jim Bridger be brought in line with the Base Year to show no increase, this resulted in a $25.9 million adjustment at the system level ($6.8 million Oregon allocated).

Q. Does Staff change these adjustments as a result of the Company's Reply Testimony?

A. No. However, because the values were updated for each of the plants in the Company's Reply Testimony, including Jim Bridger, my accompanying recommendation would change slightly if we apply the adjustment to the Company's Reply Testimony.[8] At the very least, without a methodological change in forecasting fuel stock, Staff retains its original adjustments to Opening Testimony, which total, $28.8 million ($7.6 million Oregon allocated). In addition, the Company's workpaper has a particular focus on dollar values and excludes tonnage.[9] Staff displays their updated values for tonnage in Confidential Table 3 below for reference.

CONFIDENTIAL TABLE 3: FUEL STOCK TONNAGE INVENTORY FORECAST

[BEGIN CONFIDENTIAL]

8 Instead of a $25.9 million adjustment to the total coal fuel stock held at Bridger in the Company's Opening Testimony, this would be updated to a $8,574,765 reduction to the Company's Updated Reply Testimony figures, as Bridger was adjusted downwards in the Company's Reply Testimony. The adjustment as a result of the five errors found in the discovery process would be removed as the Company includes this in its reply testimony values for fuel stock. Therefore, if Staff were adjusting instead based off the Company's reply testimony, we would recommend an adjustment of $8.5 million for the Bridger over forecast alone, and recommend additional adjustments to not increase beyond the Company's Opening Testimony for other plants. The adjustment with the Company's update would be $49.6 million at the system level ($13.9 Oregon allocated).

9 Staff/2801, PacifiCorp response to DR 638 (pdf).

[redacted]

[END CONFIDENTIAL]

Q. What reasons do you list in your Opening Testimony for the adjustment?

A. Staff provided six arguments in support of its adjustment:

1. After conversion of two units, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
2. The Company has only provided one reason for the high forecast which is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
3. The Company has the option of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
4. The Company has not provided any financial analysis that shows the tradeoffs when choosing to forecast an increase in coal fuel stock.

5. If the majority of fuel stock is inactive storage, the company should not earn a return at the expense of ratepayers.[10] After all, this is a part of rate base and should be considered used and useful during the Test Year. Staff further elaborates on this argument in Staff/1900, the Testimony of Bret Stevens, which discusses Staff's position on rate base calculations.
6. The value of oil was reduced, and Staff believes coal should be reduced as well.[11]

Q. Overall, what are Staff's additional concerns?

A. Overall, despite the Company showing a decline in actual fuel stock since 2020, the Test Year request is showing an increase from the 2023 actuals. Staff has six outstanding concerns.

1. The Company uses a 13-month average that is based on the forecast from December 2024 to December 2025. The Test Year should be based on actuals but include known changes that would be found in any Coal Supply Agreements (CSAs), as was the case with Hunter in the Company's Reply Testimony. It is not clear if this was done for all plants and it is unclear how the Company would comply with Staff's recommendation to only include capital if it is in service by January 1,

[10] Staff/2801, PacifiCorp's Redacted Response to DR 647 (pdf). "Dead storage is an industry term used to describe long-term coal storage piles located outdoors and is separate from active piles or coal storage bunkers.

[11] Staff/800, Dyck/13.

2025, and have coal that is coming in for fuel stock at any point after that during the year of 2025.

2. There was a huge gap between the actuals and forecasted value of fuel stock for 2023. The forecasts for 2024 and 2025 are remarkably higher than even the forecast for 2023. There were numerous coal events in 2022 and 2023[12] that the Company has identified, which they claim should not persist into the Test Year.[13] However Staff is doubtful of this claim. Especially since the Company stated in its' 2025 TAM that "coal supply shortages are continuing from 2023 into 2025."[14] The Company states later in the same filing, "The coal market continues to experience similar issues to the ones highlighted in the 2024 TAM filing."[15] In addition, informed by the Company's PCAM filing, Staff questions whether the Company would be able to acquire the large amount of coal they are forecasting for the Test Year. Instead, PacifiCorp may request large amounts of additional power costs (from other sources like natural gas or market purchase) in either the next TAM or PCAM filing. Further, the Company confirmed that they procure coal through Coal Supply

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[12] This was discussed at more length in the Company's PCAM filing for 2023. UE 439, PAC/100, Painter/12. The Company states here, "Coal supply constraints which began at the end of calendar year 2022, continued through 2023 and still impact the Company today, having an overarching influence on all components of actual system operations. These constraints cause the coal generation in Base NPC to be replaced by natural gas generation and market purchases, and at the same time also limit the Company's ability to make profitable wholesale sales transactions."

[13] Staff/802, PacifiCorp response to DR 525 (pdf).

[14] UE 434, PAC/100, Mitchell/19. The Company refers Staff to Confidential Exhibit PAC/107 for further evidentiary detail on these issues.

[15] UE 424, PAC/200, Owen/2. Staff is under the assumption that the same issues that occur when procuring coal for power costs would also be occurring when procuring coal for fuel stock.

Agreements (CSAs) and "the process for forecasting fuel stock in a GRC is the same as forecasting coal purchases in PacifiCorp's power cost filings, specifically the TAM filings."[16] The Company went on to state the issues and challenges in procuring more coal, furthering Staff's position which questions the Company's ability to acquire the coal that they forecast.[17]

3. In Oregon, with the passage of HB 2021, there is a greater emphasis on cutting emissions levels, and early compliance can be incentivized by the Commission.[18] However, in this instance, PacifiCorp expects customers to continue to pay a return for higher amounts of coal fuels stock despite the decommissioning of some coal plants and the conversion of others.

4. In other filings Staff has expressed its belief that the Company canceled its most recent Request for Proposals (RFP) and continues to rely on more coal, despite any uncertainty around procuring said coal. As Staff stated in the Company's 2023 IRP, "This reversion back to coal is especially troubling given the known coal supply and fuel cost issues for several of PacifiCorp's facilities, which are a driver of increased power costs in other, recently filed dockets… The uncertainty around future resource additions also stands in contrast to PacifiCorp needs. Per the

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[16] Staff/2801, PacifiCorp's response to DR 755 (pdf).

[17] Issues include but are not limited to: increased coal demand due to high domestic natural gas prices; low inventories at coal fired power plants; increased demand abroad for coal exports; international and domestic supply chain constraints; labor and material shortages; geological and weather events; and general market inflation.

[18] O.R.S. § 469A.410.

CEP, the Company will need 2 GW of non-emitting resource by 2030 to meet Oregon's energy, capacity, and compliance needs."[19] Staff notes that it appears as though one bad decision (not procuring enough resources) is propping up the other (forecasting more coal fuel stock than is prudent).

5. In relation to Bridger, the Company can transfer up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of coal from the short-term pile back to the long-term pile, however the Company can transfer unlimited amounts of coal from long term/inactive storage to short term storage to be used. For context, "The total PacifiCorp plus Idaho Power, maximum permitted average stockpile capacity is **[BEGIN CONFIDENTIAL]** [redacted][20] **[END CONFIDENTIAL]** Thus, Staff notes that the Company could have a quantity of coal that is at the mines capacity that the Company realizes a return on in its long-term stock, but also transfer this coal into its short-term stock for use, thereby earning a return on coal in long-term stock that is effectively not there.

6. Lastly, this begs the question of whether all of PacifiCorp's coal fuel stock is in fact used and useful during the Test Year. In the Company's Reply filing, it acknowledged the value for Jim Bridger was too high initially.

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[19] lc82hac329353025.pdf (state.or.us) Pages 15-16.
[20] PAC/3000, Owen/9.

However, PacifiCorp instead updated two other plants fuel stock, giving Staff little time to review.[21] While Staff can understand that the Company received force majeure claims from two of its major coal suppliers in the latter half of 2023,[22] this does not in itself demonstrate a reasonable Test Year fuel stock request for 2025. Staff would also like to reiterate that it has repeatedly recommended that the Company not rely on such a coal-heavy resource portfolio.

Q. How do the past 13-month average balances compare to the past Test Year requests and this GRC's updated Test Year request?

A. While my adjustment is focused specifically on the coal forecast for Jim Bridger, putting that into context with the Company's requests and actuals is important. Please see Figure 1 below which shows that 2023 displays a large gap. However, the Company failed to recognize either in the GRC or the 2023 PCAM (UE 439) how these costs were still included in base rates to customers (UE 399). In addition, as I discuss below, this resulted in much larger natural gas generation and market purchases reflected in power costs in the PCAM filing. Staff believes that 2023 is an example of an unreasonable coal fuel stock forecast, especially in light of how early the Company knew of concerns procuring coal.[23] Given that the Company increased its request in Reply

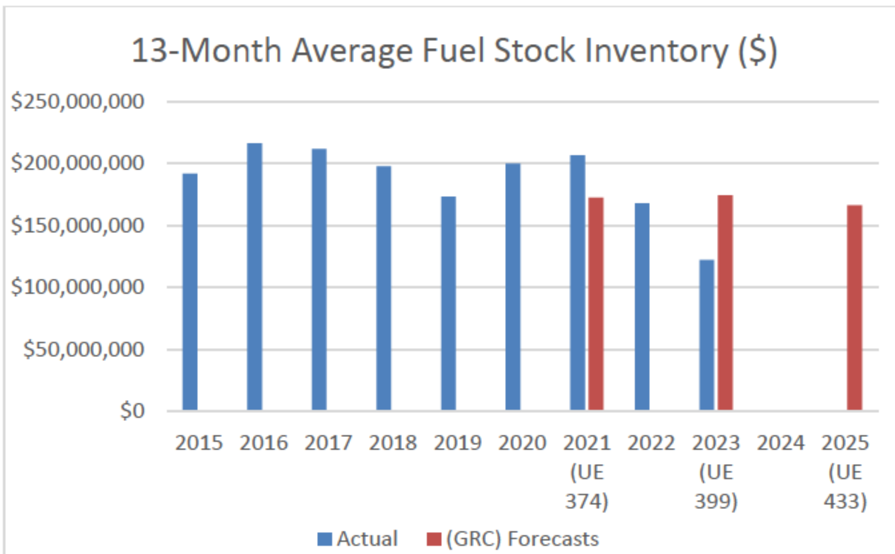
[21] This includes the response to Staff DR 756 which asked the Company to provide Coal Supply Agreements for Naughton, Bridger, and Hunter. However, it is likely that these will be submitting as highly confidential and due to the timing of the request, none of the highly confidential information is included in this testimony or Staff exhibits.

[22] UE 434, PAC/200 Owen/3.

[23] The Company stated in UE 439, PAC/100, Painter/15 that these issues began in the fourth quarter of 2022, but Staff has outstanding DRs on when exactly the Company became aware of these shortages.

Testimony, which again runs counter to Staff's previous recommendation to wean itself off of coal, Staff seeks to prevent another year in which costs are passed onto ratepayers for an unreasonable coal fuel stock request in addition to increased power costs. This essentially leaves ratepayers on the hook twice, paying for the same event or series of events which require the fuel.

FIGURE 1: 13-MONTH AVERAGE FUEL STOCK[24]



Q. Further explain how the issue of coal procurement and fuel stock was brough up in the Company's PCAM for 2023.

A. The Company discusses how coal constraints in 2023 contributed to increased natural gas expenses. The Company states, "In addition to coal supply constraints in Utah, the Jim Bridger plants also had coal supply constraints in early 2023. Due to overall lower coal fuel availability, the company had to

24 Staff/2801, PacifiCorp Response to DR 641-1 Attach (excel) and 642 Attach (excel). In addition, there are outstanding DRs issued in UE 439 the response to which may indicate how early the Company knew of the coal issues.

adjust its overall system operations through increased natural gas resource output, increased purchase power, and reduced wholesale sales."[25] Staff wants to point out the inherent contradiction between the Company using natural gas as a substitute for coal in certain years while also forecast a large inventory of coal that they earn a return on at the Jim Bridger plant. In addition, the Company went on to state,

> "Early in 2023, once the Black Butte delivery shortfall became apparent, PacifiCorp took steps to mitigate the shortfall. First, dispatch of Jim Bridger plant was adjusted to account for the shortfall. Second, PacifiCorp contracted for the delivery of NARM[26] coal which also required PacifiCorp to lease railcars. PacifiCorp received .33 million tons from NARM in 2023 to partially offset the reduction in Black Butte mine deliveries".[27]

If the Company adjusted generation at that time in 2023 and also forecasted a similar situation for the 2025 TAM[28], a larger coal stockpile in the GRC Test Year is imprudent.

Lastly, in various other dockets, Staff has expressed concern about the recent shift back to relying more heavily on coal, and how such planned actions are consistent with the actions necessary to achieve Oregon's emission reductions at a reasonable cost to ratepayers.[29] In this context Staff finds ratepayers should not be on the hook for the additional risk and cost that comes along with holding a larger amount of coal in fuel stock given the

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[25] UE 439 PAC/100, Painter/15-16. See also PacifiCorp's CONF response to DR 648 (pdf) in Staff/2802.

[26] North Antelope Rochelle Mine (NARM) in Wyoming's Powder River Basin. Historically, Jim Bridger's coal has been supplied by the captive Bridger Coal Company mine and Lighthouse Resources' local Black Butte Mine.

[27] UE 439, PAC/100 Painter/22.

[28] UE 434 PAC/100, Mitchell/9.

[29] Order No. 24-073, Page 24.

uncertainties around market operations, competing forms of lower-cost generation, and newly proposed EPA regulations.[30]

Q. Further explain the three main updates that the Company made to the Test Year fuel stock forecast in its Reply Testimony.

A. See Confidential Table 4 below which explains the major updates the Company made in its Reply Testimony update to fuel stock for three different plants.

CONFIDENTIAL TABLE 4:

MAJOR UPDATES TO FUEL STOCK TEST YEAR REQUEST

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How did the Company explain the change at Hunter?

A. The Company stated that at the time of the proceeding its fuel stock balance was based on the 2024 forecast, which did not include the updated price and

[30] lc82hac329353025.pdf (state.or.us) Page 15. For new Federal Regulations on carbon at coal plants see Clean Air Act, Section 111(d), 89 Fed. Reg. 39798, May 9, 2024. JB 3 & 4 retirement date of 2039 will require a co-firing of 40% natural gas by 2030. For new Federal Regulations on effluent limitations at coal plants see 89 Fed. Reg. 40198, May 9, 2024. JB 3 and 4 will need new investments to meet enhanced discharge limits for wastewater. For additional reference, here is the Commission Order where the Commission did not acknowledge the Company's Clean Energy Plane (CEP), 24-073.pdf (state.or.us).

coal volumes from the Hunter/Wolverine CSA second amendment in its analysis.[31]

Q. Does Staff find this increase reasonable?

A. At this time, no. Staff questions the Company's story on why they updated the forecast for Hunter. One major reason is because the Company mentioned a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Yet, the Company states they did not know about the second amendment on July 26, 2024, at the time of filing its' Opening testimony (filed on February 14, 2024 for UE 433) despite a reference **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that was also filed on February 14, 2024 (in UE 434). Staff was able to confirm through discovery that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Therefore, when looking at the timeline it does not make sense that this would have been a cause of the updated value for Hunter in the Company's Reply Testimony.

Second, because the Company makes reference to the CSA for Hunter, Staff assumption that the coal procurement process for fuel stock and for fuel in the Company's power cost forecast was confirmed by the Company. **[BEGIN CONFIDENTIAL]** [redacted]

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31 PAC/3000 Owen/5.

32 UE 434, PAC/200, Owen/4-5. See also Staff/2802, PacifiCorp's Confidential Response to DR 754 (pdf) where you can find an excerpt from this confidential opening testimony.

33 Staff/2802, PacifiCorp's Confidential Response to DR 757 (pdf).

[redacted] **[END CONFIDENTIAL]** It seems at odds that for the same year, the Company can say in one docket that costs have decreased slightly as there was difficulty procuring coal yet in a different docket say that the Company anticipates no issues in procuring enough coal to meet the forecasted fuel stock request for coal.

Staff is sensitive to the need for coal as it is used in peak weather events and has recognized the difficulty at times in procuring coal for power cost filings. However, the Company adjusting the forecasted volumes of coal consumed in 2025, since it did not match with the contracted volumes, seems at odds with an increasing fuel stock at the same plant.[34] See Confidential Table 5 below which shows the gap between the Company's contracted agreements and actuals/forecasts. While this is looking at tons needed for power costs, they are very much interrelated with the coal tons that are needed for fuel stock. In addition, the Company has yet to demonstrate the issues they describe for procuring coal at Hunter for power costs would not also be present for coal procurement for fuel stock.

[34] See UE 434, PAC/200, Owen/6, which is non-confidential, which states, "Due to these shortfalls, PacifiCorp has adjusted its forecasts for coal received and consumed at Hunter and Huntington plants in the 2025 TAM. Accordingly, the forecast volumes of consumed coal in 2025 do not match the contracted volumes for coal in the CSAs for the calendar year 2025. Furthermore, to ensure targeted coal inventory balances are available for reliability purposes, received and consumed coal quantities at the Utah plants are balanced in the 2025 TAM and stockpiled inventory remains mostly flat."

CONFIDENTIAL TABLE 5: CONTRACTUAL TONS VS. ACTUAL/FORECASTED DELIVERED TONS[35]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How did the Company explain the change at Naughton?

A. The Company simply stated that there was an error they identified in the initial filing. Staff is concerned that Naughton stock increased in value in the Company's Reply filing as it was identified in the discovery process that Naughton Units 1 and 2, 2025 ending inventory balances should be replaced with zero to account for the fact that they are scheduled for permanent cessation of coal consumption in December 2025.[36] While Staff understand that a 13-month average is used, this still begs the question of why fuel stock would be treated differently than other rate base items, which Staff recommends exclusion for if it is not used and useful by January 1, 2025.

Q. Does Staff have any concerns?

A. Yes. Staff asks that the Company provide an explanation of what exactly caused the increase, what will happen to this coal in storage when it can no

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[35] See PAC/200, Owen/6, Confidential Table 2. See also Staff/2802, PacifiCorp's Confidential Response to DR 754 (pdf) which includes the page referenced.

[36] Staff/802, Response to Redacted DR 536 (pdf). See also Staff/2801, PacifiCorp's response to DR 759 (pdf).

longer be used, and how ratepayers will benefit from any sale. The Company did confirm that by December 2025, all of Naughton's coal fuel stock should be depleted and at zero.[37] In addition, Staff asks that the Company explain how the increased request for Naughton is going to be used and useful for the Test Year, given the cessation of coal consumption in 2025. At this time, Staff does not feel that the burden of proof has been met by PacifiCorp for an increase in coal fuel stock at Naughton in the Company's Reply Testimony, but Staff is still reviewing the Company's information provided on the increase at Naughton.[38] In addition, the Commission has stated in the past, "PacifiCorp will need to explain how it is allowing for an orderly sequence towards retirement and ensuring flexibility for reduced capacity factors and consumption of the coal pile…"[39] Yet, in this docket consumption of the coal pile towards the end of a unit's life and how it is expected to change in a Test Year is not discussed.

Q. How did the Company explain the change at Jim Bridger?

A. The Company states, "the decrease in the fuel stock inventory balance at the Jim Bridger plant is due to several factors, but primarily the changing fuel suppliers mix for the Jim Bridger plant."[40] It goes on to state, "At the time of the initial filing, the coal fuel stock tonnage for Jim Bridger plant was forecast to increase between December 2023 and December 2025 based on assumptions of deliveries and consumption that resulted in building inventory to **[BEGIN**

[37] Staff/2801, PacifiCorp's response to DR 760 (pdf).
[38] Staff/2801, PacifiCorp's response to DR 761 (pdf).
[39] Order No. 21-379, page 7.
[40] PAC/3000, Owen/6.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**[41]

Q. What additional support for Staff's adjustment to Jim Bridger have you found in the discovery process since the publishing of Opening Testimony?

A. First, Staff believes the target levels for Jim Bridger are artificially inflated and should only be representative of Jim Bridger units 3 and 4 as units 1 and 2 will be converted to natural gas. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[42]

Second, because there are no true ups for rate base totals in GRC fuel stock totals, amounts forecasted in 2023[43] for example were included in the rate base total at the time despite the fact that **[BEGIN CONFIDENTIAL]** [redacted][44] **[END CONFIDENTIAL]**. For that Test Year, the Company over forecasted $52.25 million at the System Level ($13.76 million Oregon allocated), not including any

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41 PAC/3000, Owen/7.
42 Staff/2802, PacifiCorp Response to DR 647 (pdf).
43 Forecasted coal fuel sock needs for 2023 were filed and included in UE 399.
44 Staff/2802, PacifiCorp Response to DR 648 (pdf).

returns earned on this fuel stock.[45] This would also be the case if fuel stock totals are over forecasted for the UE 433 Test Year.

Third, when asked why the Company wants to **[BEGIN CONFIDENTIAL]** [redacted][46] **[END CONFIDENTIAL]** yet this does not explain the still large request for Jim Bridger in the Test Year when compared with the Company's reasoning in its 2025 TAM filing for a decrease in coal generation, with both the conversion of two of Jim Bridgers units and the fact that the Company states, "especially when considering that coal supply shortages are continuing from 2023 into 2025".[47] Therefore, Staff maintains our Opening Testimony adjustment to Jim Bridger fuel stock.

Four, even for docket UE 400, which forecasted power costs for 2023, the Commission expressed concerns and suggested PacifiCorp should look at scenarios that may involve significant change in management of the resources, such as, for example, the consequences of fueling Jim Bridger solely from Bridger Coal Company (BCC) or solely from Black Butte.[48]

Q. Does Staff have additional questions?

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45 Forecasted coal fuel stock (13 month average) was $174,547,782, Actual fuel stock (13 month average) for 2023 ended up being $122,297,000. This is a difference of $52,250,782 at the system level. The OR allocated percentage used to allocate that would be the SE factor (26.3391188369708%). This is a difference of $13,762,396 Oregon allocated.
46 Staff/2802, PacifiCorp Response to DR 649 (pdf).
47 UE 434, PAC/100, Mitchell/19.
48 In the Matter of PacifiCorp 2022 Transition Adjustment Mechanism, Docket UE 390, Order 21-379 at 14; see also UE 400, Exhibit Staff/600, Storm/16.

A. Yes, and due to the fast turnaround Staff was unable to issue further discovery on fuel stock. Below are additional questions that Staff has.

1. Is there any reason why fuel stock should treated differently than the Company's Utility Plant in Service (UPIS/EPIS)? For example, if Staff recommends that capital that comes online past the rate effective date is not considered used and useful, is there a reason why the same should not be recommended for fuel stock?
2. As the fuel that is in rate base is used, does it get transferred to an expense account that reflects the cost of fuel consumed during the generation of electricity? How does this work within the context of the GRC, is the fuel included only intended to be stored during the Test Year? If it is only intended to be stored, how is it then considered used and useful? Is there a modified definition of the phrase used and useful in the context of fuel stock?
3. The Company has a large amount of coal that is considered inactive and a small amount that is considered short-term/active. Can the Company explain why both long-term and short-term coal stored can both be considered used and useful for the Test Year when they serve different purposes and Staff is of the understanding that coal cannot be transported directly from inactive storage to be used for generation?

Q. Please restate Staff's recommendations.

A. Staff maintains its' original recommendations for an adjustment of $25.9 million ($6.8 million Oregon allocated) to the Company's original coal fuel stock request for Jim Bridger and that the Company correct their errors to its' Opening Testimony, which resulted in an adjustment of $2,947,161 total Company ($776,256 Oregon allocated).[49] In total, Staff recommends an adjustment of $28.8 million ($7.6 million Oregon allocated).

In addition, Staff recommends at this time that the Commission not approve the Company's Reply Testimony updated increases for fuel stock at Hunter and Naughton. Staff notes that even if the Commission does not approve the Company's Reply Testimony figures for Hunter, the plant would still receive recovery for increased coal fuel stock as the Company's Opening Testimony filing forecasted an increase for fuel stock at this plant, which Staff did not dispute.[50] In general, Staff is also concerned with the Company's actions in various contested cases which include updating figures from its' Opening Testimony position to its' Reply Testimony position and sometimes at multiple points along the way. The level of change and updates that Staff would expect to see should be minor given that the Company chooses when to come in for a rate case and should have a more accurate picture of its' forecasted costs when doing so.

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[49] This would remain as an adjustment to the Company's Opening Testimony filing. However, if the Company did correct these errors in its Reply Testimony, Staff asks that the Company provide evidence of these corrections. In addition, in an above footnote, Staff states what these adjustments would be if adjusting off of Reply Testimony figures. Similarly, our revenue requirement witness has that information as well.

[50] Put differently, the Company requested an increase in its' Opening Testimony filing for Hunter. In its' Reply Testimony, it requested an additional increase beyond their initial increase. Staff doesn't believe that the Company has provided enough additional evidence that the subsequent increase (mentioned in Reply Testimony) should be approved.

ISSUE 2. JUNIPER RIDGE BEND SERVICE CENTER

Q. Please restate what the Juniper Ridge Bend Service Center is.

A. This new facility will be in the Juniper Ridge Industrial and Business Park in northeast Bend and consolidate the operations of three offices now spread throughout the Bend area.[51]

Q. Restate the Company's Opening Testimony Test Year request.

A. The Company requests the project to cost $40.3 million.

Q. Restate Staff's recommended adjustment.

A. Staff recommended that the Test Year request be adjusted by $5.7 million. In addition, Staff expressed concern that the costs were 100 percent allocated to Oregon. Since then, the Company confirmed that all costs were assigned to Oregon ratepayers.[52]

Q. What support did Staff provide for its adjustment in Opening Testimony?

A. Staff recommended this adjustment for a host of reasons:

1. First, it is unreasonable to spend 35 percent of project costs in the last 10 months prior to the in-service date.
2. Second, management received lower estimates.
3. Third, outstanding project spends do not appear to be large.
4. Fourth, Company does not have compelling reason for outstanding spending.

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[51] *See* PacifiCorp News Release, "Pacific Power building new training facility and consolidated service center to serve growing Central Oregon communities" (May 3, 2021) (available at: https://www.pacificpower.net/about/newsroom/news-releases/pp-building-new-training-facility-bend-oregon.html). I have also included a copy of this press release in Staff/2801.

[52] Staff/2801, DR 671 (pdf).

5. Fifth, it is possible modifications could have resulted in increased permitting costs which could have been prevented.[53]

Q. How did the Company respond to Staff's adjustment?

A. The Company explains that the majority of the construction phase is almost entirely committed and scheduled as the Company has shown. PacifiCorp also provide an update that as of June 2024, $7.7 million is the remaining cost of the project. The Company went on to explain that the project cost increase from $37.6 million in July of 2022 to $41.6 million today was primarily due to inflation and permitting delays and project changes.[54] Lastly, the Company agreed to submit an attestation verifying that the Juniper Ridge Bend Service Center is placed in service by the rate effective date.[55]

Q. Did any other intervenors comment on the Juniper Ridge Bend Service Center?

A. Not to my knowledge.

Q. Does Staff have an updated adjustment?

A. Yes. Staff made a minor update to its' recommendation to acknowledge the spend that has already occurred but updates its recommendation as it relates to the training center. Staff is convinced of the costs that have been incurred up to this date and is confident of the ones that will be incurred during 2024 but is skeptical that the facility will be used and useful by the rate effective date. In addition, Staff disagrees with the Company that 100 percent of these costs

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53 Staff/800, Dyck/23.
54 PAC/2900 Berreth/5.
55 PAC/2000, McVee/10.

should be covered solely by Oregon ratepayers. Staff recommends a portion of these costs be disallowed based on the fact that the training center will be used by other states. At this time, four percent of the total project costs will be a placeholder for this amount as Staff is not aware of separate accounting treatment for the training portion of the Center.[56]

Q. What requirements must be met for a facility to be 100 percent allocated to a specific state, in this case, Oregon?

A. In a data response, the Company responded as follow:

> "Plant function classification follows Federal Energy Regulatory Commission (FERC) established rules. Following those rules, local service centers are classified as distribution-related general plant. Section 3.1.4 of the approved extension of the 2020 Multi-State Process (MSP) Inter-jurisdictional Cost Allocation Methodology (2020 Protocol) states that all distribution related expenses and investment that can be directly allocated will be directly allocated to the state where they are located. For more information on the 2020 Protocol, please refer to Public Utility Commission of Oregon docket UM 1050. Use of the 2020 Protocol was extended in order 23-229."[57]

The Company went on to state in a different response that facilities are 100 percent assigned to the state that they are located in.[58]

Q. Do you believe that the Juniper Ridge Service Center should be classified as a distribution-related plant?

A. No. As stated on FERC's website, "*Distribution system* means all land, structures, conversion equipment, lines, line transformers, and other facilities

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56 The Company has identified that four percent of the total facility is going to be used for training purposes.
57 Staff/2801, DR 673 (pdf).
58 Staff/2801, DR 674 (pdf).

employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includible in transmission system, as defined in paragraph A, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system."

Q. What is the purpose of the Juniper Ridge Bend Service Center?

A. The center is a consolidated operations center which also incorporates a training yard. This was intended to replace both the Bend Service Center and the Bend Metering Office. In addition, it is considered a state-of-the-art training center. This seems distinctly different than the distribution related plants as it intends to serve as the base for about 70 employees in the area but also train employees who presumably work in other states. It seems like the operations of the two parts of the center should be kept separate or at the very least follow separate accounting rules. The training part should follow the protocol allocation for either general plant customer related (CN)[59] or general (SO).[60]

Q. Does the Company provide an additional description of the purpose of the Center?

A. Yes. "The Juniper Ridge Bend Service Center will be used primarily by the Company field employees that provide operational support to the surrounding communities. Operational support includes maintenance, operations, construction of the transmission, substation, and distribution electrical network.

[59] Customer Number Factor
[60] System Overhead Factor

This new site will consolidate the three Bend-area operating centers (the leased Bend Service Center and Bend Metering Office, and the owned Bend Substation Ops) into one location and resolve end-of-lease risks for the current Bend Service Center and Bend Metering Office."[61] However, in this specific description, they make no statement regarding the center being used as a training facility.

Q. Does the Company go on to discuss the extent to which the facility will be used as a training center?

A. In a later part of the Company's Reply Testimony they state the following,

> "There will be an area in the building that will be reserved for training of employees and it is expected that there will be some employees from outside the state who will be trained there. This will be a small percentage of the trainees. The training portion of the building is approximately 4 percent of the space and an even smaller fraction of the cost when the yard is included. There is no cost for the project related to training employees from outside Oregon. The Company would not have reduced the size of the training room if non-Oregon employees would have been excluded, and it will be used by Oregon employees the majority of the time. The training rooms are not spacious, and cross-training provides a benefit to Oregon employees to interact with other highly trained trades people from other states. As noted above, the predominant function of this facility is to serve distribution facilities in Oregon."

The Company also clarified that "there is no mechanism in place to track capital costs to create a surcharge for an employee using a facility in a different state."[62]

Q. What additional support does Staff have for its adjustment?

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[61] PAC/2900, Berreth/2.
[62] Staff/2801, PacifiCorp Response to DR 677 (pdf).

A. The Company clarifies that a 100 percent allocation to Oregon is appropriate because it *primarily* supports distribution facilities across the state of Oregon. However, the Company fails to acknowledge that in their own press release they place emphasis on the fact that this will be a "state of the art training facility where employees company-wide will come to keep their skills sharp." Staff has not been provided the exact number of employees which will be trained here annually or any additional details that regarding the training center portion of the facility. Instead, the Company tries to brush over the training center portion and paints it as small in comparison, but I would argue with only 70 Oregon employees, and a cost of at least $40.3 million, it is expected that the Company plans to use the facility for many more out of state employees to train here. Presumably, there are many other facilities that are located in other states, and Oregon pays a share of those costs due to the benefit to Oregon ratepayers yet in this case where other states are going to benefit, no other state's ratepayers are sharing in the cost. Presumably we do not get the full picture or know the counterfactual for what the facility would have been without the inclusion of the training center. Also, Staff does not know the extent to which the training center is going to be developed in the future for further out of state training situations, given it already has the space to do so. In addition, if Staff is just moving in in December 2024 and are expected to finish their move-in by February 2025, how used and useful can the facility be given that they have also requested lease extensions at the other properties.[63] Staff views its

[63] Staff/2801, PacifiCorp Response to DR 534 (pdf).

updated recommended adjustment of $1.61 million as modest.[64] Staff also recommends that the Company develop a method for updating Staff on the use of the facility and how it may evolve over time.

Q. Does this conclude your testimony?

A. Yes.

64 This was calculated as a four percent reduction to the total project costs of $40,343,412 that was listed in Opening Testimony on PAC/1702, Cheung/233.

CASE: UE 433
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2801

PacifiCorp's Non-Confidential Responses to Staff Data Requests (DRs)

August 16, 2024

PacifiCorp's Response to OPUC 645 1st SUPP Attach is in electronic spreadsheet format only.

UE 433 / PacifiCorp
June 14, 2024
OPUC Data Request 640

OPUC Data Request 640

Fuel Stock – What is the updated base year and test year values for fuel stock, at the system and Oregon allocated level given the errors that are going to be corrected in rebuttal testimony as referenced in the Company's response to DR 518?

Response to OPUC Data Request 640

The Company assumes that the reference to "DR 518" is intended to be a reference to the Company's response to OPUC Data Request 518. Based on the foregoing assumption, the Company responds as follows:

As shown in Attachment OPUC 518 in the Company's response to OPUC Data Request 518, the Base Year Total Company fuel stock amount is $136,952,549 and the Test Year Total Company fuel stock amount is $137,279,899. The Oregon allocated amounts are arrived at by multiplying the Total Company amounts by Oregon's system energy (SE) allocation factor of 26.339 percent, or $36,072,095 for the Base Year and $36,158,316 for the Test Year.

UE 433 / PacifiCorp
June 14, 2024
OPUC Data Request 638

OPUC Data Request 638

Fuel Stock – Why was the tonnage for each plant provided in the forecasts included in the Company's confidential response to DR 201 Attach but not included in the Company's Test Year request 8.14 work paper?

Response to OPUC Data Request 638

The Company assumes that the reference to "DR 201 Attach" is intended to be a reference to the Company's response to OPUC Data Request 201 and Attachment OPUC 201. Based on the foregoing assumption, the Company responds as follows:

The purpose of work paper 8.14 is to bring forward the Base Year fuel stock balance to the Test Year 13-month average balance to reflect the projected dollar amount in rate base in this general rate case (GRC). This adjustment is prepared on a dollar basis and therefore quantities are not reflected. OPUC Data Request 201, subpart (c) specifically requested US dollar value (USD) as well as quantity.

UE 433 / PacifiCorp
June 14, 2024
OPUC Data Request 647

OPUC Data Request 647 **Redacted**

CONFIDENTIAL REQUEST - Fuel Stock – See the Company's response to DR 199 Attach Conf.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Confidential Response to OPUC Data Request 647

The Company assumes that the reference to "DR 199 Attach Conf" is intended to be a reference to the Company's response to OPUC Data Request 199 and Confidential Attachment OPUC 199. The Company also assumes that the reference to "DR 201 Attach" is intended to be a reference to the Company's response to OPUC Data Request 201 and Confidential Attachment OPUC 201. The Company further assumes that the reference to "PAC" is intended to be a reference to PacifiCorp. Based on the foregoing assumptions, the Company responds as follows:

(a) Subpart (a) to this request is a statement. There is no question or request to address.

(b) Dead storage is an industry term used to describe long-term coal storage piles located outdoors and is separate from active piles or coal storage bunkers.

(c) PacifiCorp and Idaho Power Company (IPC) collectively own the Jim Bridger plant and Bridger Coal Company (BCC). PacifiCorp's ownership share of the plant and mine is 66.67 percent and IPC's share is 33.33 percent. "Bridger – Total" represents the target coal inventory amounts for all owners of the generating station, and "Bridger – PAC" represents target coal inventory amounts for PacifiCorp only. Forecasts included in the general rate case (GRC) only include "Bridger – PAC" or PacifiCorp's share of fuel stock inventory. PacifiCorp is the operator of the plant and responsible for the coal stockpile at the Jim Bridger generating station, which is why both are called out in the Company's inventory policy. PacifiCorp and IPC each separately own a portion of the coal inventory which can be different than the 66.67 percent and 33.33 percent ownership share of the plant.

(d) Coal fuel stock inventory forecasted in the 2025 GRC only reflects PacifiCorp's share. The table provided in the Company's response to OPUC Data Request 199 specifically Confidential Attachment OPUC 199, page 11, shows target levels, effective January 1, 2024, after the conversion of Jim Bridger Unit 1 and Jim Bridger Unit 2 to natural gas, as [redacted]. The Company's response to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, forecasts Jim Bridger plant (PacifiCorp share) to have an ending inventory of [redacted] for the period ending December 2025. Annual burn, as indicated in the Company's response to OPUC Data Request 199, specifically Confidential Attachment OPUC 199 page 11, reflects the amount that Jim Bridger can consume in a year while plant ending inventory only reflects coal fuel stock available at a given point in time.

(e) Please refer to the Company's response to subpart (c) above.

(f) No. Wyodak is not the same as Cholla. Ending fuel stock inventory for Cholla was included in the Company's response to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, for years 2015 through 2020. PacifiCorp ceased operating Cholla Unit 4 as of December 24, 2020. Wyodak's policy was also included in the Company's response to OPUC Data Request 199, specifically Confidential Attachment OPUC 199, page 14. There is no fuel stock inventory stored at Wyodak, coal is delivered via overland conveyor from the Wyodak mine as needed. Wyodak was not included in the Company's to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, as the balance is zero.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

PacifiCorp’s Response to OPUC DR 641-1 Attach is available in electronic spreadsheet format only.

PacifiCorp's Response to OPUC DR 642 Attach is available in electronic spreadsheet format only.

UE 433 / PacifiCorp
June 19, 2024
OPUC Data Request 671

OPUC Data Request 671

Juniper Ridge Bend Service Center - See the Company's workpaper 8.4 on Pro forma additions and retirements, specifically, 8.4.27. Are the costs of the Juniper Ridge Bend Service Center 100 percent allocated to Oregon?

(a) What does an OR factor in this context mean?

(b) If they are not 100 percent allocated to Oregon, explain why the factor used in this workpaper is OR.

(c) What would the percent allocated to Oregon be?

(d) If the total project costs are estimated at 40.3 million. Provide the Oregon allocated costs.

Response to OPUC Data Request 671

Yes. The costs of the Juniper Ridge Bend Service Center are assigned 100 percent to Oregon.

(a) The allocation factor noted as "OR" is to be interpreted to mean situs assigned to "Oregon" which means 100 percent of the total Company project cost is then allocated to Oregon customers. Similarly, a "UT" factor is to be interpreted as "Utah" and so on for all of the six jurisdictions PacifiCorp serves.

(b) The costs of the Juniper Ridge Bend Service Center are 100 percent assigned to Oregon customers.

(c) Please refer to the Company's response to subpart (b) above.

(d) The total Company project costs of $40.3 million are situs (i.e. 100 percent) assigned to Oregon. Accordingly, the Oregon-allocated cost for the project is $40.3 million.

UE 433 / PacifiCorp
June 19, 2024
OPUC Data Request 673

OPUC Data Request 673

Juniper Ridge Bend Service Center - What requirements must be met for a facility to be 100 percent allocated to a specific state?

Response to OPUC Data Request 673

Plant function classification follows Federal Energy Regulatory Commission (FERC) established rules. Following those rules, local service centers are classified as distribution-related general plant. Section 3.1.4 of the approved extension of the 2020 Multi-State Process (MSP) Inter-jurisdictional Cost Allocation Methodology (2020 Protocol) states that all distribution related expenses and investment that can be directly allocated will be directly allocated to the state where they are located. For more information on the 2020 Protocol, please refer to Public Utility Commission of Oregon docket UM 1050. Use of the 2020 Protocol was extended in order 23-229.

UE 433 / PacifiCorp
June 19, 2024
OPUC Data Request 674

OPUC Data Request 674

Juniper Ridge Bend Service Center - What allocation factor have typically been used for similarly situated facilities in the past? Have they been situs assigned?

Response to OPUC Data Request 674

Facilities like the Juniper Ridge Bend Service Center are assigned 100 percent to the state they are located in. Please refer to the Company's response to OPUC Data Request 673.

UE 433 / PacifiCorp
June 19, 2024
OPUC Data Request 677

OPUC Data Request 677

Juniper Ridge Bend Service Center - If the facility is used by employees from another state, does PacifiCorp somehow charge them?

(a) If yes, how does PacifiCorp propose those revenues be credited back to Oregon?

Response to OPUC Data Request 677

The Company assumes that "if the facility is used by employees from another state, does PacifiCorp somehow charge them" is intended to mean some type of surcharge for the use of the capital facility. Based on the foregoing assumption, the Company responds as follows:

No, there is no mechanism in place to track capital costs to create a surcharge for an employee using a facility in a different state.

UE 433 / PacifiCorp
May 21, 2024
OPUC Data Request 534

OPUC Data Request 534

Juniper Ridge Bend Service Center - How much did PacifiCorp extend the leases on the Webster and Clausen Offices?

(a) When are the leases expected to end for each of these offices?

(b) Is there potential for extending the leases on the other two buildings?

(c) When will Staff start migrating to the Juniper Ridge Service Center?

(d) When will Staff migration to the Juniper Ridge Service Center be completed?

Response to OPUC Data Request 534

(a) The leases are set to terminate as follows:
- Webster: August 4, 2024
- Clausen: December 30, 2024

(b) Building Webster: PacifiCorp and the landowner are negotiating an extension to April 4, 2025 to accommodate the move in as well as complete all turnover tasks.

Building Clausen: PacifiCorp and the landowner are negotiating a six-month or shorter lease extension to accommodate the move in as well as complete all turnover tasks.

(c) Company's staff moves are anticipated to start in December 2024.

(d) Company's staff moves into the new building are expected to be completed by the end of February 2025.

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 758

OPUC Data Request 758

Coal, Fuel Stock - Confirm whether the Company implemented the $672,000 reduction to revenue requirement and the subsequent, $1.6 million Oregon allocated adjustment to FERC 151 for the Test Year that was agreed to in DR 518 supplemental and also provided in the Company's supplemental response to DR 645 Attachment.

Response to OPUC Data Request 758

The Company assumes that the reference to "DR 518" is intended to be a reference to the Company's response to OPUC Data Request 518. The Company further assumes that the reference to "DR 645 Attachment" is intended to be a reference to the Company's 1st Supplemental response to OPUC Data Request 645 and Attachment OPUC 645 1st Supplemental. Based on the foregoing assumptions, the Company responds as follows:

Yes. The Company confirms that it has implemented the $672,000 reduction to revenue requirement in its reply filing as outlined in its response to OPUC Data
Request 518. Please refer to the reply testimony of Sherona L. Cheung, Exhibit PAC/3300, Cheung/67, lines 8-17, confirming that the Company has acknowledged and accepted the five corrections identified through the discovery process (specifically in OPUC Data Requests 200, 518, and 536) and as summarized in Staff witness Julie Dyck's opening testimony.

The Company is unsure what "the subsequent $1.6 million Oregon-allocated adjustment to FERC 151" is in reference to, as the corresponding impact to FERC account 151 on an Oregon-allocated basis, underlying the $672,000 reduction to revenue requirement as presented in Attachment OPUC 645 1st Supplemental is only $776,256. Regardless, the Company has reflected a reduction to revenue requirement totaling $672,000 in its reply filing for the corrections related to fuel stock identified in previous data requests identified above.

	Oregon Allocated (OR)				
	PAC/1702, Page 8.14	OPUC 200	OPUC 518	OPUC 536	Total
	As Filed	Correction	Correction	Correction	Impact
Adjustment to Fuel Stock (OR) - FERC 151	862,477	(862,477)	(862,477)	86,221	

Impact to OR Fuel Stock of Correction		(1,724,954)	-	948,698	(776,256)
Description of Corrections Identified:					
OPUC 200 – inverted balances and incorrect base year working capital deposit balance					
OPUC 518 – test year working capital deposit balance (no change to fuel stock balances)					
OPUC 536 – Naughton pro forma balance correction					

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 755

OPUC Data Request 755

Coal, Fuel Stock - How does the Company procure its coal for fuel stock?

(a) Explain how this is different than procuring coal that is needed in power cost filings and relies on CSAs.

(b) Do the same issues with procuring coal that were discussed in UE 434 apply to coal procurement for fuel stock? If not, explain why not? If so, explain any issues in procuring coal for fuel stock.

Response to OPUC Data Request 755

The Company procures coal through coal supply agreements (CSA) which are negotiated typically one of two ways; either through a request for proposals (RFP) process, or in the case of mine-mouth plants, directly with the only mine available from which to purchase.

(a) Fuel stock forecasts used for general rate case (GRC) filings are based on CSAs at the time of the filing. If the forecasted test year for a filing exceeds the current term of a CSA, assumptions are used in forecasts which are based on historical pricing and availability, budgeted business plans, market pricing and inflationary factors, and generation load requirements. The process for forecasting fuel stock in a GRC is the same as forecasting coal purchases in PacifiCorp's power cost filings, specifically the transition adjustment mechanism (TAM) filings.

(b) The Company assumes that the reference to "UE 434" is intended to be a reference to the direct testimony and reply testimony of Company witness, James C. Owen, in PacifiCorp's 2025 TAM proceeding, Docket UE-434. Based on the foregoing assumption, the Company responds as follows:

Yes. The challenges and risks discussed in the reply testimony of Company witness, James C. Owen, in PacifiCorp's 2025 GRC, Docket UE-433, specifically PAC/3000 Owen/3, greatly affected the Utah coal markets in 2022, 2023 and 2024. Similar issues in other markets which the Company procures coal fuel stock also occurred. These issues and challenges were discussed in detail in Mr. Owen's direct testimony and reply testimony in the 2025 TAM proceeding. Issues include but are not limited to: increased coal demand due to high domestic natural gas prices; low inventories at coal fired power plants; increased demand abroad for coal exports; international and domestic supply chain constraints; labor and material shortages; geological and weather events; and general market inflation.

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 759

OPUC Data Request 759

Coal, Fuel Stock - For the Naughton plant, in the Company's Reply Testimony (PAC/3000, Owen/5), the Company stated that they found an error that resulted in a rather large increase. Explain specifically what the error was and how it impacted both the dollar value and tonnage forecasted.

Response to OPUC Data Request 759

Due to the planned closure of the Naughton plant December 31, 2025, the fuel stock forecast should have reflected a zero balance in December 2025 to reflect the closure. However, in the direct testimony, this amount incorrectly incorporated a negative fuel stock balance. Because a 13-month average is used for fuel stock (December 2024 through December 2025), the negative inventory number incorrectly skewed the calculation. Once corrected, the Naughton plant 13-month average accurately aligned with historical forecasts as well as accounted for the closure of the plant. Please refer to the reply testimony of Company witness, James C. Owen, Exhibit PAC/3000, Owen/4, specifically Confidential Table 2 and the confidential work papers supporting Mr. Owen's reply testimony.

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 760

OPUC Data Request 760

Coal, Fuel Stock - For Naughton. Staff asks that the Company explain what will happen to this coal in storage when it can no longer be used, and how ratepayers will benefit from any sale of the coal.

Response to OPUC Data Request 760

Naughton fuel stock coal inventory will be used as needed throughout calendar year 2025 to meet generation and load requirements until it is depleted which is forecasted to coincide with the planned closure date of December 2025.

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 761

OPUC Data Request 761

Coal, Fuel Stock - For Naughton, Staff asks that the Company explain why an increase in coal fuel stock at Naughton for the Test Year is necessary given the cessation of coal at the plant in December 2025.

Response to OPUC Data Request 761

As discussed in the reply testimony of Company witness, James C. Owen, Exhibit PAC/3000, Owen/5, the initial filings included an error in coal fuel stock balances for Naughton. This error resulted in a correction that increased the average fuel stock calculation to accurately reflect coal costs prior to the closure of the plant in December 2025. This correction is not a result of increased fuel stock balances at the Naughton plant. Actual ending fuel stock balance for the Naughton plant for 2021 through 2023 averaged approximately $19.3 million (as provided in the Company's response to OPUC Data Request 201), whereas the 13-month average fuel stock balance for the Naughton plant in James Owen's reply testimony is calculated as approximately $6.27 million (as provided in Exhibit PAC/3000, Owen/4, Confidential Table 2).

CASE: UE 433
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2802

PacifiCorp’s Confidential Responses to Staff Data Requests (DRs)

August 16, 2024

OPUC Data Request 648

CONFIDENTIAL REQUEST - Fuel Stock – See the Company's response to DR 525 Conf Attach.

[CONFIDENTIAL BEGINS]

[redacted]

[CONFIDENTIAL ENDS]

Confidential Response to OPUC Data Request 648

The Company assumes that the reference to "DR 525 Conf Attach" is intended to be a reference to the Company's response to OPUC Data Request 525 and Confidential Attachment OPUC 525. The Company assumes that the reference to "confidential attachment to DR 199" is intended to be a reference to the
Company's response to OPUC Data Request 199 and Confidential Attachment OPUC 199. The Company also assumes that the reference to "the Attachment to
DR 201" is intended to be a reference to the Company's response to OPUC Data Request 201 and Confidential Attachment OPUC 201. The Company further assumes that the references to "PAC" are intended to be references to PacifiCorp. Based on the foregoing assumptions, the Company responds as follows:

(a) **[CONFIDENTIAL BEGINS]** [redacted]

[redacted] **[CONFIDENTIAL ENDS]**.

(b) In the Company's response to OPUC Data Request 525, specifically Confidential Attachment OPUC 525, cell AG16 represents daily burn in tons for the PacifiCorp share of the Jim Bridger plant, which is also provided in the
Company's response to OPUC Data Request 199, specifically Confidential Attachment OPUC 199, page 11. The daily burn in tons represents the amount of coal in tons capable of burning at the Jim Bridger plant daily. The "Days Burn" metrics provided in columns AA through AF represent the number of days of coal inventory available to burn under normal operations. This is calculated by taking coal inventory levels in tons divided by the daily burn amount in tons. This equates to the number of days the plant could operate normally without additional deliveries at that specific point in time.

(c) Please refer to the Company's response to subpart (a) above.

(d) The Jim Bridger plant storage capacity in tons provided in the Company's response to OPUC Data Request 199, specifically Confidential Attachment OPUC 199, page 11, is **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** combined for PacifiCorp's share. Additionally, PacifiCorp and Idaho Power Company (IPC) each separately own a portion of the coal inventory which can be different than the 66.67 percent and 33.33 percent ownership share of the plant.

(e) Ending coal fuel stock inventory amounts for Jim Bridger plant provided in the Company's response to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, are the PacifiCorp share.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 647

CONFIDENTIAL REQUEST - Fuel Stock – See the Company's response to DR 199 Attach Conf.

[CONFIDENTIAL BEGINS]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[CONFIDENTIAL ENDS]

Confidential Response to OPUC Data Request 647

The Company assumes that the reference to "DR 199 Attach Conf" is intended to be a reference to the Company's response to OPUC Data Request 199 and Confidential Attachment OPUC 199. The Company also assumes that the reference to "DR 201 Attach" is intended to be a reference to the Company's response to OPUC Data Request 201 and Confidential Attachment OPUC 201. The Company further assumes that the reference to "PAC" is intended to be a reference to PacifiCorp. Based on the foregoing assumptions, the Company responds as follows:

(a) Subpart (a) to this request is a statement. There is no question or request to address.

(b) Dead storage is an industry term used to describe long-term coal storage piles located outdoors and is separate from active piles or coal storage bunkers.

(c) PacifiCorp and Idaho Power Company (IPC) collectively own the Jim Bridger plant and Bridger Coal Company (BCC). PacifiCorp's ownership share of the plant and mine is 66.67 percent and IPC's share is 33.33 percent. "Bridger – Total" represents the target coal inventory amounts for all owners of the generating station, and "Bridger – PAC" represents target coal inventory amounts for PacifiCorp only. Forecasts included in the general rate case (GRC) only include "Bridger – PAC" or PacifiCorp's share of fuel stock inventory. PacifiCorp is the operator of the plant and responsible for the coal stockpile at the Jim Bridger generating station, which is why both are called out in the Company's inventory policy. PacifiCorp and IPC each separately own a portion of the coal inventory which can be different than the 66.67 percent and 33.33 percent ownership share of the plant.

(d) Coal fuel stock inventory forecasted in the 2025 GRC only reflects PacifiCorp's share. The table provided in the Company's response to OPUC Data Request 199 specifically Confidential Attachment OPUC 199, page 11, shows target levels, effective January 1, 2024, after the conversion of Jim Bridger Unit 1 and Jim Bridger Unit 2 to natural gas, as **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**. The Company's response to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, forecasts Jim Bridger plant (PacifiCorp share) to have an ending inventory of **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** for the period ending December 2025. Annual burn, as indicated in the Company's response to OPUC Data Request 199, specifically Confidential Attachment OPUC 199 page 11, reflects the amount that Jim Bridger can consume in a year while plant ending inventory only reflects coal fuel stock available at a given point in time.

(e) Please refer to the Company's response to subpart (c) above.

(f) No. Wyodak is not the same as Cholla. Ending fuel stock inventory for Cholla was included in the Company's response to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, for years 2015 through 2020. PacifiCorp ceased operating Cholla Unit 4 as of December 24, 2020. Wyodak's policy was also included in the Company's response to OPUC Data Request 199, specifically Confidential Attachment OPUC 199, page 14. There is no fuel stock inventory stored at Wyodak, coal is delivered via overland conveyor from the Wyodak mine as needed. Wyodak was not included in the Company's to OPUC Data Request 201, specifically Confidential Attachment OPUC 201, as the balance is zero.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 433 / PacifiCorp
June 14, 2024
OPUC Data Request 649

OPUC Data Request 649

CONFIDENTIAL REQUEST - Fuel Stock – See the Company's response to DR 536. **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

Response to OPUC Data Request 649

The Company assumes that the reference to "DR 536" is intended to be a reference to the Company's response to OPUC Data Request 536. Based on the foregoing assumption, the Company responds as follows:

[redacted]

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 757

OPUC Data Request 757

Coal, Fuel Stock - See UE 434, PAC/3000, Owen/5 which states, "At the time of the initial filing of this proceeding, PacifiCorp based its fuel stock balance on the 2024 budget, which did not include the updated price and coal volumes from the Hunter/Wolverine CSA second amendment in its analysis".

(a) How many amendments does the Hunter CSA have?

(b) Provide all dates that the amendments were implemented or agreed to.

(c) Please provide copies of all amendments to Hunter.

Confidential Response to OPUC Data Request 757

The Company assumes that the reference to "UE 434, PAC/3000, Owen/5" is intended to be a reference to the reply testimony of Company witness, James C. Owen, specifically Exhibit PAC/3000, Owen/5 in this general rate case (GRC) proceeding, Docket UE-433. Based on the foregoing assumption, the Company responds as follows:

(a) The Company assumes that the reference to "Hunter CSA" is intended to be a reference to the Hunter Plant Wolverine coal supply agreement (CSA). Based on the foregoing assumption, the Company responds as follows:

[CONFIDENTIAL BEGINS] [redacted] **[CONFIDENTIAL ENDS]**.

(b) **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

(c) The Company assumes that the reference to "amendments to Hunter" is intended to be a reference to the amendments to the Hunter Plant Wolverine CSA. Based on the foregoing assumption, the Company responds as follows:

PacifiCorp considers these Coal Supply Agreements to be highly confidential and requests special handling for these agreements. A modified protective order would be necessary to provide the coal supply agreements.

UE 433 / PacifiCorp
August 14, 2024
OPUC Data Request 757

Confidential information is designated as Protected Information under the general protective order, Order No. 23-132, applicable in this proceeding and may only be disclosed to qualified persons as defined in that order.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

PacifiCorp's Response to DR 754 below from UE 434 Opening Testimony.

[redacted] The impact of reduced available coal supplies and higher coal pricing discussed above informed both coal volumes and pricing assumptions in the 2025 TAM.

Q. Can PacifiCorp use coal supplier force majeure claims to renegotiate contract terms?

A. [redacted]

The Company focuses on achieving its target coal supply at a reasonable price, along with contract terms that provide flexibility. However, in Utah□s current supplyconstrained market, the Company has limited leverage to accomplish these goals. [redacted]

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[1] In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism, Exhibit PAC/500, Owen/15 (April 3, 2023).

[redacted]

Q. How are PacifiCorp□s coal facilities impacted by the coal supply constraints in Utah, and how has that been reflected in coal volumes for the 2025 TAM?

A. Since 2022, both Hunter and Huntington plants have not received their contracted coal volumes due to the various reasons discussed in my testimony. These coal supply shortages along with market instability are expected to remain in 2024 and 2025. Specifically in 2024 and 2025, the Company forecasted the Hunter/Bronco CSA [redacted].[2] Confidential Table 1 provides a breakdown of the Hunter/Bronco CSA contractual tons versus the actual/forecast delivered tons, from 2023 to 2025:[3]

Confidential Table 1: Contractual Tons vs. Actual/Forecast Delivered Tons

[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

Additionally, the Company forecasted coal delivered at the Huntington plant under the Huntington/Wolverine CSA for 2024 [redacted] Confidential Table 2 provides a comparison of the Huntington/Wolverine CSA and the Hunter/Wolverine CSA contractual tons versus the actual/forecast delivered tons, from 2023 to 2025:

Confidential Table 2: Contractual Tons vs. Actual/Forecast Delivered Tons

[2] In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism, Exhibit PAC/500, Owen/9, 12, and 19 (July 24, 2023).

[3] The 2025 TAM Direct values in the tables throughout testimony are rounded for display purposes, but the underlying calculations for variances and totals are not based on the rounded display values.

[redacted]

Due to these shortfalls, PacifiCorp has adjusted its forecasts for coal received and consumed at Hunter and Huntington plants in the 2025 TAM. Accordingly, the forecast volumes of consumed coal in 2025 do not match the contracted volumes for coal in the CSAs for the calendar year 2025. Furthermore, to ensure targeted coal inventory balances are available for reliability purposes, received and consumed coal quantities at the Utah plants are balanced in the 2025 TAM and stockpiled inventory remains mostly flat.

Q. How has the increase in market coal prices impacted the 2025 TAM estimated fuel costs?

A. Similar to the 2024 TAM, the total coal fuel expense is estimated to decrease in the 2025 TAM, but coal prices on a per-ton basis increase at some plants. Historically, the Company□s prudent coal contracting practices have largely shielded the Company and its customers from significant, short-term coal price increases. Currently, due to the increased demand for coal in both foreign and domestic markets, coal suppliers have increased opportunities for coal sales. Additionally, the mining, economic and geologic issues have caused multiple force majeure claims from PacifiCorp coal

CASE: UE 433
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2900

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Bret Farrell. I am a Senior Utility and Energy Analyst employed in the Energy Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is provided in Exhibit Staff/900 and my Witness Qualification Statement was provided in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. I am responding to the PacifiCorp's (PacifiCorp, PAC or Company) Reply Testimony regarding uncollectible expense and customer payment fees.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff Exhibit 2901 – Uncollectible Workpaper
- Staff Exhibit 2902 – PacifiCorp Response to OPUC Data Request 691
- Staff Exhibit 2903 – PacifiCorp Response to OPUC Data Request 692
- Staff Exhibit 2904 – PacifiCorp Response to OPUC Data Request 696

B. **How is your testimony organized?**

A. My testimony is organized as follows:

ISSUE 1. UNCOLLECTIBLE EXPENSE

Q. Please summarize the Company's initial proposal for uncollectible expense.

A. In opening testimony, PacifiCorp proposes a methodology in which the Company calculates the uncollectible rate for the 12 months ending June 2023 and then applies this uncollectible rate to the Test Year general business revenues. This results in a forecasted Test Year uncollectible rate of 0.626 percent, and a total forecasted Test Year uncollectible expense of $10.5 million.

Q. Please describe Staff's analysis and recommendations in Opening Testimony.

A. Staff reviewed the Company's methodology and found that it is not sufficiently robust to justify deviating from the historic precedent of a three-year average. Staff argued that using only one year of data to estimate the Test Year uncollectible rate was overly simplistic and fails to consider broader patterns of trends in the uncollectible rate within the Company's Oregon service territory.

Q. How did the Company respond to Staff's proposed treatment of Uncollectible Expense?

A. In Reply Testimony, the Company disagreed with Staff's overall approach of a three-year average methodology and attempted to refute Staff's objections with the Company's proposed methodology.

Q. Please describe the Company's objections to Staff's three-year average methodology.

A. The Company claims:

1. The three-year average is not a Commission precedent and each instance where it has been adopted by the Commission has been the result of a stipulation between parties.
2. The 2020-2022 uncollectible rate range proposed by Staff is an unreasonable basis for establishing a Test Year uncollectible rate.
3. Staff incorrectly used net-write offs when calculating the Test Year uncollectible rate.

Q. How does Staff respond to the Company's claim that the three-year average methodology is not a Commission precedent?

A. The Company claims that the use of a three-year average is not a Commission precedent, which is true in the sense that that the Commission has not adopted a policy prescribing this methodology for calculating the uncollectible rate when utilities file a GRC. However, the use of either a three-year average methodology or some other form of a rolling-average methodology has been common practice for setting test year uncollectible rate across multiple utilities' GRCs over the past several years.[1] Staff believes that given the consistent use of this approach in previous dockets and the historic agreement on this

[1] See, e.g., In the Matter of Avista Corporation, UG 246, Order No. 14-015 at 3 (January 21, 2014) and In the Matter of Avista Corporation, Docket No. UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); but see In the Matter of Idaho Power Company, UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average) and In the Matter of Cascade Natural Gas Corporation, UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

approach among parties, that a deviation from this approach must be sufficiently justified. Staff believes that the Company fails to justify their methodology.

Q. Does the Company provide any evidence to support their proposed methodology?

A. No. The Company claims that "For well over a decade, PacifiCorp has relied on Base Period actuals, rather than an averaging methodology"[2] but PacifiCorp fails to provide any evidence as to why this approach is justified or superior to a three-year average methodology.

Q. Why does Staff believe that a three-year average approach is superior?

A. A rolling-average methodology, such as a three-year average approach is meant to track the overall trend of the uncollectible rate while smoothing out year-over-year variances. By taking a rolling-average, underlying changes to the uncollectible rate are gradually incorporated into the Test Year forecast. This ensures that key variables influencing the uncollectible rate are being factored into the Test Year forecast and that the effect of anomalous events are limited. The rolling-average also requires no complex modeling, no tenuous assumptions, and is practically simple and straightforward.

Furthermore, rolling averages can be particularly useful in identifying turning points or inflection periods. A rolling-average tends to respond more gradually than relying on a single past year, providing a more reliable signal of a potential shift in the forecasted value that is less prone to anomalous shocks.

2 See PAC/3300 Cheung/17.

Staff therefore believes that the three-year average methodology better accounts for fundamental changes and will more reasonably reflect forward-looking conditions than would the Company's proposed Base Year actuals approach.

Q. How does Staff respond to the Company's claim that the 2020-2022 period is an unreliable predictor of the Test Year uncollectible rate because of the impact of the COVID-19 pandemic?

A. Staff believes that the purpose of the three-year average methodology is to smooth out year-over-year variances and anomalous events such as the COVID-19 pandemic. The uncollectible rates observed by the Company during the period from 2020-2022 were not extreme outliers in comparison to historic uncollectible rates (See Figure 1); therefore, Staff believes that the period remains an adequate predictor of the Test Year uncollectible rate.

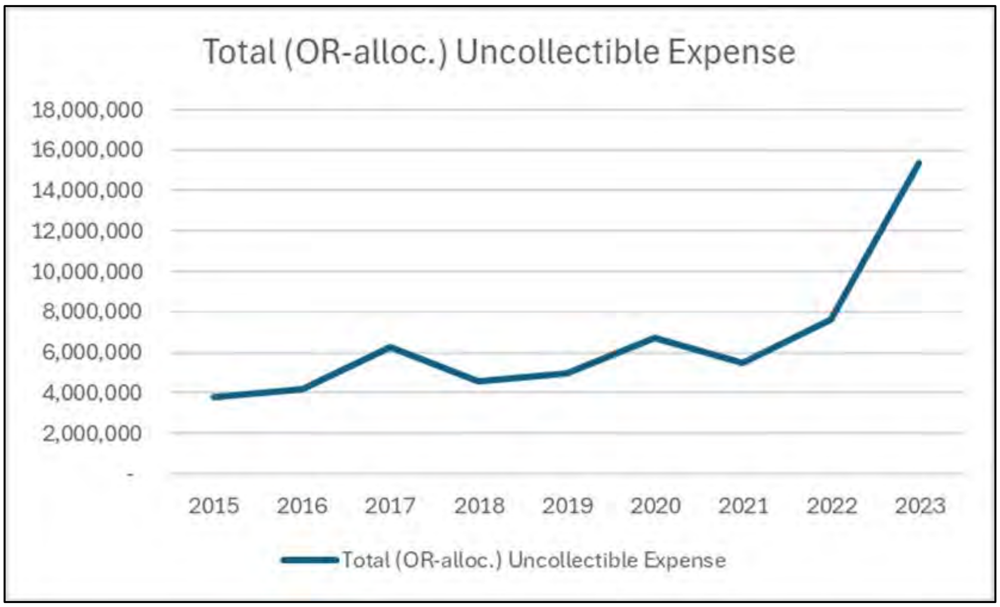
Figure 1[3]

[3] Staff Exhibit 2901 – Uncollectible Workpaper.

Q. Does Staff believe that the Company's proposed base period is a reliable predictor of the Test Year uncollectible rate?

A. No. PacifiCorp's total uncollectible expense dramatically increased in 2023 (See Figure 2) well above historical levels and therefore Staff believes using this period would be unreliable in predicting the Test Year uncollectible rate.

Figure 2[4]



Q. How does Staff respond to the Company's claim that Staff incorrectly used net-write offs when calculating the Test Year uncollectible rate.

A. Staff acknowledges that the initial calculation in opening testimony was made using net write-offs as opposed to total uncollectible expense and therefore adjusts the proposed Test Year uncollectible rate to reflect the updated three-year average (See Figure 3).

4 Staff Exhibit 2901 – Uncollectible Workpaper.

Figure 3[5]

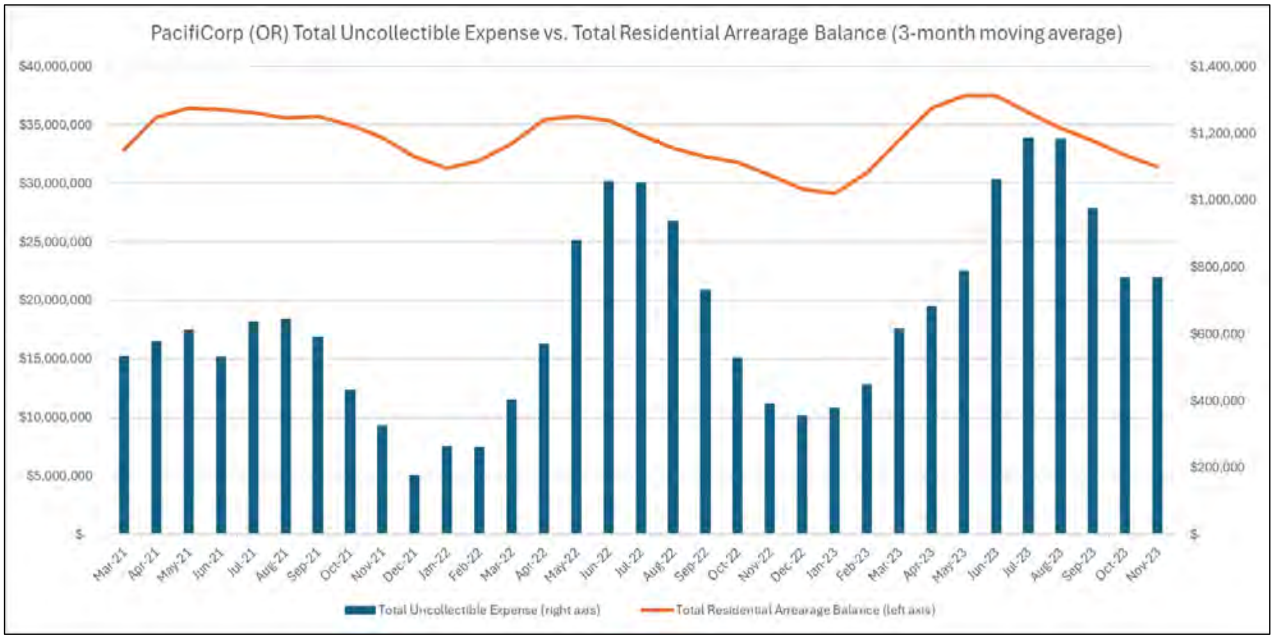
	2020	2021	2022	Staff Proposal (three-year average)
Staff Initial Proposal (net write-offs)	0.189%	0.284%	0.551%	0.342%
Staff Revised Proposal (Uncollectible Rate)	0.514%	0.440%	0.626%	0.527%

Q. Does Staff believe there is a relationship between customer arrearage balances and total uncollectible expense?

A. Yes. Staff believes that higher arrearage balances among residential customers often leads to higher uncollectible expense, as these unpaid amounts have a greater chance of becoming bad debt, especially as balances become higher and go unpaid longer (See Figure 4).

[5] See PAC/3300 Cheung/19

Figure 4[6]

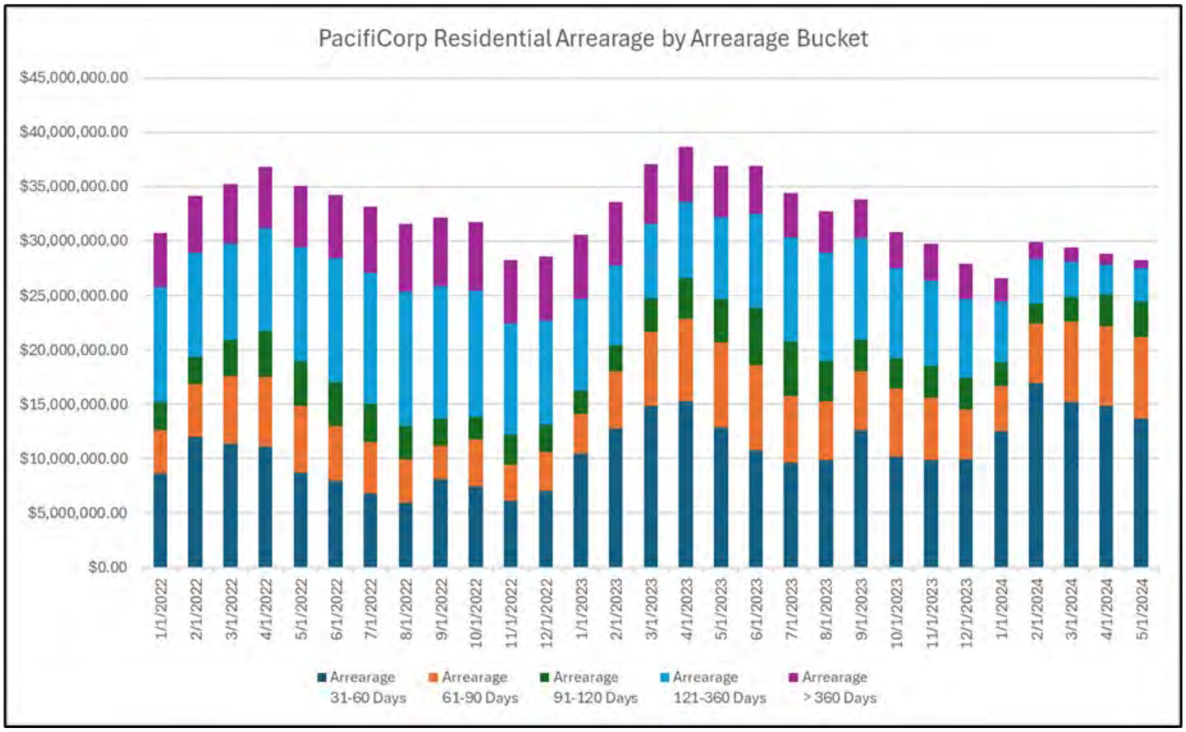


Q. Summarize the overall state of the Company's residential arrearages.

A. Since the end of the COVID-19 disconnection moratorium, the Company's residential customer arrearage balances have been elevated above average historical levels. As of May 2024, the Company has over 1,000 customers who have an arrearage balance greater than a year old, and nearly 25,000 customers who have an arrearage balance between 91-120 days past due (See Figure 5).

6 Staff Exhibit 2901 – Uncollectible Workpaper.

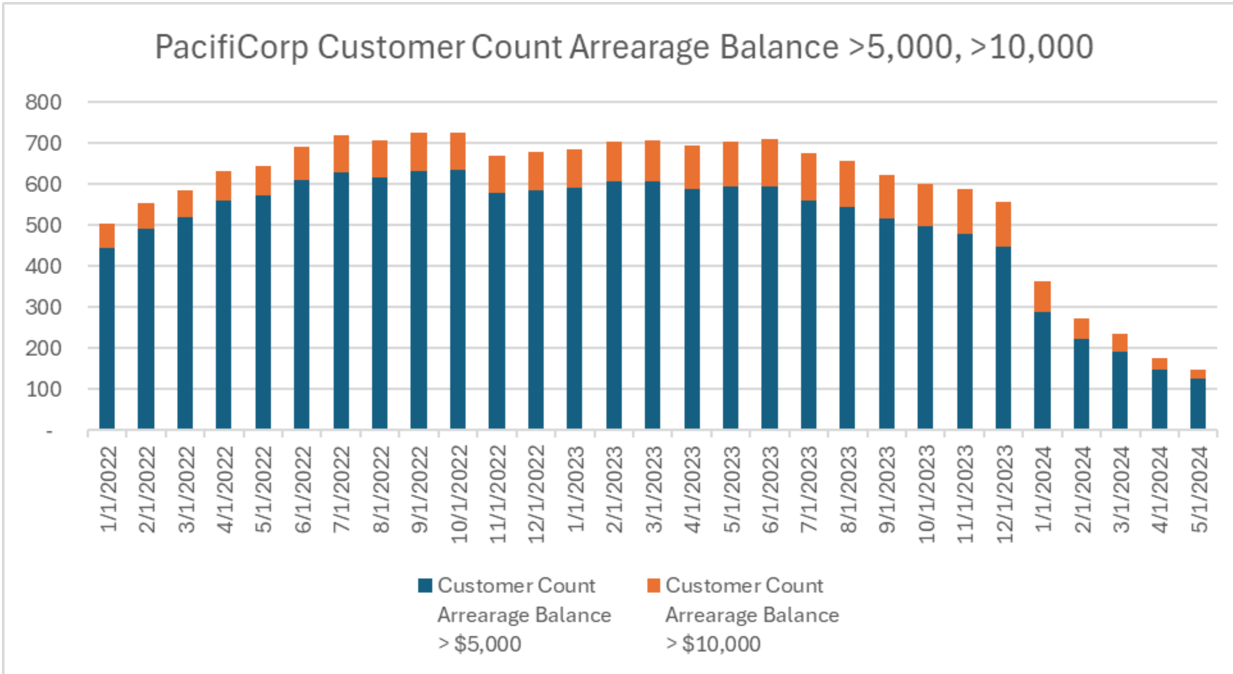
Figure 5[7]



Between January 2022 and May 2024, at its peak the Company had 609 customers with an arrearage balance greater than $5,000 and 116 customers with a balance greater than $10,000 (See Figure 6). Staff asked the Company to explain the significant decrease in the number customers with $5,000 and $10,000 arrearage balances from December 2023 to January 2024 as shown in Figure 6. The Company stated that this decrease was "the result of additional collection efforts."[8] These additional collection efforts by the Company led to a 225 percent increase in the number of residential customers disconnected for non-payment from December 2023 to January 2024.[9]

[7] Staff Exhibit 2902 – PacifiCorp response to OPUC Data Request 691.
[8] Staff Exhibit 2902 – PacifiCorp response to OPUC Data Request 691.
[9] Docket No. RO 12 – Quarterly Disconnection Report.

Figure 6[10]



Staff asked the Company to provide the ten largest residential arrearage balances as of May 2024 (See Figure 7). The data provided by the Company showed that there are multiple residential customers with balances greater than $20,000.

Figure 7[11]

	Pre-Covid Balance	Balance at resumption of disconnects following COVID moratorium	Highest Balance	Current Balance
Customer 1	$ 1,019	$ 8,803	$ 30,132	$ 30,132
Customer 2	$ 2,070	$ 13,573	$ 21,955	$ 21,955
Customer 3	$ 1,753	$ 11,047	$ 20,387	$ 20,387
Customer 4	$ 3,035	$ 11,244	$ 18,554	$ 17,595
Customer 5	$ 659	$ 5,541	$ 17,814	$ 17,814
Customer 6	$ 2,684	$ 33,446	$ 37,035	$ 24,567
Customer 7	$ 4,463	$ 22,514	$ 23,642	$ 18,232
Customer 8	$ 3,476	$ 19,512	$ 36,338	$ 11,020
Customer 9	$ 650	$ 4,116	$ 13,797	$ 13,797
Customer 10	$ 1,192	$ 8,783	$ 15,862	$ 15,227

10 Staff Exhibit 2902 – PacifiCorp response to OPUC Data Request 691.
11 Staff Exhibit 2903 – PacifiCorp response to OPUC Data Request 692.

Q. Does the Company have specific processes in place to limit the total amount that a customer can become past due?

A. No. In response to a Staff DR regarding this question the Company stated "the Company does not have a specific process to limit the total amount a customer can become past due. The Company has in place ways to help the customer limit their past due balances."[12]

Q. Does Staff believe the Company should be granted a higher uncollectible rate for having large residential customer arrearage balances?

A. No. Staff believes that the Company should take more proactive measures in order to limit the amount that customers can become past due and as a result limit the total uncollectible expense. Staff is concerned that the Company has little incentive to manage customer arrearage balances if it can expect to easily recover arrearage expenses through the uncollectible rate when the balances ultimately become bad debt. PacifiCorp's approach seems to address the symptom, not the cause. The Company focuses too much on cost recovery through the uncollectible rate and not enough on avoiding costs that provide no benefit to ratepayers. Staff recommends that the Company use a reasonable and justified uncollectible rate and then work with Staff and stakeholders to ensure that arrears are lowered in a way that benefits ratepayers, shareholders, and the individual customer.

Q. What is Staff's proposed adjustment for the uncollectible rate and uncollectible expense for the 2025 Test Year?

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12 Staff Exhibit 2904 – PacifiCorp response to OPUC Data Request 696.

A. Staff, again, proposes using the three-year average methodology of the uncollectible rate between 2020-2022. The Company provided this average in their Reply Testimony, an average of 0.527 percent.[13] Staff proposes applying this rate to the final agreed upon general revenues to calculate the appropriate level of uncollectible expense to be included in the 2025 Test Year. At this time, based on the Company's proposed general revenue, Staff proposes a decrease to the Company's Test Year uncollectible expense of $1.7 million.

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[13] See PAC/3300, Cheung/19.

ISSUE 2. CUSTOMER PAYMENT FEES

Q. Please summarize the Company's initial proposal for customer payment fees.

A. In opening testimony, PacifiCorp proposed to eliminate fees charged to customers who make a payment at a pay station or pay their bills online with a credit or debit card.

Q. Please describe Staff's analysis and recommendations in Opening Testimony.

A. Staff reviewed the Company's reasoning for eliminating customer payment fees along with historic annual costs from customer payment fees. Staff stated that it was willing to support removing residential card payment fees and pay station fees provided the Company give evidence to support its position in Reply Testimony. Staff also stated that:

- The Company's historic base period (2023) was a significant outlier and should not be used as the sole means of estimating the Test Year expense for eliminating customer payment fees. Staff instead proposed using a three-year average of the fee count for pay stations and residential card payments for the years 2020 through 2022 and multiplying this average by the current fees in place for the Company.
- Staff believes that non-residential customer payment fees should not be eliminated and therefore the costs associated with non-residential card payment fees should be removed from the forecast.

- Staff proposed a $3.5 million adjustment to Test Year revenue requirement.

Q. Please describe the Company's proposal in Reply Testimony.

A. In Reply Testimony, the Company agreed to using Staff's three-year average methodology and acknowledged that their 2023 base period used in opening testimony to calculate the Test Year expense was inaccurate. The Company included updated and corrected figures for the 2023 base period in their Reply Testimony. PacifiCorp also provided further evidence to support the removal of residential customer payment fees but argued that non-residential card payment fees should be removed as well. The Company proposed a $3.4 million Test Year revenue requirement adjustment which included the removal of non-residential card payment fees.

Q. Does Staff agree with the Company's proposal in Reply Testimony?

A. Not entirely. The Company's argument for eliminating payment fees as stated in testimony is that "Eliminating these fees will remove a hardship that vulnerable customers face and make it easier for them to pay their electricity bills using a method that is feasible for them in their situation."[14] Staff disagrees that eliminating non-residential payment fees benefits vulnerable customers and aligns with the Company's stated reasoning for eliminating payment fees. Staff is willing to support the Company's proposal to eliminate residential pay station and card payment fees but remains opposed to the elimination of

[14] See PAC/1900, Meredith/37.

non-residential card payment fees as the Company has failed to adequately justify the need to do so.

Q. What is Staff's proposed adjustment for the Test Year expense related to the elimination of customer payment fees?

A. Staff again, proposes a Test Year expense related to the elimination of pay station and residential card payment fees of $1,257,738. This proposal results in a $3,550,817 adjustment to the Company's Test Year revenue requirement.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2901

Staff Uncollectible Workpaper

August 16, 2024

Staff Uncollectible Workpaper is provided in Electronic Format

CASE: UE 433
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2902

PacifiCorp Response to OPUC Data Request 691

August 16, 2024

PacifiCorp Response to OPUC Data Request 691 is provided in Electronic Format

CASE: UE 433
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2903

PacifiCorp Response to OPUC Data Request 692

August 16, 2024

Highest Residential Arrearages

Customer 1

Open Date: April 5, 2022

Pre COVID-19 Balance: $1,019.48

Balance at resumption of disconnects following COVID moratorium - $8,803.76

High Balance $30,132.44 June 2024

Balance: $30,132.44

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022.
3. Credit disconnection completed on:
    a. January 2, 2024
        i. Payment made by customer to reconnect service; payment returned for insufficient funds.
    b. February 28, 2024
        i. Payment made by customer to reconnect service; payment returned for insufficient funds.
    c. April 1, 2024
        i. Payment made by customer to reconnect service; payment returned for insufficient funds.
    d. June 26, 2024

Customer made multiple payments to reconnect service and/or guarantee electric service that were returned.

Once a customer has three or more returned payments in a 12-month period the customer is not allowed to make check payments via online/phone however customers are still able to mail in payments and make payments at a pay station to circumvent the process.

Customer 2

Open Date: January 12, 2015

Pre COVID-19 Balance: $2,070.16

Balance at resumption of disconnects following COVID moratorium - $13,573.28

High Balance: $21,955.81 May 2024

Balance: $21,955.81

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Collection noticing (past due notice, final notice, outbound calls)
3. Customer given late payment exemption through February 19, 2026
4. Customer claimed medical, halting collections for 30 days.
5. Credit disconnection completed on:
    a. October 21, 2021
    b. March 29, 2023
        i. Payment made by customer to reconnect service; payment returned for no account/unable to locate account.
    c. April 27, 2023
        i. Payment made by customer to reconnect service; payment returned for no account/unable to locate account.
    d. June 26, 2023
        i. Payment made by customer to reconnect service; payment returned for no account/unable to locate account.
    e. January 30, 2024
        i. Customer removed co-customers name resulting in creation of new account.
    f. April 25, 2024
        i. Payment made by customer to reconnect service; payment returned for insufficient funds.

Customer made multiple payments to reconnect service and/or guarantee electric service that were returned.

Once a customer has three or more returned payments in a 12-month period the customer is not allowed to make check payments via online/phone however customers are still able to mail in payments and make payments at a paystation to circumvent the process.

Customer 3

Open Date: April 13, 1964

Pre COVID-19 Balance: $1,753.36

Balance at resumption of disconnects following COVID moratorium - $11,047.55

High Balance: $20,387.98 June 2024

Balance: $20,387.98

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Multiple payment arrangements to assist customer with bringing balance current. Current arrangement set for 24 months to reduce monthly required amount.
3. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
4. Customer claimed long term medical October 2023. Monthly attempts to make personal contact with the customer to discuss medical and arrangements on account.
5. Shortened window for disconnect combined with medical profile has hampered effort to disconnect for non-payment.

Customer 4

Open Date: June 25, 2013

Pre COVID-19 Balance: $3,035.37

Balance at resumption of disconnects following COVID moratorium - $11,244.74

High Balance: $18,554.83 April 2024

Balance: $17,595.512

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Multiple payment arrangements to assist customer with bringing balance current. Current arrangement is set for 48 months to reduce monthly required amount.
3. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
4. Customer given late payment exemption through November 15, 2025.
5. Customer claimed verbal medical, halting collections for 30 days.
6. Credit disconnection completed on:
    a. July 1, 2024
        i. Customer has been quoted for reconnection

Customer 5

Open Date: July 3, 2019

Pre COVID-19 Balance: $659.34

Balance at resumption of disconnects following COVID moratorium - $5,541.17

High Balance: $17,814.62 June 2024

Balance: $17, 814.62

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Payment arrangements to assist customer with bringing balance current.
3. Customer claimed long term medical. Monthly attempts to make personal contact with the customer to discuss medical and arrangements on account. Medical certificate expired in January 2023 and has been removed.

Customer 6

Open Date: August 11, 2016

Close Date: N/A

Pre COVID-19 Balance: $2,684.52

Balance at resumption of disconnects following COVID moratorium - $33,446.89

High Balance: $37,035.74 September 2023

Current Balance: $24,567.88

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Multiple payment arrangements to assist customer with bringing balance current. Current arrangement is set for 24 months to reduce monthly required amount.
3. Customer given late payment exemption through January 5, 2025. Removed $605.06 in late fees billed to the account.
4. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
5. Customer has a non-standard meter which requires disconnection to occur manually.

Customer 7

Open Date: July 18, 2017

Pre COVID-19 Balance: $4,463.04

Balance at resumption of disconnects following COVID moratorium - $22,514.32

High Balance: $23,642.64 November 2021

Current Balance: $18,232.38

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Multiple payment arrangements to assist customer with bringing balance current.
3. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
4. Customer given late payment exemption through May 22, 2026.
5. Customer claimed verbal medical, halting collections for 30 days.

Customer 8

Open Date: February 19, 1999

Pre-COVID: Balance $3,476.89

Balance at resumption of disconnects following COVID moratorium - $19,512.69

High Balance: $36,338.63 January 2024

Current Balance: $11,020.69

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Multiple payment arrangements to assist customer with bringing balance current.
3. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
4. Credit disconnection completed on:
    a. June 6, 2024

Customer paid in January 2024 to guarantee service; payment was for no account/unable to locate. Customer also paid in June 2024 to guarantee service and payment was returned for insufficient funds.

Customer 9

Open Date: January 20, 1989

Pre-COVID: Balance $650.94

Balance at resumption of disconnects following COVID moratorium - $4116.16

High Balance: $13,797.10 May 2024

Current Balance: $13,797.10

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Multiple payment arrangements to assist customer with bringing balance current.
3. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
4. Customer given late payment exemption through January 24, 2026
5. Customer claimed verbal medical, halting collections for 30 days.
6. Customer has a non-standard meter which requires disconnection to occur manually.

Customer 10

Open Date: April 12, 2012

Pre-COVID: Balance $1,192.81

Balance at resumption of disconnects following COVID moratorium - $8783.97

High Balance: $15,862.17 June 2024

Current Balance: $15,227.63

Actions taken by Pacific Power

1. Monthly statement provided to customer.
2. Payment arrangement to assist customer with bringing balance current.
3. Collection noticing (past due notice, final notice, outbound calls) beginning October 2022 after Oregon rulemaking was completed.
4. October/November 2023 outbound calling response issue corrected, then holiday moratorium in both November and December 2023.
5. Customer claimed long term medical June 2023. Monthly attempts to make personal contact with the customer to discuss medical and arrangements on account.
6. Customer given late payment exemption through August 30, 2025

CASE: UE 433
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2904

PacifiCorp response to OPUC Data Request 696

August 16, 2024

UE 433 / PacifiCorp
July 9, 2024
OPUC Data Request 696

OPUC Data Request 696

Does the Company have a process in place to limit the total amount a customer can become past due? If yes, provide the process or procedure, including any internal documentation. If no, please explain the following:

(a) Why does the Company not attempt the limit the amount a customer can become past due?

(b) At what total dollar amount past due would the Company intervene?

Response to OPUC Data Request 696

No, the Company does not have a specific process to limit the total amount a customer can become past due. The Company has in place ways to help the customer limit their past due balances. Please refer to the Company's response to OPUC Data Request 695.

(a) Pacific Power attempts to keep arrears to a minimum by providing options to customers if they are unable to pay their total monthly bill which includes, payment arrangements, energy assistance organization information, and Low-Income Discount (LID) to assist with future billings. Customers will continue to receive electric service and therefore become past due until such time payment is received or pledged, payment arrangements are made, or the Company disconnects service through the collection process. Note: customers that use check payments to guarantee service and/or reconnect service that are returned unpaid by their financial institution will increase arrears for customers.

(b) The Company begins sending residential customers notices prior to disconnection when the past due balance is equal to or greater than $50.

CASE: UE 433
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3000

RebuttalTestimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Luz Mondragon. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/1100, and my Witness Qualifications Statement is provided in Exhibit No. Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp's Reply Testimony regarding:

- Utility Plant in Service and New Plant,
- Wildfire Mitigation Capital,
- Wildfire Mitigation Plan (WMP) Automatic Adjustment Clause (AAC) true up,
- Routine Vegetation Management (WMVM), and
- UM 2116: 2020 Wildfire Cost Amortization.

Q. Did you prepare any exhibits for this docket?

A. Yes. Exhibit No. Staff/3001. This supporting exhibit shows PacifiCorp responses to Staff Data Requests (DR).

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ELECTRIC PLANT IN SERVICE

Q. Please summarize Staff's initial proposal regarding Electric Plant in Service (EPIS).

A. In Opening Testimony, Staff questioned the prudency of purchasing 38 new vehicles at the same time as the Company fleet required and purchased 65 replacement vehicles. The Vehicle purchases sum up to 106 vehicles and $16.6 million in Rate Base.

Q. How did the Company respond to the Staff's concerns?

A. PacifiCorp states that the purchases were prudent to the Company's business needs based upon several years of lower vehicle replacements and lower internal operating workforce prior to this regulatory period. PacifiCorp held capital vehicle replacement costs at lower levels between 2015 and 2019 as attrition in headcount in the field classifications occurred as a result of lower work volumes due to lower new connect and replacements. Since that time, new connect volumes, asset resiliency projects, asset inspection and asset correction work have all increased, driving increased field headcount, especially in 2022 and 2023.[1]

Q. What process does the Company undertake to determine when to purchase vehicles?

A. PacifiCorp uses several metrics to evaluate their fleet. These metrics include mileage driven, engine hours, cost of preventive and corrective maintenance, age of vehicle, and safety of vehicle operation. Once a vehicle is determined

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1 PAC/2900 Berreth/8.

to require replacement, PacifiCorp uses the Request for Proposal process (RFP) to select the least cost vendor for purchases. [2]

Staff inquired regarding the use of Equipment/Vehicle replacement schedules in order to spread out the purchases and the costs to customers. The Company provided a replacement schedule in which they outline at what mileage and years certain types of equipment are to be replaced.[3] However, when used along with the vehicle listing provided, Staff was unable to determine if the vehicles or equipment being replaced followed the schedule.

Q. What does the Company do with the vehicles or equipment being replaced?

A. Any equipment or vehicles being replaced were either sold at auction or used to replace other equipment.[4] The Company has received $63,790 in gains from the sale of twelve vehicles and equipment with forty-one more vehicles still pending at auction. Per PacifiCorp, gains on sales of Vehicle are credited to accumulated depreciation, which serves as a reduction to rate base.[5]

Q. In regard to the Company's statement that the purchases were prudent based on lower vehicle replacement in the past and lower internal operating workforce, what was Staff's analysis?

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2 PAC/2900 Berreth/7-8.
3 Staff Exhibit 3001, PacifiCorp's response to DR 372.
4 Staff Exhibit 3001, PacifiCorp's response to DR 356.
5 Staff Exhibit 3001, PacifiCorp's response to DR 753.

A. Staff analyzed the Company's fleet count for the past ten years as well as field employee count. Staff found that the Company's statements are misleading. From 2013 to 2023 the company has increased the number of mobile equipment/vehicles each year. The increase in vehicle counts from 2013 to 2023 is actually 532, from 629 vehicles to 1,161 in 2023. When looking at it as a ratio, in 2013 there was one vehicle per six employees, in 2017 the ratio was one vehicle per four employees and in 2023 the ratio is one vehicle per three employees. Staff is unsure what the Company meant by "lower vehicle replacement" as in the past ten years, the number of vehicles being purchase have continued to increase over the previous year, except in 2016, 2018, and 2019.[6]

However, Staff does agree that the field employee counts have decreased since 2013. In 2013 there were 3,557 field employees, decreasing by 392 by 2023 for a total of 3,165. The following two graphs compare the increase in fleet to the decline in field employees, which appear to be going in opposite directions.[7]

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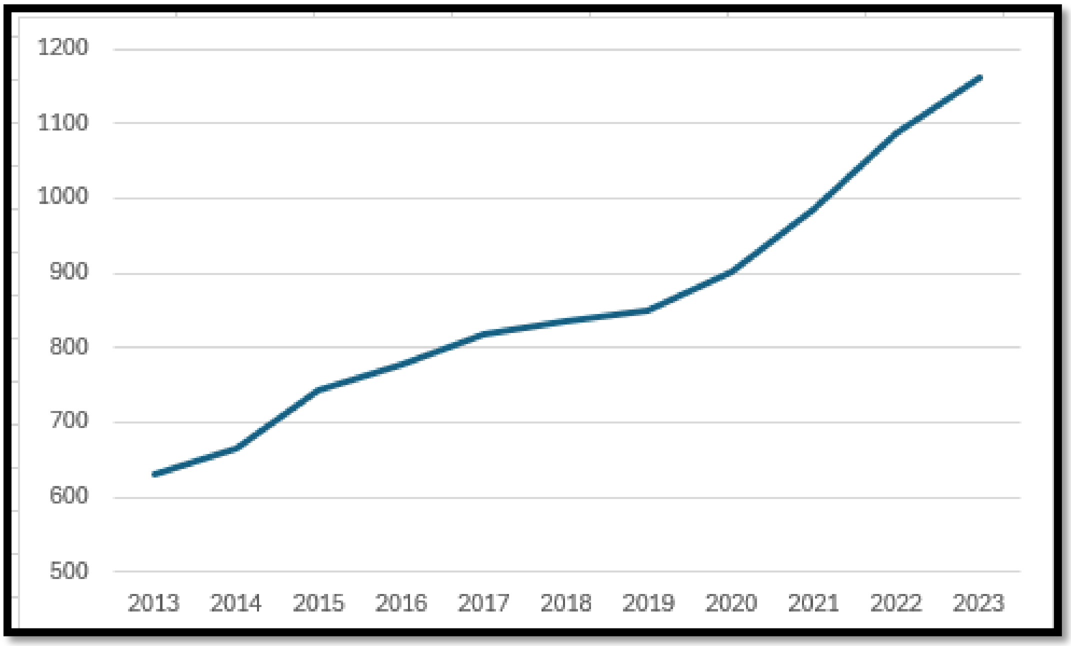
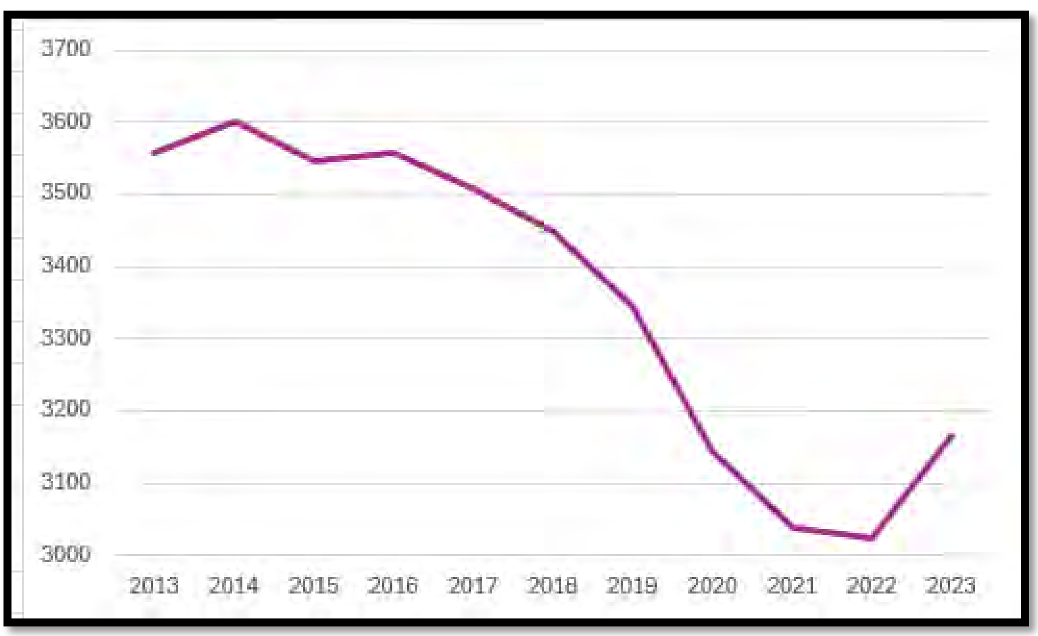
6 Staff Exhibit 3001, PacifiCorp's response to DR 751.
7 Id.

Mobile Equipment/Vehicle Counts



Field Employee Count



Q. Does Staff have an update to the original adjustment?

A. No. Staff finds that the Company's statement of prudency is unsupported by their data. Staff continues to advocate for a disallowance of $3.2 million for vehicles that are not replacing others.

ISSUE 2. WILDFIRE MITIGATION CAPITAL-TRANSMISSION CAPITAL

Q. Please summarize Staff's initial recommendation regarding Wildfire Mitigation (WM) capital.

A. Staff raised a concern that the Company's investments in Oregon were disproportionately low and recommended the Commission adopt an allocation across the states for WM Transmission costs at a percentage that represents the actual investments the Company has made in Oregon's and other state's High Fire Consequence Areas (HFCA). Staff recommended the Commission use this direct assignment until the Company remedies its underinvestment in Oregon and WM Transmission investments in Oregon are approximately equal to 27.43 percent when compared to total wildfire transmission capital investments.

Q. What is the Company's response to Staff's recommendation?

A. PacifiCorp's states that the Company's investment in wildfire mitigation transmission capital should not be proportional across the states, but rather as necessary in response to the wildfire risk in each area. The Company also testified that Staff's recommended allocation of transmission wildfire mitigation capital investments runs completely afoul of the Commission-approved allocation methodology, which specifies that transmission plant be allocated on the SG factor.

Q. What is Staff's response to the Company's reply on this issue?

A. Staff agrees that investments in Wildfire Mitigation Transmission capital should be made in the wildfire risk areas as necessitated by each state's risk zones.

However, Staff finds that the Company's investments in Oregon do not reflect that approach and questions the prudency of the Company's investment decisions.

Secondly, to clarify, Staff is not recommending allocating Wildfire Mitigation Transmission capital based on the SO factor. Staff is recommending an allocation factor that represents the actual transmission investments in each state's HFCA, *until* investments are more proportionate to the Company's HFCA in Oregon. This amount is relatively close to the SO factor.

In response to the Company's concerns about disrupting approved allocation factors, the Commission could address Staff's concerns over disproportionate underinvestment in Oregon HFCA by disallowing a portion of the WM transmission investments allocated to Oregon under the Commission-approved allocation methodology, also known as PacifiCorp's 2020 Protocol.

Q. What analysis was completed to arrive at Staff's recommendation?

A. Staff reviewed workpaper Adjustment 8.4 Pro Forma Capital Additions and Retirements and identified $55.5 million system-wide WM Transmission Plant costs. A System Generation (SG) allocation factor of 26.884 percent is used to allocate costs to Oregon, resulting in the $14.9 million the Company is seeking to include in Rate Base. Staff issued and analyzed DRs regarding the location of WM transmission investments.

Staff's review found that 80 percent of the allocatable investments, from 2017-2023, of Transmission plant in HFCA's have been made in Utah and only nine percent in Oregon.[8] Additionally, Staff found that 80 percent of the WM Transmission Plant in this GRC is in Utah.[9] However, the transmission mileage within a HFCA located in Utah is half of that which is in Oregon. Arguably the amount of capital investment PacifiCorp added should be one-third to two-thirds, not ten times the amount in Oregon. The level of Transmission investments does not match what the mitigation priority should be and speaks to prudency of choosing where to make plant investments. Staff would like to see PacifiCorp's Transmission investments in each State match in proportion the line miles that are in HFCA.

Figure 1: Utah HFCA Line Miles[10]

Asset	Total	Historical FHCA	
	Line Miles	Line Miles	% of OH Service Territory
Overhead Transmission	**7,139**	**220**	**1.2%**
46kV Transmission Lines	2,044	80	0.4%
69kV Transmission Lines	542	17	0.1%
138 kV Transmission Lines	2,082	98	0.5%
230 kV Transmission Lines	547	11	0.1%
345 kV Transmission Lines	1,923	14	0.1%
Overhead Distribution	**11,004**	**429**	**2.4%**
Total Overhead Transmission and Distribution	**18,143**	**649**	**3.6%**

8 Staff Exhibit 3001, PacifiCorp's response to DR 687.
9 Staff Exhibit 3001, PacifiCorp's response to DR 615.
10 Utah 2023-2025 WMP. Table 3. Page 21. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/2023_Utah_WMP_V4.pdf.

Figure 2: Oregon HFCA Line Miles

	Total Service Territory Line Miles	Line Miles	Existing FHCA % of Service Territory
OH Transmission Line Miles	3,059	413	2%
57kV Transmission Lines	14	0	0%
69kV Transmission Lines	914	96	1%
115 kV Transmission Lines	999	177	1%
230 kV Transmission Lines	610	90	1%
500kV Transmission Lines	522	50	0%
OH Distribution Line Miles	14,075	2,275	13%
Total	17,133	2,688	16%

Q. Why is Staff proposing the SO factor as a measurement instead of the SG factor typically used to allocate Transmission costs?

A. In Opening Testimony, Staff completed an analysis of PacifiCorp's allocation of wildfire costs, based on risk, specifically to be used in the Catastrophic Fire Fund.[11] In the analysis Staff observed that several of its more objective weightings resulted in allocation model similar to the 2020 System Overhead (SO) factor and would default to those weightings absent additional analysis.[12]

Staff understands that Transmission costs are typically allocated based on the SG factor, but because Staff's analysis of WM Transmission Capital resulted in a mismatch of Oregon's wildfire risk and Company investments, Staff is advocating for an allocation factor that is representative of the

11 Staff/2200 Brewer, Pileggi, and Stevens/32.
12 Staff/2200 Brewer, Pileggi, and Stevens.

Company's actual investments in Oregon High Fire Risk Zones. The SO factor would be used to gauge how close the Company is to meeting the State's fire risk.

Q. Please recap Staff analysis in Staff Exhibit 2200.

A. Staff attempted to consider additional external and objectively developed data to assess wildfire risk history. Staff's overarching philosophy in its analysis was to link allocations to the probability and potential magnitude of damages. To do this Staff estimated probability of a fire by using publicly available data from the National Weather Service for Red Flag warnings and watches and fire history data to understand the risk of ignition and publicly available property value data as a proxy for the magnitude of the liability a fire would create. An overview of the analysis can be found in Exhibit Staff/2203.

Staff consolidated data for red flag warning, red flag watch, fire boundary, population, and property value into three distinct areas. The three evaluated areas were state boundaries, PacifiCorp distribution service territory, and areas within 500 ft of a PacifiCorp owned or operated transmission line.

Staff accounted for year over year variations and trends by averaging the annual results from 2006-2023 for red flag warning, red flag watch, fire count, and acres burned. Staff also compared the results for using average from 2006-2023 using 500 feet transmission line corridor analysis, and the results were very similar to the chosen state averages based on service territory.

After analyzing the various external datasets, Staff developed a model to integrate the data results into PacifiCorp's proposed nine options. Staff used the states' distribution percentage averages for red flag, fire history, and census tract property value as additional factors to weigh in on Staff's allocation analysis of Catastrophic Fire Fund.[13]

Q. Does Staff have an update to the original adjustment?

A. Yes, in Opening Testimony, Staff proposed the allocation methodology discussed above but did not propose an adjustment as the analysis was still incomplete. Now, using the Staff-recommended approach, of the $55.5 million of System-Wide WM Transmission Plant additions, Staff recommends a decrease to Rate Base of $9.988 million in order to disallow the amount over nine percent from being recovered from rate payers. The purpose of this adjustment is to incent the Company to make wildfire investments, prioritizing those states with the highest risk instead of its current apparent practice which appears to be to be focused on Utah.

13 Staff/2200 Brewer, Pileggi, and Stevens/24-31.

ISSUE 3. WILDFIRE MITIGATION CAPITAL-INDIRECT LOADING

Q. Please summarize Staff's initial recommendation regarding Wildfire Mitigation Capital Indirect Loadings.

A. In Opening Testimony, Staff proposed an increase to Rate Base of $2,449,396 to keep recovery of capital indirect loadings in base rates per the terms of Exhibit 1 in ADV 1529.[14]

Q. What is the Company's response to Staff's recommendation?

A. PacifiCorp's position is that their proposal to move indirect loading to the Wildfire Mitigation Plan Automatic Adjustment Clause (WMP AAC) during the GRC process is consistent with the settlement terms from ADV 1529.[15] The Company agrees to continue to exclude indirect loadings from the incremental wildfire mitigation capital project costs from WMP AAC filings in between GRC filings, as a way to preclude concerns over potential double-recovery. The Company states their proposal simplifies the recovery of these costs and helps to reduce the administrative burden for the Commission's review by consolidating all fully capitalized costs for wildfire mitigation capital projects into one recovery mechanism at each future instance when base rates are reset. Indirect loadings for incremental wildfire mitigation projects will only need to be separately tracked in between GRC test years.

Q. Does Staff agree that the Company's proposal simplifies the recovery of these costs?

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[14] Staff/1100 Mondragon/37.
[15] PAC/3300 Cheung/86.

A. Yes. Staff agrees that there are benefits in consolidating all costs associated with building an asset in order to provide the true cost of the asset per Generally Accepted Accounting Principles (GAAP).

Q. Does Staff agree that the Company's proposal alleviates concerns regarding double-recovery?

A. No. Staff's initial concerns regarding the potential for over-recovery in Capital are based on how the Company, during the GRC, forecasts the allocation of shared costs between O&M and Capital. Once the new rates go into effect, a Company can start collecting the O&M portion of those shared costs, while the Capital portion of the costs will be collected once Plant goes into service.

Figure 3 demonstrates the potential for over-collection of Shared Costs. In the example, actual expenditures and investments deviate from the forecasted allocation of such costs. Here we see the over-collection in O&M, which will be recovered again when Capital is placed in service.

Figure 3: Over-collection of Shared Costs Example

	2025 Test Year	2025 Actual	Deviation	Explanation
O&M	70	60	10	Company collects revenue of 70 in shared costs, while actual expenditures total 60. There is an over-collection of 10.
Capital	30	40	10	Actual Capital investments and shared costs exceed forecast by 10. This increases capital by 10, revenue will be collected once plant goes into service.
Shared costs	100	100		

Q. If Staff agrees with the benefits of consolidating capital costs but disagrees that over-recovery issue is alleviated by it, what is Staff's solution?

A. Staff feels that the solution is in additional reporting and analysis during the annual WMP AAC filing. To do so, Staff proposes the Company conduct an annual study which will provide Staff with the following:

- Test Year forecasted shared-cost and cost allocation breakdown agreed to during the most recent GRC.
- Actual shared costs and allocation breakdown of such cost for the WMP AAC filing year.
- The Actuals breakdown would include all O&M and Capital investments regardless of whether they are recovered through rates or another recovery mechanism, in order to assess how the approved Test Year Shared Costs were actually and truly allocated.

If the analysis concludes that the WMP AAC filing includes amounts or percentage allocations that would lead to over-collection, the identified amount will be excluded from the WMP AAC in order to prevent over-collection of shared costs. This is the same disallowance treatment currently followed in the WMP AAC when dealing with costs that are not incremental.

Q. Does Staff have an update to the original adjustment?

A. Yes. Staff will agree with the Company's recommendation to move indirect loadings into the AAC during GRC filings. In return the Company will provide the additional reporting required to fully analyze the allocation of shared cost and the potential for over-recovery.

ISSUE 4. ROUTINE VEGETATION MANAGEMENT

Q. Please summarize Staff's initial recommendation regarding Routine Vegetation Management (WMVM).

A. In Opening Testimony Staff recommended decreasing the Test Year amount for Vegetation Management by $402,608 in order to fully remove the $50 million already included in rates.

Q. What is the Company's response to Staff's recommendation?

A. The Company explains that this case's revenue requirement is calculated using accounting data from the 12 months ended June 2023 as the starting point. This means the base year is made up of the last half of calendar year 2022 and the first half of 2023. Additionally, these two calendar years have different approved in-base rates vegetation management O&M levels which would result in a total net vegetation management O&M expense that is not equal to $50 million. Additionally, the timing of when expenses are incurred and when deferral entries are made (and for which calendar year) could cause the amounts recorded in a certain period to not match the exact approved amount from Docket No. UE 399.

Q. What is Staff's response to the Company's reply on this issue?

A. Staff understand that the base year is the 12 months ended June 2023 and that the base year amount is made up of two halves of separate years. However, the proposed adjustment is not to the Base Year but to the Test Year. PacifiCorp's proposed Test Year is the 12 months ending December 31, 2025, in other words, a full and single calendar year. As such, Staff's analysis is based on the fact that if an increase to WMVM was not proposed, the amount collected, for WMVM, through rates, in 2025 would be $50 million. As the Company has proposed to increase the WMVM in rates to $67 million in 2025, the $50 million currently being collected annually, would first need to be removed from the full calendar Test Year of 2025 in order to be replaced by the proposed full calendar Test Year amount. This is further supported by PacifiCorp's workpapers Adjustment 4.11 where the full proposed Test Tear amount of $67 million is used to calculate the adjustment.

Typically, the Base Year is used as a representation of the Company's expenses which would then be escalated for inflation and/or other known and measurable factors to arrive at the Test Year. The "total net vegetation management O&M expense"[16] that the Company is using as the WMVM Base Year is irrelevant as Staff's recommendation is not in disagreement with the Company's proposed amount but how the Company calculated the adjustment. The adjustment calculation to arrive at the $67 million should not remove the Base Year, as these are expenses from a previous period and not an example of what would have been collected in 2025. Instead, the calculation should remove the amount the Company would have collected in the absence of the GRC, which is the $50 million.

Q. Does Staff have an update to the original adjustment?

[16] PAC/3300 Cheung/36.

A. No. Staff maintains that a reduction to the Test Year amount for Vegetation Management by $402,608 is necessary in order to fully remove the $50 million already included in rates.

ISSUE 5. WILDFIRE MITIGATION PLAN

AUTOMATIC ADJUSTMENT CLAUSE (AAC) TRUE UP

Q. Please summarize Staff's initial recommendation regarding WMP AAC True-up.

A. In Opening Testimony Staff recommended decreasing the Test Year amount for Wildfire Mitigation O&M by $5,273,983 in order to fully remove the $19.7 million already included in rates.

Q. What was the Company's response to the recommendation?

A. The Company's response to Staff's recommendation was similar to that in Issue 4, Routine Vegetation management. The Company believes that "Staff mistakenly believes that in order to "clear the slate" in the Base Period of WMP expenses, the fully approved in-base rate amount of $19.7 million has to be removed."[17] The Company again explains that the amount recorded in a 12-month period may not match the approved annual amount:

> One reason is that this case includes a base year which is made up of the last half of calendar year 2022 and the first half of calendar year 2023. The $19.7 million approved in base rates was approved through docket UE 399, with rates effective January 1, 2023. Finally, the timing of when expenses are incurred, and deferral entries are made (and for which calendar year) could cause the amounts recorded in a certain period to not match the exact approved amount.[18]

Q. What is Staff's response to the Company's reply on this issue?

A. Staff responds to the Company with the same line of logic as in Routine Vegetation Management. Staff is not recommending an adjustment to the

[17] PAC/3300 Cheung/37.
[18] PAC/3300 Cheung/38.

Base Year, nor to the Company's proposal to move the amount currently in rates to the WMP AAC. Staff's recommendation is merely based on the amounts used to calculate the Test Year once the Wildfire Mitigation amount, currently in rates, gets removed from the full calendar year of 2025.

The Base Year amount of $14.4 million is not a true representation of what would have been collected from customers through rates in 2025, nor is the amount moved to the WMP AAC for recovery for 2025. This, again, is supported by the PacifiCorp's workpapers Exhibit PAC 1710-WMP AAC Rate True-Up, where the Company includes in the AAC the full 2025 prospective amount, inclusive of the $19.7 million, to their recalculation of Schedule 190. Staff reiterates that the calculation of the Test Year amount should remove the amount the Company would have collected in the absence of the GRC (and True-Up) and not a historical expense amount.

Q. Does Staff have an update to the original adjustment?

A. No. Staff maintains that a reduction to the WMP AAC True-Up of $5.3 million is necessary in order to fully remove the $19.7 million currently included in rates.

ISSUE 6. UM 2116-2020 WILDFIRE COST AMORTIZATION

Q. Please summarize Staff's initial recommendation regarding UM 2116-Amortization of 2020 Wildfire Costs?

A. Staff proposed multiple adjustments to UM 2116, listed below:

- Adjustment to Recovery Costs:
  - Employee Convenience Supplies: Decrease by $2,875 to align with Staff recommendations regarding meals and refreshments of adjusting at 50 percent.
  - Books & Subscriptions/Distribution (593): Decrease by $572.50 for transactions recorded in error.
  - Order No. 22-140 unrecoverable transactions: Decrease by $150,444.
    - O&M Distribution (593): Decrease of $155.
    - Depreciation Expense (403): Decrease by $150,329 for unrecoverable transactions.
- Decrease Rate Base by $1,361 to remove damaged net plant amount included in the Base Period.
- Decrease the deferred Revenue Requirement on New plant by the revenue requirement collected on the damaged plant in Rate Base. Staff does not have enough information to calculate this but asks the Company to incorporate this in its Reply testimony and provide workpapers.
- A sharing mechanism of 30/70 (70/30) for restoration costs. In Staff's preliminary calculations the sharing mechanism adjustment decreases

amortization by $13.3 million. This issue will be further discussed in Staff Exhibit 4200.

Q. Did the Company accept any of Staff proposed adjustments?

A. Yes, the Company accepted the following adjustments:

- Reduction to deferred O&M by $573 for transactions recorded to the wildfire restoration order in error as identified in OPUC Data Request 587.
- Removal of $1,361 in rate base that was included in the Base Period data of this case and should have been removed as identified in OPUC Data Request 588.
- Offset the deferred revenue requirement of new plant by the revenue requirement of damaged net plant removed as identified in OPUC Data Request 584.
- In theory, Staff's proposed adjustment to remove depreciation expense. The Company agrees that the depreciation expense incurred during the unrecoverable period should be excluded. The Company disagreed with Staff's proposed amount of $150,000, which is depreciation for the full month. The Company is proposing the unrecoverable depreciation expense to be based on the number of days where deferral of costs was not allowed. This results in a disallowance of $97,000.[19]

Q. Does Staff oppose the Company's calculation of depreciation disallowance?

[19] PAC/3300 Cheung/72-74.

A. Staff does not oppose.

Q. What other deferred cost Staff adjustments did the Company oppose and how does Staff respond?

A. The Company rejected Staff's recommended decrease of $155 for O&M expenses of during the unrecoverable period. The Company states that the amount provided as part of their DR response was a month-end accrual accounting entry which was later reversed, hence if the accrual is removed, then the corresponding reversal should be removed as well.[20] Staff disagrees with the Company's statement because costs incurred during the unrecoverable period should be disallowed, regardless of the related accounting entries. In accrual entries, the cost incurred is being moved between periods, not removing the costs as if it didn't happen. However, this amount is immaterial, and Staff will not dispute further.

PacifiCorp also rejected Staff's recommendation to treat meals and refreshments found in Employee Convenience Supplies as Meals and Entertainment (M&E) expenses, as they are typically treated. PacifiCorp's reason for the rejection is that the Company routinely excludes storm and fire restoration work-related amounts from the M&E reduction adjustment and that this treatment had been implemented consistently as in the Company's previous two GRCs. The Company states "Providing meals during emergency situations like storm and fire restoration efforts is critical in facilitating efficient and prompt reconnection of electric service to customers, which the Company

[20] PAC/3300 Cheung/73.

does not consider "discretionary.""[21] Staff Exhibit 3700 Rossow addresses the Company's reply and opposition to Staff's treatment of M&E in emergency situations. Rossow disagrees with the Company's treatment of storm and fire restoration work related M&E. As it relates to the UM 2116 deferred costs, I follow suit and continue to propose the disallowance of 50 percent of M&E.

Q. Did the Company make additional changes to the UM 2116 recovery amount in Reply Testimony?

A. Yes. While reviewing Staff and Intervenor adjustments, the Company realized they had made a mistake on workpaper 8.18.1 by deleting the opening balance. This results in a $718,000 increase in the Oregon allocated recovery amount.

Q. Did Staff analyze the additional costs?

A. Yes. Staff confirmed the $718 thousand increase prior to any other updates to the deferred amount. The Company provided updated workpaper, that incorporate the Staff adjustments agreed to by the Company. Inclusive of the adjustments the correction resulted in an increase of $618,113.[22]

Q. Did any intervenors propose adjustments on this topic?

A. Yes. Alliance of Western Energy Consumers (AWEC) made the following recommendations regarding UM 2116:

- Exclude amortization of the UM 2116 deferral from rates. Further addressed in Staff Exhibit 4200.

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[21] PAC/3300 Cheung/75.
[22] PAC 8.18_R Wildfire Restoration Costs Deferral Amortization Workpaper.

- Exclude the portion of Labor Day Wildfire capital additions, including gross plant, accumulated depreciation, and depreciation expense, attributable to the remailing life of the retired assets.
- Exclude the rate base impacts of cost of removal of assets retired due to the Labor Day Wildfires.
- Exclude incremental interest expense associated with Labor Day Wildfire credit rating changes.[23]

Q. Why did AWEC make the recommendations?

A. AWEC's testimony finds that PacifiCorp's gross negligence and willful and reckless conduct are inconsistent with prudent utility management and that the Company has not offered evidence of prudency in spite of the court findings.[24]

Q. What is Staff's response to AWEC's recommendations?

A. Staff supports the first two AWEC proposals:

- Exclude amortization of the UM 2116 deferral from rates. Discussed further in Staff Exhibit 4200.
- Exclude the portion of Labor Day Wildfire capital additions, including gross plant, accumulated depreciation, and depreciation expense, attributable to the remailing life of the retired assets.

Q. Why does Staff not support AWEC's third and fourth proposal?

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[23] Docket No. UE 433 In the Matter of PacifiCorp dba Pacific Power, Request for a General Rate Revision. AWEC's Opening Testimony. I. Introduction and Summary, https://edocs.puc.state.or.us/efdocs/HTB/ue433htb329699054.pdf.

[24] AWEC/2000 Kaufman/17.

A. Staff did not analyze the information in AWEC's proposal to exclude incremental interest expense nor the impacts of cost of removal of assets retired. Although Staff does not support, Staff does not oppose AWEC's recommendations.

Q. How did the Company respond to the AWEC's proposal?

A. PacifiCorp responds to AWEC's testimony by stating that AWEC conflates prudence with a jury's finding of negligence and that relying solely on the negligence findings in a jury verdict without further independent analysis does not provide sufficient evidence to support a finding that the Company acted imprudently or that documented costs of repairing its system to restore service to its customers after wildfires should be disallowed.[25] Staff Exhibit 4200 discusses this issue further.

Q. Does Staff have an update to the original recommendation?

A. Yes. Listed below are the updates to Staff's original adjustments:

- Order No. 22-140 unrecoverable transactions:
  - O&M Distribution (593): $155 previously identified is immaterial, Staff will no longer dispute.
  - Depreciation Expense (403): Company pro-rated and adjusted in Reply Testimony. Staff does not oppose.

The 30/70 sharing recommendation is addressed in Staff Exhibit 4200. All other previously recommended adjustment, not listed here, have been accepted by the Company.

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[25] PAC/2000 McVee/35.

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff proposes the following adjustments:

- Electric Plant-Vehicles: A reduction in Rate Base of $3.2 million for vehicles not replacing others.
- WM Transmission Capital: A reduction to Rate Base of $9.988 million to reflect a disallowance of costs exceeding nine percent of the $55.5 million of WM Transmission Plant additions.
- WM Capital-Indirect Loadings: Staff agrees to move indirect Capital loadings to the WMP AAC. In return the Company will conduct the study mentioned in Issue 3.
- Routine Vegetation Management (WMVM): Reduction to the Test Year amount for Vegetation Management by $402,608.
- WMP AAC True Up: Reduction of O&M Test Year of $5.3 million.
- UM 2116: Staff maintains the recommended adjustment of disallowing $2,875, or 50 percent, of Employee Convenience Supplies as they are Meals and Entertainment.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3001

Exhibits in Support
Of Rebuttal Testimony

August 16, 2024

UE 433 / PacifiCorp
May 1, 2024
OPUC Data Request 356

OPUC Data Request 356

Plant In Service - Regarding Cheung's 8.4.27, for the $16.7 million in vehicles purchased please:

(a) Provide a listing of the vehicles purchased, include:

i. Year
ii. Make
iii. Model
iv. Purpose/usage
v. Cost

(b) Were these vehicles purchased as replacements?

i. If so, what did the Company do with the existing vehicles.

(c) Were competitive bidding RFPs used?

(d) What factors were considered in the decision making?

(e) How does the purchase of new vehicles benefit the customer vs continuing to use the existing vehicles?

Response to OPUC Data Request 356

(a) For subparts i, ii, iii and v, please refer to Attachment OPUC 356 which lists vehicles purchased from July 2023 through March 2024. Note: the $16.7 million is a projected total amount from July 2023 through December 2024.

iv. Mobile equipment purchases are necessary to keep the mobile equipment fleet in compliance with American National Standards Institute (ANSI), Occupational Safety and Health Administration (OSHA), and Company safety requirements and to avoid increased maintenance expense. This equipment also enhances productivity of our labor force. Work requirements are evaluated and additions to the fleet are purchased when justified to allow greater safety and productivity to be achieved. Due to the age and condition of the vehicles being replaced, they are quickly becoming irreparable (or subject to extensive and time-consuming repairs), thus jeopardizing fleet availability. Parts on many of these units are becoming increasingly difficult, if not impossible, to locate due to obsolescence. Other benefits of these mobile equipment purchases include (1) enhancing the ability of the crews and individual employees to work

UE 433 / PacifiCorp
May 3, 2024
OPUC Data Request 372

OPUC Data Request 372

Wildfire Mitigation Plant - Regarding Wildfire Mitigation indirect loadings costs excluded from ADV 1529, please,

(a) Provide a narrative on how they are being presented in this GRC.

(b) Provide or direct staff to the workpapers can be used to verify the information.

Response to OPUC Data Request 372

(a) Consistent with the Company's proposal with wildfire mitigation capital cost recovery in this general rate case (GRC), indirect loadings and direct capital costs related to wildfire mitigation capital projects placed in service by December 31, 2024, are being excluded from base rates calculations in this GRC. Simultaneously, the fully capitalized costs of wildfire mitigation projects that were placed in-service through May 2023 are being included the Wildfire Mitigation Plan (WMP) Automatic Adjustment Clause (AAC) Rate True-Up calculation presented in Exhibit PAC/1710. Indirect loadings are not separately tracked or carved out to be included in the base rates proposal in this GRC.

(b) Please refer to Exhibit PAC/1710 and corresponding work paper "Exhibit PAC1710 – WMP AAC Rate True-Up Illustration.xlsx" for further details supporting the total wildfire mitigation capital costs being proposed to be moved in its entirety to the WMP AAC with the base rates update that will be effective with the outcome of this GRC on January 1, 2025.

UE 433 / PacifiCorp
June 17, 2024
OPUC Data Request 615

OPUC Data Request 615

Wildfire Mitigation Plant (WMP) - Regarding the Company's response to DR 370, for all WMP Transmission Plant outside the state of Oregon please provide the following:

(a) In service dates.

(b) State where Plant is located.

(c) Transactional data including:

i. Project description/name;
ii. Cost element;
iii. Line description; and
iv. Which High Risk Fire Zone it will benefit.

Response to OPUC Data Request 615

PacifiCorp objects to this request as overly burdensome, requiring a new report or analysis, lacking a high degree of relevance to the proceeding and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing objection, the Company responds as follows:

The Company assumes that the reference to "DR 370" is intended to be a reference to OPUC Data Request 370. Based on the foregoing assumption, the Company responds as follows:

The Wildfire Mitigation Plan (WMP) Transmission Plant projects for line work outside of the state of Oregon as described in the Company's response to OPUC Data Request 370 is a pro forma forecast (July 2023-December 2024) of assets anticipated to be placed in service.

Please refer to Attachment OPUC 615 for the requested information. Information regarding the benefits to individual high risk fire zone is not readily available, but can be provided for an individual project if requested.

UE 433 / PacifiCorp
July 3, 2024
OPUC Data Request 687

OPUC Data Request 687

Wildfire Mitigation Plant (WMP) - Please provide the response to Staff's IR 14 in the Catastrophic Fund Proposal.

Response to OPUC Data Request 687

Please refer to Attachment OPUC 687.

UE 433 / PacifiCorp
August 13, 2024
OPUC Data Request 751

PacifiCorp OPUC Data Request 751

UM 2116 and Vehicle/Mobile Equipment - Regarding Vehicles/Mobile Equipment, for each of the past 10 years, 2013-2023, please provide the following information,

(a) Fleet count each year, by mobile equipment type.

(b) Field personnel each year, including 2024.

(c) Provide a listing of the vehicles purchased each year, include:

i. Date of purchase
ii. Year
iii. Make
iv. Model
v. Purpose/usage
vi. Cost

(d) Were these vehicles purchased as replacements? If so, provide the following:

i. Vehicle/Equipment number, matching Repl Veh column.
ii. Net book value at the time of disposal
iii. Disposal type
iv. Loss/Gain on disposal (if any)

Response to OPUC Data Request 751

PacifiCorp objects to this data request to the extent it requests 10 years of information and as such is overly broad and not reasonably calculate to lead to the discovery of admissible evidence. Subject to and without waving the foregoing objection, PacifiCorp responds as follows:

(a) Please refer to Attachment OPUC 751.

(b) For purposes of this response, the Company clarifies that "field locations" does not include work from home, corporate or call center work locations. In addition, counts include full-time and part-time, union and non-union employees in the non-mining business. Based on the foregoing clarifications, the Company responds as follows:

Please refer to the table provided below:

UE 433 / PacifiCorp
August 13, 2024
OPUC Data Request 751

Date	Count of Full-Time / Part-Time Employees
December 2013	3,557
December 2014	3,602
December 2015	3,547
December 2016	3,557
December 2017	3,509
December 2018	3,449
December 2019	3,343
December 2020	3,145
December 2021	3,038
December 2022	3,025
December 2023	3,115
July 2024	3,165

(c) Please refer to Attachment OPUC 751.

i. Date of purchase - Please refer to Attachment OPUC 751 ("All Years Data" tab).
ii. Year - Please refer to Attachment OPUC 751 ("All Years Data" tab).
iii. Make - Please refer to Attachment OPUC 751 ("All Years Data" tab).
iv. Model - Please refer to Attachment OPUC 751 ("All Years Data" tab).
v. Purpose/usage - Vehicles are used for the provision of electric service to customers. Trailers are requires to transport equipment. Forklifts may be used in warehouses or loading equipment. Off road vehicles, UTV/snowmobiles are used to address line issues in remote areas of the right-of-way, other vehicles transport employees and crews.
vi. Cost - Please refer to Attachment OPUC 751 ("All Years Data" tab).

(d) Please refer to Attachment OPUC 751.

i. Vehicle/Equipment number, matching Repl Veh column - Please refer to Attachment OPUC 751 ("All Years Data" tab).
ii. Net book value at the time of disposal - Please refer to Attachment OPUC 751 ("All Years Data" tab).
iii. Disposal type – Auction.
iv. Loss/Gain on disposal (if any) - Please refer to Attachment OPUC 751 ("All Years Data" tab).

UE 433 / PacifiCorp
August 13, 2024
OPUC Data Request 753

OPUC Data Request 753

UM 2116 and Vehicle/Mobile Equipment - Please provide a narrative on how the Gains from the Sale of Vehicles has been or will be used to offset customer rates.

Response to OPUC Data Request 753

Gains on sales of vehicles are credited to accumulated depreciation, which serves as a reduction to rate base.

CASE: UE 433
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3100

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. I provided Staff Opening Testimony in Exhibits Staff/1200-1202.

Q. What is the purpose of your testimony?

A. I rebut PacifiCorp's (PacifiCorp, PAC, or Company) Reply Testimony addressing my Opening Testimony positions concerning materials and supplies (M&S) and incremental Operations and Maintenance (O&M) expense.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MATERIALS AND SUPPLIES

Q. Please summarize Staff's position on Materials and Supplies in Exhibit Staff/1200.

A. In Opening Testimony, I proposed a materials and supplies Test Year Oregon-allocated balance of $107,826,222. This resulted in an adjustment of ($21.9 million) to PacifiCorp's forecast balance. My adjustment was arrived at by using an average of monthly average balances for the years 2021-2023 and then escalating for inflation to the Test Year using what I had understood as PacifiCorp's inflation index of 0.31 percent.

Q. What was PacifiCorp's response to Staff's proposal?

A. PacifiCorp rejected Staff's proposal. The Company argued that Staff's methodology for calculating forecast Test Year balances was an inaccurate characterization of how PacifiCorp forecasts its Test Year balance.

Q. Does Staff agree with PacifiCorp's response?

A. No. In fact, Staff's methodology for calculating Test Year materials and supplies rate base is consistent with how Staff has historically forecast this component of rate base. It is incorrect to suggest that Staff's methodology is a change from how Staff consistently views this rate component. The Company may view Staff's methodology as deficient, but PacifiCorp has not made the case for why its own methodology provides a more accurate forecast of necessary materials and supplies. The Company's own methodology of using a 13-month simple average basis results in a more costly projection. The Company claims, but has not in any measure substantiated, that PacifiCorp's method more accurately anticipates future operational needs and procurement costs.

Q. What other issues does PacifiCorp address regarding Staff's materials and supplies recommendation?

A. The Company points out in rebuttal testimony that Staff's reference to the Company's Oregon-allocated Test Year materials and supplies balance is slightly different from what is actually referenced.[1]

Second, the Company questions how Staff determined the allocation factor of 0.331889 applied to the system-level FERC Account 154 balance to arrive at the revised Oregon-allocated Test Year balance (PAC/3300, Cheung/69). The Company claims that it cannot confirm the source of the referenced allocation factor of 0.331889, and that properly assigning allocation to Oregon in accordance with the 2020 Protocol requires isolating each component of the protocol, including situs-assignment, system overhead, and system net-plant distribution factors.

Third, PacifiCorp disputed Staff's application of 0.31 inflation factor to the average balance, saying that the IHS Markit indices referenced in the Company's filing were only applied to O&M FERC accounts.

Q. How does Staff respond to these issues?

A. First, the test year amount described in PacifiCorp's Reply Testimony is incorrect. The correct amount in the Company's filing is $129,895,465[2] – not

[1] PAC/1702, Cheung/39, line 2092.
[2] PAC/1702, Cheung/39, line 2092.

$128,895,465 noted in Exhibit No. PAC/3300, Cheung/68. Second, Staff calculated the adjustment to materials and supplies at a system level and applied the same overall percentage to the Oregon-allocated amount that the Company used. In doing so, the allocation factors for individual components specified by the 2020 Protocol are maintained. Third, I make adjustments in response to PacifiCorp's testimony concerning the inflation factor.

Q. Does Staff recommend any changes to its adjustment in Opening Testimony?

A. Yes. I recalculated the forecast Test Year balance by applying the all-urban CPI inflation factor of 2.2 percent, instead of using the IHS Markit index of 0.31 percent. This resulted in a system-level adjustment of ($60.15 million). Applying the corresponding Oregon-allocated percentage represented in the Company's filing, the Oregon-allocated adjustment is ($19.9 million).

Staff maintains its original position that its historical practice of using an average of monthly average balances over a three-year historical period and escalating for inflation projects a reasonable Test Year amount, absent any evidence to the contrary. Using a three-year average minimizes the impact of anomalous events that may occur in a given year that wouldn't be reflective of the Test Year. Since PacifiCorp has not demonstrated that its forecast methodology is more accurate in anticipating the Company's operational needs, rather than simply arriving at a higher rate base amount, PacifiCorp's method should be rejected.

ISSUE 2. INCREMENTAL O&M

Q. Please summarize Staff's position on Incremental O&M in Exhibit Staff 1200.

A. Staff's Opening Testimony in Exhibit Staff 1200 focused on the incremental O&M costs for post-conversion Jim Bridger Units 1&2 (JB 1&2). Staff's review and subsequent adjustment was based on attempting to determine the reasonableness of O&M costs for these plants. Because the Company was unable to provide forecast Test Year expense of other gas-fired plants in PacifiCorp's service territory,[3] Staff focused on a comparison of Test Year JB 1&2 costs with the actual historical O&M costs of other gas-fired plants. JB 1&2 projected expense of $50.1 million was more than four times higher than the historical expense for any other gas plant.[4] Staff used an average base-year expense of the other gas-fired plants, escalated for inflation, to derive an estimate of expense for JB 1&2. This resulted in a ($33.58 million) adjustment to the expense at a system level, and a ($9 million) adjustment Oregon-allocated expense.

Q. What was the Company's response to Staff's proposal?

A. Company witness Brad Richards (PAC/2800) recommended the Commission reject Staff's adjustment, stating that JB 1&2 units are "large gas fired boilers with remarkably different technology, vintage, and size than other PacifiCorp gas plants (excluding Naughton Unit 3)".[5]

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[3] See Exhibit Staff/1202 – Company response to Staff DR No. 567.
[4] See Exhibit Staff/1200, Moore/7 – Tables 1 & 2.
[5] PAC/2800, Richards/2.

Q. Is Staff persuaded by the Company's Reply Testimony?

A. The Company makes the reasonable point that JB 1&2 are not directly comparable to other gas-fired plants that are modern combined-cycle gas-fired plants. However, in Reply Testimony PacifiCorp suggests a similarity to Naughton Unit 3, which is also a previously coal-generating plant that converted to gas.

Ultimately, the Company fails to provide an evidentiary basis to support its forecast expense. PacifiCorp states it cannot provide forecast Test Year costs for its other gas-fired plants, but it expects the Commission to accept Test Year costs that are at least four times higher than historical expense for any other gas plant. In comparison, the 2023 base year costs for the similarly situated Naughton Unit 3 are $3.26 million.

In addition, the Company claims in Rebuttal Testimony that the incremental O&M represents expense for all four units of Jim Bridger, contradicting its filing that represents the amount is for units 1&2 only.

Q. Does Staff recommend a change to its original adjustment recommendation?

A. Yes. In light of PacifiCorp's argument regarding the differing technology and vintage of its various plants, Staff reduces its original adjustment by 50 percent. Because PacifiCorp cannot provide Test Year forecast estimates for its other gas plants, and the Company has not provided support to substantiate its forecast expense for JB 1&2, Staff recommends the Commission adopt Staff's adjustment. I recommend an adjustment of ($17 million) total expense, and ($4.6 million) Oregon-allocated.

An alternative recommendation the Commission may wish to consider is to use the similarly situated Naughton Unit 3 as a proxy for JB 1&2. Escalating Naughton Unit 3 costs (times 2) by inflation to the Test Year would result in an adjustment of: ($43.4 million) total expense, and ($11.7 million) Oregon-allocated.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3200

Rebuttal Testimony
Public Comments

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Melissa Nottingham. I am the Consumer Services Manager employed in the Water, Telecom, Safety and Consumers Programs of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is provided in Exhibit Staff/1300 and my Witness Qualification Statement was provided in Exhibit Staff /1301.

Q. What is the purpose of your testimony?

A. Consistent with the Commission's Internal Operating Guidelines as addressed in Order 20-065 in Docket No. UM 2055, public comments received by the Commission are now made part of the Staff's Rebuttal Testimony in a General Rate Case (GRC). The first round of public comments was included in Staff Opening Testimony Exhibit/Nottingham 1302.

The purpose of this testimony is to include subsequent public comments not previously included in Exhibit 1302.

Presenting comments at a Commission Informational Hearing or through the Commission's website does not subject the commenting person to cross examination. Any party, though, may respond to Staff's summary of the public comments or the comments themselves in evidentiary testimony.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/3201, consisting of 94 pages.

SUMMARY OF COMMENTS

Q. How are public comments obtained by Staff?

A. Comments may be submitted via an online form, an email, a letter, or a telephone call. All comments are submitted and published to the docket's webpage and are available for review at any time. Please see: PACIFICORP REQUEST FOR A GENERAL RATE REVISION.

Q. Please summarize the supplemental public comments received after opening testimony in this rate case.

A. Since opening testimony filed on June 28, 2024, Pacific Power's UE 433 has received 304 public comments. The Oregon Utility Rates for Small Business submitted a detailed letter outlining their concerns with specific exhibits from Staff's Opening Testimony.

Consumers' comments express a strong concern about the financial strain imposed on households facing multiple utility rate cases. They highlight families are already struggling with current electricity rates, and further increases would exacerbate their financial difficulties, especially for those on fixed incomes, such as senior citizens and people receiving social security. The proposed rate hikes are seen as disproportionately affecting vulnerable groups, including the elderly, disabled, and low-income families. Commenters are concerned that these populations will have to choose between essential needs like food and electricity.

Sentiment is strong that PacifiCorp should bear the costs of its negligence and legal settlements, particularly related to the wildfires, rather than passing these costs onto consumers. Commenters argue that the company should use its profits to cover these expenses instead of burdening customers. Comments reflect a general dissatisfaction with the Company's handling of PacifiCorp's financial and operational responsibilities and how costs should be shared between the Company and ratepayers.

Overall, commenters are worried about both the individual household and the broader economic impact of the rate increases. They argue that higher electricity costs will lead to increased prices for goods and services, making it even harder for people to make ends meet. There is also concern about the potential for increased homelessness and financial instability within the community. A strong plea is made to the Public Utility Commission to reject the proposed rate increases due to the financial impact of increasing rates.

Q. Are any of these issues addressed in Staff's Rebuttal Testimony?

A. Yes. Staff's rebuttal testimony addresses the themes, concerns, and issues raised by the public in many different exhibits. In Exhibit 2300, Michelle Scala, Energy Justice Program Manager, discusses the impact of rate increases on energy justice communities and the overall impact on vulnerable communities. She also points to Staff testimonies addressing concerns raised in Public Comments received by the Commission. Kate Ayers', Energy Justice Analyst, Exhibit 2600, details the Company's low-income assistance program and arrearage management.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3201

Public Comments
June 15, 2024 to August 8, 2024

August 16, 2024

Fair Oregon Utility Rates for Small Business ("FOUR") advocates for the fair treatment of small nonresidential customers, also known as small general service or small commercial customers. On behalf of these customers, particularly Schedule 23, with regard to the Pacificorp dba Pacific Power General Rate Case UE 433, we submit this public comment to the Oregon Public Utility Commission ("PUC") to consider our following remarks, organized basically by topics covered by Staff's Opening testimony yet inclusive of Company's Reply testimony:

The jury in Multnomah County found Pacific Power not the small business consumer class liable for 2020 wildfires. It is important that small businesses are not unfairly burdened by the financial implications of Pacific Power reckless and grossly negligent conduct. Although the Company's Reply testimony essentially separates the jury verdict from PUC proceedings regarding recoverable wildfire expenses or insurance costs, Pacific Power's attempt to push off some of the associated costs of their liability onto ratepayers in different ways is noticeable. Furthermore, the Company admits in its Reply testimony that disconnections have increased since the pandemic due to arrearages accumulated in part during the pandemic. FOUR respectively responds to the following staff testimony:

Staff Exhibit 300 - Michelle Scala

Overall, we suggest changes to ensure procedural equity and an inclusive rate spread/ rate design is truly met. Small business owners are community members with leadership roles that shape our state and unique perspectives essential to developing accountable clean energy policy and programs. It is imperative that small general service customers are included in the discussion on equity and disconnection because disconnection essentially ends that business operations. The consequences of doing so has the potential to severely damage the livelihood of small nonresidential customers including family-owned businesses. FOUR appreciates the in-depth discussion regarding the shared investor and customer risk, and Staff's recognition that although the "uncollectible" may be recovered by the utility, the burden on the customer remains. Still, leaving out the small nonresidential customer from resolving this issue is unconscionable.

We know that equity issues inevitably arise when decision makers fail to recognize the presence of the small business consumer class. For instance, although small businesses were not included in COVID-19 programs they still pay for the aggregate costs of the utility moratoriums. In Medford 70+ small commercial ratepayers totaled over $120,000 in costs for 90+ days arrearages per the Company's December 2023 COVID-19 report. Staff testimony 300 follows the pattern of leaving small businesses out of the table. Even though the small general service customers are the highest proposed increase, Staff's equity concerns focus exclusively on residential ratepayers. This does not reflect true "community" impacts and undermines our collective goal to fairly distribute the benefits and burdens across all segments of communities.

Regarding energy efficiency, the Company should be required to report on energy efficiency programs in the highest consuming industries in the Schedule 23 customer class. And we are concerned that the almost double "off-peak" increase would be unfair to the Schedule 23 class with time of use patterns dissimilar to that of residential customers. See Dloughy/22.

Staff Exhibit 700 - Curtis Dlouhy

We are incredibly concerned that Staff engages large and very large customers in the specific dialogue on nonresidential rate spread/rate design. We encourage Capacity Reservation Charge and Excess Demand Charge with revenues from the deferral to be spread to all customers based on class revenue requirement. We wonder what part of the program impacts and demand response of the "Commercial & Industrial Demand Response Program" in Table 2 were attributable to small general service customers. FOUR agrees that the Time of use for Schedule 23 be structured as residential for now in lieu of NO time of use however 1) whether the tool properly reflects the usages of Schedule 23, and 2) whether it is advertised adequately to Schedule 23 customers, should be closely reviewed.

Regarding COVID deferral amortization, we think that the reference to UE 374 is a misprint where UM 2063 is the COVID-19 docket and Staff referred to the UE 399 stipulation as having resolved the COVID-19 rate spread. If it is not a misprint, we urge Staff to more fully explain the relation of that docket with COVID cost allocation agreed to in UE 399. As small businesses who directly experienced COVID-19 challenges we remain concerned regarding fair treatment of Schedule 23 in the fair and reasonable allocation of costs from the pandemic.

Staff Exhibit 900 - Bret Farrell

FOUR supports the Company's proposal to eliminate card payment fees. Staff provides no reason that the non-residential fee of Schedule 23 should NOT be eliminated. Regarding the Company's proposals for Uncollectible expense, FOUR requests that staff provide a basic description of when arrearages become "uncollectible" and when and if 91+ day arrearages of over $125,000 are distributed among Schedule 23 customers. FOUR also requests that Staff expand its investigation of residential uncollectible expenses to include Schedule 23 Uncollectibles in order to ascertain whether the Company is operating using sound business practices. See Staff/900 Farrell/6.

Staff Exhibit 1900 - Bret Stevens

FOUR strongly urges Schedule 23 to be included in any workshop involving "parameterization" of load forecasting. Furthermore, FOUR notices that Staff lumps all commercial customers together in describing "load forecast" and refers to them as "customer class." See Staff/1900, Stevens/3. Despite Staff's claims that these models are "reasonable," we wonder how lumping small and the large and very different commercial customer classes together is reasonable.. Staff/1900 Stevens/9. FOUR finds Staff's treatment of "commercial customers" inequitable toward small general service customers given that the Schedule 23 small commercial class is the second most numerous class of customers served by this utility. Staff supports but does not mention the impact of a 22.4% increase on small general service customers except where it sees a difference between 22.4% and 4.5% "intractable" but still maintains the large increase for Schedule 23. Staff should examine the Schedule 23 rate base as it did the residential rate base.

Staff Exhibit 2200 - April Brewer, Rose Pileggi, Bret Stevens

Regarding the proposed Catastrophic Fire Fund, FOUR strongly contends that the PUC should not issue a final decision on such a large issue with major financial and legal implications without another opportunity for public comment. Staff recognizes in its Opening that the allocation of the Catastrophic Fire Fund is a very difficult issue, and we believe it is not fair and reasonable for the Commission to make a determination in this rate case with so little information in such a large and controversial issue.

Thank you for considering our public comment.

Sincerely,

s/ Chelsea Alatriste-Martinez

Fair Oregon Utility Rates for Small Business

Please file the following article under the general rate case: PacifiCorp UE 433.

PAC massively burns our state releasing harmful CO_2 emissions and destroying property and precious natural resources[1], obstructs renewable energy interconnections[2][3][4][5], raises rates 12.9 percent, and now proposes another 17.9 percent rate increase on Oregonians while donating $5.3Billion away[6].

Daniel Hale

Reuters

Warren Buffett Donates Record $5.3 Billion of Berkshire Shares to Charity

by Jonathan Stempel – Reuters – Jun. 28, 2024

Warren Buffett donates record $5.3 billion Berkshire shares to charity | Reuters

[1] https://www.opb.org/article/2023/06/12/oregon-wildfire-verdict-pacificorp-labor-day/
[2] https://edocs.puc.state.or.us/efdocs/HAC/um1930hac165947.pdf
[3] https://edocs.puc.state.or.us/efdocs/HBC/um2118hbc145412.pdf
[4] https://edocs.puc.state.or.us/efdocs/HNA/um2177hna17438.pdf
[5] https://edocs.puc.state.or.us/efdocs/HAS/um2322has327943024.pdf
[6] https://www.reuters.com/business/warren-buffett-donate-up-53-bln-berkshire-shares-2024-06-28/

Berkshire Hathaway Chairman Warren Buffett attends the Berkshire Hathaway Inc annual shareholders' meeting in Omaha, Nebraska, U.S., May 3, 2024.

Warren Buffett donated another $5.3 billion of **Berkshire Hathaway stock** to the **Bill & Melinda Gates Foundation and four family charities**, his biggest annual donation since he began making them in 2006.

Buffett's donation **boosted his overall giving to** the **charities to about $57 billion**, including to the in the last two Novembers.

The **latest donation**, announced on Friday, **included about 13 million Berkshire Class B shares**.

Buffett donated 9.93 million shares to the **Gates Foundation**, and has donated more than **$43 billion** of Berkshire shares there **overall**.

He also donated 993,035 shares to the **Susan Thompson Buffett Foundation**, named for his late first wife, and **695,122 shares** to **each** of **three charities led by his children Howard, Susan and Peter**: the **Howard G. Buffett Foundation**, the **Sherwood Foundation** and the **NoVo Foundation**.

Buffett, 93, plans to give away more than 99% of the fortune he built at Omaha, Nebraska-based Berkshire, which he has run since 1965, with his children serving as executors of his will.

Berkshire is an **approximately $880 billion conglomerate** that owns dozens of businesses including the BNSF railroad and Geico car insurance, and stocks such as Apple.

Buffett still owns 14.5% of Berkshire's outstanding shares, a Friday regulatory filing shows, despite having given away more than half of his stock since 2006.

His $128.4 billion fortune makes him the **world's 10th-richest person**, according to Forbes magazine.

In a statement, Buffett said he was worth about $44 billion when the donations began, but that the benefits of compounding, "simple and generally sound capital deployment" at Berkshire, and the "American tailwind” produced his current wealth.

Buffett, Bill Gates and Melinda French Gates also pioneered the Giving Pledge, in which 245 people like OpenAI's Sam Altman, Michael Bloomberg, Carl Icahn, Elon Musk and Mark Zuckerberg committed at least half of their wealth to philanthropy.

The **Susan Thompson Buffett Foundation** works in reproductive health. The **Howard G. Buffett Foundation** works to alleviate hunger, mitigate conflicts including in Ukraine, and improve public safety. The **Sherwood Foundation** supports Nebraska nonprofits, and the **NoVo Foundation** has initiatives focused on girls and women.

Friday's filing suggests based on Buffett's holdings that Berkshire has repurchased little or none of its own stock since April 19.

First Name	Last Name	City	Comment
Leo	Myr	CAVE JUNCTION	Rates are increasing more than the cost of living increase, price gouging at it's finest. Upgrades to equipment and paying settlements to those affected by the fires should come out of corporate profits, not out of the pockets of consumers.
Mark	Kounz	MEDFORD	Please Oregon PUC, investigate the blatant incompetence exhibited by Pacific Power! Numerous communities here in Southern Oregon are being repeatedly hit with black outs over a short time frame. Pacific Power blames everything from birds to squirrels, to Mother Nature's PMS for their ineptitude. A full, unbiased investigation is requested with remedial action!
Cassandra	S	GRANTS PASS	We cannot afford groceries, let alone a hike in our bills.
		GRANTS PASS	Already paying more than I can afford for electricity and my home is all electric. I suffer through the heat as much as I can before I turn on AC. I'm on social security for income. After I pay my bills each month I have $12 left for food gas and other incidentals. This rate increase would probably put me homeless. Please don't increase we just have one at that long ago and it was devastating on my budget.
Karen	Arnold	MURPHY	Please don't let PP&L do another rate increase. We can't afford it now! Thanks.
Jeremy	McElroy	GRANTS PASS	Please don't let them do this to us. With utility rates at an all-time high already, everyone is struggling to keep their heads above water with what they're charging. Besides, we all know what this rate increase will really be used for: Making the rich executives even richer. They have enough, they don't need any more.
Terrence	Quast	MEDFORD	Pacific Power has been negligent in maintaining transmission systems for years. The cost of repairs should be shouldered by the company, reducing dividends and liquidation of company assets, as well as slashing executive compensation. In the real world, citizens pay for their mistakes monetarily and perhaps prison time. They should be held to an even higher standard. Terrence Quast Medford, OR
NA	NA	NA	To Whom it may concern: My comment on the proposed rate increase is no! Electricity costs are out of control as it is and Pacific Power wants all of their customers to end up paying for their negligence, restorations, upgrades? They should have been responsible prior to the fire for maintaining and upgrading their infrastructure & perhaps the devastating fires would not have occurred. Restoration wouldn't be necessary if their faulty equipment hadn't started the fires to begin with. Just seems the little guy always ends up propping up the corporations, banks, you name it. It' a bail out in disguise. Sent from my iPhone
Stephen	Frolander Sr.	NA	Good Morning, I am contacting you again after reading that the United States has entered into a new Treaty with Canada regarding the use of the electricity being generated on the Columbia River Hydro-electric System. With the US receiving 37% more of this cheap power you MUST SAY NO to the rate increases being requested by Pacific Power Company. NO considerations of any kind until after 2032. In fact with this new TREATY there should be a 37% roll back reduction in rates NOW.... Stephen D. Frolander Sr.
NA	NA	NA	Pacific power found liable for fires, ordered to pay millions , instead of losing profits, make they're costamers through ridiculous rate hikes !
NA	NA	NA	Don't raise the people' rates. Your punishing us and making us literally pay for your mistakes.

First Name	Last Name	City	Comment
Sandee	Galligan	MEDFORD	I am writing to ask you to not allow Pacific Power to increase their rates 16.9%. People in Oregon are struggling as it is with high cost of housing groceries to get by paycheck to paycheck. I am a single mom I have four kids, and I can barely pay the rent and the current electric bill along with other necessities. Pacific Power Should not be allowed to do this to our community and into our state. They recently agreed to pay plaintiff for their negligence or actions in the 2020 fires and with this hike it appears that they are rolling that over to the customers and the people that live here in Oregon, we have no choice, but to go with Pacific Power , and they are taking advantage of that . Please do what' right for the people of Oregon and not make it even harder to live here. Sandee Galligan Medford, OR 97504
Cathy	Freeman	NA	I have just read about the companies desire to raise rates 16 %. This is so sad to hear from a company that says they care about the environment..Well, guess what...Your and my environment has one species you don't seem to consider. And it is the ONLY environmental species that PAYS you. HUMANS. You want to charge your customers for your WRONG business decisions.You have losses from 2020 due to settlement payments YOU were penalized for. Not Acceptable. SHAMEon you and Shame is what I'm feeling for this Bull S$#@! Business practice of not caring.... Cathy Freeman
NA	NA	NA	Hello I'm responding to an investigation into The Pacific Corp rate increase. If I'm understanding this correctly, they want the people, their customers, to pay for the lawsuits they incurred for the fires they were responsible for in the last 2 or 3 years? Why should the public pay for the negligence of a private entity? Everybody likes to talk about how great capitalism is, and yet these mega corporations are protected by government so that when they make bad business decisions, or in this case neglect to update or maintain equipment, it is the very same people who have suffered losses which end up financing their recovery. Does that sound about right? Thank you
NA	NA	NA	Pacific Power wants its customers to pay for their failures to plan & manage. Sent from my iPhone
NA	NA	NA	Pacific Power wants its customers to pay for their failures to plan & manage.
NA	NA	NA	I don't believe you people should be gouging us because you got sued for the fires we can't afford the power rates now my power bill is 4 to 500 sometimes $600 a month. How do you expect people to afford that shut off all the freaking time and you guys make bank. Why why don't you give us a break for once? Why do you guys always have to make millions of millions of dollars while we're out here suffering get a clue Pacific power. I wish there was other power around here that we could tap into besides, you guys cause you guys are horrible.
NA	NA	NA	I don't support the rate increases which amount to pacific corp just gouging customers to cover for their legal and negligent failures. Customers are already struggling to pay all the bills they have with out companies arbitrarily increasing when ever they feel like it. This should be put on a ballot for voting and ended there.
Gary	Krause	NA	I think it's shameful that Pacific Power is asking rate payers to cover their losses from those fires that they caused. This will impact the poor, young and older Oregonians. It's bad enough that I can't afford my power bill now as it is let alone the rate increase. This rate increase will negatively impact Oregon's economy. Gary Krause

First Name	Last Name	City	Comment
Dawn	Riddervold	NA	From: Dawn Riddervold. Pacific power outrage Pacific powers profit for 2023 was 2.24 billion dollars, up 24% from year prior. The government, u ppl, have decided to burden the public even more with placing undo increases to utility on the back of the same ppl who can neither afford such increases to increase corporate profits and by refusing to protect the general public sector from these unwarranted increases. Making the ppl pay for more corporate profits should be a giant red light for all of you to be fired and replaced with ppl who might actually protect the public from corporate greed. U have made the general public pay for pacific powers negligence in the wildfires.....shame on u and oregon
NA	NA	NA	This last rate hike is outrageous. One of the costs of doing business involves risk management. Ideally RM occurs before and not after a failure occurs. In this case PacificCorp could have placed lines underground to mitigate or avoid the fires the companies poor oversight & maintenance caused. The focus on lower cost, above ground lines may serve the stockholders well by insuring a profit, but the cost to the consumer, in this instance with few other options, is outrageous. The actions PC is now taking for future RM with a 16.1% rate hike, with prior rate hikes increasing consumer cost 30 plus % in one year is nothing short of greed and if approved, there should be a required sunset on this last rate hike. After accumulating the reserves PC deems necessary - which they should have already allocated had they not placed profits ahead of good management, the rates should be required to be reduced by as much as possible for benefit of the consumer. The sad reality of this increase by this PUC monopoly is that consumers once again are harmed and have no choice but to accept this heavy economic burden. Yes, a business owes a fiduciary responsibility to its shareholders, but how about the responsibility to the consumer where other options are limited or non-existant? Seniors, and those economically unable to bear the heavy cost burden will no doubt NOT cool or heat their homes as needed and surely will be harmed. Many will be disconnected due to non-payment. All consumers will be harmed in an environment in which the cost of a mandatory utility is added to the increased costs of living post covid, in which supply chain disruption increased costs failed to lower once the disruption ended. This rate hike should not be approved and an annual cap should be implemented to protect consumers.
Joelle	NA	NA	To whom it may concern within the Public Utility Commission, As I am sure you are aware, the Rogue valley is home to a majority of folks living within or barely above the poverty line. Our bills increased in cost last year across the board. Food, all utilities, cost of insurance, taxes etc. As you know, the increased cost of living is nearly impossible. The average Oregonian cannot afford the ongoing increases. Our paychecks are not being increased at the same rate our bills are. People like me, who live paycheck to paycheck, but budget to pay bills in full will likely start having larger outstanding balances and will get behind on their payments. Folks are barely scraping by in order to pay them now. A rate increase will only make it so they are negligent on their/our invoices. We will also be looking into solar if this increase goes in to effect. PacificCorp profits enough to make the changes they need to make without making the customer pay for the upgrades and additions. Alameda should NOT BE PAID FOR by customers. Please understand that for most of us, another increase in already skyrocketed utility bills will not be feasible. LISTEN TO YOUR CUSTOMERS WHEN WE SAY NO. Friends and family of mine.. From doctors, to gas station clerks, to nurses to engineers.. Have all said they are NOT OK with this. It is abuse of the pseudo-monopoly Pacificorp has on this valley and it's customers. It is unfair, and unreasonable. Please consider the wellbeing of those who are loyal, on-time, paying customers. Sincerely, Joelle (Deleted Link)

First Name	Last Name	City	Comment
NA	NA	NA	As senior citizens living on Social Security fixed income we strongly oppose any more rate increases for our power service. Recent report by KDRV, the local television station, showed that PPL has a surplus in some of their accounts. I feel like PPL is holding us hostage with threats of shutting off the power if they don't get their demand for additional monies from the citizens. PLEASE DO NOT APPROVE THIS INCREASE!!
Ian	Barton	SELMA	Another price hike by Pacific Power is ridiculous and uncalled for. These greedy corporations should not be allowed to continually raise rates every year. The PUC is supposed to protect us from this exact story of thing and it appears that Pacific Power is in their pockets. This is going to add more of a financial burden on already stressed communities. When is enough enough? Why are we all forced to pay for their negligence and failure to upgrade and safeguard their systems, including the lawsuits they have to pay? The PUC needs to stand up for the citizens. Power is one of our largest bills every month. If this is allowed to go through it reeks of corruption at the government regulatory level.
Bob	Baroni	CAVE JUNCTION	I'm a retired construction worker on a low income pension. My wife and I live in Cave Junction, Oregon. We realize the fires have caused many lawsuits over the last few years, but we also know that Pacific Power has been making record profits for many years prior to that! Our utility rates have been going up every year. It is not the consumers fault and we should not be penalized for the company' poor maintenance practices! Your commission was put in place to protect us consumers, please do your job and disallow these exorbitant fee increases!
Tonya	Harboldt	GRANTS PASS	The costs being listed as support for the increased rates are to pay off charges the company incurred because of their own negligence. Passing along your punishment for negligence is just continued negligence. Instead, rather than incurring higher profits, reinvest the money you already are making to cover these costs. Develop the repairs and systems necessary to ensure these events are covered and properly security measures are put in place to prevent further similar events. But passing the buck to the consumer because you don't want to shoulder the innate burden of the very job you charge fees for is ridiculous. Take care of the people you provide service to, without passing along your incurred expenses from when you failed to protect them before. We have already paid enough.
Kathleen	Cortapassi	GRANTS PASS	We live on a fixed income that inflation has eaten up. The cost of groceries have left us BROKE! There is no way we can afford a 16.9% rate hike. The second reason is, here in Grants Pass Oregonâ€¦.our power gets shut off multiple times a week. How in the world do you think Pacific Power deserves a rate increase when they can't even make sure old people have power in 105Â° summer days? We do not support a rate hike of any amount, we just got a 13% hike a few months ago.
Dana	Hunt	CAVE JUNCTION	Look p.g.&e.we can't afford any more hikes. Dang,your putting a solar field on Laurel rd & caves hwy here in cave junction oregon and we didn't approve or didn't have a choice to vote it in!!! Plus,we won't even get anything from it.Stop ripping us off and play fair ??.
Cathleen	Fuller	GRANTS PASS	Please do not approve another increase that most of us can't afford just because Pacific Power was AGAIN found negligent! They need to be responsible for their actions. We the over price gouged law abiding citizens should not have to bare the weight of another huge increase. Thank you.
Kathleen	Cortapassi	GRANTS PASS	i disagree with the idea that they should be getting a 16% rate increase. They just got one in january. Are we going to have to now chose between electric food and medication each month? We already have to juggle the bills as it is we can't afford this.

First Name	Last Name	City	Comment
Flo	Lopez	CAVE JUNCTION	The September 8,2020 wildfire: Slater Fire took everything we had . We lived there February 1983 My grandparents and I lived there since 1962. So my family lost everything all unrepeatable items. And more how can pacific power not offer us more money. How they are treating their life long customers. It' just wow
Donna	Wilkinson	SELMA	This proposed rate hike is really to much. I understand prices going up due to wages etc., but 16.9%! I live off of social security and it only went up 2.5%. Even with Community Care discount this will really put me in a bind. We live in an area where it snows in the winter and extremely hot in the summer (as it is right now). I am lucky i have a heat pump with air conditioner, but my bill is going to be really high, and if this raise passes, wel, I don't know what I'm going to do.
NA	NA	NA	PGE has been hiking our rates at insane levels for years now. Claims of service improvement and maintence are often at the forefront of this price increases and yet on the very first 90 degree day of the summer power goes out in SE portland. It should come as no surprise to PGE that lots of power was going to be used today and yet here we are with no projected repair schedule. The food in my fridge and freezer will melt and spoil overnight, I'll sleep in sweat with no fans. These are small inconveniences, and if I was not paying extortion level prices for my electricity I would see them as such. Yet I pay a premium, so that my power company can burn down forests and fail to maintain a grid during expected surges. So now I ask you, what will you do about this? How can hold PGE accountable to its clients and why have you let them take this this far?
John	Littleton	NA	From: John Littleton. Subject: Pacific Power Proposed Rate Request john@jelittleton.com<mailto:john@jelittleton.com>. To: Oregon Public Utility Commission Re: Public comments sought on Pacific Power proposed double-digit rate hikes I am opposed to the rate increases requested by Pacific Power. Each year, comparing month to month, and on average, I am consistently reducing my energy usage. Yet, each year, despite using less electricity for the month, when the bill arrives, it is 15-20% higher than the same period for last year. Why? What is different? What changed between last year and this year? The public expect businesses to also bear a fair share of the responsibility for the current economic conditions and the rampant "greedflation" as evidenced in multiple economic reports and seen throughout the business world. Many people on fixed incomes will be disproportionately harmed by this questionable rate increase. I ask the Oregon PUC to make every effort to minimize the financial impact to Oregon citizens. Finally, I request to be informed of any discussions, meetings, actions, or decisions regarding Docket No. UE 433. All correspondence may be provided to the email address for this request: John@JELittleton.com<mailto:John@JELittleton.com> Thank you. - John Littleton -
Maureen	Binder	GOLD HILL	UE433. No additional increase, seniors cannot afford this

First Name	Last Name	City	Comment
John	Bellville	GRANTS PASS	Certainly! Here's a letter you can use to express your concerns about Pacific Power's proposed rate increase: --- **Subject: Concerns Regarding Proposed Rate Increase** Dear Pacific Power, I hope this letter finds you well. I am writing to express my deep concern about the recent proposal to raise rates for your services. As a loyal customer, I believe it is essential to share my perspective on this matter. While I understand that utility companies face various challenges, including rising costs and the need for infrastructure investments, I urge you to reconsider the proposed rate adjustment. Here are a few reasons why I believe this increase should be reconsidered: Many of your customers, especially those on fixed incomes, will find it difficult to absorb higher monthly bills. As responsible corporate citizens, it is crucial to consider the financial well-being of the communities you serve. I appreciate your commitment to integrating renewable resources. However, I encourage you to explore alternative funding mechanisms for these initiatives without burdening customers with substantial rate hikes. I recognize the importance of wildfire risk management, but passing the entire cost onto customers seems inequitable. Perhaps there are other ways to allocate these expenses more fairly. I respectfully request that Pacific Power reevaluates the proposed rate increase and explores alternative solutions that balance the company's needs with the well-being of its customers. Together, we can find a path forward that ensures reliable service while minimizing the financial strain on households. Thank you for your attention to this matter. I look forward to hearing from you soon. Sincerely, John
Wendy	Staykow	GRANTS PASS	I think any percent of increase is uncalled for and unnecessary.Especially in light of the power lines that have caused fires.Power prices have gotten out of control.Too many cannot afford their power bills now.More and more people will look to solar or other alternative power sources. Thank you.
Christopher	Wade	SALEM	Pacific corp states increased expenses for infrastructure after the 2020 Labor Day fire. The company was found liable for the fires so why should I have to pay such a large increase because the company was not doing it's due diligence in maintaining, upgrading and repairing facilities and infrastructure that their own negligence caused
Jamie	Griffin	GRANTS PASS	I already can barely afford my power bill. Often it comes down to power or food. This increase would be devastating to the families like mine that are already struggling. You already have a monopoly on power in our area. Your rates are already high. Give families a break!
John	Herrmann	CAVE JUNCTION	I find this to be ridiculous they just raised it and they want to raise it again what about the disabled people that are on low income and the elderly people that are on low income that can't afford price hike pretty soon people with kids and elderly are going to be without power because they're not going to be able to afford the power bill
John	Friedt	GRANTS PASS	A monopoly does not give you the right to raise prices. Stop installing new power lines that pacific power cannot work on , stop harrying out of state installing power lines and polls that can't be serviced by local power company.
Terry	Lyle	CAVE JUNCTION	I believe electricity should come from member owned co-ops not private companies seeking profits... Nonetheless, a whopping 17.9% "general rate revision" cannot be justified! The profits say otherwise!!
T'Keyah	Culbertson	KERBY	Our power bills are already at an extreme high. There are so many people who cannot afford to cover them as it is, and limited funding to help. There are people choosing not to use ac at all in 110Â° because of their power bill. Pacific power raising their rates is absolutely ridiculous with how expensive they already are.

First Name	Last Name	City	Comment
Jacklyn	Stromberg	CAVE JUNCTION	No way, we already are having a hard time affording power. If rates do raise then federal government needs to give way more funding to places that will help pay in their communities. This is absolutely rediculous to continue to raise rates. Makes me wonder if buying a generator or putting in solar power would be cheaper. I say everyone do that and boycott all power companies.
Cameo	Conrad	CAVE JUNCTION	I do not believe the increase should be happening. Our economy is currently failing as it is, and an increase in the price we pay to have electricity is beyond ridiculous considering our circumstances in the state and the nation. The people need power, and unfortunately the increases are going to equal more people losing their homes due to lack of electricity. We cannot be going bankrupt while corporations are eating away at our hard earned money. Please reconsider this update! The working class needs someone to take a stand for us!
NA	NA	CAVE JUNCTION	Unnecessary revisions. Pacific Power is not utilizing their profits the way they should be if they're wanting to increase everyone by such a large amount.
Cathy	Maxwell	CAVE JUNCTION	I can hardly afford power! If ucan didn't help me I couldn't heat or cool my 70 yr old sick body. I don't know how I can go on the 4 months I have to pay with no help stresses me out. It's very scarry maybe I won't be able to container living cuz I can't afford Power! Thank God for UCAN
Karen	Kidd	GRANTS PASS	A rate increase of 16.9% is too high for the majority of people who.live in Josephine County Many are elderly and disabled and need help paying there power bill now and there are eaitliay for the local agency UCAN who handles energy assistance in this area. It is also difficult.to access any help if individuals are not tech savvy with smart phone or computer. Please do raise the rates.
Patti	Pogorelc	CAVE JUNCTION	Cost of living increases to benefit programs such as social security do not cover anywhere near the requested increase. This puts an unacceptable burden on retirees, SSI recipients and those on other assistance programs. I'm pretty sure the shareholders can withstand a little less profit. The wildfire excuse for increase is due to neglect by Pacificorp in previous years.
Janine	McClure	CAVE JUNCTION	I am on SS and since the county has elected to increase my property tax, my home owners insurance has increased, all of my food and gas has been increased, I CAN NOT AFFORD ANOTHER INCREASE JUST TO LIVE. I am penalized for making to much money as a widow. I am penalized and have to submit things as single. Not widow. I'm drowning
Shelly	Hooks	O BRIEN	Our power bill is ridiculous.They are turning Oregon into California.Why should we pay for there screw ups which had cost them millions of dollars.What was there profit for the last several years.Living on SS we don't get 12-17 percent raises
Eric	Hanson	CAVE JUNCTION	The request by PEP to further increase their rates must be countered with a price cap. The condition of the transmission lines and their surroundings has not been maintained or upgraded as they initially promised to the PUC. This situation will cause more wildfires, property damage and deaths. Pipe needs to utilize their parent company's contingency funds and cut the huge corporate profits this time. Thank you. Eric and Susie Hanson.

First Name	Last Name	City	Comment
Catherine	Allegretti	CAVE JUNCTION	Our community cannot afford a rate increase. We no longer have local commerce and jobs since the cannabis industry left. People must commute a minimum of 1.5 hours per day just to secure work. A rate increase would devastate us. Inflation and high fuel costs have been hard enough. Our food pantries are over burdened. Our local resource for federal monies to help pay electric (UCAN) is running out of money. The wait list for an appointment to get help is 6 weeks- that' just to make an application. Our elderly are using wood in the winter and staying hot in the summer just to keep our bills down. I'm 55 and I chop wood even in the heat to think ahead toward winter since I can't afford to run my 35 year old heat pump. The reality is, when rates go up the government and local organizations step in help cushion the blow to the consumer.
Becky	Hartwell	CAVE JUNCTION	Stop the gouging!
Sutherlin	Kahler	GRANTS PASS	It's already hard enough to live in this area with how expensive it is. You wanna create more homeless people!? The rate increase has already gone up around 14% the past two years, is it gonna increase every single year?! People can't afford this and there is no way maintenance costs are the only reason why. Power is a necessity just like food and water, people need it to live and soon the won't be able to have it. These price hikes have to stop after this year power will have rose around forty percent higher then it's ever been, enough is enough. People are hurting and we don't wanna have to choose whether to starve, get heatstroke in the summer, or freeze to death in the winter.
Becky	Hartwell	CAVE JUNCTION	This increase is ridiculous! Stop gouging our community!!
Rob	Fifield	GRANTS PASS	It seems a little shady to me that Pacific Power(who was found negligent and responsible for multiple wildfires in 2020) wants an increase to 16% to rebuild their infrastructure. They didn't do their job in maintaining THEIR lines and it cost hundreds of people dearly. Yet they have the audacity to ask us to pay for their mistakes
NA	NA	EAGLE POINT	I would like to know how much the CEO of Pacific Corp makes. I do not appreciate corporations using citizens to pay for maintenance of their businesses while they are all continuing to make millions. I absolutely oppose the increased rates. Stop trying to steal from average Americans to keep yourselves rich!!!
Gerry	Stanley	MEDFORD	PacPower is proposing a 16.9% rate increase in January 2025 for residents. This increase comes on the heels of a 13% rate increase in January of this year. The proposed increase is, in part, to cover the cost of wildfire mitigation as well as the creation of a catastrophic wildfire fund. This increase comes after PacPower recently reached a $178,000,000 settlement with 403 plaintiffs who suffered losses due to the 2020 Labor Day wildfires. PacPower wants ratepayers rather than stockholders/investors to pay for their mistakes, i.e. negligence (lack of adequate maintenance), mismanagement and lack of foresight. Residents will be on the hook for this overall 30% rate hike in one year alone. First, The Public Utilities Commission' primary responsibility is to protect the public not the Corporation' bottom line. Second, with homeowner' insurance rates spiraling out of control, the average homeowner is being squeezed by both sectors for a situation that is largely out of their control. Please put a stop to this outlandish power grab. Our pockets are not deep enough to sustain their imagined entitlement.
Steve	Wirth	CENTRAL POINT	Did everybody get a 13%raise last year an a16% raise in 2025we are on ssi our raise isn't close to that as we have to pay for dams removal low income electricity ppl just needs to buckle up.an pay there own bills not asking for more money let the bigshots take a cut in pay

First Name	Last Name	City	Comment
Bill	Putnam	KLAMATH FALLS	It is not up to us to pay pp&l's bill..if they can't provide service to their customers at the exorbitant price it is now they need to step aside and let another electric company provide service at a reasonable price..I don't understand how these companies are making billions of dollars off it's customers and turning electric off for said customers when they get behind on their bill yet this company wants said residents to pay their bill and not be held accountable for their actions..we are on a fixed Income and elderly and disabled and Im on oxygen full time and we have a hard time paying our electric bill every month but we pay what we owe and this company needs to take responsibility and pay what they owe .it's not up to private customers to pay their bill..it is the sole responsibility of the company to pay theirs..it's not ours to pay..we pay for a service period
Bill	Putnam	KLAMATH FALLS	It is not up to us to pay pp&l's bill..if they can't provide service to their customers at the exorbitant price it is now they need to step aside and let another electric company provide service at a reasonable price..I don't understand how these companies are making billions of dollars off it's customers and turning electric off for said customers when they get behind on their bill yet this company wants said residents to pay their bill and not be held accountable for their actions..we are on a fixed Income and elderly and disabled and Im on oxygen full time and we have a hard time paying our electric bill every month but we pay what we owe and this company needs to take responsibility and pay what they owe .it's not up to private customers to pay their bill..it is the sole responsibility of the company to pay theirs..it's not ours to pay..we pay for a service period
Darlene	Putnam	KLAMATH FALLS	It is not up to us to pay pp&l's bill..if they can't provide service to their customers at the exorbitant price it is now they need to step aside and let another electric company provide service at a reasonable price..I don't understand how these companies are making billions of dollars off it's customers and turning electric off for said customers when they get behind on their bill yet this company wants said residents to pay their bill and not be held accountable for their actions..we are on a fixed Income and elderly and disabled and Im on oxygen full time and we have a hard time paying our electric bill every month but we pay what we owe and this company needs to take responsibility and pay what they owe .it's not up to private customers to pay their bill..it is the sole responsibility of the company to pay theirs..it's not ours to pay..we pay for a service period
Paul	Schneider	SHADY COVE	So after reading this Pacific Corp wants to charge the additional 16% rate increase due to fires caused by negligence of themselves, equipment upgrades, line run and so on. We as their customers should not have to pay an increase due to their own negligence. Not so far in the near future many people on a fixed income or single income household will need to choose between electricity and food. Many people are already doing this. With the increase that has already happened PacifiCorp had a peak revenue in 2023 of 13.0 million. They need to learn to better manage the money they already receive in order to run a successful â€œmonopolizedâ€ business instead of passing their issues onto their customers.
Kris	Seabrook	MEDFORD	Your new rate increase you're asking for certainly LOOKS SUSPICIOUSLY like a recoup of the money you had to PAY for being held liable for wildfires. You still want to give your investors the same rate of return they had previously and expect taxpayers to foot the bill for your new wildfire programs. Hello? Why should we pay for that when your company could and should have anticipated wildfires (do you not get California news?) This rate increas e after the rate increases after the double digit ones from the last several years is too much, not fair to the tax payers and only be efits your investors. It's time they pay too. This is comment for Pacific Power Rate increase for 2024.

First Name	Last Name	City	Comment
Teresa	Santucci	GRANTS PASS	i am opposed to the enormous rate increase proposed by pacific power. they were negligent and had to make payments on settlements and now they want the customer to pay for that. sorry. that is why you have insurance. no one and i mean no one can keep paying these ridiculous rates. put a stop to this now. just say no!
Cindi	A	CENTRAL POINT	The public should not have to pay for any of those lawsuits and it looks like that' the biggest part of this increase is to fund the dang lawsuits, we the public dont have the money for increases with all the inflation . My opinion is the Democratic state that wants all solar they are clearing and destroying thousands and thousands of acres of forest trees and terrains in Oregon for solar facilities and the only ones getting anything out of it is is the STATE check it out it' the Oregon green initiative!! They want to control everyone' household while they get rich and sell this solar power, This has to STOP everyone needs to research OREGON GREEN INITIATIVE most people don't know about this.
Eric	Donnell	GRANTS PASS	This rate increase is no different from the proposed rate increase earlier this year that was denied by the PUC. Citizens of Oregon cannot be responsible for PacifiCorp's mistakes that resulted in monetary liabilities. I understand the increased insurance and other mitigation costs but the main part of this rate increase is for PacifiCorp to recoup their losses due to the lawsuit settlements made. This rate increase, along with any further attempts by PacifiCorp to recoup lawsuit losses from their customers, must be denied.
NA	NA	ROGUE RIVER	The public cannot keep paying more for power. We have endured three recent hikes already (12.9% in 2024, 21% in 2023, and 15% in 2022. Now they want another increase? This one partly due to costs they incurred due to fires they started, fires that have increased our homeowners insurance (ours recently doubled due to the fires). There has to come a time when the â€œlittle guyâ€ is not charged more and more to help sustain the profits of â€œthe big guyâ€, to the point that they can no longer afford to live in their homes. Please deny this request for another increase.
Charyse	Halverson	GOLD HILL	They have already gone up recently. I'm on a fixed income and on oxygen there is only so much I can afford. Isn't there a way we all could get a community meeting?
Mary	Hansen	GRANTS PASS	I would hope you would consider what a rate increase fro Pacific Power would do to so many. I am so concerned as to what all these rate hikes are doing to our country. For the greater good of all I pray you do your part in curbing all these costs.
Michele	Pitts	CENTRAL POINT	I would like to know how much revenue Pacific Power generates every year, and how much is needed to restore power lines, equipment, upgrading. I would like to know when repairs started from the 2020 Fire in Jackson County Oregon, we are approaching 4 years this September. We as customers deserve this kind of information, to explain what has or has not been done since 2020. How long they expect this to take to upgrade and repair. I am speaking for myself, but I am sure others might be thinking the same..What have they been doing all this time? We can appreciate the safety measures but at the same time, why the long power outages that went from a few hours at the most to 12 hours plus? Safety issue is presented for the vulernable to be with out power in the heat for hours on end, not to mention replacement of food lost in the freezers and refridgerators on top of the budgets are getting tighter with the economy.

First Name	Last Name	City	Comment
Christopher	Bodenhamer	MEDFORD	Why should ratepayers be responsible for costs incurred on wildfire where utilities are found criminally negligent? I oppose this increase, as claimed increased costs are the result of utility's own settled negligence. Passing this increase allows the utility to avoid repercussions for negligence (settled and convicted). Utility did not perform actions in a proactive manner and therefore should be responsible for costs incurred as a consequence of failed stewardship and regular course of business. These costs are not a 'benefit' as utility claims, but a requirement of being a utility operator, and a risk that utility has acknowledged through obtaining insurance.
SUSAN	LOPEZ	GRANTS PASS	How in the world can Pacificorp continue to raise their rates. They had a 13% raise already this year, and now want an additional 16.9%. Fine they had a lot of repairs because of fires, they get money from the state and insurance companies. They can do a temporary increase and then lower it back down. Don't continue to rape us and ripe us off. I am on a fixed income and I can't afford to keep myself warm in the winter and cool in all the heat now! What am I and hundreds of other seniors suppose to do? These increases are ridiculous, Pacificorp makes enough money, they don't need any more. Think of the people who absolutely can't afford another increase on anything, much less a total increase of 29.9% in ONE YEAR for Pacificorp. This needs to STOP!!! Our Governor needs to stand up for once and help people who pay their bills, or we may be the next homeless on the street!!!!! Susan L
Kai	Chow	MEDFORD	My family moved away from Portland, OR because we were being priced out of the area (taxes, utilities, and rent). We moved to Medford to try to have a chance to live. You raised the rates 13% on January 2024, now you are proposing raising the rates again because you had to payout lawsuits for Labor Day 2020 wildfires. This doesn't seem like you are holding the public' interest in mind and you are making your customers pay the bill for your previous and future lawsuits. I do not agree with a 16.9% rate increase.
Sean	Beall	MEDFORD	The 13% rate increase this January was already bad enough now they are asking for a 16.9% increase to cover the cost of insurance premiums and restoration after the 2020 fires the list of fires includes fires they had to pay settlements due to their negligence in the wildfires. People' power bills are already outrageous if it goes up another 16.9% what are people supposed to do chose between keeping the lights on and groceries or gas to get to work?
Glenn	Pitcairn	MEDFORD	Please do not allow these utility increases, we cannot afford them. I understand some increase, but the double digit increase request is too much and is mostly due to the utility company trying to make customers pay for the wildfire issues the company faces due to not maintaining their equipment over time. Their negligence should not be passed on to us the customers. They should seek cost cutting first! Look at what news reports say about PacifiCorp profits: the power company behemoth earned $2.24 billion in 2023, an increase of 24.6% in profits compared with 2022. Also maybe salaries of PacifiCorp could be lowered to reflects their customers wages? ---- The average PacifiCorp executive compensation is $232,309 a year. The median estimated compensation for executives at PacifiCorp including base salary and bonus is $236,093, or $113 per hour. At PacifiCorp, the most compensated executive makes $450,000, annually. Let's start with the company streamlining and not penalizing us the customers for all the wildfire issues and lack of continually maintanence of their lines.
Kimbra	LeCornu	WHITE CITY	We oppose and find the rate increase insulting. That' over a 25% increase in under two years. Daily electricity costs for our home has already increased from $7 a day to $12 & $15 day. (During the winter there were days that we were charged $25 a day) Another increase and we won't be able to afford electricity at all. Manage your budget better, just because you lost the lawsuits does not mean you collect the fine off the customers. This is a needed utility not a optional. Do better.

First Name	Last Name	City	Comment
Darlene	Putnam	KLAMATH FALLS	I think our power bills have soared since January and another increase would make it impossible for residents on a fixed income and seniors to pay their power bills .it's not up to private residents to pay a companies bill .we pay our bills..but we are not liable for a companies debt..only our own..we are private residents..it's not our responsibility to pay for something we arent responsible for..it's not our fault..we can't afford to pay for their guilty verdict
Jeremy	Coyle	MEDFORD	This rate increase would be CRIPPLING to many families (including my own) in Southern Oregon. After a nearly 15% increase in January of 2024, to have another 16.9% the very next year is simply unsustainable in a community already struggling with housing costs, general inflation in day to day necessities, and a job market where wages have not risen to match these costs. Electricity is an essential utility in today' day and age for not only basic heating and cooling, but also internet, telephone communication, and scholastic education for many children. Please consider these points and deny this request for rate increase. Thank you.
Kathy	Smith	ROGUE RIVER	Please do not allow another price increase from Pacific Power. When it comes to electric power we have NO choices, there is not another option. Solar is way to expensive and it infringes on our home maintenance of the roof. You are our only hope to keep prices reasonable for seniors and others on a fixed income. How can they afford to pay for Pacific Power's business model and poor management? As a public utility commission please look out for the people and give us a voice. Thank you.
Rhonda	Young	SHADY COVE	I oppose a RATE INCREASE . These things you state should be figured in your yearly budget because they happen. You where fined and now you want More money. You got last year. SENIORS 70 AND OVER LOW INCOME CAN NOT AFFORD IT. WE CAN HARDLY EAT. WE SHOULD GE A 50% DECREASE. If no shut offs ever. And you start replacing all new lines in southern Oregon maybe it fair. But not that much. Do not see where you need it.
NA	NA	MEDFORD	So your company gets sued and the customers have to pay for your lawsuit?? That' kind of a coward and disrespectful move for a company to make, is it not?? This is the most ridiculous proposal I have ever seen. If you did your job like your company was/is supposed to do and actually upgrade your lines, before the fires, and keep up on tree growth, before the fires, then none of this would be happening. So because of your negligence and lack of care for your communities, the customers now have to pay for your lawsuit instead of it coming from your personal massive wallets. Congratulations, you get away with it once again as a big company does these days. You big companies are a disgrace to this country, just killing people and destroy their lives and just get away with it to do it all again. Appreciate it.
NA	NA	MEDFORD	They were negligent and shouldn't be given more money for not doing their job.
NA	NA	GRANTS PASS	To whom it may concern: The proposed rate increase for the Pacific Northwest (Josephine County, etc) should not be approved. This company should not be allowed to install faulty equipment the customers did not want (Smart Meters for example), and then force it's customers to pay for the damages that were then incurred by said faulty equipment. I have lived in this area for over 50 years and never before had major fires been started by the old meters we originally had on our houses or any other equipment of the Power companies. We did not have our power turned off to prevent fires from the old equipment during heat spells. I would rather pay $20 bucks to get my old meter back than to be forced to pay for the future damages and lawsuits that are going to occur under their current system. People are already struggling to pay their bills, food costs, and mortgages/rent, now we have to pay for the irresponsibly placed equipment that can't handle the job? Please reconsider approving this increase. Thank you.

First Name	Last Name	City	Comment
Lori	Hazel-Horton	GRANTS PASS	I feel that all of these rate hikes are unnecessary and self serving. With the cost of everything else we cannot afford another rate increase from Pacific Power. They are getting too greedy! It' already too high. With all the outage complaints my question for you is Do you just want use to die in this heat or go without food or medications to pay this increase? We are all struggling to make ends meet, well most of us anyway. Keep this up and only the rich will be afford to survive I don't know if you also have any interest or power on the issue of water cost in Grants Pads. There is no hope of decrease in either water or electricity. Grants Pass leaders are using the water rate hikes to fund everything else. As a single person, living alone, retired, fixed income my base rate or cost is over 80 dollars. Seems a little excessive don't you think. God forbid I use any extra water in a month. I will be looking for a more reasonable state and region to live in, unless these increases kill me first. Who can tolerate these temps without air conditioning?
PATRICIA	HASKIN	GRANTS PASS	If you raise the electricity any more I won't be able to live in my house. every thing is electric even our well, so i would have no water either. I am 90 years old and should not be treated this way.
Gary	Reed	MEDFORD	Please stop PP&L from attempting what I can only call â€œattempted Rapeâ€of Oregonians by attempting over 30% rate increase In just two years as they begin to punish rate payers for their companies negligence in fire liabilities. I am retired and on fixed income and am asking you not to let them getaway with what they are attempting.
Jenilynn	Monfrey	GRANTS PASS	Not sure I picked correct docket no. I wish to oppose Pacific Power's request for another rate increase by 16.9%. This is in addition to recent 13% rate increase! This is horrible and will make it impossible for people to keep up. They reported they had money left from last year. Please DENY THIS REQUEST!!!
Sharon	Emsley	GRANTS PASS	Even if inflation was not hitting consumers as hard as it has been for the past 3+ years; even if insurance companies were not doubling and tripling rates; and even if Pacific Power had been more responsible over time in maintaining their infrastructure, it must be brought to bear that double-digit back-to-back rate hikes are not affordable by the majority of those being billed. How can the average citizen keep warm in the winter and cool in the summer with such exorbitant increases?? Those earning minimum wages or, worse, the elderly and disabled on limited fixed incomes, are being forced out of their homes due to the combined cost of food, electricity, insurance and health care! Pacific Power continues to show significant profits every year. If they need more money to keep up with demand and properly maintain their infrastructure then I strongly suggest they look to trim their overhead costs, including management salaries, in order to exercise their corporate responsibility to provide a necessary service to those whose survival depends upon it. Do NOT approve another rate hike! Please!
John	Ellis	MERLIN	I'm sick of pacific power' terrible service and constant rate hikes! I strongly oppose the new suggested rate hike of 16.9%
Michael	Brown	MERLIN	To whom it may concern Pacific Power wants to raise rates to 16% after they raised rates in January.I am on a fixed income and don't know how a lot of people are going to be able to afford this.Thank you for listening
Alexander	Gregg	GRANTS PASS	As a resident of Oregon, I strongly oppose the proposed general rate increase. Raising the costs of a vital utility need (heat, power) in such financially trying times will absolutely cause more harm than good for many. Please do not approve the rate increase request proposed by Pacificorp. The cost of living is already so high, putting more financial stress on everyone, especially those on a fixed income, would only make things worse for the entirety of the state.

First Name	Last Name	City	Comment
Mark	Mc Soroey	CENTRAL POINT	I am not ok with the rate increase. It looks like they are looking to increase rates to cover settlement for Labor Day 2020 fires. They already did rate increase at the start of this year, no reason for another one next year, especially with energy prices being the way that they are. I am on a fixed income and it' getting to be unaffordable. I looked at solar but due to being in manufactured home, I can't get them. This rate increase is unjustified and unfair. This puts a burden on those that can't afford it.â€
Hannah	McKissick	GRANTS PASS	Cannot afford another rate hike . People on limited income would like to continue living in the home they own
Cindy	Shepard	SUNNY VALLEY	There should be no more rate increases. PAC is a monopoly and customers don't have a choice. The PUC should be advocating for their customers and not for a company to help pay off a lawsuit by increasing rates. The customers were not fined, it was the company, so we shouldn't be paying for those. It should be coming out of the pockets of the company. The state of OR is allowing the monopoly and the customers hands are tied regardless of the service. The customers don't get to vote with their money. There are senior citizens who can't afford the rate increases and you are forcing them out of their homes.
Donna	Stage	GRANTS PASS	In regard to Pacific Powers latest request for rate increase of 16.9%, please deny the request. I can't pay anymore to power my home. I and am too old & on a very small budget. I can't buy solar even. Old people on fixed incomes & young people with family', we're all struggling daily to stay in our home as is. Please consider us
A	P	ROGUE RIVER	Rates are too high as it is, Pacificorp can't even keep their grid maintained for what they're charging. My generator went on 7 times in 3 months.
Beverly	Herriott	WILLIAMS	I live in rural Oregon and am 75 years old, live in my own home. Pacific Power & Light are again raising our rates. They are making it impossible for some of us to remain in our homes due to increased power bills on very limited budgets. Please stop these increases!
Linda	Hutzell	MEDFORD	I am mortified that the company is allowed to ask for this rate increase especially since they just got one last january. our news outlet said that they had all this money stored away that they had to pay for wild fire law suits so I just think that they're using this rate case to replace that money that they lost. I'm a senior citizen and I should have to pay this my bill was $280.00 last month so us seniors shouldn't have our bill raised at all.
Valerie	Gottschalk	CAVE JUNCTION	I just saw that Pacific Power is AGAIN asking for another rate increase. ' Pacific Power is also proposing a 16.9% rate increase for residents. That rate increase is due in part to increased budgeting for wildfire mitigation, with a proposal for a catastrophic fire fund.' Retired and on a fixed income, I, along with MANY others, cannot afford to just keep financing their problems. They make no effort at efficiency to avoid wasting man hours or equipment costs and the only move I have left is just that: MOVE.. out of state. Please turn this raise in rates down.. There is no GOOD reason for it!!
Tj	Kohler	KLAMATH FALLS	Power already cost way too much
Cheryle	Hite	CENTRAL POINT	I use the equal payment option for Pacific Power. Going by their schedule for that option I used 107 less KWH but my equal payment went up $108, $9 a month. So I'm paying a $1.00 more each month for every KWH I saved. You guys are killing us.

First Name	Last Name	City	Comment
Lynne	Hutchinson	REDMOND	To Whom it May Concern: Please do not raise our electric bill with Pacific Power. We are struggling as it is and it has had raises a while ago. We are on a fixed income and are having a hard time keeping up with all the raises for everything. We have a disabled daughter who lives on a little more than $1,000 a month. What will she do with a large raise and we cannot help her and outside help is always iffy. Please think of all of those like us and ask the big guys to tighten up too. Sincerely, Lynne Hutchinson
Wade	Mc Kee	GRANTS PASS	My bill increased from $220 to $311 and it had nothing to do with usage, but rate increase. I think it' ridiculous and it needs to be lowered, not increased.
		KLAMATH FALLS	I oppose further increases in power bill. Discounts for low income people should be removed instead
NA	NA	KLAMATH FALLS	No!
Kelley	Minty	KLAMATH FALLS	This is a huge burden to our agricultural community and community at large. I oppose this increase on behalf of my 70, 000 constituents.
			I for one am in protest of this (yet another?) rate increase. I have seen my monthly rate quadruple in the last 5 years and mostly in the last 3. How much more can the general public take of inflation and rate increases?, I for one am NOT made of money especially for problems Pacific power has brought upon itself , why must the users bear the brunt of yearly if not more rate hikes? . During the recent years I have seen in the news of Pacific power hand out funding and grants by the millions while rates have been quickly raised of it's users , how does this make any logical sense? , stop handing out moneys to special projects and groups and pass the savings to it's users!, the very people which PAY the bills of the utility. I feel almost pressured to fall back on "assistance" programs which Pacific Power floods my mailbox and inbox with after EVERY rate increase -I DONT WISH ASSISTANCE with ANY bill (yet!). I pride myself NOT needing assistance and being able to stand on my own feet - but at this rate Im getting close to a breaking point , I can only tighten my belt "so much" to stay afloat monetarily. One to TWO rate increases yearly - and not just a few percentage points , this is maddening for what used to be a very affordable commodity (electricity) . Please , ask Pacific Power re-think their position on the increase and the way they throw-around the very money meant for supplying the public with power for daily living and NOT for frivolous pet "projects" and "grants" Thank you , Laszlo, Bend Oregon ,and life long Pacific Power customer.
Brandon	Pinkerton	WHITE CITY	Hello, as an Oregonian we've always had good reliable power service at a reasonable price especially compared to other states. Unfortunately, the cost of power has changed dramatically in the last couple of years. The rate change at the beginning of 2024 really impacted our monthly cost for electricity. It was a dramatic increase that has made it much harder to pay our bills each month. Our household has been hit in all directions when it comes to increase costs. We feel it at the grocery store, gas pump, dining out, etc. We've made major changes to our monthly expenses and cut-out many â€œoptionalâ€ costs. We no longer grab a coffee from Starbucks, Dutch Bros, etc and brew coffee at home. We've stopped dining out. We changed many grocery items to the generic brand. We're no longer budgeting for a vacation this year. Overall, our basic living has changed dramatically, just to keep paying for the same things. With all that said, I urge you, the PUC to stop the increase for our utilities. It' a basic need that is affecting all people of Oregon and it' unsustainable for us. Costs are going up everywhere, but our income has not increased (for many years now) to match the increases. Please help Oregonians out by putting a stop to double digit increases for our utility costs.

First Name	Last Name	City	Comment
Gene	Souza	KLAMATH FALLS	Klamath Irrigation District opposes the general rate change. A 22.4% increase for agricultural producers is excessive, as PacificCorps is already charging Klamath farmers over three times the average rate for other Oregon producers in the same market. Agricultural producers cannot increase product prices to recoup these losses to PacifiCorps as the market is set regionally. Klamath County is classified as a disadvantaged community by the state of Oregon. Klamath Irrigation District also acknowledges and supports the comments sent by Klamath Water Users Association. Klamath Irrigation District further agrees with Represenative Reschke, we "recommend the PUC consider in order to help Oregonians combat inflation â€" decrease rates by 1Â¢/kW across the board. Just as a rate increase will negatively ripple through economy and hurt Oregonians, a rate cut would have the same dynamic impact, but yielding positive results. A rate reduction now would help quell the rising costs of almost everything and help Oregonians stretch their budgets. A rate reduction is something the PUC should consider (not a rate increase) to best serve the current needs of all Oregonians."
Gene	Souza	KLAMATH FALLS	Klamath Irrigation District opposes the general rate change. A 22.4% increase for agricultural producers is excessive, as PacificCorps is already charging Klamath farmers over three times the average rate for other Oregon producers in the same market. Agricultural producers cannot increase product prices to recoup these losses to PacifiCorps as the market is set regionally. Klamath County is classified as a disadvantaged community by the state of Oregon. Klamath Irrigation District also acknowledges and supports the comments sent by Klamath Water Users Association.
Frank	Blackston	GRANTS PASS	PLEASE stop approving rate increases. You have already allowed recent rate increases. Pacific Power makes enough money to should shoulder some of the rate increases. You keep approving passing all costs to consumers (Oregon residents), when we are already facing very high cost of living. you are making it untenable for people to live here.
Arman	Kluehe	REDMOND	The public CAN NOT afford to pay for another rate increase. Please find a way to lower your cost of operation.
NA	NA	REDMOND	I these rate increases are crazy for us on fixed income.

First Name	Last Name	City	Comment
Andrew	Nichols	KLAMATH FALLS	Subject: Opposition to Pacific Power' Proposed Rate Increases (Docket UE 433) Dear Oregon Public Utility Commission, I am writing to express my strong opposition to Pacific Power' proposed rate increases under docket number UE 433. The significant increases across various customer classes, including residential, small businesses, and agricultural services, will have a detrimental impact on our community, which is already classified as disadvantaged by the state of Oregon. Effect of Proposed Rate Changes: Residential: 21.6% Small Businesses: 22.4% Small Businesses (31-200 kW): 10.4% Small Businesses (201-999 kW): 11.3% Large Businesses (>= 1,000 kW): 14.1% Agriculture Pumping Service: 22.4% Street Lighting: 4.5% Many residents in our community live on fixed incomes and cannot afford such substantial increases in their electricity bills. The proposed rate hikes will significantly affect their quality of life and financial stability. Beyond the direct impact on households, the increased costs for small and large businesses will likely lead to higher prices for goods and services, exacerbating the financial burden on residents. Combine this rate increase with inflation, and those on a fixed income will not be able to afford heating their home in the winter months. The 22.4% increase for Agriculture Pumping Service is particularly unjust, placing an excessive strain on our agricultural sector. Farmers and agricultural businesses are already dealing with numerous challenges, and this disproportionate increase could jeopardize their livelihoods. Please remember Klamath Basin Agriculture is already struggling due to water policy, increased power rates will be devestating to farmers and ranchers. The cumulative impact of these rate increases, especially in the wake of last year' substantial hikes, is untenable. It is crucial to consider the broader economic implications for a community that is already struggling. I urge the Oregon Public Utility Commission to reject Pacific Power' request for these rate increases. Maintaining fair and affordable utility rates is essential for the well-being of our community and the economic health of our local businesses. Thank you for considering my comments. Sincerely, Andrew Nichols
Jonathan	McNeil	TIGARD	No. Hell to the no no no no Nope. Nah. Negative. Nuh Uh Stop spending my money.
D	Wadd	DAMASCUS	It is completely irresponsible to except rate holders to pay another increase. Two plants have been shut down in Oregon with thought or concern about how power was going to be replaced. We should have to brunt the cost of your irresponsibility.

First Name	Last Name	City	Comment
E. Werner	Reschke	MALIN	I write to express my stern opposition to the rate increases proposed by Pacific Power. For nearly three years inflation has been plaguing Oregonians; now is the worst possible time for rate increases. Electricity is at the foundation of our economy. Any increase, no matter how small, ripples throughout the economy with a multiplier effect. The proposed rate increase will dynamically and negatively impact the cost of everything which requires electricity to cool, light or power. Practically these rate increases will increase the cost of fuel, groceries, heating, cooling, medical care â€" literally everything. Business which incur these increased operational costs will merely pass these costs along by raising prices for their goods and services. Moreover, the direct rate payer increases, by ~20%, is unprecedented in recent times. Many Oregonians are trying to just afford the basics. This request for rate increases by Pacific Power come at a time when many Oregonians are still behind in their budgets due to impacts of inflation. I understand the reasons for Pacific Power' request: wildfire protection, new capital investments and better insurance. But these are not new or unforeseen costs. Pacific Power should have been using their revenues and profits to prepare for such resiliency and improvements as part of their long-term planning. Rate payers should not be penalized for poor planning or mismanagement by a multi-billion dollar corporation. Therefore, I sincerely request that the PUC rejects Pacific Power' request to increase rates. Finally, here is a proposal that I recommend the PUC consider in order to help Oregonians combat inflation â€" decrease rates by 1Â¢/kW across the board. Just as a rate increase will negatively ripple through economy and hurt Oregonians, a rate cut would have the same dynamic impact, but yielding positive results. A rate reduction now would help quell the rising costs of almost everything and help Oregonians stretch their budgets. A rate reduction is something the PUC should consider (not a rate increase) to best serve the current needs of all Oregonians. Sincerely, E. Werner Reschke STATE REPRESENTATIVE, HD 55
Diana	Velasquez	BEND	I absolutely oppose any rate increase.
Outraged	Citizen	MULTNOMAH	The Oregon PUC is violating ORS 757.020 Duty of utilities to furnish adequate and safe service at reasonable rates. The rate increases are causing burdens on customers while enriching energy companies, NGO' and social justice groups rather than their sole duty to provide affordable services. Taxpayers should not be funding for profit utilities and enriching third parties. You are passing out air conditioners while people can't afford to run them. Providing reduced cost services to low income recipients violates the public contract to provide affordable services to all.
Edward	Murrer	BEND	Show the complete financial justification including operating budget, salaries, maintenance costs, asset plans. Prove the rate increase is justified. Incidentally, a justification is NOT that the fires have required big settlements. If the utility is responsible for a fire then it it on then to bear the financial penalty, not the public.
Karen	Frick	GRANTS PASS	I am against the rate increase. PAC has had a few sizable rate increases and as a consumer we are not getting cost of living increases, or much of ones. I am on SS and not much of an increase. The company has had plenty in the last few years. I feel consumers are being punished for bad decisions with the wildfires from the company.

First Name	Last Name	City	Comment
Nicki	Strain	KLAMATH FALLS	I am writing in opposition to the proposed rate increase by Pacific Power. With the current climate of inflated prices on food, fuel, housing and other essential items, I feel that this rate increase will cause additional hardship. Just last year, Pacific Power was granted a substantial rate increase and is now asking for another large increase that will affect every consumer. Citizens, small businesses and farmers are already struggling to keep their heads above water. Having to foot the bill for another unexpected and unnecessary increase in utility costs is extremely unfair. I ask you to consider all of these factors regarding this proposal.
Jason	Morrow	KLAMATH FALLS	Our community is classified as disadvantage because of income. It is going to put a burden on the citizens and businesses.
Del	Fox	DAIRY	This new increase on top of the last 3 increases will make it impossible to irrigate or drain our district. the net result will stop irrigated agriculture and close Hwy 140 E during the winter through Pine Flat. There is no natural drainage in Pine Flat and the water must be pumped out to prevent Hwy 140 E from flooding.
Linda	Shewmaker	GRANTS PASS	I was retired and am currently getting SS as I'm well over the full retirement age. Owned a home for 30 years, but due to high cost of home ownership, I sold my home. Now I've returned to working because of the high cost of rentals. If utility costs rise more than the current rate, can you offer a solution beyond the actions I've taken to afford the monthly cost of rent and proposed utility increase!
Ron	Adams	LYONS	Pacific Power and PGE both companies Everytime they have to pay a fine they make the rate payers pay for it. The Commissioners need to take a good look before they approve this for both companies. i don't mind paying my fair share but this isn't it, for either company. They're both monopolies and they don't need this much money to run the company. You need to look at decreasing the rates for the consumers not raising them.
Cassandra	Allen	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. CASSANDRA ALLEN 1913 SE Main St Portland, OR 97214-3826 cassandra.j.allen@gmail.com

First Name	Last Name	City	Comment
Hal	Anthony	GRANTS PASS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. My truck is over 30 years old, gets 15-16 mph, and is falling apart. My SS check is tiny and I am dying with Stage 4 cancer because of the VA and Asante's total negligence. Please, DO NOT ALLOW PAC POWER'S OUTRAGEOUS RATE INCREASE! An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Hal Anthony 3995 Russell Rd Grants Pass, OR 97526-9781 threepines@centurylink.net

First Name	Last Name	City	Comment
Hal	Anthony	GRANTS PASS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I am living on (dying on) just over $15,000 annually, with waaay too small of COLA increases in SS. Allowing a hugely profitable outfit like Pacific Power to increase their fees at these endlessly attempted and quite HIGH IN THE SKY rates is an insult to veterans like me, and every single one else. Please do something constructive, like truly fix the rotten VA whose negligence gave me Stage 4 cancer; or your approval for sending BILLIONS to Israel to murder civilians in souther Gaza who were NOWHERE NEAR WHERE HAMAS COMITTED THEIR ATROCITIES (atrocities which Nutjobyahoo out-mercenaried by 200%). WTF? Why does an increase this large does not need to happen right now??! This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Hal Anthony 3995 Russell Rd Grants Pass, OR 97526-9781 threepines@centurylink.net
Jesse	Appling	GRANTS PASS	I'm not sure who in this state is receiving 15-25% increases in wages but all the people I know are not. If I get in an accident and my insurance goes up, I got to suck it up and live within my means. That's great they wanna start these wildfire funds and protection funds etc., that is on them though. Something they should be trimming the fat for not placing that burden on their customers. What do the last 5 years of rate increases add up to? It doesn't take much to see that these are ridiculous increases.
Bob	Baroni	CAVE JUNCTION	Please disallow these outrageous rate increases. These utility companies have been collecting millions of dollars for years with out making necessary repairs! Also, put a cap on upper management salaries!

First Name	Last Name	City	Comment
Dawn	Barry-Griffin	WARRENTON	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also DO NOT want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Dawn Barry-Griffin 89163 Manion Drive Warrenton, OR 97146 dawninpdx@msn.com
Nola	Becket	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Nola Becket 9728 N Syracuse St Portland, OR 97203-1432 alon7715@gmail.com

First Name	Last Name	City	Comment
AL	Beltram	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr Al Beltram 6195 Rosemarie St NE Albany, OR 97321-7405 rabeltram@gmail.com
Rebecca	Bent	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Rebecca Bent PO Box 820104 Portland, OR 97282-1104 reclaimdemo@yahoo.com

First Name	Last Name	City	Comment
Samuel	Berg	NEWBERG	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr Samuel Berg 29601 NE David Ln Newberg, OR 97132-6457 sber6415@gmail.com
Donna	Bonetti	BEND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Donna Bonetti 1997 Oak St North Bend, OR 97459-2020 donnambirdlady@yahoo.com

First Name	Last Name	City	Comment
Daria	Brickner	BEND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs Daria Brickner 2875 NE Boyd Acres Rd Unit 1 Bend, OR 97701-8551 dariab@bendbroadband.com
Kellay	Briggs	PORTLAND	Hello- I am writing in regards to the price increase Pacific Power regarding a rate increase for customers. On August 5th, 2024, myself and other customers of Pacific Power received an email informing us of the proposed rate increase of 11.9%. I am deeply concerned about Pacific Power's proposed rate increase. This significant hike would add undue financial burden on households, particularly during challenging economic times. Many families are already struggling with rising living costs, and an additional $21.49 per month could push some into financial hardship. While investments in infrastructure and green energy are important, the cost should not fall disproportionately on consumers, especially those with limited means. Given the monopoly power companies hold, consumers have no choice or control over choosing their power provider, making this increase especially unfair. I urge the Oregon Public Utility Commission to reconsider this proposal and seek alternative funding methods.

First Name	Last Name	City	Comment
Robert	Brosius	GRANTS PASS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. These increases never stop. There is no other area of our economy increasing at this rate. This request is outrageous. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Robert Brosius 1909 SE Portola Dr Grants Pass, OR 97526-4052 brosius@usa.net
Robert	Burch	COQUILLE	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Robert Burch 56965 Gladewood Rd Coquille, OR 97423-8509 robertburch51@gmail.com

First Name	Last Name	City	Comment
Jaime	Burnap	REDMOND	I am writing to express my strong opposition to Pacific Power's proposed rate increase for 2025. I believe that this increase is unjustified given the company's financial performance and the negative impact it will have on consumers. In 2023, Pacific Power reported a profit of over $2 billion. This substantial profit demonstrates that the company is financially stable and capable of funding its operations without passing the costs on to consumers. Despite this profitability, Pacific Power has consistently raised rates in recent years, even as energy costs have declined. These continual rate increases place a significant burden on individuals and businesses across Oregon. The poor, middle class, small businesses, and non-profits are particularly vulnerable to the effects of rising energy costs. These increased expenses limit their ability to thrive and contribute to our communities. I urge the Oregon Public Utilities Commission to carefully consider Pacific Power's financial health and the impact of this rate increase on consumers. I believe that Pacific Power should be required to utilize its substantial profits to fund necessary improvements and maintain reliable service without burdening Oregonians with additional costs. Thank you for your time and consideration of this important matter.
Jason	Burns	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Jason Burns 7216 SE 13th Ave Portland, OR 97202-5804 nc2pdx@protonmail.com
Marcos	C	BEND	I want to point out that this rate increase has nothing to do with the ability to operate a power network. This is simply corporate greed. Berkshire Hathaway Energy, parent company of Pacificorp posted a net profit of $689 million dollars in Q1'2024 alone. A 12% increase is unjustifiable for a service that is a basic need in people's lives.

First Name	Last Name	City	Comment
Caren	Caldwell	ASHLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make electricity bills unaffordable for people who live at the lower end of the economic scale. As the cost of living remains high, raising bills this much will have a significant negative impact on fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want people's bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Rev. Caren Caldwell 124 Ohio St Ashland, OR 97520-1119 caren97520@yahoo.com
Rachel	Capasso	BEND	My power was shut on and off 3-5 times in the middle of the night last night, waking everyone up each time. This is not a rare occurrence. The parent company of Pacific Power made over half a million in net profit in only the first quarter of this year alone. Electricity is a basic need. It is illegal to shut power off to squatters for that very reason. If we all collectively stopped paying rent and squatted instead would we be better off? This is ridiculous.

First Name	Last Name	City	Comment
Benjamin	Chambers	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. Nearly 22%?! My wife and I are retired, and we can't absorb this kind of increase on a fixed income â€“ certainly not when Oregon's for-profit utilities have been asking for 15-20% increases almost every year since 2020. I get that climate change is affecting their business; but they have a long history of trying in sketchy, underhanded ways to shift costs from shareholders to ratepayers -- not to mention taking almost no action to adjust to climate change -- so I'm skeptical that they need this kind of increase now. And in any case, in what other business can shareholders expect anyone else to foot the bill for increased costs? Ratepayers are captive; shareholders and leave at any time â€“ why should ratepayers take the brunt? Raising bills this much will have a significant negative impact on my household and fellow Oregonians. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. (Frankly, I'd limit it even more if it were up to me, but I accept that they probably recognize what the so-called "market" will bear.) And btw, I don't want my utility bills to pay for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. The idea that customers should pay for "self-insurance" is risible when the company doesn't properly manage its own risks. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must hae more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Benjamin Chambers 3114 NE 47th Ave Portland, OR 97213-1823 wapshot1@gmail.com
Joy	Childers	BEND	Didn't they just do a rate revision in a time where costs are soaring everywhere? This would just had to the expenses of our family is struggling to meet.
Rebecca	Clark	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Rebecca Clark 5035 N Depauw St Portland, OR 97203-4418 bjclark@siderial.com

First Name	Last Name	City	Comment
Tianna	Collier	BEND	I am writing to express my strong opposition to the proposed 14.9% increase in electricity rates for residential customers. This substantial increase is deeply concerning, especially considering the financial strain that many of us are already under. Berkshire Hathaway Energy, the parent company of Pacific Power, made $689 million in net profit in the first quarter of 2024 alone. This demonstrates that the company is already highly profitable. Additionally, inflation in the last three years (2021-2023: 16.9%) nearly matches the inflation seen over the previous ten years (2011-2020: 17.4%). Given these figures, it is difficult to justify such a significant rate hike at a time when many households are struggling to keep up with rising costs. Electricity is a basic need, and this increase in rates will disproportionately affect low- and middle-income families. The average residential customer, using 950 kilowatt-hours per month, would see a $21.49 increase on their monthly power bill. For many, this additional cost is simply unaffordable and will force difficult choices between paying for electricity and other essential needs. Higher utility bills could lead to an increase in homelessness, as more people may be unable to afford their living expenses. It is crucial to consider the broader social and economic impacts of this proposal. I urge you to reconsider this rate increase and to find alternative solutions that do not place an undue burden on residents who are already struggling to make ends meet. Thank you for your consideration.
Elizabeth	Darby	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Elizabeth Darby 1020 NW 9th Ave Portland, OR 97209-3473 elizabethdarby137@gmail.com

First Name	Last Name	City	Comment
Larry	De Young	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Larry De Young 5047 N Park Ct NE Albany, OR 97321-9541 lldeyoung2@gmail.com
Teresa	DeLorenzo	ASTORIA	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. The proposed rate increase is unnecessary and ill-advised. This January, we saw record bills during the ice storm after two years of double-digit rate increases. Approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lower. Payment of my bills should underwrite Pacific Power's wildfire liability -- that's the responsibility of the corporation and its shareholders, not the ratepayers. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. It is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Teresa DeLorenzo 93121 Knappa Dock Rd Astoria, OR 97103-8469 tde@teleport.com

First Name	Last Name	City	Comment
Julienne	DeMarch	MRYTLE CREEK	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Julienne DeMarsh 1152 N Old Pacific Hwy Myrtle Creek, OR 97457-9461 juliennedemarsh@gmail.com
Christian	Dolan	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. In January, we saw record bills during the ice storm after TWO YEARS OF DOUBLE-DIGIT RATE INCREASES. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. For-profit utilities should be subject to limited rate increases. I do not want my bills to go toward paying for Pacific Power's wildfire liability. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Christian Dolan 2427 SE 66th Ave Portland, OR 97206-1205 2427se66@gmail.com

First Name	Last Name	City	Comment
Levi	Doty	MEDFORD	Not sure if this will fall on deaf ears or not - Pacific Power is price gouging the citizens of Oregon, we saw our power bill go to $440 in one month because of the heat and having to run AC, it was 110 degrees and more some of July to they propose that we just don't use power to afford to live? I cannot sustain $400 a month power when the only think running is our Fridge and our AC because we can't risk the bill going any higher. I grew up here in SO Oregon, raised my family here, now I am faced with the prospect of having to sell my house and move somewhere we can afford to live, and I work at a good job, I cannot imagine what lower income households are going through. If Pacific Power raises rates another 21% in 2025 we are effectively being pushed out of the state to find cheaper living. There are no other power companies in the monopoly they have going, we cannot just switch. Solar is NOT a viable option the hidden fees and costs involved in getting a solar setup mean 10 years down the road it might pay for itself and that just tacks on a new bill we cannot afford. Something needs to be done about this highway robbery they call a power company, none of these rate hikes are sustainable how do they expect people to afford that along with massive food inflation, as well as home insurance rate hikes. Something has to give and unfortunately it is going to be us leaving the state I have called home for my entire life. Sincerely Levi Doty Medford Oregon
Craig	Emerick	CORVALLIS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Craig Emerick 221 NW 9th St Corvallis, OR 97330 cemerick5@comcast.net

First Name	Last Name	City	Comment
Mary Lou	Emerson	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. Sincerely, Mary Lou Emerson I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Mary Lou Emerson 922 SE Lambert St Portland, OR 97202-6328 marylouemerson1947@gmail.com
Joseph	Endres	COOS BAY	Dear persons, A 12% rate increase is outrageous for Pacific Power. This is going to harm a majority of customers in Oregon who live paycheck to paycheck. Gouging customers to help stock price is thievery. Especially since inflation is now completely under control.
Dianne	Ensign	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I am a senior citizen living on a fixed income. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Dianne Ensign 11600 SW Lancaster Rd Portland, OR 97219-7655 roughskinnednewt@hotmail.com

First Name	Last Name	City	Comment
Joseph	Falletta	TERREBONNE	I just read the article about yet another proposed rate increase for Pacific Power.. and while they did decrease what they were asking for, it's still more than the previous increase! I ask that you turn this down. Not only is this more than what we retired folks on Crooked River Ranch can afford, we've also had to put up with power outages...four that I count over the past month. This last one was down for 2.5 hours. I hope you will do the right thing for all of us and veto this rate increase.
Thomas	Fawell	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. Pacific Power customers could be paying 63% more for electricity than in 2022! This is too much of an increase and too fast! We need a cap on billing rate increases. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Dr Thomas Fawell 2204 NE 38th Ave Portland, OR 97212-5260 tfawell@yahoo.com
Michael	Fitzgerald	KLAMATH FALLS	I understand that Pacific Power is seeking to raise our electricity rates 21.6%! Such a rate increase is unconscionable! Pacific Power can not be given free reign to raise rates. A 21.6% rate increase is indicative of poor business practices. Regulators must put a limit on Pacific Power rate increases and require that any increases be justified. If Pacific Power finds that it can not do business in such a manner as to provide us with electrical power at a reasonable rate then efforts should be undertaken to transform Pacific Power into a public-service corporation owned by the people. Michael J Fitzgerald 11417 Hill Rd Klamath Falls, OR 97603 (541) 880-6036
Shawn	Flot	TALENT	Pacific Power in Talent has had a recent history of multiple outages and a lot of them compared to other communities in the area. I received notice of a price increase and yet the outages are frequent and long. And I'm talking at least 10 that I've experienced in the last month. This is beyond any "outage" What actions do we have to ask for the outage tendency be rectified before any price increase
Sara	Foerster	BEND	Electricity is a public need, yet the parent company of Pacific Power (which made $689 million net profit in the first quarter of 2024) is increasing rates to make more money off me and my family. I am out of work and on unemployment insurance, all our other expenses have skyrocketed in the past few years, and we can't move anywhere else because of the price of housing and interest rates. Please reconsider allowing this rate increase. It is destructive to the middle class. We need a break.

First Name	Last Name	City	Comment
Porter	Friedman	BEND	Please do NOT ALLOW them to raise our prices yet again... Can we consumers/citizens have a break for once? Rising costs of staples like groceries, rent, and now utilities? And its not even a small adjustment (like <5%) its a a FIFTEEN PERCENT increase! How about we hold pacific power responsible for their infrastructure, wildfires, and insurance costs? They are making tons of money...
Cyndi	Gentry	LEBANON	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. This, coupled with the small rebates available through Energy Trust to switch from gas heat to electric, certainly does not encourage power users to move away from fossil fuels. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Cyndi Gentry 390 W Sherman St Lebanon, OR 97355-2627 Cyndi-Gentry@nwascopud.org
Kirsty	Giles	CLACKAMAS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Kristy Giles 14381 SE Charjan St Clackamas, OR 97015-9347 kristygiles@aol.com

First Name	Last Name	City	Comment
Mariea	Gill	MEDFORD	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. In fact, it had better NOT happen! This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Mariea Gill 1009 W 9th St Medford, OR 97501-3009 gill.marieac@gmail.com
Phil	Goldsmith	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Phil Goldsmith 3110 NW 112th Pl Portland, OR 97229-4051 phil@lopglaw.com

First Name	Last Name	City	Comment
Michelle	Graas	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. Pacific Power demands this exorbitant rate increase (this would be the third double-digit RI in just a few years!) to force Oregonians to pay for the damages resulting from its gross negligence during the 2020 fire season. It is absurd and unreasonable for customers to bear responsibility for funding the majority of the Catastrophic Fire Fund or to "self-insure" their properties. We didn't cause the problem and shouldn't be made to pay for it -- Pacific Power's corporate leadership and stockholders should be held accountable. But the problem isn't just with Pacific Power: more and more of Oregon's for-profit utilities have requested multiple 15-20% increases over the last few years. As weather patterns become less predictable and storms more volatile, ratepayers face record-high bills after major events (like January's ice storm!) with no relief in sight. Oregonians deserve reasonable and realistic utility rates, not these price-gouging tactics. I firmly believe that Pacific Power and all other for-profit utilities should be subject to limited rate increases, and I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lower. If for-profit utilities cannot provide appropriate service with that limitation, then they should convert to state-owned or not-for-profit models. Because this isn't working for any of us. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Michelle Graas 7624 N Albina Ave Portland, OR 97217-1308 amgraas@efn.org
Matthew	Gray	CORVALLIS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Matthew Gray 1915 NW 14th St Corvallis, OR 97330-2033 tomattsiphone@gmail.com

First Name	Last Name	City	Comment
Peter	Green	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Peter Green 5228 SW Westwood Vw Portland, OR 97239-2768 peterfgreen@comcast.net
Emily	Gross	BEND	Please reconsider raising residential electricity costs yet again. This is entirely unsustainable - everything is expensive, and many hard working people like myself are being squeezed more and more so that a few wealthy people can make a profit. This does not serve the customer base and increases financial hardship when the situation is already so dire for so many families and individuals who are living paycheck to paycheck. Berkshire Hathaway Energy, the parent company of Pacific Power, made $689 million dollars of Net Profit in the first quarter of 2024 alone. Inflation in the last three years ('21-'23: 16.9%) was about equal to the inflation seen in the ten years ('11-'20: 17.4%) before that. Electricity is a basic need, and they are squeezing us so that their quarterly profits can get closer to a billion dollars. Again, please reconsider raising rates and making working people pay the price.

First Name	Last Name	City	Comment
Chris	Guillory	PORT ANGELES	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Chris Guillory 420 S Laurel St Apt 5 Port Angeles, WA 98362-2803 chris_no51@yahoo.com
Ted	H	BEND	To Whom it May Concern, I oppose the suggested rate increase. Electricity is a basic need and should not be subject to egregious profiteering. My family struggles with the rate of inflation in recent years and this will only exacerbate our depleted finances. Thank You.
Ally	Harris	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Ally Harris 4312 SE 24th Ave Portland, OR 97202-3903 ally@ojta.org

First Name	Last Name	City	Comment
Randy	Harrison	EUGENE	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Randy Harrison 4051 Wagner St Eugene, OR 97402-8725 ran6711@comcast.net
Melissa	Hathaway	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Melissa Hathaway 601 NE 162nd Ave Apt 74 Portland, OR 97230-5778 infomavn@teleport.com

First Name	Last Name	City	Comment
David	Hawley	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to suddenly happen. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. David Hawley 1191 NW Jordan Dr Albany, OR 97321-9223 kayndavid@comcast.net
Matt	Hays	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Matt Hays 7555 SW Brier Pl Portland, OR 97219-2811 mhays08@mac.com

First Name	Last Name	City	Comment
Susan	Heath	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Susan Heath 2552 Mount Vernon St SE Albany, OR 97322-8898 forbux@hotmail.com
Leslie	Heilbrunn	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. The yearly double-digit price increases we've been seeing are an outrage, going well beyond the cost of inflation. Families have budgets and utilities are taking up too much of them these days. Doing this at a time when Pacific Power is being held liable for wildfire damages that boggle the mind and I am experiencing more blips that ever before makes me question what I'm paying for. The utility model is broken -- utilities are encouraged to make capital investments that don't necessarily make sense but somehow are okayed as "used and useful" by the OPUC; Pacific Power is actively trying to have customers pick up the tab for their negligence that caused wildfires, which I strongly oppose; the fiscal waste I have witnessed at these companies as they act in ways motivated by compliance and risk avoidance rather than customer benefit is substantial; and the executive salaries are ridiculous, especially considering they are running regulated monopolies. I am concerned about the proposed additions of "self-insurance" paid by customers and don't think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Leslie Heilbrunn 4340 NE 49th Ave Portland, OR 97218-1700 leslieheilbrunn@gmail.com
Johann	Helf	BEND	Your parent company made almost 700 million in profits in the first quarter alone. Electricity is a basic human need. Stop fleecing struggling customers for the almighty dollar.

First Name	Last Name	City	Comment
Hector	Hernandez	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Hector Hernandez 4047 SE Brooklyn St Portland, OR 97202 hectorhhg@comcast.net
Margaret	Heydon	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Margaret Heydon 2352 NE 150th Ave Portland, OR 97230-4552 heydonm84@gmail.com

First Name	Last Name	City	Comment
Theodora	Hight	MEDFORD	Members of the Public Utility Commission: My name is Theodora Hight, and I have resided at 1200 Mira Mar Ave., Apt. 1018 with my husband Rob since 2018. We retired and moved back to Medford in 1989. We have been Pacific Power customers since then and members of Blue Sky until PRS started paying our electric bill. We live in one of three towers and live with about 900 residents on Rogue Valley Manor Campus. We are charged for this resource yet indirectly through our monthly fees. This fee has been increased 6% for next year as of yesterday. Yet the Pacific Power Company is asking for an additional 21.6% on the electricity used here. And the usage is considerable! This means we could be paying 63% more for electricity than we paid in 2022. If the increases were limited to 7% plus inflation or to 10% whichever is lower, we could accept the cost of doing business, yet we are aware Oregon's for-profit utilities have navigated 15 to 20% increases nearly every year for the last 4 years! Thus we are asking for a cap for all for-profit utilities, not just Pacific Power. We walk around our building turning off unnecessary lights every evening. It is something we feel obliged to do, as we realize the energy wasted is not recovered and we pay for the extravagant use of electricity here. I don't know our monthly bill yet imagine 6 figures? We have had an energy audit done recently and our Green Team here at the Manor is focused on reducing our carbon footprint as we have educated ourselves over the years. Our resources are not sustainable because we are using future generations share. We want fervently to become more resilient and hope that these rate increases aren't lining CEO's and stock holders pockets. Yet it seems greedy even if it is just transitioning us into renewable sources of energy and away from fossil fuels. If they are at least doing that it would be less painful. Young families and elderly people in our community do not have the ability we might have to bear this added monthly expense (if it is approved) and will have to do without food or medicine. Combined with our hottest summer day on record (our small blue dot's average) just recently, this might be a difference between life and death. Thank-you for your time and consideration, Sincerely, Theodora Hight
Robert	Hight	MEDFORD	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. My wife and I have been members of the Medford Congregational United Church of Christ, 1801 E. Jackson since 2001. Our pledges help pay our bills as we have to operate within the budget prepared by our board and approved by members. The COVID pandemic hit our aging congregation hard and we also were without a settled minister until yesterday! We met virtually for years and then slowly have been rebuilding a resilient church family, a welcoming community resource for a Montessori School, non-profits and substance abuse support groups meeting most days. We had a gas furnace in our sanctuary that failed over 6 years ago and never had a/c in that huge space. Last Oct. we had 6 heat pumps installed there and 3 heat pumps, mini splits in social hall. We are pleased with returning to worship in our beautiful sanctuary with heat and a/c. Our electric bill is being averaged yet it is $1,000.00 more a month since last Oct. 2023 when this HVAC project was completed. We envision a transition to renewable energy support in the future, yet you can see what our small congregation is dealing with concerning this unreasonable increase (considering the 15 to 20% annual increases we have already weathered?). I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Robert Hight 1200 Mira Mar Ave Apt 1018 Medford, OR 97504-8556 rnthight@gmail.com

First Name	Last Name	City	Comment
Thor	Hinckley	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Thor Hinckley 7421 SE Grant St Portland, OR 97215-4180 thorhinckley53@gmail.com
Steve	Hocker	LINCOLN CITY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Steve Hocker 1373 SE 41st St Lincoln City, OR 97367-5302 steve.hocker@comcast.net

First Name	Last Name	City	Comment
Tena	Hoke	PORTLAND	Dear Public Utility Commissioners, I am strongly opposed to Pacific Power's request for a rate increase of 21.6%. Such a huge increase is far beyond the budgets of those of us who are retired and see our savings decrease in value every year. Even 10% is too much. Due to global warming our energy bills are already higher than they used to be due to our need to run air conditioning (which we are fortunate to have) during the hot summer months. Something needs to be done with all electric utilities to decrease these egregious rate hikes. I understand the need to upgrade our power delivery infrastructure, but I have no faith that Pacific Power will do in the most cost effective way. Please stop the rate hike! Best regards, Tena Hoke 5026 SE 46th Ave Portland, OR 97206
Thomas	Holley	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Thomas Holley 1711 NE 125th Ave Portland, OR 97230-1802 thomasholley@icloud.com

First Name	Last Name	City	Comment
Ann	Hollyfield	WALDPORT	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Ann Hollyfield PO Box 999 Waldport, OR 97394-0999 hollyhast@peak.org
Paul	Hosey	WEST LINN	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. The average homeowner did not receive a 21.6% raise in income in the past year. Let alone citizens on fixed incomes such as social security. Their cost of living increases are tied to inflation. Now running at closer to normal. 3-4%. Your prosed increase is unreasonable. Please cut dividends to shareholders first. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Paul Hosey 1354 Troon Dr West Linn, OR 97068-1877 p.hosey@comcast.net

First Name	Last Name	City	Comment
Jynx	Houston	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Jynx Houston 7605 SE Lincoln St Portland, OR 97215-4153 jynxcdo@gmail.com
Laurence	Hoye	HOOD RIVER	I do not support any rate increase this year. PacifiCorp had its double-digit percentage of 11% rate increase last year. That should be good for 3-5yrs. No increase should be more than cost of living increases for a public utility.
Rory	Isbell	BEND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Rory Isbell 1354 NW Federal St # 1 Bend, OR 97703-2337 roryjamesisbell@gmail.com

First Name	Last Name	City	Comment
Dan	Jaynes	BEND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Dan Jaynes 2210 NW High Lakes Loop Bend, OR 97703-6973 dan.jaynes@gmail.com
Terry	Jess	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am concerned and worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and many fellow Oregonians. I do not support draconian behavior nor "billionaire thinking". Demonstrate clearly a commitment to humane and supportive actions. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Terry Jess 955 5th Ave SW Albany, OR 97321-1907 terry.e.jess@gmail.com

First Name	Last Name	City	Comment
Sandra	Joos	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Dr. Sandra Joos 4259 SW Patrick Pl Portland, OR 97239-7202 joosgalefamily@comcast.net
Tracey	Katsouros	WALDPORT	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Tracey Katsouros 1322 Harwich Dr Waldorf, MD 20601-3322 traceycsmallwood@gmail.com

First Name	Last Name	City	Comment
Phila	Kelsey	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. We are senior citizens and as we are on a fixed income this increase will hit us hard. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Phila Kelsey 14808 NE Newport St Portland, OR 97230-4673 philakelsey@gmail.com
Judith	Kenyon	TALENT	433 - PACIFICORP REQUEST FOR A GENERAL RATE REVISION. NOPE, no huge rate increase!
Rebecca	Kimsey	SUBLIMITY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. Shareholders need to do more to ensure that the corporation is responsibly acting in the community. I'm not getting any 20% increase in MY funding, so the heck with Pac Power's thinking it will just pawn its negligence over on me. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Rebecca Kimsey 815 SW 9th St Sublimity, OR 97385-9682 rkimsey68@gmail.com

First Name	Last Name	City	Comment
Colleen	Kiser	MERLIN	Power bills have increased dramatically with the last rate increase. The economic hardship of the last increase is still being adjusted to by our communities and an additional 16.9% will dramatically reduce our communities health due to increased food, housing, and utility insecurities. It also reduces income available to be spent in the economy for essential items.
Nora	Kroese	LEBANON	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Nora Kroese 1680 Cascade Dr Lebanon, OR 97355-3507 meowing1thru10@gmail.com
Charles	Kuttner	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. In an era in which consumers are being urged to change from natural gas for heating to electricity, from gasoline-powered vehicles to electric--both of which I think are great ideas for the environment--to raise rates is very likely going to provoke considerable backlash in addition to terribly straining households' budgets. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Dr. Charles Kuttner 4006 SW Dakota St Portland, OR 97221-3334 ckuttner@jhu.edu
Rikki	Larese	CAVE JUNCTION	I don't support an increase to my current rate

First Name	Last Name	City	Comment
NA	LD	ASHLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, my sister saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my sister's household and fellow Oregonians. _______>>>>>> I have a friend who lives in a "trailer park" and is very poor. She goes without heat many days in the winter, the INDOOR temperature in her house dipping down as low as 45 DEGREES. WHY? Because she can't afford high bills. <<<<<<<______ We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. L D 183 E Ashland Ln Ashland, OR 97520-9601 de5franco5@gmail.com
John	Lem	MEDFORD	I oppose this. PacifiCorp is owned by a large investment fund that is highly profitable. Inflation has already hit everyone extremely hard and this is going to just make it tougher for families.
Ann	Littlewood	PORTLAND	annlittlewood3@everyactioncustom.com. Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. This is a huge increase! How can you expect people of low income to manage this? We will see more heat deaths as people try to save on their bill and more shut-offs with this rate increase. We've had two years of double-digit rate increases. As the cost of living remains high, raising bills this much will have a significant negative impact on my fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. Share holders should be payingg for Pacific Power's wildfire liability, not customers. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Ann Littlewood 2915 NE 21st Ave Portland, OR 97212-3445 ANNLITTLEWOOD3@GMAIL.COM

First Name	Last Name	City	Comment
Susan	Longstreth	GRANTS PASS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. I'm retired. If ONLY my Social Security benefits would also increase 21.6%, or anything close to what Pacific Power has previously increased my power bills. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Susan Longstreth 389 Quail Ln Grants Pass, OR 97526-9644 susan@cathexisconsulting.com
Linda	Lu	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large CANNOT happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want to live where people's bills go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. This is wrong! WE PAY FOR SERVICE AND THE COMPANY MUST SHOULDER most of MAINTENANCE AND R&D COSTS. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. Pacific Power, YOU ARE FIGHTING A LOST BATTLE. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Linda Lu 3622 SE Gladstone St Portland, OR 97202-3242 lindalu@reed.edu

First Name	Last Name	City	Comment
Brian	Lum	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Brian Lum 5020 NE 52nd Ave Portland, OR 97218-2022 bklum@hey.com
Rosemary	Martin	MEDFORD	UE 433 - PACIFICORP REQUEST FOR A GENERAL RATE REVISION. Berkshire Hathaway Energy, the parent company of Pacific Power, made $689 million dollars of Net Profit in the first quarter of 2024 alone. inflation in the last three years ('21-'23: 16.9%) was about equal to the inflation seen in the ten years ('11-'20: 17.4%) before that. electricity is a basic need, and we are being squeezed so that the quarterly profits can get closer to a billion dollars.
Greg	Martin	PORTLAND	As a Pacific Power customer, I urge the OPUC not to approve the utility's proposed 21.6% rate hike in full. A double-digit increase for the third straight year will be hard enough for customers to absorb without jacking the rates up so high that many will not be able to afford to heat their homes in winter and cool them in summer. As I understand it, a large portion of this request stems from PP's proposal to pass along to customers the majority of its costs related to wildfire liability, insurance, and mitigation. It's not fair to make customers pay more of these costs than PP's shareholders pay -- especially as PP continues to invest heavily in systems that are worsening climate change and increasing wildfire risk. I suspect that PP's rate filing also contains a certain amount of "junk" in the form of other corporate expenses that shareholders, rather than customers, should pay for. Please scrutinize all such expenses to ensure that customers pay no more than their fair share. OPUC should disallow utilities' practice of asking for multiple rate increases each year, which make it difficult to project how much of an overall increase customers can expect. Instead, the commission should impose a reasonable cap on rate increases of no more than 10% per year. Thank you for your consideration. Greg Martin NE Portland
Katherine	Martushoff	EAGLE POINT	The rates are already too high. Please say no to another rate icrease.

First Name	Last Name	City	Comment
Laura	Matthiessen	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Laura Matthiessen 6815 N Congress Ave Portland, OR 97217-1948 lmatthiessen@gmail.com
Roger	May	MEDFORD	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Roger May 4509 Wolf Run Dr # OR97504 Medford, OR 97504-9673 rhmay7@gmail.com

First Name	Last Name	City	Comment
Angel	Mayall	ROSEBURG	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Angel Mayall 203 NE Neptune Ct Roseburg, OR 97470-1497 angel81fire@yahoo.com
Annie	McCuen	SALEM	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Annie McCuen 1825 Fairmount Ave S Salem, OR 97302-5209 mccuen7691@comcast.net

First Name	Last Name	City	Comment
Bruce	McGavin	MILWALKIE	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Bruce McGavin 13149 SE Pennywood Ct Milwaukie, OR 97222-3113 mcgavinski@duck.com
KC	Mckillip	ROSEBURG	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I own Backside Brewing Co. in Roseburg, Oregon. Simply put, the increase in power costs are not sustainable. At this rate within 2 years we won't be able to pay our electric bill at our business. Not just my business but businesses across Oregon. This is contributing to the crazy high inflation rates. Businesses have to charge more for their products just to pay their electric bill. We work on a budget and try to cut costs to stay in business and be fair to our customers. We would hope Pacific Power would be open to doing the same. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. KC Mckillip 1640 NE Odell Ave Roseburg, OR 97470-3320 kc@backsidebrew.com

First Name	Last Name	City	Comment
Kai	McMurtry	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Kai McMurtry 822 NE 72nd Ave Portland, OR 97213-6208 kai.mcmurtry@sierraclub.org
Linda	Meier	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Linda Meier 7817 SW Ruby Ter Portland, OR 97219-4643 lmeier@hevanet.com
Ian	Meyer	BEND	Electricity is a basic need. There's nothing in their service offering that necessitates such an increase. If anything, the increase goes to either paying for Pacificorp's legal issues relating to wildfires over the past 4 years, or making the executives/investors richer. Or both. My bill having increased by $40 over the past two years is completely unreasonable, as I'm sure many others have experienced. Do better.

First Name	Last Name	City	Comment
Vanessa	Meyer Crooks	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs Vanessa Meyer Crooks 3721 NE 23rd Ave Portland, OR 97212-1447 vmeyercrooks@gmail.com
David	Millenheft	NA	This is my complaint for Pacific Power raising utility rates after loosing the lawsuit. They should not be allowed to pass on that cost to customers for pacific power's negligence in causing the fire. Please stop the increase, Mr. David Millenheft
Anne	Mitchell	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest only because it is better than the current rules. My preference would be a limit to rate increases at 5% once every 2 years. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. I'm unsure if 50% is even too high. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Anne Mitchell 2821 SE 65th Ave Portland, OR 97206-1203 mitchellanne@hotmail.com
Ed	Momper	PRINEVILLE	If the company is making a profit then rates should not be increased.

First Name	Last Name	City	Comment
Sherry	Monie	DAMASCUS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Sherry Monie 23665 SE Borges Rd Damascus, OR 97089-6521 sherry.monie@gmail.com
Ed	Motteler	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr Ed Motteler 6530 SW Chelsea Pl Portland, OR 97223-7512 edmotteler@aol.com

First Name	Last Name	City	Comment
Amy	Murray	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Amy Murray 6530 SE Carlton St Portland, OR 97206-6628 gem2amarra@gmail.com
William	Musser	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Dr. William M. Musser IV 3225 NE 29th Ave Portland, OR 97212-2535 wmusseriv@icloud.com

First Name	Last Name	City	Comment
NA	NA	NA	I think it's time for the public utilities commission to be investigated. Raising consumers rates to pay for litigation costs and lawsuit fines is not what they are supposed to be doing yet you pave the way for them again and again to create undue hardship on its customers while considering a bill to limit consumer lawsuits and shareholders continue to get big payouts. The anti trust laws should be protecting us from this kind of monopoly but because they have the PUC of Oregon in there pocket they create a "legal" loophole to monopolize the system and suck the consumers dry when they get sued. Who allows this? It's time to find out. The lines should have been buried from the very beginning but money makes man evil, profit over life. All eyes should be on everyone responsible not sure pacific power.
NA	NA	NA	Pacific power.. this will put new people on the streets cause huge amounts of an already broken Covid mentality and someone has to stop raising prices!!
NA	NA	N	I CANNOT pay what I already have to pay for!!! Everything is too high and MY INCOME hasn't increased so this will result in huge increases in homelessness and anger within the community!!
NA	NA	N	There is a basic problem with electric companies raising rates. We are in the process of ending our dependence on fossil fuels. In order for that process to be successful we must have an alternative to oil. That alternative is, of course, electricity. If electricity's cost gets higher and higher the chance of this whole process working gets lower and lower. It just won't work and we are left with NO power option. The end.
Sheryl	NA	COQUILLE	We have had 2 rate increases since May and I am a disabled senior citizen. I cannot afford to pay their bill. This isn't making any sense. If they increase the rates a lot of people will be sitting in the dark. We are looking for help. We do not get increase in our pay enough to help.
NA	NA	BEND	Please do not raise the rates for power. I am struggling financially and work as a school teacher. Inflation is high and pacific power's rate increase is more than just adjusting for inflation, it's greed! We also have no other options from where to get our power. Don't think of the share holders, think of your customers.

First Name	Last Name	City	Comment
Donald	NA	BEND	I am writing to express my strong opposition to the proposed average rate increase of 14.9% for residential customers by Pacific Power, docket number UE 433. As a concerned resident of Oregon, I believe this rate hike is both unreasonable and unjustifiable. The proposed increase would result in an additional $21.49 per month for the average residential customer using 950 kilowatt-hours. In a time when many families are already struggling to make ends meet, this added financial burden is simply unacceptable. Electricity is a basic necessity, and increasing rates by such a significant margin will disproportionately impact low- and middle-income households. Moreover, it is important to consider the broader economic context. Inflation in the past three years (2021-2023) has been 16.9%, nearly equal to the inflation rate of the previous decade (2011-2020) which was 17.4%. This demonstrates that families are already facing higher costs across the board and cannot afford additional expenses. It is also worth noting that Pacific Power's parent company, Berkshire Hathaway Energy, reported a staggering $689 million in net profit in the first quarter of 2024 alone. This level of profit indicates that the company is financially robust and does not need to pass on additional costs to its customers to maintain its operations. It appears that the primary motivation behind this rate increase is to further boost already substantial profits, potentially aiming for nearly a billion dollars in quarterly earnings. Such a profit-driven approach to a basic utility is unfair and exploitative. The proposed rate increase would exacerbate financial hardships for many residents while significantly benefiting an already profitable corporation. I urge the Oregon Public Utility Commission to reject this proposal and protect the interests of Oregon's residents over corporate profits. Thank you for considering my comments.
NA	NA	BEND	What is the reason for this increase? Just more corporate greed? Berkshire Hathaway Energy (who owns Pacific Power) made $689 million in net profit in ONLY THE FIRST QUARTER OF THIS YEAR. Is that just not enough for them or something?
NA	NA	PROSPECT	NO
NA	NA	TERREBONNE	A 14.9% RATE INCREASE?!?!?!?. You already raised rates 21% last year. Out of curiosity what was pacific power's profit margins last year? I'm installing solar immediately. *middle finger emoji inserted here*
NA	NA	BEND	There is no way I support Pacific Power increasing their rates again. They say it is to help with infrastructure plus other reasons. But I would love for you to research in the past 20 years, how much money they have invested in infrastructure vs. how much compensation their management and shareholders received. If there was minimal money being invested into their infrastructure compared to how much shareholders and management received, then there should be no increase. They need to suffer the consequences of their choices. I am sick and tired of management passing the buck down onto their customers. They should be held accountable.
NA	NA	NA	Just say 'NO'! If you haven't decided yet let me tell you what we have dealt with lately. We got solar a few years ago to help on our electricity bill and last winter they sent us a letter telling us our credit was going to be given to those on poverty. We are at the poverty level! We go into debt ever more to buy solar and then want to give our credit to others? Our winter bills are ridiculous and that credit saves us. Now in the last week we have lost power AT LEAST five times. Once when it was reported we were told it wouldn't be back for 12 hours. When it did come back it went out again a few hours later, it came back for about 15 minutes and went out again. Goodbye freezer items. It went out now 3 of the last 4 days. The power station is just down the road and there are no fires in this area right now. Please tell them no on the increase, they can't keep it on now, why raise the rates? Yahoo Mail: Search, Organize, Conquer

First Name	Last Name	City	Comment
David	Nichols	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Dr. David Nichols 5107 NE Couch St Portland, OR 97213-3021 davemult@aol.com
Phillip	Norman	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. We know that solar in the Pacific Power portfolio is key to lower production cost. In this, Pacific Power is a laggard. All of us want cleaner energy. Few of us can sensibly invest on their own rooftop. My neighbor's trees are an asset to my house, but ruin solar opportunity. A brief try of Blue Sky proved a foolish idea, especially where my house is now a very-superior rental. I might make a dumb investment, but could not pass the cost to others undeclared. (Deleted Link) Blocking rate increases may be necessary to promote Pacific Power solar farm and battery investments. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Phillip Norman 1234 NE 118th Ave Portland, OR 97220-2129 pjnorman@gmail.com
John	Olson	DALLAS	Outrageous particularity for those of us in retirement on limited income.
Nyssa	Oru	PORTLAND	I oppose the rate increases proposed in the Pacific Power rate increases Proposed in the reply testimony from Pacific Power Corp on 7/26/24. It will place undo hardship on residents and small businesses for failures of the companies administration to maintain their network safely. Consumers should not be punished for PACIFICORP's short comings, and the 11.9% proposed base increase far exceeds the 3% general inflation increase for 2024. For some people living in the margins and paycheck-to-paycheck this increase could have a serious impact on their access to essential cooling or heating, as well as potential decisions between power bills and other necessities. Please say no to the UE 433 rate increases and ask for additional lowered revisions as this docket goes into settlement.

First Name	Last Name	City	Comment
Nieba	Paige	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. Yet another huge rate increase on the heels of several huge increases in the immediately prior years, when wages for the majority of working people haven't even caught up with the last increases, is highway robbery! This January, we saw record bills during the ice storm after two years of double-digit rate increases. This increase will continue to make our electricity bills even more unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Nieba Paige 1322 SE 60th Ave Portland, OR 97215-2807 nieba4@gmail.com
Nicole	Palmesano	REDMOND	To the Oregon Public Utilities Commission, I recently received an email from Pacific Power indicating they are going to decrease their proposed rate increase for 2025 from 17.9% to 11.9%. While they feel this is reasonable, from a consumer standpoint an extra 20.00-30.00 per bill is STILL a considerable amount. In our current state of our country, inflation is skyrocketing and even buying everyday essentials such as food has been a challenge and struggle on Americans. In my opinion, Pacific Source is taking advantage of the customers and their reasons for doing so are not fair or justified. Their errors and mis management of funds should not fall to the people. Aside from reaching out to you to plead our cases, we are stuck with this company for our power. Our hope and faith is in you to really determine if it's necessary to do this to the customers who have their hands tied and no choice to choose another utility for power. I am pleading today that we are heard and not the victims of another cost increase during an already exorbitant time to live. If it is determined that a rate increase MUST happen, a REASONABLE increase in my mind is no more than 5% or less. People understand small adjustments, but this proposal is outrageous. If they decided it would be okay to drop down to 11.9% then there should be no problem dropping down to a realistic increase that doesn't instill hardship on vulnerable customers. Please hear us!
Laura	Poueymirou	BEND	There is no way I support Pacific Power increasing their rates again. They say it is to help with infrastructure plus other reasons. But I would love for you to research in the past 20 years, how much money they have invested in infrastructure vs. how much compensation their management and shareholders received. If there was minimal money being invested into their infrastructure compared to how much shareholders and management received, then there should be no increase. They need to suffer the consequences of their choices. I am sick and tired of management passing the buck down onto their customers. They should be held accountable.

First Name	Last Name	City	Comment
Gary	Poulos	TALENT	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I do not want my bills to go toward paying for Pacific Power's $578 million wildfire liability. The company management, not customers, was found grossly negligent in the 2020 Labor Day fires and it, through its shareholders, should be responsible for damages. Corporate officers whose decisions led to this negligence should be fired, all current and future forms of compensation should be immediately withdrawn, and shareholder dividends should be suspended until the negligent liability has been satisfied. I am concerned that the proposed additions of "self-insurance" would be paid by customers. Customers were not responsible for the decisions that resulted in the negligence judgments. I do not think it is reasonable for customers to pay for insurance against negligent management decisions. Shareholders elect board members and chairmen who, in turn, hire and direct management. When management make negligent business decisions, either independently or under direction of the board, the cost must be born by the shareholders who voted for them. Shareholders must also have responsibility in funding liability costs from wildfires, especially when these costs resulted from decisions made by their elected board members and the executives hired and/or directed by the board. If the shareholders don't like this, they should fire their Board Of Directors and its Chairman. Pacific Power was granted a power monopoly. Their shareholders, executives, and board members were not exempted from losses, especially when they are self-induced. They were also not exempted from the responsibility to provide reliable power to customers. If they cannot operate this granted monopoly within these parameters, it should be revoked. This is not a rate increase issue. This is a corporate monopoly governance issue. NOTE: I do not endorse the CUB comments that are inserted before and after my comments without my consent. It is inappropriate to associate these comments with my views. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Gary Poulos 333 Mountain View Dr Unit 57 Talent, OR 97540-9314 garyjp@gmail.com

First Name	Last Name	City	Comment
Greg	Radich	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Greg Radich 5240 SE Hawthorne Blvd Portland, OR 97215-3364 greg.radich@wk.com
Maryellen	Read	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Maryellen Read 125 SW Collins St Portland, OR 97219 maryellenread@gmail.com

First Name	Last Name	City	Comment
Byron	Rendar	PORTLAND	The cumulative impact on proposed increases by Pacific Power - 21% and NW Natural - 18% will have a devastating effect on people struggling to pay utility bills now and people who can just afford to pay their current bills. You need to look closely on why the utilities are asking for such a high increase in rates and the cumulative effect on consumers. In particular Pacific Power was found negligent and should not put the burden on all users because of their mistakes. I can afford an increase of $480 per year but I may cut back on discretionary spending or repairs to my house. Byron Rendar 3586 NE Stanton St Portland 503 281-1633
Matt	Richmond	MILWAUKIE	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Matt Richmond 4545 SE Ina Ave Apt 6 Milwaukie, OR 97267-5918 rudabussy1@outlook.com
Max	Roberts	REDMOND	Pacificcorp parent company made a net profit of over 700 million in the first quarter of 2024. There is no reason for this rate increase other than corporate greed. Let's do the right thing and not continue to absolutely wreck the working class of central Oregon for the sake of profit. What a joke this is to even consider an increase. DISGRACEFUL
Lindsay	Roberts	BEND	Energy is a basic need. Inflation has jumped more in the last 4 years than the previous decade. Pay rates have remained the same. This feels like a money grab for the parent company to increase their already astronomical profits in spite of people struggling to pay their rent, medical bills, electricity, food, etc. They know they have a monopoly over this area, but this unchecked greed. This increase will put undo hardships on the American people, my friends and neighbors, and myself. We need to hold companies accountable.

First Name	Last Name	City	Comment
Brent	Rocks	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Brent Rocks 1518 SW Upper Hall St Portland, OR 97201-6132 brent_rocks@comcast.net
Laura	Roe	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. In January, we saw record bills during the ice storm after TWO YEARS OF DOUBLE-DIGIT RATE INCREASES. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. For-profit utilities should be subject to limited rate increases. I do not want my bills to go toward paying for Pacific Power's wildfire liability. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Laura Roe 2427 SE 66th Ave Portland, OR 97206-1205 2427Se66@gmail.com

First Name	Last Name	City	Comment
Richard	Rohde	ASHLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Richard A Rohde 124 Ohio St Ashland, OR 97520-1119 rvoarich@yahoo.com
Donnette	Roland	BEND	With the cost of everything rising so high right now. Enforcing a rate increase could be devastating to most people. This could increase homelessness and a child going hungry because someone is trying to decide which bill to pay.
John	Ruth	EAGLE POINT	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. JOHN RUTH 764 Crescent Dr Eagle Point, OR 97524-7815 j762538@aol.com

First Name	Last Name	City	Comment
Andrew	Santosusso	DALLAS	Dear Commissioners, I am writing to express my strong objection to Pacific Power's proposed 11.9% rate increase. As a resident and consumer in Oregon, I am deeply concerned about the impact this substantial hike will have on individuals and families in our community, especially in light of the current economic climate. The proposed rate increase far exceeds the current inflation rate, which according to the U.S. Bureau of Labor Statistics, has been fluctuating around 3-4% over the past year. This discrepancy raises significant concerns about the justification for such a steep increase in utility rates. In comparison, wage growth has been notably sluggish. Personally, I received only a 2.5% raise last year, which does not come close to matching the proposed rate hike by Pacific Power. This disparity between the proposed rate increase and the economic realities faced by many Oregonians is alarming. For households already struggling to make ends meet, an 11.9% increase in utility rates would create an undue financial burden. Essential services such as electricity are non-negotiable expenses, and significantly raising rates could lead to difficult choices between paying for utilities and other necessary expenses like food, housing, and healthcare. In addition to individual financial hardships, a substantial rate increase could have broader economic repercussions. Higher utility costs can dampen consumer spending and strain small businesses, further slowing economic recovery and growth. I urge the Oregon Public Utility Commission to consider the severe impact this proposed rate increase will have on the residents of Oregon. It is crucial to ensure that utility rate adjustments are fair, justified, and considerate of the current economic conditions faced by consumers. Thank you for your attention to this important matter. I hope that you will take the concerns of Oregon residents into account and reconsider the approval of Pacific Power's proposed rate increase.
Erich	Schmidt	REDMOND	I am writing to express my strong opposition to the proposed 11.9% rate increase by Pacific Power. This increase would result in a substantial burden, especially during these economically challenging times. While Pacific Power cites rising insurance costs and the need for system upgrades due to extreme weather threats as reasons for this increase, it is important to consider the broader context. Berkshire Hathaway Energy, the parent company of Pacific Power, reported a staggering $689 million in net profit for the first quarter of 2024 alone. This significant profitability calls into question the necessity of passing additional costs onto consumers, particularly when inflation has already strained household budgets. The cumulative inflation rate from 2021 to 2023 was 16.9%, nearly matching the inflation rate of the entire preceding decade (2011-2020), which was 17.4%. Electricity is a basic necessity, and it is unacceptable for Pacific Power to further squeeze consumers to edge closer to a billion dollars in quarterly profits. The proposed rate increase places an undue burden on families and individuals who are already facing significant financial pressure. I urge the Oregon Public Utility Commission to reject this rate increase and to consider the financial well-being of Oregonians who rely on affordable and reliable electricity.

First Name	Last Name	City	Comment
Samantha	Schmidt	REDMOND	To the Oregon Public Utility Commission, I am writing to express my strong opposition to the proposed 11.9% rate increase by Pacific Power. This increase would result in an additional $21.49 per month for the average residential customer, which is a substantial burden, especially during these economically challenging times. While Pacific Power cites rising insurance costs and the need for system upgrades due to extreme weather threats as reasons for this increase, it is important to consider the broader context. Berkshire Hathaway Energy, the parent company of Pacific Power, reported a staggering $689 million in net profit for the first quarter of 2024 alone. This significant profitability calls into question the necessity of passing additional costs onto consumers, particularly when inflation has already strained household budgets. The cumulative inflation rate from 2021 to 2023 was 16.9%, nearly matching the inflation rate of the entire preceding decade (2011-2020), which was 17.4%. Electricity is a basic necessity, and it is unacceptable for Pacific Power to further squeeze consumers to edge closer to a billion dollars in quarterly profits. The proposed rate increase places an undue burden on families and individuals who are already facing significant financial pressure. I urge the Oregon Public Utility Commission to reject this rate increase and to consider the financial well-being of Oregonians who rely on affordable and reliable electricity. Thank you for your attention to this critical issue. Sincerely, Samantha Schmidt
Renee	Schrunner	NA	Please, please, please do not approve this rate increase. We have had rate increases in the last two years that have been difficult to manage in a Retirement Fixed Income, which is what I have. And now to read they are requesting EVEN MORE FOR 2025 is beyond my comprehension! Its too much! Last year alone my monthly payments were up $30 and then in January 2024 they went up another $40. I can no longer afford yet another huge increase for 2025. I will become one of the unfortunate people who will live in my home and not use the heating system. Please work something out and avoid this disaster. Too many people I know will not be able to afford this increase. Senior citizens who have been retired awhile never planned on this huge of a rate increase with their power bill in Oregon. Thank you for your help. Renee Schrunner
Kemp	Scott	HOOD RIVER	Please keep the cost increases at a minimal level. A nearly 12% increase is not in the interest of the public that has granted a " monopoly "to a "Public Utility ". We should not have to cover for a lack of business foresight. Thank You

First Name	Last Name	City	Comment
Charleigh	Sheffer	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mx. Charleigh Sheffer 7015 N Moore Ave Portland, OR 97217-1729 charlotteshuff@gmail.com
Linda	Shewmaker	GRANTS PASS	I was retired and am currently getting SS as I'm well over the full retirement age. Owned a home for 30 years, but due to high cost of home ownership, I sold my home. Now I've returned to working because of the high cost of rentals. If utility costs rise more than the current rate, can you offer a solution beyond the actions I've taken to afford the monthly cost of rent and proposed utility increase!
Jamie	Shields	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs Jamie Shields 15739 NW Rondos Dr Portland, OR 97229-8985 jfillmore66@gmail.com

First Name	Last Name	City	Comment
Kristin	Shisler	REDMOND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Kristin Shisler 2602 SW Umatilla Ct Redmond, OR 97756-8607 kristinshisler@gmail.com

First Name	Last Name	City	Comment
Rick	Silverman	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. They ask, you should look under the hood sort of and figure out why they need more money every year, beyond the cost of doing busniess as an electric utility. How can you not look at the impact of past rate increases on today's operations and reasonable profit. Not addressing their liability, they are responsible for operation efficiently and with cost control. Not what we are getting. Their problems are not the rate payers, another utility will buy their operations and run it better if you leave it to the market, as regulators. We the rate payers are not making 20 plus percent more now versus the most rate increase. There has to be some connection to real world costs, not just their demands! I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, - Rick Silverman 2416 SW Mitchell St Portland, OR 97239-2129 gizmot@teleport.com
Rachel	Slocum	PORTLAND	Dear Commissioners, Please cap utility bill increases. I simply can't afford a 21.6% increase each month. At current rates, I already don't heat my house enough for comfort in the winter and I don't own an AC unit because I couldn't afford to use it. In these next few days of 90+ temperatures, I can't cook unless it's very early in the morning because the apt will simply get too hot. The apt (built in the late 40s) does not cool down even though I leave the back door and windows open all night. I qualify for Multco's low income weatherization program but the landlady is not convinced that Multco would do a good job weatherizing this single-paned, uninsulated dwelling. Please consider the fact that there are many in my situation whose lives are endangered by heat, who live in places where assistance is denied, and who will need to make a choice between staying cool enough to live and paying rent. It is not clear to me that the state and the PUC has a plan to deal with the fact of poverty (especially black, brown, and elderly), rising temperatures, increasing need for cooling, and the cost of wildfires. If profit is allowed to be the primary consideration, in the end, you will be sanctioning premature death. Sincerely, Rachel Slocum 2210 NE Wygant Portland OR 97211

First Name	Last Name	City	Comment
Garry	Smith	STAYTON	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I only wish I had the ability to ask for a raise to my social security in such an amount. Unfortunately I am on a fixed pension that increases minimally most years to attempt to keep up with cost of living which includes increased costs in utilities. When Pacific Power is granted a 21.6% increase it comes right off the top of my monthly pension. What am I supposed to cut? I do all my shopping at cut rate grocery stores like WINCO. We don't eat out very often but might go to WENDYs for a special treat. So what do I cut out to pay this increased cost from Pacific Power. Garry P. Smith Stayton I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, cdr garry smith 1630 Mountain Dr Stayton, OR 97383-1489 garrypsmith01@gmail.com
Tina	Springer	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Tina Springer 1640 N Nebergall Loop NE Albany, OR 97321-1530 kenagy@proaxis.com
Julie	Stageberg	CORVALLIS	Hathaway Energy, the owner of Pacific Power, made $689,000,000 of profit in Q1 of 2024 alone. Yet Pacific Power wants to increase the rates of working people and take even more money while throwing whatever excuse they can out there. Electricity is a basic need, to profit off it is inhumane.

First Name	Last Name	City	Comment
Valerie	Stanik	CORVALLIS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable for many more than already struggle. Even with new photovoltaic panels I was unpleasantly disappointed to get the highest, by far, bill I have ever gotten from PP&L. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I understand that retrofitting the system to prevent fires is finally underway now that it is in crisis. This may even be your argument for raising rates. You surely could have seen this coming years ago and been proactive when the first sign that the system was a fire threat. Why you didn't, only you know for sure. That said, I do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, ms Valerie Stanik 5901 SW Country Club Dr Corvallis, OR 97333-1352 stanikv@peak.org
Donna	Steadman	TIGARD	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. Enough is enough! An increase of this size is tantamount to price-gouging. on the heels of other large annual increases.. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mrs. Donna Steadman 9440 SW Lakeside Dr Tigard, OR 97224-5691 dab1219@comcast.net

First Name	Last Name	City	Comment
Daniel	Stillwaggon	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr Daniel Stillwaggon 68 SE 57th Ave Portland, OR 97215-1221 dstillwa@gmail.com
Richard	Strasser	CHILOQUIN	When and how were we advised of he open public comment period for Pacific Power rate increase?
Timothy	Sveen	CHILOQUIN	They want another rate increase. I'm a fixed income and Pacific Power has gotten more rate increases in 2 years then I've gotten in 5 years from social security. they need to cut the wages their paying to those hundred thousand Execs their paying to sit on their asses ??
Chelsea	Taylor	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. CHELSEA Taylor 7421 SE Rural St Portland, OR 97206-7271 Taylor.chelsea.n@gmail.com

First Name	Last Name	City	Comment
Christine	Taylor	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. I am a senior on a fixed income and cannot manage your proposed rate increase An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Christine Taylor 3205 NE 47th Ave Portland, OR 97213-1824 litasberrypatch@gmail.com
Rod	Terry	CORVALLIS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr Rod Terry 1010 NW 32nd St Corvallis, OR 97330-4412 terryr@peak.org

First Name	Last Name	City	Comment
Christina	Valentine	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Christina Valentine 5265 N Syracuse St OR97203 Portland, OR 97203-5265 seavalentine@yahoo.com
Pilar	Velez	PORTLAND	Given PacifiCorp's (owner of Pacific Power) 2023 10k filing indicating CEO Cindy Crane's base salary is $2.14 million dollars, VP and CFO Nikki Kobliha's base salary is $896.4K (2023) perhaps some of the reason for the excessive cost increase is the Executive pay. In addition, part of the increased cost of insurance could be due to the negligence claims Pacificorp faces in settled and current lawsuits. One jury has already found PacificCorp liable of negligence, and Oregon utility regulators will not be limiting PacifiCorp's liability in wildfire lawsuits. Perhaps this is the reason for the rate increase. Maybe CEO Crane is not deserving of the multi-million dollar paycheck. Perhaps the cost of energy would be more reasonable if PacifiCorp were more responsible with sustaining its infrastructure and responding to fire officials' warnings during emergencies. Perhaps it's time for PacifiCorp to pay for its own mistakes, and not pass its fees down to the customers who are NOT a part of Berkshire Hathaway entities, and most of whom do not earn a seven figure salary. I do NOT support this rate increase.
Jeremy	Verke	BEND	Berkshire Hathaway Energy, the parent company of Pacific Power, made $689 million dollars of Net Profit in the first quarter of 2024 alone. Inflation in the last three years ('21-'23: 16.9%) was about equal to the inflation seen in the ten years ('11-'20: 17.4%) before that. Electricity is a basic need; a highly inelastic good for most consumers--beyond this, many consumers in my area have no choice of provider other than Pacific Power--if they have been given a governmental monopoly, they cannot be using it to squeeze every day people for more than half a billion dollars in quarterly profits. This is downright unethical.

First Name	Last Name	City	Comment
Carol	Wagner	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Carol Wagner 350 Timber Ridge St NE Albany, OR 97322-7436 carol@craftedbycarol.com
Carol	Wagner	ALBANY	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. GREEDY, GREEDY, GREEDY!!! I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Carol Wagner 350 Timber Ridge St NE Albany, OR 97322-7436 carol@craftedbycarol.com

First Name	Last Name	City	Comment
Marie	Wakefield	NEWPORT	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms Marie Wakefield 3054 Highway 20 Newport, OR 97365-9519 wakefieldm_2000@yahoo.com
Beth	Walker	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms. Beth Walker 9707 SE 43rd Ave Portland, OR 97222-5768 bethw.1223@gmail.com
Stephen	Waller	REDMOND	Why would you let a public utility raise rates in an already difficult time? This is infuriating. They are part of a publicly traded company and you would let them walk all over us? Please deny this request the rich already have enough.

First Name	Last Name	City	Comment
Peter	Ware	MEDFORD	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Peter Ware 1309 Pear Tree Ln Medford, OR 97504-4504 flyfishman@aol.com
Ann	Watters	SALEM	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, ms Ann Watters 1940 Breyman St NE Salem, OR 97301-4352 twofivestars@comcast.net

First Name	Last Name	City	Comment
Dana	Weintraub	BEAVERTON	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Dana Weintraub 17124 SW Marty Ln Beaverton, OR 97003-4249 mrdanaweintraub@tutanota.com
Andrew	West	BEND	As a local homeowner I oppose the rate increase. You have already raised rates the past few years and I would like to know how much your house have actually increased. The cost of electricity generation cannot keep increasing this much every year, this is unacceptable. Electricity is a basic need, more important than corporate profits.
Dana	Wientraub	BEAVERTON	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Dana Weintraub 17124 SW Marty Ln Beaverton, OR 97003-4249 mrdanaweintraub@tutanota.com

First Name	Last Name	City	Comment
Ashley	Wolf	BEND	Oregon PUC - electricity is a basic need. Profiting $689 MILLION dollars (Berkshire Hathaway Energy) in the first quarter of 2024 alone is NOT a need, especially off the backs of customers. Why is Pacific Power requesting to raise rates when their Q1 profit is near a billion dollars? Any rate increase with profit margins like that is pure greed. You should be vehemently denying this request and telling Pacific Power/Berkshire Hathaway Energy NO.
Michael	Wolf	PORTLAND	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Michael Wolf 3126 NE 7th Ave Portland, OR 97212-3141 mchlwlf@lycos.com
Margo	Wyse	MIMBRES	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Ms margo wyse 110 El Otro Lado Rd Mimbres, NM 88049-8081 bodica6086@yahoo.com

First Name	Last Name	City	Comment
Brian	Yorgey	CORVALLIS	Dear Public Comments Oregon Public Utility Commission, I am writing to comment on Pacific Power's rate case (UE 433). As a Pacific Power customer, I'm deeply concerned about how a 21.6% rate increase for residential customers will impact my household. You must be kidding me! This is ridiculous. An increase this large does not need to happen right now. This January, we saw record bills during the ice storm after two years of double-digit rate increases. I am worried approving this increase will continue to make our electricity bills unaffordable. As the cost of living remains high, raising bills this much will have a significant negative impact on my household and fellow Oregonians. We have seen a growing pattern of Oregon's for-profit utilities asking for 15-20% increases nearly every year for the last four years. Pacific Power and all other for-profit utilities should be subject to limited rate increases. I support the Oregon Citizens' Utility Board's proposal to limit rate increases to 7% plus inflation or to 10%, whichever is lowest. I also do not want my bills to go toward paying for Pacific Power's wildfire liability without significant shareholder contributions. The company was found grossly negligent in the 2020 Labor Day fires and it should be responsible for damages, not customers. I am concerned about the proposed additions of "self-insurance" paid by customers. I also do not think it is reasonable for customers to pay 80% or more of the Catastrophic Fire Fund. Shareholders must have more responsibility in funding liability costs from wildfires. I urge the Commission to reduce this increase wherever possible, create limits on rate increases, and make utility rates more affordable. Sincerely, Mr. Brian Yorgey 2220 NW 12th St Corvallis, OR 97330-1422 brian.yorgey@gmail.com

CASE: UE 433
WITNESS: SUDESHNA PAL

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 3300

REDACTED
Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Sudeshna Pal. I am a Senior Economist employed in the Energy Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. I provided Opening Testimony in Exhibit No. Staff/1400, and my Witness Qualification Statement can be found in Exhibit No. Staff/1401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut Reply Testimonies of Mr. Rick Link, Exhibit No. PAC/2500, and Mr. Rick Vail, Exhibit No. PAC/2600.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. PACIFICORP'S TRANSMISSION INVESTMENTS

Q. Please summarize the issues discussed in your opening testimony on the Gateway South (GWS) transmission line investment for which PacifiCorp is seeking rate recovery during the test year 2025.

A. I addressed three main issues around the eligibility of the Gateway South investments to be included in customer rates for the test year. First, whether the GWS transmission line and associated projects will be used and useful during the test year 2025. Second, whether the timing of the GWS transmission project is well supported by the Company's economic analysis or if it is primarily driven by its obligations to meet uncertain Open Access Transmission Tariff (OATT) requirements. Third, to what extent will Oregon customers realize the benefits associated with the GWS line as described by the Company to support the timing of its construction, to justify paying its share towards this investment over the test year.

Additionally, I raised issues with planning and management which undermine the economic analysis used to justify GWS (and associated wind investments):

a. The Company abandoning its initial plans on early retirement of various coal plants and its increased reliance on market purchases over time.

b. Consideration of the Ozone Transport Rule and the Company's potential financial obligations towards wildfire related lawsuits in its decision to move forward with a significant transmission investment.

Q. What was Staff's conclusion and recommendation regarding used and useful status of GWS and related projects?

A. Staff noted in its opening testimony (Staff/1400) that GWS construction and related projects were at various stages of completion but had similar in-service dates towards the end of 2024. Staff recommended that PacifiCorp provide an attestation by a corporate officer that each of the transmission projects has been completed by January 1, 2025. PacifiCorp has agreed to provide the attestation.[1]

Q. What was Staff's conclusion regarding the factors driving the timing of the GWS project?

A. Staff concluded that the timing of the project was primarily driven by PacifiCorp's OATT obligations to meet transmission service and interconnection service requests for projects that were at an uncertain stage of development.

Q. What factors did Staff consider in evaluating whether the GWS investment was prudent?

A. As explained in Staff/1400/Pal/10, Staff referred to Commission established prudence standards, which states, among other things, that "A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed."

[1] PAC/2600/Vail 29/Lines 1-6.

Q. What information did Staff use to determine whether it was reasonable and prudent for PacifiCorp to prioritize and proceed with the construction of GWS?

A. Staff relied on the economic analysis provided by the Company and evaluated circumstances that could have been reasonably foreseen by the Company at the time of its decision to move forward with the construction of the GWS transmission line.

Q. In PAC/2500, Mr. Link suggests that reduction in customer costs is not a pre-requisite for prudence determination. Do you agree?

A. Yes, that is not a requirement for every action taken by a utility.

Q. How then does the economic analysis help in evaluating prudence?

A. The economic analysis is useful to determine whether the timing of GWS investment is well supported by the best available information. First, PacifiCorp itself, has presented an economic analysis in support of the GWS project, similar to the one in its 2021 Integrated Resource Plan, as evidence of the reasonableness of its GWS investment decision. Second, Staff understands that the purpose of an economic analysis is to quantify the best available information in terms of costs and benefits related to a particular action and use it to justify the action taken. In this case, the action being the decision to move forward with the transmission project. Staff, therefore, relied on the economic analysis provided by PacifiCorp to determine whether the GWS investment was a prudent decision. Finally, Staff considered directions in Commission Order No. 22-178 that seek to consider full project costs in prudence determination of the GWS project, as discussed in more detail in Staff/1400/Pal/18.

Q. What was Staff's concern with the economic analysis that the Company provided to support the timing of the GWS project?

A. An economic analysis has two sides to it. One is the benefit side, and the other is the cost side. While Staff acknowledges that the economic analysis adequately accounts for quantifiable benefits of GWS by incorporating the Eastern Wyoming wind projects (and associated Production Tax Credits) in the analysis, Staff was concerned that the analysis did not incorporate the total cost of the project ($2.1 billion) for which the Company is seeking recovery. Instead, the economic analysis applied a cost offset of $1.4 billion that the Company stated was a conservative estimate of avoided transmission cost, representing an alternative 230-kV transmission project that the Company had to build in response to a point-to-point transmission service request for 500 MW of transfer capacity by a certain customer.

Q. In PAC/2500, Mr. Link explains that in the 2021 IRP Preferred Portfolio the timing of GWS was driven by resource needs and coincided with the in-service dates of five Wyoming wind projects that rely on GWS, and therefore Staff's conclusion that meeting OATT obligations was the primary driver behind the prioritization of the line is unfounded. Does Staff agree?

A. Staff does not agree. Staff does not believe the cost of GWS was accurately modeled in the portfolio analysis that yielded this outcome. As explained previously, the application of a $1.4 billion cost offset (estimated cost for an alternative 230-kV transmission line that the Company would have to build to meet a transmission service request by a single customer) to the GWS project in the 2021 Integrated Resource Plan (IRP) analysis prevented visibility into PacifiCorp's resource choices under true transmission costs. It also introduces an element of uncertainty in the analysis around the amount of the cost offset and delays or withdrawals associated with the transmission service request. Notably, PacifiCorp did not apply any cost offset for alternative transmission lines in modeling GWS in its 2019 IRP. It only did that in the 2021 IRP. That is an inconsistent treatment of the same resource in two consecutive IRPs.

Q. Did PacifiCorp respond to Staff's concerns around the cost offset?

A. Yes. In PAC/2500, Mr. Link explained, without supporting documentation, that $1.4 billion was a conservative estimate for an alternative 230-kV transmission line and even if one transmission service request (e.g. the 500 MW point-to-point request, which necessitated construction of the 230-kV line) did not materialize, PacifiCorp would still need to provide services to the 12 interconnection service agreements that it has committed to, and therefore required to build some transmission line presumably at a higher cost (compared to $1.4 billion).

Q. Did PacifiCorp respond to Staff's concerns around transmission and interconnection service request related risk analysis?

A Yes. In PAC/2600, Mr. Vail explains that it is extremely unlikely that the 12 interconnection requests will all be withdrawn, and that the five wind projects that will interconnect on GWS remain on schedule for completion at the end of 2024. Mr. Vail also describes various alternatives that would maintain the need for GWS even if the 500 MW point-to point transmission service request is withdrawn, including serving lower priority requests, and if nothing else, then the Company itself using the transfer capability to deliver to load.

Q. Does that mitigate Staff's concern around the uncertainty introduced in GWS cost modeling in the IRP portfolio analysis?

A. No. While Staff understands that there would be enough transmission service and interconnection requests, it still does not address concerns about the speculative nature of the $1.4 billion cost offset applied to GWS cost in the reference case IRP portfolio analysis. Moreover, there is no alternate study to show that the 230-kV line was the only other way to meet the 500 MW point-to-point transmission service request which would justify including the cost for this line in the IRP analysis.

Q. Does Mr. Vail's explanation that there would be a need for GWS even if the transmission service request is withdrawn justify inclusion of the cost offset in the economic analysis for GWS?

A. Staff does not believe so. The hypothetical 230-kV line that could potentially meet the single 500 MW point-to-point transmission service request and GWS are serving two very different purposes. While the construction of GWS would also address the transmission service request in question, the hypothetical 230-kV line would not have connected the wind resources that GWS does.

This is evident from the Company's modeling of GWS jointly with the East Wyoming wind resources in its 2021 IRP analysis. These two lines are not perfect substitutes, and hence Staff does not believe the cost offset is justified.

Q. What was Staff's concern regarding benefits of GWS for Oregon customers?

A. Staff expressed concern that although PacifiCorp in its 2021 IRP explained that the GWS transmission line will be useful in supporting the transition of its system out of coal and reduce its reliance on markets, its subsequent actions were a departure from its 2021 IRP resource strategy. PacifiCorp abandoned its plan for early retirement of several of its coal plants and its 2023 IRP showed a significant increase in market reliance going forward which raises questions around whether and when Oregon customers will receive benefits associated with emissions reduction from coal retirements and lower risks from less market reliance.

Q. How does PacifiCorp respond to Staff's concerns about its increased reliance on market?

A. In Link/2500, Mr. Link explains that although PacifiCorp's market reliance has increased between the 2021 IRP and 2023 IRP Update, without GWS the increase in market reliance would be greater. Mr. Link also interprets Staff's concern as suggesting that GWS has increased the Company's reliance on markets compared to the 2021 IRP as shown in the 2023 IRP and 2023 IRP Update.

Q. Can you clarify what was Staff's position regarding the connection between GWS and market reliance?

A. One of the many benefits of GWS used to justify this major investment was to reduce the Company's reliance on markets during times of scarcity, thereby lowering risk exposure for its customers. However, Staff notes that, in the 2023 IRP and IRP Update, the significant increase in the Company's market reliance undermines the asserted risk reduction benefit associated with GWS.

Q. In PAC/2500 Mr. Link suggests that Staff wrongly associated PacifiCorp's coal retirement plans with the construction of GWS. Do you agree?

A. No. Staff, in its opening testimony (Staff/1400), did not suggest that GWS was the reason PacifiCorp was going to retire its coal plants, as implied by Mr. Link's Reply Testimony. Staff's goal was to point out that PacifiCorp's claim that one of the projected benefits of GWS was to support its system as coal plants retire. Such benefits of GWS were a selling point in dockets such as the 2020 AS RFP (UM 2059) when PacifiCorp stated that "(r)elative to the "LN Bid" portfolio, the "SNS Bid (LN)" portfolio primarily adds wind resource bids in eastern Wyoming, along with the Energy Gateway South transmission line. Again, this results in the largest reductions in coal generation for the Hunter and Huntington units in Utah South (where Energy Gateway South delivers), as well as reductions at Jim Bridger." Contrarily, for instance, PacifiCorp has signed new coal supply contracts for increased availability of coal for the

Hunter plant, so it can be run more often.[2] Statements like the one in UM 2059 (see above) and in other dockets painted a link between these projects and coal retirements. What has been learned is that these retirements and emission reductions were far more reliant on the OTR taking effect, rather than any development of new wind projects and the associated GWS infrastructure.

Q. How does the change in coal retirement plans impact benefits for its Oregon customers?

A. The change in retirement plans undermines more than the economic analysis presented in the IRP. It also undermines the emissions reduction benefits that would have materialized with the support of GWS (by potentially replacing coal with more renewable resources) and exposes Oregon customers to more higher costs and risks of complying with emissions reductions requirements. As Staff/1400/Table 4 shows, several coal retirements were delayed in the Company's most recent 2023 IRP than what was projected in the 2021 IRP analysis that also selected GWS as a preferred portfolio resource. Under HB 2021, GWS will be required to serve Oregon customers in a non-emitting environment for 54 out of 60 hours (2030 onwards) or 90 percent of its useful life (assuming the useful life to be 60 years and that the line is in service at the end of 2024). This will not materialize given the delays in coal retirements.

Q. What other issues did Staff raise in its opening testimony?

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[2] In the Matter of PacifiCorp 2025 Transition Adjustment Mechanism, Docket UE 434, Exhibit PAC/500/Owen/10.

A. Staff suggested that PacifiCorp, in its decision to proceed with billions of dollars in transmission investment, should have considered the possibility of the stay of the Ozone Transport Rule (OTR) or that it would otherwise not take effect, and the possibility of the Company incurring liabilities in potential wildfire related lawsuits.

Q. Does PacifiCorp agree that this information should have been considered?

A. No. In PAC/2500, Mr. Link states that the GWS construction decision was made a year before the Tenth Court of Appeals issued the order enforcing the stay of the OTR. Similarly, Mr. Link pointed out that PacifiCorp had not identified any wildfire liability as of June 2022 when GWS construction began.

Q. Why does Staff believe PacifiCorp's failure to fully analyze the OTR is important to the cost recovery of GWS?

A. PacifiCorp, in Reply Testimony, argues that while the OTR was proposed in April 2022, before its decision to construct GWS, any impacts from the OTR are not relevant to the prudence review because the rule was not finalized at that time.[3] PacifiCorp is correct that EPA's FIP was a proposed rule, without a guarantee of the final rule language. While the decision by the Tenth Court of Appeals did occur after the June 2022 construction start of GWS, several legal challenges to the OTR began in early 2022, and it was certainly foreseeable that the rule would not become final or that, if it did, a stay may be granted.

[3] PAC/2500, Link/23.

Thus, PacifCorp knew that a stay of the OTR was possible, given the many legal challenges. Yet, PacifiCorp never assessed the economic value of GWS in the context of a stay of the OTR or other action that kept the OTR from taking final effect. Rather, PacifiCorp argues it acted appropriately by assuming the rule "would only increase the benefits of Gateway South" and capturing such benefits in the Company's economic analysis, without considering a future more grounded in reality.[4] The Company further faults Staff for not recognizing PacifiCorp would be obligated to model carbon emissions reduction requirements.[5] It appears, as discussed further below, that the Company relied entirely on the modeling exercise of the 2021 IRP and did not consider the information available when it made the construction decision on GWS in 2022.

Q. What impact would no OTR have had on PacifiCorp resource decisions?

A. PacifiCorp has stated that the OTR is a key driver of the Company's overall resource strategy. Planning without the OTR would cause PacifiCorp to shift back to coal generation and limit the need for acquisition or contracting of more renewables and storage. As such a stay of the OTR would most likely lead to resource decisions that resulted in higher costs and emissions than forecasted in PacifiCorp's 2021 IRP.

[4] PAC/2500, Link/24.
[5] PAC/2500, Link/26.

Q. In UE 433, has the Company developed a record of the benefits to Oregon ratepayers used in the economic analysis to support the June 2022 construction date of GWS, as called for in Order No. 22-178?

A. Yes, but only partly. PacifiCorp has provided a record of benefits associated with GWS analysis that includes new wind resources that would meet significant capacity needs estimated in its 2021 IRP, an estimated $750 million present value in production tax credits associated with wind resources, meeting FERC reliability standards amidst growing load on the system and serving OATT obligations to meet transmission service and interconnection service requests.

Q. Does Staff believe these benefits will materialize once GWS is online?

A. Yes. Clearly there are reliability benefits from adding transmission not only to PacifiCorp's system, but to the western USA. Additionally, the wind projects enabled by GWS have economic and emissions benefits.

Q. Are there other benefits from GWS that Oregon customers were hoping to realize?

A. Yes, as discussed previously, according to PacifiCorp's 2021 IRP, GWS was going to support a system transitioning out of the costs and risks of reliance on coal, and therefore reducing emissions associated with these plants for Oregon customers. Additionally, GWS was also going to reduce the Company's reliance on markets in times of scarcity, thereby lowering risk exposure for Oregon customers.

Q. Does Staff believe that the record of benefits provided by PacifiCorp in UE 433 in support of the June 2022 construction decision is complete?

A. No. The economic analysis did not consider risks associated with a potential stay of the OTR, which was foreseeable as discussed above. The stay of the OTR has triggered foreseeable changes in resource decisions made in the 2021 IRP ultimately impacting benefits to Oregon customers. Market purchases have increased, and coal closures are delayed despite increasing costs, leaving risk reduction benefits, system transition support benefits, and emissions reduction benefits from GWS unrealized. In fact, system emissions are projected to increase in the most recent 2023 IRP Update through 2030 (see Table 1 below) (a critical timeline to meet Oregon House Bill 2021 emissions reduction goal). This exposes Oregon customers to unnecessary costs and risks of compliance. PacifiCorp did not do a deeper analysis related to policy uncertainties in its 2022 economic analysis for GWS.

Table 1: PacifiCorp System CO2 Emissions Projections

Total CO2 Emissions in Million MT CO2e	2021 IRP	2023 IRP	2023 IRP Update
2023	34.82	41.478	[Begin Confidential] [redacted]
2024	33.31	39.2909	[redacted]
2025	27.08	37.5659	[redacted]
2026	23.34	25.1899	[redacted]
2027	22.83	27.0765	[redacted]
2028	18.89	26.0362	[redacted]
2029	17.65	19.3271	[redacted]
2030	15.44	16.5174	[redacted]
2031	13.63	16.3665	[redacted]
2032	12.6	10.0213	[redacted]
2033	11.25	7.0395	[redacted]
2034	10.73	7.2359	[redacted]
2035	10.46	6.9921	[redacted]
2036	10.99	7.2669	[redacted]
2037	10.12	7.0113	[redacted]
2038	5.84	6.7747	[redacted]
2039	5.74	7.6311	[redacted]
2040	5.99	5.7666	[redacted] [End Confidential]

Q. Staff criticizes the Company's 2022 decision based on information that has since come to light. Isn't prudence based on the decision at the time of the investment?

A. Yes. Staff agrees that the Commission's determination of prudence is based on the information that the Company knew at the time of investment. But Staff would note that the Company did likely know some additional information related to the OTR that it did not consider. Further, we are two years removed from the investment decision of a 60-year investment. Already half of the benefits used to justify the investment have been proven false. Staff questions the legitimacy of the analysis that led to a decision based on such false assumptions. Staff has concerns that the analysis was disingenuous, since the

Company has made multiple decisions in the last two years which undermine the assumptions used to justify GWS. Staff would not have such concerns if this were a case where the benefit assumptions just didn't materialize due to a random course of events, but the Company's own actions eroded the benefits for Oregon customers. These include the stay of the OTR, the coal retirement delays, the Company's plan to pursue increased reliance on coal and the market, signing new coal contracts at the coal plants that just so happen to be located at the terminus of the GWS line. In this circumstance, where we are evaluating the analysis and decision-making criteria for prudence purposes, Staff believes it is appropriate to consider new information in order to determine the reasonableness of the decision. In light of that, Staff struggles to see evidence that the Company has shown this investment is in the best interest of Oregon ratepayers both at the time of the investment and now.

Q. Does Staff want to add anything else to the benefits analysis related to GWS?

A. Yes. Staff notes that in the context of reliability studies on GWS to meet FERC reliability requirements published in PAC/2600/Vail/19, PacifiCorp states "the 2019 TPL-001-4 planning assessment identified three deficiencies on the existing system that are mitigated by Gateway South and Segment and four additional deficiencies that are projected to happen by 2029 due to typical system changes and normal load growth." This indicates that GWS will not provide essential transmission capacity and enhanced system reliability until 2029.

Q. Does Staff continue to support Staff's initial recommendation?

A. Yes. Staff continues to recommend a temporary reduction in the rate of return (ROR) until analysis is presented documenting the full benefits to Oregon ratepayers, as recommended by the Commission in Order No. 22-178. Oregon ratepayers are being asked to bear the full amount of Oregon's proportional share for GWS beginning on January 1, 2025. PacifiCorp's actions prior to and after GWS construction, however, appears to have diminished many of the benefits. The matching principle calls upon the Company to better establish the benefits in a future prudency review.

Q. Did the previous IRPs fully establish the benefits of GWS?

A. No. As the Commission Order No. 22-178 stated, "To the extent [PacifiCorp] believes it can justify the Gateway segments in terms of the benefits provided to Oregon customers, we look forward to the development of that record for prudency review." Staff expected testimony in UE 433 to more fully establish a record of the benefits of GWS to Oregon ratepayers based on PacifiCorp's analysis at the time construction was begun in June 2022, as the Commission found PacifiCorp had not fully done so in the 2021 IRP. Yet, PacifiCorp continues to revert back to the 2021 IRP economic analysis as the basis for benefits to Oregon ratepayers despite the clear evidence that GWS had no impact in lowering overall system emissions nor on reducing the Company's expensive reliance on market purchases. It is difficult to see how the Company could have developed such analysis between the 2021 IRP and the start of construction as emissions have only increased, and will continue to increase, over forecasted levels from the 2021 IRP – threatening to make near-term compliance with HB 2021 more expensive – and the forecasted levels of expensive market purchases have increased dramatically since the conclusion of the 2021 IRP, despite GWS scheduled to be before 2025.

Q. Based on the Company's Reply Testimonies does Staff change the recommendations it made in Opening Testimony?

A. No. Staff is not proposing changes to recommendations published in its Opening Testimony at this time. Accordingly, Staff's recommendations are the following:

1. Allow PacifiCorp only the Modified Blended Treasury (MBT) Rate of Return (ROR) of 5.6 percent on Oregon's allocated share of capital investments of $563.9 million for GWS. The MBT ROR for GWS be applied until the project demonstrates the benefits identified in planning that would show that this transmission project is then timely constructed. This results in a decrease in a $16.2 million in revenue requirement.
2. Charge PacifiCorp with a management disallowance amounting to ten percent of its Oregon-allocated share of the GWS and GWS supporting project investment, which is calculated to be $56.4 million (0.10*$563.9 million).

ISSUE 2. REVIEW OF AWEC'S TESTIMONY ON TRANSMISSION

Q. What is Staff's position on AWEC's recommended adjustments for inappropriate costs in GWS transmission project, Allowance for Use of Funds During Construction (AFUDC), and associated Construction Work in Progress (CWIP) costs?

A. Staff is monitoring AWEC's position on AFUDC and associated CWIP and PacifiCorp's response on whether the cost adjustments proposed by AWEC are justified.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3400

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Senior Economist employed in the Accounting and Finance Section of the Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is provided in Exhibit Staff/1500 and my Witness Qualification Statement was provided in Exhibit Staff /1501.

Q. What is the purpose of your testimony?

A. In this testimony I reiterate my adjustments and provide further discussion of issues raised in my Opening Testimony regarding these aspects of PacifiCorp's (Company) request for a general rate revision, docketed as UE 433. I also rebut the Company's Reply Testimony on the issues listed below.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare additional exhibits for this testimony?

A. Yes. I prepared Exhibit Staff/3401, Staff's work paper for AFUDC adjustment calculations.

ISSUE 1. DEPRECIATION (COAL POWER PLANTS) – NET SALVAGE

Q. Would you like to respond to PacifiCorp's statement in Reply Testimony that, "…a statement in witness Peng's testimony asserting that, '[g]enerally speaking, as the depreciable life of an asset is extended, the net salvage rates tend to be lower,' is fundamentally incorrect."[1]

A. Yes. I would like to clarify the net salvage rate issue. It is common for the negative net salvage rate of coal power plants to fluctuate based on their anticipated operational life. When the lifespan of a coal power plant is shortened, the negative net salvage rate typically becomes more negative (the cost of removal increases). Conversely, if the plant's operational life is extended, the negative net salvage rate becomes less negative (the cost of removal decreases).

Q. Why is this?

A. Net salvage is calculated as Gross Salvage minus Cost of Removal. The cost of removal for power generation plant consists of two parts: (1) Interim Removal and (2) Terminal Removal (decommissioning). Generally:

- Shortened Life: If a plant's expected life is reduced from 40 years to 20 years, the increased decommissioning costs per year raise the negative net salvage rate.
- Extended Life: Extending the life from 20 years to 40 years spreads decommissioning costs over more years, reducing the annual negative net

[1] PAC/3300 Cheung/46.

salvage rate.

Q. Are there any exceptions when it comes to extending the operational life for coal power generation plant, but the depreciation expenses increase?

A. Yes. Most coal power generation plants reach their original engineered lifespan of 40-45 years, but there are exceptions when it comes to extending their operational life. For instance, in Oregon, the Jim Bridger coal-fired power plants will be fully depreciated by the end of 2025, meaning their book value will be $0. Given that the plant is fully depreciated, the company only needs to account for additional decommissioning costs, which will be spread over the extended operational period.

Assuming there are no significant capital additions during the extended period and that the primary expense is the evenly distributed decommissioning cost (for example, over a 5-year extension), the decommissioning cost will be incurred at the end of the plant's life. Consequently, depreciation expenses will increase due to the coal power plant’s extended life, even when its book value is at or near $0.

Q. What fundamental principle is represented in your adjustment?

A. In general, this adjustment reflects the principle that a longer lifespan for coal power assets results in a lower annualized cost for removing the asset, which in turn influences the net salvage rate.

ISSUE 2. JIM BRIDGER DEPRECIATION RATES

Q. Would you like to address PacifiCorp's statement in Reply Testimony that, "It appears Staff witness PENG may be misreading the data presented in OPUC data request (DR) 156,"[2] and "the Company has already incorporated the updated depreciation rates."[3]

A. Yes. Staff DR 156 to PacifiCorp in this rate case is reproduced for review here:

> DR 156: "Depreciation & Amortization Expenses and Reserves, Plant, Depreciation Rates, AFUDC, CWIP, WACC
>
> Please provide the calculations of depreciation and amortization expenses and reserves and include all: (a) links, (b) formulas, (c) references, (d) notes, and (e) term definitions to your work paper in this filing.
>
> Your response should enable Staff to verify such data as: (a) Plant Balance, (b) Depreciation Rates, (c) Depreciation Expense, (d) Depreciation Reserve, and (e) Oregon Allocation Factors (<u>including all ties to the UE 433 Revenue Requirement Model</u>), Gross Plant, Accumulated Depreciation, and Depreciation Expense.

Q. Was Staff's analysis based on the data provided by PacifiCorp in response to this DR 156?

A. Yes. Staff's analysis was based on the Attachment PacifiCorp provided in response to Staff's DR 156.[4] PacifiCorp claimed that "the Company has already incorporated the updated depreciation rates."[5] However, PacifiCorp's response to DR 156 does not show that the depreciation rates for Units 1, 2, and Common assets have been updated. Furthermore, the calculated results in DR 156 do not align with (tie to) the UE 433 Revenue Requirement Model as requested.

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[2] PAC 3000, Cheung/47.
[3] PAC 3000, Cheung/48.
[4] Staff/1500, Peng/6.
[5] PAC 3000, Cheung/48.

Q. Does Staff want to change its adjustment on this issue at this time?

A. Not yet. Staff will remove its adjustment of $12 million on JB 1, 2, and Common asset depreciation expenses, along with the associated recommendations on the depreciation reserve, if it receives the company's supplemental data response to DR 156 (tab name: “Oregon Coal”, line numbers: 218-232, 250-257) confirming that the new depreciation rates have been updated and used in the calculation of its revenue requirement.

ISSUE 3. HYDRO LICENSING FEES

Q. Would Staff like to respond to PacifiCorp's statement in Reply Testimony regarding Hydro Licensing Fees that, "Staff's concern is invalid"?[6]

A. Yes. Staff restates these concerns: Hydro licensing fees are recovered through amortization. If construction costs, for example, under FERC Account 332 - Reservoirs, Dams, and Waterways, are funded directly by these fees, they should not be depreciated as a tangible asset to avoid double counting.[7] As of 2024, PacifiCorp owns 30 Hydroelectric Plants.[8]

Q. Is PacifiCorp obfuscating and failing to address the issues raised by Staff in Opening Testimony?

A. Yes. Staff did not intend to discuss the possibility of using the funds to build fishery facilities or environmental protection infrastructure projects and depreciating them in the revenue requirement on the accounting paperwork. Instead, Staff wants to know whether PacifiCorp both amortized the hydro licensing fees and simultaneously depreciated the fee-funded construction costs in its actual operations.

Q. Was the Company's Reply Testimony sufficient for Staff to change its request?

A. No. Staff expects PacifiCorp to address Staff's issue raised of potential double counting as articulated above.

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[6] PAC 3000, Cheung/52.
[7] See Staff/1500 Peng/21.
[8] PacifiCorp — Hydro, pacificorp.com.

ISSUE 4. RECORDING EXCESS AFUDC

Q. Did Staff provide a response with attached examples to PAC's DR 23 regarding FERC's required treatment of AFUDC capitalization in instances when the FERC-calculated AFUDC rate is different than the state-approved rate?

A. Yes. In PAC's data request No. 23, the Company asked:

> If the FERC [Allowances for Funds Used During Construction (AFUDC)] rate is different than the state-approved rate, should the AFUDC capitalized be split between utility plant and a regulatory asset, with the amount capitalized in utility plant based on the FERC AFUDC rate? Please provide the source or supporting documentation for this statement.

Staff responded with two attachments regarding FERC's required treatment of AFUDC. These attachments explained that if the FERC AFUDC rate is different than the state-approved rate, the AFUDC capitalized should indeed be split between utility plant and a regulatory asset, with the amount capitalized in utility plant based on the FERC AFUDC rate.

Q. Does PAC state that the company is not aware of any guidance from FERC capping its AFUDC rate at the state-approved WACC?

A. Yes. In Exhibit PAC/3300, Cheung/56 indicated that the Company is not aware of a requirement that its AFUDC rate is essentially capped at its state-approved WACC (rate of return). Additionally, the Company was not aware of any such guidance from FERC capping its AFUDC rate at the state-approved WACC.

For context, WACC represents the investors' rate of return in a regulated utility. In the U.S., a revenue requirement is measured by the cost of service. Under regulation, once the WACC (rate of return) is stipulated by the parties and authorized by the Commission, the company's AFUDC rate is typically expected to align with or be lower than the OPUC-authorized WACC to prevent over-recovery from ratepayers. Please note:

1. AFUDC is categorized under capital cost, and the return on rate base includes the cost of debt and equity. The return on rate base is calculated using the WACC, so the AFUDC rate should not exceed the authorized rate of return set by the Commission.
2. By capitalizing these excess amounts as plant costs, the utility inflated the asset base, leading to higher rates charged to customers. Therefore, the AFUDC rate should comply with the authorized WACC rate.

Q. Did Staff offer an adjustment to the revenue requirement for this proposal? How did the Staff adjust PAC's excess portion of AFUDC?

A. Yes. Staff's adjustment required that PacifiCorp's capitalized AFUDC be split between utility plant and a regulatory asset. This involved pulling the excess amount out of the utility asset from a rate base and placing it into the regulatory assets under the Operating Expenses in a revenue requirement. Please note that regulatory assets are not included in the rate base. Instead, they are treated as deferred costs that will be recovered over time.

Q. What is the impact on Oregon utility customers and the revenue requirement, and how does Staff's adjustment on this issue protect customers?

A. By capitalizing these excess amounts as plant costs, PacifiCorp would have inflated the asset base, leading to higher rates charged to customers. Staff's adjustment ensures that the Company does not over-recover their financing costs from customers, which maintains fair and just rates. Recording excess AFUDC as a regulatory asset prevents the Company from overcharging customers immediately. Instead, these costs are spread out and recovered over time.

Instead of immediate capitalization in a rate base, this excess AFUDC is recorded as a regulatory asset. This regulatory asset represents future recoverable amounts under the operating expense in a revenue requirement. The regulatory asset is amortized over a period as determined by the regulatory body, ensuring that the utility recovers these costs in a controlled manner that avoids sudden rate increases for customers.

Q. Did Staff provide a workpaper to support this adjustment?

A. Yes. Staff's calculation in its work paper illustrates the process of removing an overcapitalized portion of AFUDC from the rate base and reclassifying it as a regulatory asset. The regulatory asset is then included in the revenue requirement through amortization and a potential return, ensuring the utility can recover the associated costs.

For detailed dollar impact, please see Staff's work paper in Exhibit 3401.

Q. In addition to the two attachments provided by Staff regarding FERC's required treatment of AFUDC in Staff Data Response No. 23, can Staff also provide the FERC accounting policies?

A. Yes. In addition to the two attachments regarding FERC's required treatment of AFUDC provided in Staff Data response No. 23, Staff provides the relevant FERC accounting policies on the following page.

FERC Accounting Policies

FERC 18 C.F.R. Part 101 - Electric Plant Instructions

The Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts, detailed in 18 C.F.R. Part 101, provides comprehensive instructions on accounting practices for public utilities, including the treatment of Allowance for Funds Used During Construction (AFUDC).

Relevant Sections:

- **Electric Plant Instruction No. 3**: This section outlines the procedures for calculating and capitalizing AFUDC. It specifies that the AFUDC rate must not exceed the rate derived from the formula set forth in these instructions.
- **Capitalization Limits**: If a utility's AFUDC rate exceeds the allowable rate, the excess cannot be capitalized directly into Construction Work in Progress (CWIP). Instead, it must be treated as a regulatory asset, provided it is probable that these costs will be recovered through future rates.

For the complete details, you can access the 18 C.F.R. Part 101 document on GovInfo.

FERC Accounting Release No. 5 (AR-5)

FERC Accounting Release No. 5 provides specific guidance on the treatment of AFUDC and the handling of excess amounts. It outlines the steps utilities should take to ensure compliance with FERC regulations:

- **Capitalization of Allowable AFUDC**: The allowable portion of the AFUDC rate can be capitalized in CWIP.
- **Recording Excess AFUDC**: The excess portion of the AFUDC rate must be recorded as a regulatory asset if future recovery is probable. This ensures that utilities do not inflate their asset base with costs that may not be recoverable.

FERC Accounting Guidance

18 C.F.R. Part 101 - Electric Plant Instructions

- **Electric Plant Instruction No. 3**: Details on calculating and capitalizing AFUDC. It states that the AFUDC rate must not exceed the rate obtained by the formula specified. Excess amounts are typically not capitalized directly into CWIP.

FERC Accounting Releases

The principles of regulatory accounting suggest that excess costs should be treated as regulatory assets if recovery through future rates is likely. This is in line with general regulatory accounting practices where costs expected to be recovered in future rates can be recorded as regulatory assets.

CONCLUSION

Q. Has Staff maintained its adjustments on these topics?

A. Staff maintains its adjustments for the following items:

1. Net Salvage: This accounts for a $1.149 million reduction in depreciation expense and the associated changes to the depreciation reserve.
2. JB 1 & 2 and Common Plants Depreciation: Staff will remove its adjustment of $12 million on JB 1 & 2 and Common plants depreciation expenses if Staff receives the company's supplemental data response in DR 156, confirming that the new depreciation rates have been updated and used in the calculation of its revenue requirement.
3. Hydro Licensing Fees: The Company must clarify whether PacifiCorp both amortized the fees and simultaneously depreciated the construction costs included in those fees.
4. Recording Excess AFUDC: PacifiCorp's AFUDC capitalized should be split between Utility Plant and a Regulatory Asset by pulling out the excess amount from the utility asset and placing it into the regulatory assets.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3401

Exhibits in Support
Of Rebuttal Testimony

Staff's work paper for AFUDC adjustment
is available as an Excel file

August 16, 2024

CASE: UE 433
WITNESS: NICOLA PETERSON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 3500

REDACTED
Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Nicola Peterson. I am a Senior Telecoms Analyst employed in the Water, Telecom, Safety and Consumers Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony was provided in Exhibit Staff/1600 and my Witness Qualification Statement was provided in Exhibit Staff/1601.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address any outstanding issues detailed in my Opening Testimony and PacifiCorp's Reply Testimony in relation to Administrative & General (A&G) expenses, Employee Benefits, and Insurance.

Q. Did you prepare exhibits for this testimony?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ADMINISTRATIVE & GENERAL EXPENSES

Q. Are there any remaining questions in your Opening Testimony that have now been resolved?

A. Yes. In my Opening Testimony I had outstanding data requests and further analysis to complete prior to making a final recommendation on whether an adjustment was required.

Q. Having received those data requests and completed the additional analysis, are there any adjustments that you recommend for these accounts?

A. No. Staff is not recommending any adjustments to these accounts.

EMPLOYEE HEALTH INSURANCE & BENEFITS

Q. Did PacifiCorp address Staff's Employee Health Insurance & Benefit adjustment in their Reply Testimony?

A. Yes.[1] The Employee Health Insurance and Benefit adjustment in Staff's Opening Testimony was based on reducing the escalation of Medical and Dental benefit expense from eight percent to six percent. PacifiCorp addressed this percentage change and the calculation of the adjustment.

Q. Did PacifiCorp agree with Staff's adjustment?

A. Yes, but with corrections. PacifiCorp agreed with Staff that an escalation rate of six percent was more appropriate, but the Company disagreed with how Staff had calculated their proposed adjustment. PacifiCorp explained that Staff's calculation was based on Total Company amounts and failed to take into consideration capitalization assumptions.

Q. Has Staff's recommended adjustment changed?

A. Yes. After reviewing the Company's testimony and checking the methodology behind the Company's revised amount, Staff has reduced its adjustment from $1.157 million to $0.212 million, which is the amount proposed by PacifiCorp.

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[1] Pac/3300/Cheung/6.

INSURANCE EXPENSE

Q. Did PacifiCorp address Staff's recommendation regarding Insurance Expense in the Company's Reply Testimony?

A. Yes.[2] Staff proposed two adjustments to FERC Account 925 and PacifiCorp addressed both of these adjustments.

Q. Did the Company agree with Staff's adjustment?

A. No. As stated above, Staff had proposed two adjustments to this account. The first adjustment was based on removing one "substantial" cash payment from the three-year average which was used to establish an annual Injuries and Damages Provision. The second adjustment was the averaging of legal expense in this account to a three-year average.

Q. Did PacifiCorp provide an explanation as to why they rejected Staff's proposed adjustment?

A. Yes. With regards to the Injuries and Damages Provision, PAC insists that all expenses should be included and stated that the averaging in rate proceedings was to "normalize spikes and dips in historical data that do not follow a consistent trend but can fluctuate significantly from year-to-year, recognizing that those spikes and dips are a given in the normal course of business".[3]

PacifiCorp goes on to address the averaging of legal fees and states that "the Company believes that the legal fee amount included in the Base Period, which is the most recent reporting period data available at the time this filing

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2 PAC/3300/Cheung/25.
3 PAC/3300/Cheung/26.

was prepared, would be more representative of the anticipated level of legal fees in the Test Period. According to the Company, legal fees have been increasing consistently over the last three years such that a three-year average methodology would not reflect the level of expense needed for the Test year.

Q. Does Staff agree with PAC's view of FERC Account 925?

A. No. With regards to the injuries and damages provision, Staff removed the one claim because such a large claim did not occur in the normal course of business and therefore should not be included. This adjustment aligns with the Company's reasoning that the injuries and damages calculation is reserved to normalize spikes and dips which occur in the normal course of business. Staff finds this same rationale applies to Staff's adjustment to legal fees. Legal fees in this account were below **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

PacifiCorp is asking to maintain this level of legal expenses into the Test Year. Staff believes that a normal level of legal fees would not include the excessive expenses occurred in the last two financial years and averaging the last three years which results in maintaining the 2021-2022 level of legal fees is more than justified. Staff does not find the Company's rationale for the recent increase in legal fees to be dispositive or compelling in regard to a permanent change that is beyond the Company's control.[4] Staff recommends an average

[4] PAC response to DR 601.

because it provides a reasonable and normalized estimate that provides the Company with proper incentives to ensure legal fees are maintained at a level that is in the best interest of ratepayers.

Q. Did Staff propose an adjustment to FERC Account 924?

A. At the time of publishing Staff's Opening Testimony, Staff had an outstanding data request which asked for the details of the losses used to calculate the 10-year average property damage provision. Staff requested this to understand the implications to the provision of expenses relating to wildfires. Although there were expenses relating to wildfires included in the losses, these expenses were not of a magnitude to be material to the overall calculation.

SUMMARY OF RECOMMENDATIONS AND ADJUSTMENTS

Q. Please summarize your recommendations and adjustments.

A. The following are my recommendations and adjustments.

1. A & G Expenses: No adjustment.
2. Employee Health Insurance & Benefits: Adjustment of $1.157m reduced to $0.212 million.
3. Insurance: No change to opening testimony recommendation. Adjustment of $4,856,923, consisting of an adjustment to the Injuries and damages provision of $3,148,965 and an adjustment to legal fees of $1,707,958.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 3600

REDACTED
Rebuttal Testimony Fall Creek Fish Hatchery, Cost of Long-Term Debt

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Rose Pileggi. I am a Senior Energy Analyst employed in the Energy Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/1700 and my witness qualifications statement is provided in Exhibit No. Staff/1701.

Q. What is the purpose of your testimony?

A. I address PacifiCorp's (PacifiCorp, PAC, or the Company) filed Reply Testimony regarding the Fall Creek Fish Hatchery, another Klamath Dam removal issue, and Cost of Long-Term Debt, and Alliance of Western Energy Consumers' (AWEC) filed Opening Testimony regarding Cost of Long-Term Debt.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/3901, Staff's updated Cost of Long-Term Debt Work Paper, and Exhibit Staff/3902, PacifiCorp's response to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. FALL CREEK FISH HATCHERY

Q. Please provide a brief summary of PacifiCorp's Reply Testimony pertaining to this issue.

A. PacifiCorp continues to support the full recovery of this project in rates. The Company provides background information that the capital costs of settlement of the Klamath Hydroelectric Settlement Agreement (KHSA) did not include the capital costs that arose from the interim measure 19.[1] The Company states that "…recovery of the Company's costs to construct the Fall Creek Hatchery is consistent with ORS 757.374…."[2]

Q. Has Staff's recommendation changed since filing of Opening Testimony?

A. Yes. Consistent with what was noted in Staff's Opening Testimony and in PacifiCorp's Reply Testimony,[3] that Staff might change its recommendation if it was found that the amounts were not included in the depreciation schedules, Staff is altering its recommendation. Staff's recommendation is the Commission either disallow the entirety of the project or require that all proceeds from the sale or leasing of the property go directly to offset customer rates.

Q. What is the basis for Staff's changed recommendation?

A. Staff again acknowledges that under ORS 757.734(2)(d) the Commission was directed to use depreciation schedules set no more than six months after

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[1] PAC/2700, Hemstreet/3
[2] PAC/2700, Hemstreet/1
[3] Staff/1700, Pileggi/4 and PAC/2700, Hemstreet/1, footnote 1.

execution of the KHSA to establish rates and tariffs for the recovery of "undepreciated amounts prudently invested by PacifiCorp in a Klamath River dam" including amounts "spent by PacifiCorp for settlement of the issues of relicensing or removal of the dam." The KHSA interim measures contemplated PacifiCorp funding for a different scenario than this final outcome. The KHSA provided that PacifiCorp would fund the ongoing operations and maintenance of the hatchery, a one-time payment for capital costs associated with changes necessary for continued production, and ultimately transfer the property and its improvements to the California Department of Fish and Game.[4]

On January 13, 2021, PacifiCorp entered into a Property Transfer Agreement which also included a lease for the Fall Creek Fish Hatchery to meet hatchery requirements.[5] This docket was consolidated into UE 219, and an order approving the Property Transfer Agreement was entered July 29, 2021.[6] Only after this was done did PacifiCorp make the determination, in July of 2022, that the best option to meet hatchery production was to improve the Fall Creek Fish Hatchery.[7] This completely changes the nature of the capital costs incurred by the Company.

Q. What is the impact of these changes?

A. The settlement appears to have contemplated a hatchery that would be transferred to the California Department of Fish and Game, a property transfer

4 KHSA Section 7.6.6
5 UP 415, Exhibit 1, Page 6 https://edocs.puc.state.or.us/efdocs/HAQ/ue219haq13328.pdf.
6 UE 219, Order No. 21-242.
7 See Staff/3902, Page 1, PacifiCorp's response to Staff Data Request No. 728.

approved by the Commission. Once PacifiCorp had an order approving the Property Transfer Agreement and lease to the Fall Creek Fish Hatchery, PacifiCorp knew that any improvements made would be investments from which the Company would benefit.

PacifiCorp did not create a final plan to determine the best option to meet its settlement obligations, citing timing issues.[8] The Company states that "PacifiCorp will explore options to sell or lease the facility to allow it to continue to meet those needs after PacifiCorp's obligations with respect to the facility have been met."[9] Instead of customers funding improvements necessary to meet obligations of the KHSA, in which the benefit of improvements was to the California Department of Fish and Game, PacifiCorp is asking that customers fund improvements to an asset that the Company will retain, and intends to later sell or lease.

Q. How does this support Staff's updated recommendation?

A. Staff understands that ORS 757.734(2) authorizes recovery of undepreciated investment, not to create an asset on which that PacifiCorp may later earn a return. While Staff had initially understood the project to be dictated by the KHSA, it now appears to be unilateral change in approach by the Company that was not required by statute or the KHSA.

Q. Did PacifiCorp raise any other issues related to Klamath Dam Removal in its Reply Testimony?

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8 See Staff/3902, Page 2, Response to Staff Data Request No. 727.
9 See Staff/3902, Page 3, Response to Staff Data Request No. 723.

A. Yes. Though PacifiCorp witness McVee expressed concern that Staff and CUB indicated their review of the filed case was ongoing and additional issues and recommendations may be identified as the evidentiary record unfolds,[10] PacifiCorp itself adds a new issue in its Reply Testimony related to Klamath River dam removal. At PAC/3300, Cheung/92-93, PacifiCorp states that in May 2024:

> PacifiCorp was informed by the Klamath River Renewal Corporation (KRRC) that the Company would need to provide $15 million in contingency funds, as per the December 2022 Memorandum of Agreement, to support the removal of the Klamath Dams. The Oregon-allocated portion of this is approximately $4.0 million, and PacifiCorp will be seeking to include it in the regulatory asset that was described in my direct testimony and identified in page 8.20 of Exhibit PAC/1702.

Q. Does this statement raise concerns for Staff?

A. Yes. Staff finds this comment quite surprising because Staff is not aware of any authority for PacifiCorp's proposal to collect an additional $4 million from Oregon customers for amounts used by the KRRC for its dam removal activity. Such an amount would be above the maximum customer obligation of $184 million for dam removal activity, an amount which has already been collected and disbursed to the KRRC on behalf of Oregon customers.[11] Staff is opposed to any attempt to include this amount as a regulatory asset.

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[10] PAC/2000, McVee/70.
[11] See Docket No. UE 219, Order No. 24-154 at 3-4 (May 29, 2024).

ISSUE 2. COST OF LONG-TERM DEBT

Q. Did the Company revise its requested Cost of Long-Term Debt in Reply Testimony?

A. Yes. The Company has increased its requested Cost of Long-Term Debt from the 5.18 percent requested in its Opening Testimony to 5.28 percent.[12] This increase of 0.1 percent reflects the shift in pro forma debt issuances to include Junior Subordinated Notes (JSN) rather than the First Mortgage Bonds (FMB) initially used.

Q. What are the significant differences between Junior Subordinated Notes and First Mortgage Bonds?

A. JSNs are treated by both Standard & Poor's and Moody's as 50 percent equity and 50 percent debt in ratings. Additionally, JSNs lack the same assurance to the bondholder that an FMB would have. In the event a company is unable to meet its obligations, a JSN does not have the same backing that an FMB does. A FMB is first in line and tied to specific assets as collateral. A JSN is junior to other debts and not backed by collateral. The nature of the JSN requires an investor to demand a higher return to compensate for the increased risk.

Q. What was AWEC's recommendation in its Opening Testimony?

A. AWEC's recommended Cost of Long-Term Debt for PacifiCorp was 5.13 percent.[13] The rationale provided was to remove the impacts of the 2020 Labor Day Fires on the Company's credit ratings.[14]

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[12] PAC/2100, Kobliha/2.
[13] AWEC/200, Kaufman/55.
[14] Id.

Q. Does Staff agree with AWEC's rationale in Opening Testimony?

A. No. Staff does acknowledge that PacifiCorp's issue credit ratings were impacted by the fires, however, the debt issued thus far in 2024 has been FMBs, which are rated separately from the issuer ratings. AWEC's Opening Testimony was filed prior to the Company's shift to include JSNs in its pro forma issuances.

As a junior form of debt, unbacked by collateral, JSNs are far more sensitive to changes in issuer ratings than an FMB would be. The fluctuations in premiums paid for similarly rated FMBs, are attributable to many factors—such as the market's appetite for that specific type of security, market and industry trends, regional events and expectations for risks, and expectations of changing yields, etc. To tie the fluctuations in premiums to an isolated event would require significant analysis, beyond simply comparing premiums paid by various peers at a couple of points in time. There are likely some impacts to PacifiCorp's Cost of Long-Term Debt, however AWEC has not provided analysis that Staff believes would accurately capture this.

Q. Is Staff updating its recommendation to the Cost of Long-Term Debt?

A. Yes. Incorporating the Company's revisions to the pro forma debt issuances yields a recommendation of 5.301 percent Cost of Long-Term Debt. This is 2.1 basis points (bps)[15] higher than the Company's update to requested Cost of Long-Term Debt.

[15] 1 basis point (bps) is equal to 1 percent of a percent.

Q. Why is Staff's recommended Cost of Long-Term Debt higher than the Company's updated request?

A. The cause driving Staff's calculation to yield a higher recommendation than PacifiCorp's updated request is the difference in methodologies. The Company utilizes a 5-quarter end average, whereas Staff's method is to utilize a single point in time for the outstanding debt. The difference is minimal at only 2.1 bps.

Q. Did Staff forecast its own estimated coupon for the new pro forma issuances?

A. No. Staff has reviewed PacifiCorp's estimated coupon for the JSN issuances and finds them to be similar to what Staff would see from other sources. Staff accepts the Company's estimated coupons on the JSN as being within reasonable expectations.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3601

CONFIDENTIAL

Exhibits in Support
Of Rebuttal Testimony
Cost of Long-Term Debt Workpaper

August 16, 2024

CASE: UE 433
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3602

Exhibits in Support
Of Rebuttal Testimony
PacifiCorp Responses to Data Requests

August 16, 2024

UE 433 / PacifiCorp
August 2, 2024
OPUC Data Request 728

OPUC Data Request 728

Fall Creek Fish Hatchery - When did PacifiCorp make the determination that pursuing the Fall Creek Fish Hatchery was the best option?

Response to OPUC Data Request 728

The determination was made in July 2022.

UE 433 / PacifiCorp
August 2, 2024
OPUC Data Request 727

OPUC Data Request 727

Fall Creek Fish Hatchery - Please provide the final plan that PacifiCorp developed under Interim Measure 19.

Response to OPUC Data Request 727

PacifiCorp did not produce a final plan as contemplated under Klamath Hydroelectric Settlement Agreement (KHSA) Interim Measure 19 because the license surrender process required development of a hatchery management and operations plan by the co-licensees prior to issuance of the Federal Energy Regulatory Commission (FERC) license surrender order.

UE 433 / PacifiCorp
August 2, 2024
OPUC Data Request 723

OPUC Data Request 723

Fall Creek Fish Hatchery - What are PacifiCorp's intentions for the Fall Creek Fish Hatchery after the 8-year period is over?

Response to OPUC Data Request 723

PacifiCorp expects that the Fall Creek Fish Hatchery will still be necessary to support Klamath basin salmon recovery and Tribal, commercial and sport fishing harvest objectives after the eight-year period of PacifiCorp's obligation. As such, PacifiCorp will explore options to sell or lease the facility to allow it to continue to meet those needs after PacifiCorp's obligations with respect to the facility have been met.

CASE: UE 433
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3700

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Paul Rossow. I am a Utility Analyst employed in the Accounting and Finance Section of the Commission's Energy Program. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is provided in Exhibit Staff/1800-1804.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to PacifiCorp's (Company) Reply Testimony regarding the Company's memberships, dues, donations, and subscriptions; meals, entertainment, and awards expenses.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations are as follows:

- Issue 1 (Memberships, Dues, Donations, and Subscriptions) – A total adjustment of ($199,640) to the Oregon allocated Test Year expense for FERC Account 930; and
- Issue 2 (Meals, Entertainment, and Awards) – A total adjustment of ($78,858) to the Oregon allocated Test Year expense for FERC Accounts 500 through 935.

ISSUE 1: MEMBERSHIPS, DUES, DONATIONS, AND SUBSCRIPTIONS

Q. What was Staff's recommendation as published in Opening Testimony for memberships, dues, donations and subscriptions expenses?

A. Staff followed Commission policy in Staff's review of expenses for memberships, dues, donations, and subscriptions listed in the Company's response to Standard Data Request (SDR) 90 and Exhibit No. PAC/1702, Cheung/103-105, pages 4.8-4.8.2, including the corresponding workpaper. Staff identified expenses for memberships related to economic development and civic organizations that should be disallowed, resulting in an Oregon escalated Test Year adjustment amount of ($199,640), which is an additional disallowance of $25,545 more than the Company's Initial Testimony adjustment of $174,095.

Q. Does the Company agree with Staff's proposed adjustment to memberships and subscriptions?

A. No. The Company disagrees with Staff's proposed full disallowance of trade and economic-related memberships.[1]

Q. Did PacifiCorp provide any evidence or proof that Staff is proposing a full disallowance of trade-related memberships?

A. No. The Company did not identify by name any trade organizations or provide documentation indicating that an organization included in Staff's adjustment is a trade organization.

Q. Please describe PacifiCorp's historical treatment on this issue.

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[1] See PAC/3300, Cheung/30, Lines 6-11.

A. Following a stipulated outcome in Docket No. UE 94, Company witness Cheung included 75 percent of annual membership and subscription expenses in rates.[2]

Q. Does PacifiCorp assert that chamber of commerce and economic development organizations in previous general rate cases had not been excluded?

A. Yes. Company witness Cheung mentions two dockets, UE 399 and UE 374, suggesting that none of the type of organizations for which Staff is proposing to disallow 100 percent were previously excluded in UE 399 and UE 374 or suggested for removal at any point in the rebuttal or surrebuttal processes of both general rate cases.

Q. Does Staff agree with PacifiCorp's idea that Staff does not remove chamber of commerce and economic development organization costs from rates?

A. No. For example, in Docket No. UE 374, Staff's opening testimony proposed to disallow an Oregon allocated amount of $25,000 in civic and economic development memberships. At Staff/1200, Rossow/5 Staff states, "Finally, Staff applied a 100 percent disallowance of the expenses associated with technical, commercial, trade, community affairs, and economic development organizations."

[2] See Order No. 96-175, issued on July 10, 1996.

Q Please describe why PacifiCorp believes that belonging to chamber of commerce and economic development organizations benefits ratepayers.

A. PacifiCorp asserts that its membership in these organizations strengthens relationships, provides a venue to communicate with customers and the community it services, allows the Company to strengthen relationships with key community and business leaders, builds sustainable communities through enhanced economic, environmental and educational opportunities, indirectly assists prospective customers with their siting decisions; to the extent that customers locate in the Company's service territory, provide updates to utility service, rate changes, and safety matters.[3]

Q. Does any of PacifiCorp's Reply Testimony address concerns raised in Staff's Opening Testimony?

A. No. Staff's Opening Testimony recommended a full disallowance of these costs because they are expenses related to community affairs and economic development organizations.[4] Commission precedent prohibits cost recovery of these types of expenses from ratepayers.[5] This includes both the chamber of commerce and economic development organizations identified in Staff's Opening Testimony. The Company's Reply Testimony fails to provide any evidence demonstrating the Commission should treat these expenses

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[3] See PAC/3300, Cheung/31-32.
[4] See Staff/1800, Rossow/9-11.
[5] *See In the* Matter *of Portland General Electric Company Request for a Rate Revision*, Docket No. UE 197, Order No. 09-020, pp. 20-21 (January 22, 2009).

differently or change existing policy. The essential nature of these organizations supports civic engagement and economic development.

Q. Does the Company's membership in chamber of commerce and economic development organizations benefit shareholders?

A. Yes. In general one may see a chamber of commerce as an organization of business owners and entrepreneurs who promote the interests of their local business community. Further, a chamber of commerce may also try to influence or lobby local community leaders to pro-business stances. While Staff invites the Company to explain further why a portion of chamber of commerce memberships could benefit Oregon utility customers of PacifiCorp, Staff's position at this time is that said members are best treated as a mix of charitable community work and business promotion, for which responsibility would fall to shareholders, absent good reason otherwise.

Q. Is Staff staying with its adjustment for memberships, dues, donations, and subscriptions publishes in Staff's Opening Testimony?

A. Yes. Staff is not changing position from its initial adjustment of ($199,640), meaning the effective Staff adjustment is $25,545 more than the Company's initial adjustment of $174,095 to expense. This is consistent with Commission precedent and practice.

ISSUE 2: MEALS, ENTERTAINMENT, AND AWARDS

Q. Please summarize your adjustment from your Opening Testimony.

A. Staff reviewed Exhibit PAC/1702, Cheung/106-108, pages 4.9-4.9.2, and PacifiCorp's response to SDR 57[6] to identify O&M non-payroll discretionary expenses that appear to be excessive, without sufficient business purpose, or not related to the provision of safe and reliable energy to customers. In the Company's response to SDR 57, the Company provided its Base Period, 12 months ended June 30, 2023, O&M non-payroll transactional expenses in Excel format. The accounting data includes 94 spreadsheets comprising but not limited to descriptions, category fields, account number, account number name, FERC accounts, transaction descriptions, source, and currency amount.

After reviewing O&M non-payroll expenses, Staff identified 2023 total Company Base Year expense of $425,192 with an associated Oregon-allocated Base Year amount of $153,224. Removing 50 percent of the allocated Base Year expenses results in a disallowed amount of ($76,611).

Q. Did PacifiCorp accept Staff's proposed adjustment?

A. Partially. The Company accepts Staff's proposed adjustment relating to expenses recorded in the catering services and on-site meals and refreshment categories but rejects the proposed adjustment for expenses recorded in the coffee/water/beverage services category.

[6] SDR No. 57 requested the Company to provide information for all non-payroll expenses recorded in all FERC accounts for the base year.

PacifiCorp further excluded expenses for catering and on-site meals relating to storm and fire restoration from three categories mentioned above. With these revisions, the Company incorporated in its Reply Testimony filing an additional Oregon allocated non-labor O&M expense adjustment to reduce expenses identified as follows:[7]

TABLE 5-Incremental M&E Expenses Subject to Sharing in Reply

Expenditure Category	G/L Account	OR-Allocated O&M
Catering Services – Non-Employee	530035	$3,081
On-Site Meals & Refreshments	503115	$128,748
Total Expenses (subject to sharing)		$131,978

Constructed from within the above two categories and excluding coffee/water/beverage services category, or amounts related to storm and fire restoration work, the Company's revised reduction is of approximately $66,000 to M&E expenses.

Q. Does Staff agree with PacifiCorp's rejection of expenses recorded to the Coffee/Water/Beverage Services category?

A. No. The Company rejects Staff's adjustment on the basis that Coffee/Water/Beverage Services are a standard common business expense, provides employees with basic hydration options during working hours, and does not appear to be excessive.

In Docket No. UE 197, the Commission clarified its policy that expenses for meals and entertainment, office refreshments, catering, gifts, and awards

[7] See PAC/3300, Cheung/24.

are discretionary and should be shared equally by customers and shareholders.[8] While PacifiCorp may find it appropriate to offer coffee and water services at no expense to its employees, this remains a discretionary action on its part, and should remain subject to sharing.

Q. Does Staff agree with the Company's recreated analysis for the Base Period for the three specific cost categories mentioned above and the further exclusion of storm and fire restoration work-related expenses without providing a textual list showing all excluded expenses that comprises Company Witness Cheung revised analysis?

A. No. The Company's filed Reply Testimony along with corresponding workpapers included FERC Account Nos. 500-935, a number Type identified with the number 1, Total Company and Oregon Allocated currency amounts by corresponding FERC Account Number, Factors in the form of acronyms, and the Factor with its corresponding percentage.[9] The Company excluded the textual portions of each expense transaction that comprises Company Witness Cheung revised analysis.

Staff does not agree with the Company's exclusion for expenses recorded in the Coffee/Water/Beverage Services category and storm and fire restoration work-related expense amounts. Stated in Staff's Opening Testimony at Staff/1800, Rossow/12, the Commission clarified its policy that expenses for

8 Ibid, 5.
9 See PacifiCorp's 4.9 Meals and Entertainment and Awards Adjustment Workpaper.

meals and entertainment, office refreshments, catering, gifts, and awards are discretionary and should be shared equally by customers and shareholders.

In Order No. 09-020, the Commission agreed with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. This is a fair approach that somewhat mirrors the policy for bonuses (50 percent sharing between ratepayers and shareholders) and the handling of these expenses for income tax purposes.

For income tax purposes, the amount allowable as a federal income tax deduction for business meal and entertainment is generally limited to 50 percent of the total expense. Based on Witness Cheung's recreated analysis for the three specific categories mentioned above and considering any offsetting amounts within the three specific categories. Staff acknowledges Witness Cheung's recreated analysis of expenses identified as follows.[10]

TABLE 4-Staff Identified Incremental M&E Expenses Corrected

Expenditure Category	G/L Account	OR-Allocated O&M
Catering Services – Non-Employee	530035	$3,081
Coffee/Water/Beverage Services	503430	$5,770
On-Site Meals & Refreshments	503115	$148,865
Total expenses subject to sharing		$157,716

Q. Did Staff Issue Data Requests asking for Witness Cheung's revised analysis?

A. Yes. Staff issued Data Request Nos. 739 and 740, due August 8, 2024, requesting each transaction expense including the transactions textual portions

[10] See PAC/3300, Cheung/23.

comprising of Cheung's revised analysis. The Company did not perform the requested analysis to identify all transactions identified in Staff's analysis. Based on the Company's response to Data Request No. 739, PacifiCorp opted to retrieve the total base year period expenses from its accounting system as reported in the Company's base period 12 months ended June 2023 figures. Therefore, Staff agrees with PacifiCorp's revised extraction of the total expenses subject to sharing in the amount of $157,716, on an Oregon basis.

Q. Is Staff holding at their original Opening Testimony meals and entertainment and awards adjustment?

A. No. Staff is moving from its original Oregon allocated Base Year disallowed amount of ($76,611) and proposing an amount of ($78,858), which is 50 percent of $157,716, which is approximately $12,858 more than the Company's revised amount of $66,000 to M&E expenses.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 3800

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Bret Stevens. I am a Senior Economist employed in the Energy Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit No. Staff/1900, and my Witness Qualifications Statement is provided in Exhibit No. Staff/1901. I also provided joint testimony in Exhibit No. Staff/2200.

Q. What is the purpose of your testimony?

A. I respond to PacifiCorp's (PAC or Company) Reply Testimony on several issues including PAC's Test Year load forecast, class cost-of-service (CCOS) study and rate spread, rate design, proposed insurance surcharge, and the calculation of rate base for purposes of establishing the return component of PAC's revenue requirement.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LOAD FORECASTING

Q. Please briefly describe PacifiCorp's methodology for this forecast.

A. PacifiCorp uses an autoregressive moving average (ARMA) time-series model for its customer count and energy forecasts. PacifiCorp separately estimates usage per customer and customer counts. The product of these separate forecasts constructs the load forecast for each class. The Company uses historical and predicted weather and economic data in order to parameterize these forecasts. Schedules with a small number of customers use a combination of load forecasting techniques and input from regional business managers to forecast loads.

Q. Please summarize Staff's recommendations in Opening Testimony.

A. In Staff's Opening Testimony, Staff recommended that the Company:[1]

- Use algorithmically parameterized ARIMA models as the baseline model and document and explain any deviations from these prescribed models.
- Present evidence either here or in its next general rate case showing that the use of the SAE "XHeat" and "XCool" variables add a sufficient level of explanatory power above more transparent weather variables to justify their use.
- Use a software which allows for differencing of models or present evidence for each of their models justifying the differencing, or lack thereof, for each model.

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[1] Staff/1900, Stevens/11.

- Host load forecasting workshops between now and their next general rate case to facilitate Staff and Intervenor input into these analyses.

Staff's recommendation on this issue remains largely unchanged.

Q. Did any other parties offer adjustments to PAC's load forecast?

A. No.

Q. How did PacifiCorp respond to Staff's recommendation to algorithmically parametrize ARIMA models as a baseline?

A. The Company stated that using an algorithmic ARIMA model would create a disconnect between the Oregon forecast and the forecast in other states. The Company argued that it has a long history of producing reliable forecasts and that there are true-up mechanisms to protect customers and the Company from unexpected change in load. Lastly, the Company argued that there are human capital costs to learning new software and methodologies that would accompany this change.[2]

Q. How does Staff respond to the Company's position?

A. Staff believes that the Company should always be looking to improve its load forecasting methodologies as new methods and tools are created. The forecasting and econometric literature is always evolving. Staff is not concerned if Oregon's load forecast methodology differs from the other states that PacifiCorp serves. PacifiCorp should be using transparent methods when setting rates in Oregon regardless of what is done in the other states it serves.

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2 PAC/3200, Elder/2.

However, it would seem prudent for the Company to want to improve its load forecasting methodologies in *all* of its jurisdictions.

While the Company's forecasts have not necessarily deviated from actuals by so much that Staff is arguing for immediate changes in this case, the Company's forecasts have not been so accurate that there is no need for improvement. Figure 1 below shows the difference, in percentage terms, between the Company's monthly forecast and actuals. In this figure, a negative number represents a case where the forecast is lower than the actual usage for that month.

Figure 1. Oregon Forecast Error

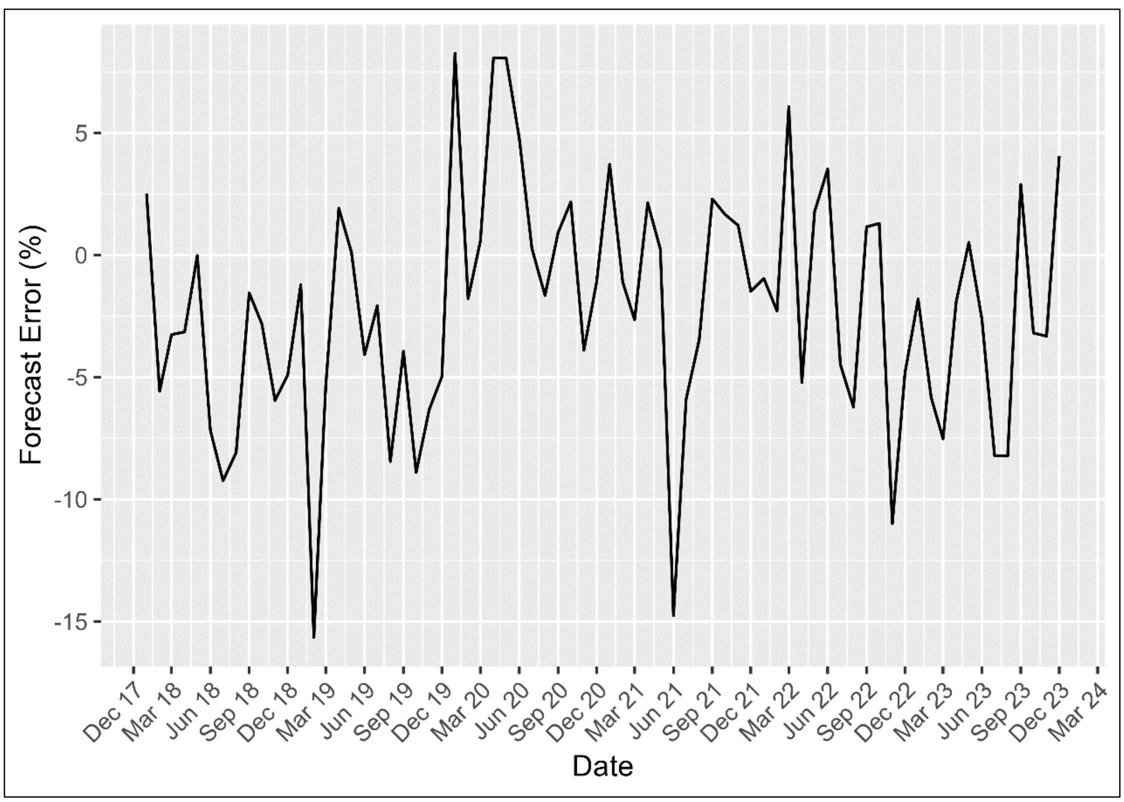

Figure 1 shows that there are indeed cases where the Company's forecast materially deviates from actuals, particularly at the monthly level.

While deviation from the forecast is to be expected, the goal of the forecaster should always be to reduce out-of-sample error while not introducing systematic bias. Further, the average deviation from actuals over the time horizon presented above is -2.1 percent. This is concerning as under-forecasting load financially benefits the utility by setting higher rates in general rate cases. To be clear, a -2.1 percent average monthly error does not imply that the Company is intentionally deflating its forecasts. However, the Company's process for model selection inherently lacks transparency. Using an automated parameterization would simplify the review process and put to rest any concerns over the intentional deflation of forecasts.

Q. Do other Oregon utilities use methods similar to what Staff is recommending in this case?

A. Yes. Per Staff's recommendation, PGE has successfully implemented these changes in both UE 416[3] and UE 435.[4] PGE was able to implement these changes during a rate case. Staff understands that PacifiCorp's load forecasting operation is much larger, which is why Staff did not recommend changing the forecasting procedure in this case.

Q. How did PacifiCorp respond to Staff's recommendation to present evidence of the added benefit of the "XHeat" and "XCool" variables in its next rate case?

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3 *In the Matter of Portland General Electric Company, Request for a General Rate Revision; and 2024 Annual Power Cost Update*. Docket No. UE 416, Second Partial Stipulation, Page 4 (August 21, 2023).

4 *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 435, PGE/700, Riter-Greene/7.

A. The Company argued that removing these regressors would remove relevant knowable information from the model. The "XHeat" and "XCool" indexes contain information from the Company's biannual residential survey and the U.S. Energy Information Administration (EIA) regarding the impact of future changes in appliance efficiency regulations on residential end-use consumption.[5]

Q. How does Staff respond to the Company's position?

A. Staff understands that these indexes use relevant information in their construction. However, these data are then transformed and combined in an unintuitive manner to create a single index which is used as a proxy variable in the forecasting model. While it is not uncommon to use proxy variables in forecasting models, it again makes the effect of each of these data points difficult to understand and interpret. For example, if the coefficient or raw value of "XHeat" is unusually high in a forecast it is extremely difficult to back out why this would be the case. The Company or Staff would have to analyze and validate all the raw input data to attempt to back out the cause. Even then, if the unusual result was the product of a combination of effects in the input data, it may be difficult or impossible to fully understand the result. This again, systematically makes validating the Company's model extremely difficult. This is problematic as the load forecast has direct implications for the Company's ability to earn, or over earn, its base rate revenue requirement.

[5] PAC/3200, Elder/3.

Staff is not opposed to using data from the biannual survey or the EIA. However, Staff would like the Company to prove that the use of the transformed proxy variable provides a distinct and measurable improvement over a more transparent model specification. Staff is willing to work with the Company between now and its next rate case to look into this issue as the time constraints imposed by a rate case can impede this type of analysis.

Q. How did PacifiCorp respond to Staff's recommendation to use a software which allows for differencing of models or present evidence for each of their models justifying the differencing, or lack thereof, for each model?

A. PacifiCorp argued that the software they use is used by many different utilities across the country and that their data shows no signs of non-stationarity. They also stated that the Company has implemented a process to allow for differencing.[6]

Q. How does Staff respond to the Company's position?

A. Staff's primary concern is that the Company is able to use an ARIMA model if need be. If the Company is indeed able to include differencing in its model search, then Staff's recommendation is largely satisfied. Staff continues to recommend that the Company discuss in future testimony why the Company chose or chose not to difference its data.

Q. How did PacifiCorp respond to Staff's recommendation for the Company to host load forecasting workshops between now and their

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[6] PAC/3200, Elder/4.

next general rate case to facilitate Staff and Intervenor input into these analyses?

A. PacifiCorp stated that they are willing to host a load forecasting workshop between now and the next rate case.[7]

7 PAC/3200, Elder/4-5.

ISSUE 2. MARGINAL COST STUDY

Q. Please summarize your positions on PAC's marginal cost study from Opening Testimony.

A. In Opening Testimony, Staff recommended that PacifiCorp use generation resources from its preferred portfolio to parametrize the energy component of its generation MC study as opposed to only using market purchases.[8] Staff's recommendation on this issue has not changed.

Q. Did any other parties offer adjustments to PAC's marginal cost study?

A. Yes. AWEC proposed a handful of adjustments in Opening Testimony. AWEC proposed the following changes to PacifiCorp's marginal cost study:[9]

1. Remove double recovery of local facility costs for customers who receive no Line Extension Allowance (LEA) for transmission and distribution (T&D) facilities.
2. Exclude reserve value from battery energy value.
3. Correct formula error in the calculation of the cost of energy.
4. Assign 100 percent of uncollectable costs to customer billing function.
5. Allocate commercial and industrial write-offs based on each schedule's share of the 5-year average.

Q. How did PAC respond to Staff and AWEC's proposals?

A. PacifiCorp argued that Staff's proposal to use generation resources from its preferred portfolio was too complex.[10] It also argued that wholesale market

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8 Staff/1900, Stevens/13-15.
9 AWEC/200, Kaufman/23.
10 PAC/3500, Merideth/3.

purchases are the best representation available for the marginal cost of energy.[11] This is a departure from the Company's past marginal cost studies[12] and does not reflect the recommendations Staff made in UE 399[13].

PacifCorp adopted two of AWEC's proposals. PacifiCorp agreed with AWEC that the functionalization of uncollectables should be 100 percent assigned to customer costs. They also corrected the formula error found by AWEC, along with an additional error discovered while making the functionalization of uncollectables change.[14]

PacifiCorp opposed all of AWEC's other recommendations. PacifiCorp argues that the customer identified by AWEC that did not receive an LEA, did in fact, receive a LEA. As such, AWEC's proposal to remove local facility costs for customers who receive no LEA is not valid.[15] PacifiCorp also disagreed that the reserve value provided by energy storage is a capacity value. PAC argues that it reflects the incremental benefit of lower dispatch from freeing up cost-effective resources to generate energy to serve load or support off-system sales.[16] Lastly, PAC argued that basing the uncollectables allocation on a 5-year average is inappropriate because of COVID-era restrictions on collections. The 5-year average would result in an artificially low marginal uncollectable cost for residential customers.[17] However, Staff notes that

[11] *Id.* at 3-4.
[12] UE 399, PAC/100,7-8.
[13] UE 399, Staff/700, Dlouhy/6-11.
[14] PAC/3500, Meredeth/5.
[15] *Id.* at 6.
[16] *Id.* at 7.
[17] *Id.* at 4.

AWEC's proposal is a methodology to spread uncollectables for only non-residential customers.   Staff believes the Company may have misunderstood AWEC's recommendation.

Q. How does Staff respond to PAC's position regarding using generation resources from its preferred portfolio in its generation marginal cost study?

A. Staff does not agree with the Company's position. To be clear, Staff is not recommending that PacifiCorp model each and every proxy resource from its preferred portfolio over the entire planning horizon of the portfolio. Staff's recommendation is to select a few proxy resources from the portfolio that can be used to represent the types of generation resources PAC plans to build in the near future.

As discussed in Opening Testimony, the point of the marginal cost study is to reflect the long-run costs to the system and in the long-term PAC should expect to meet its own load. Wholesale market purchases do not solely reflect the costs faced by the utility. As stated in the Company's response to DR 657, PacifiCorp's recent Integrated Resource Plans (IRP) have all included wind, solar, energy storage, and peaking resources. Staff is recommending that the Company reflect the marginal costs of these types of resources in addition to market purchases in its marginal cost study. The Company could then use the projected mix of these resources to find the weighted average energy and capacity costs. Staff notes that this is consistent with its recommendation in UE 399.[18]

Q. Are there any examples of utilities in Oregon that use the type of marginal cost study that Staff is proposing?

A. Yes. Staff's proposal is similar to Portland General Electric's (PGE) generation marginal cost study as seen in both UE 416[19] and UE 435.[20] Staff views this type of marginal cost study as a more direct analog to the studies used by both PGE and PAC in previous cases.

Q. Has Staff completed the type of marginal cost study it is proposing in this case?

A. No. Staff did not have the resources to generate its own marginal cost study in this case. However, Staff is willing to work with the Company before its next rate case to provide feedback on implementing Staff's proposed changes.

Q. Does Staff agree with AWEC's proposed change to account for double counting of certain costs for large customers who did not receive an LEA?

A. No. According to the Company's testimony, the sole Primary Schedule 48 customer AWEC identified as not receiving a LEA did receive one.[21] Staff does agree with AWEC that once customers start connecting to the system

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[18] *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*, Docket No. UE 399, Staff/700, Dlouhy/6-11 (June 22, 2022).
[19] Docket No. UE 416, PGE/1200, Macfarlane-Keene/2-6.
[20] Docket No. UE 435, PGE/800, Macfarlane-Manley/3/-7.
[21] PAC/3500, Meredith/6.

without receiving a LEA, changes to the marginal cost study or rate schedule will have to be made in order to reflect their cost of service. In the absence of any customers receiving this treatment to date, Staff does not agree that these changes should be made.

For Transmission Schedule 48 customers, Staff agrees with the Company's statement that the schedule receives some benefit from the local transmission network.[22] However, Staff agrees with AWEC that a more in-depth calculation of this schedule's cost of service may be in order. If Transmission Schedule 48 customers are paying, in part, for local transmission upgrades needed to serve them, they should receive a partial credit for this contribution either in the marginal cost study or through a credit. The rates a customer pays reflect the fact that the company made investments to serve their load. If the customer instead made those investments, the rate they are charged should reflect that investment.

In general, Staff would prefer that any compensation for this contribution be on a customer-by-customer basis based on their Network Upgrade contribution and not based on schedule-wide calculation as this leads to intraclass cross subsidization concerns. Staff has not had time to form a specific recommendation in this case but is willing to work with PacifiCorp and other intervenors between now and the Company's next rate case.

Q. Does Staff agree with AWEC's proposal to exclude the reserve value from the battery energy value?

[22] PAC/3500, Meredith/6-7.

A. No. Staff agrees with the Company's position on this issue.

Q. Does Staff agree with AWEC's proposal to allocate 100 percent of uncollectable expense to the customer billing function?

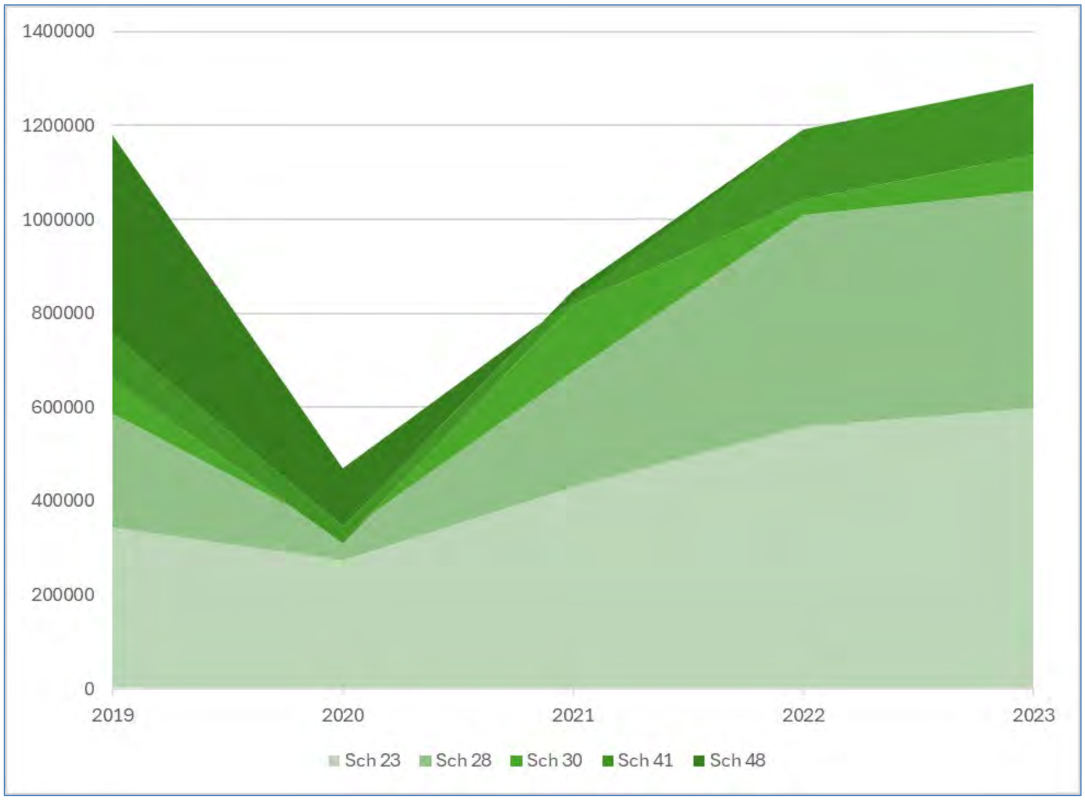
A. Staff does not oppose this change at this time.

Q. Does Staff agree with AWEC's proposal to allocate commercial and industrial write-offs based on each schedule's share of the five-year average?

A. Not entirely. Staff agrees that spreading uncollectables on revenues does not follow cost causation principles. However, using the average level of net write-offs over the past five years will likely not reflect the level of net-write offs in 2025. As seen in Figure 2, small commercial customers saw a large increase in uncollectables expense during 2021 and 2022.[23]

[23] Response to AWEC Data Request 102.

Figure 2. Non-Residential Net Write-Offs



This increase in uncollectables is undoubtedly linked to the COVID-19 pandemic and is likely not representative of the level of uncollectables in the Test Year. As such, Staff advocated using a three-year average using years 2017, 2018, and 2019. This time frame represents more typical economic activity and provides multiple years to average over. Typically, Staff would prefer to use more recent data, but in order to have enough data to average over, Staff decided to use pre-pandemic figures. In subsequent rate cases, Staff will likely advocate for averaging over the three years prior to the rate case barring any abnormal data.

Q. This recommendation seems to differ from Staff Witness Bret Farrell's recommendation on uncollectables expense.[24] Is Staff's position on uncollectables inconsistent?

A. No. Mr. Farrell's recommendation of using the 2020-2022 three-year average to establish the uncollectables rate is entirely different from what Staff is proposing here. The three-year average proposed by Mr. Farrell is meant to predict the overall Test Year uncollectables rate. The proposal to use the 2017-2019 net-write off spread for non-residential customers is meant to predict the spread of uncollectables over the Test Year for non-residential customers. Mr. Farrell's recommendation is agnostic to the spread of the uncollectables rate and is solely focused on the sum of all uncollectables, and not which customer class produces them.

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[24] Staff/2900, Farrell/2-12.

ISSUE 3. RATE SPREAD

Q. Please summarize your positions on PAC's rate spread from Opening Testimony.

A. In Opening Testimony, Staff did not oppose PacifiCorp's proposed 125 percent cap. However, Staff recommend a uniform floor of 59.2 percent of the average increase for all schedules. PacifiCorp was effectively applying different floors for different rate schedules. Staff recommended this uniform floor as without it, there was a very large gap between the customer class seeing the highest increase at 22.4 percent and the customer class seeing the lowest increase at 4.5 percent. Further, this lower floor added a layer of subjectivity to the rate spread. Staff's recommendation on this issue has not changed.

Q. Did any other parties offer adjustments to PAC's rate spread?

A. Yes. Both Fred Meyer and KWUA made recommendations regarding rate spread. Fred Meyer argued that PAC's proposal would provide excessive rate mitigation and slow movement towards cost-based rates. It would also move Schedules 23 and 41 further from cost of service.[25] Instead, Fred Meyer proposed a cap of 150 percent of the average increase.[26] KWUA on the other hand argued for a smaller cap of 115 percent of the average increase.[27] Both of these recommendations exclusively benefitted the customer groups represented by these parties.

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[25] FM/100, Beiber/7.
[26] *Id.*, at 8.
[27] KWUA/100, Reed/12.

Q. How did PAC respond to Staff and Intervenor's proposals?

A. PacifiCorp disagreed with all three recommendations and stuck with their original proposal. The Company largely argued against Staff's recommendation as it mainly affected the lighting class. The Company argued that the lighting class pays the highest RMA of any class and that the revenue raised by the higher floor is de minimis. As such, there is no practical benefit to raising the floor.[28] PacifiCorp further argued since the views of Staff and intervenors were so divergent, the Company's proposal is likely reasonable.[29]

Q. How does Staff respond to PacifiCorp's and Intervenor's positions?

A. Staff maintains its position from Opening Testimony. Staff argues that in the face of an extreme increase, such as the one PacifiCorp is requesting, a tighter rate spread is necessary to ensure fairness among the rate classes.[30,31] This general philosophy would preclude the type of cap proposed by Fred Meyer as it would put a disproportionate burden and rate shock on Schedule 41 and Schedule 23 customers. However, Staff also believes that KWUA's recommendation for a 115 percent of the average increase cap would also deviate too much from the cost to serve customers both affected by the cap and subsequently higher floor. Staff understands PacifiCorp's concern about the small amount of revenue raised by the

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[28] PAC/3500, Meredith/9.
[29] *Id.*
[30] Docket No. UE 426, Staff/1500, Stevens/37.
[31] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Staff/1800, Shierman/13 (April 18, 2024).

higher floor for lighting customers, but again maintains that a uniform floor offers more transparency and fairness compared to differential arbitrary floors for different rate classes.

Q. Has the nominal effect of Staff's cap and floors changed given PacifiCorp's revised revenue requirement?

A. Yes. Table 1 below displays the rate impact for each schedule under PacifiCorp's newly proposed revenue requirement.

Table 1. Staff's Proposed Rate Spread

Schedule	Proposed Increase	Ratio
Residential - 4	14.9%	125.2%
General Service (0-30kW) - 23/723	14.9%	125.2%
General Service (31-200kW) - 28/728	4.5%	37.8%
General Service (201-999 kW) - 30/730	6.0%	50.4%
Combined Sch. 28 & Sch. 30	5.1%	42.9%
Large General Service (≥1,000 kW) - 47/747/48/748	9.8%	82.4%
Ag Pumping - 41/741	14.9%	125.2%
Lighting Schedules	5.1%	42.9%
Overall	**11.9%**	**100%**

ISSUE 4. RESIDENTIAL BASIC CHARGE

Q. Please summarize your positions on PacifiCorp's residential basic charge from Opening Testimony.

A. In Opening Testimony, Staff recommended that the single-family basic charge be set at $12, and the multi-family basic charge be kept at $8. This is in contrast to PacifiCorp's proposal to raise the single-family basic charge to $16 and the multi-family basic charge to $9. Staff discussed equity concerns regarding higher basic charges, PAC's cost-informed basic charge calculation, PAC's basic charge history, and PAC's comparison to peer utility basic charges.[32] Staff's recommendation on this issue has not changed.

Q. Did any other parties discuss the residential basic charge in their Opening Testimony?

A. Yes. CUB recommended that both the single-family and multi-family basic charges not be changed. CUB discussed their concerns that increasing the residential basic charge could negatively impact low-income households, energy efficiency efforts, and cause reductions in DER investments such as solar.[33] Like Staff, CUB argued that the Company's calculation of what should be included in the basic charge included cost elements that were inappropriate such as poles, conductors, and transformers.[34] Again similar to Staff, they point out that the Company's list of peer utility basic charges

[32] Staff/1900, Stevens/21-25.
[33] CUB/200, Wochelle-Jenks/4.
[34] *Id.,* at 13-14.

includes COUs. When narrowing down to only investor-owned utilities (IOUs), the Company's proposed single-family $16 basic charge is much higher than PacifiCorp's peer utilities.[35] CUB also argued that competitive businesses generally do not recover fixed costs through fixed charges. Instead, they recover costs through volumetric sales.[36]

Q. How did PAC respond to Staff and Intervenor's positions?

A. PacifiCorp disagreed with both CUB and Staff's basic charge proposals. PacifCorp argued that Staff and CUB did not provide compelling evidence that low-income customers are disproportionately affected by higher basic charges.[37] PacifiCorp also argued that the basic charge calculation should include poles and transformers as they do not include marginal demand related distribution pole and transformer costs. They also argue that if it were not included, there would be no rationale for the differential basic charge between single-family and multi-family homes.[38] PacifiCorp maintained that the comparison group for basic charges should include community owned utilities (COUs). The Company argued that since most of the rate increase is still coming through the volumetric rate, that CUB's concern about discouraging energy efficiency and DSM investments is misplaced.[39] They also argue that having a very low basic charge can

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35 *Id.*, at 11.
36 *Id.,* at 12.
37 PAC/3500, Meredith/13.
38 *Id.*, at 14.
39 *Id.* at 15.

discourage fuel switching.[40] Lastly, PacifiCorp pointed out that not all competitive industries are based solely on volumetric sales. Industries like buffets and streaming services even go as far as only having a fixed price.[41]

Q. How does Staff respond to PacifiCorp's assertion that Staff and CUB did not present convincing evidence about the equity impacts of a higher basic charge?

A. Staff agrees, somewhat, and said as much in Opening Testimony.[42] However, it should be noted that Staff and Intervenors do not bear the sole burden of this equity analysis. To date, only Staff and CUB have raised this concern and attempted to provide any analysis into this issue. In contrast, the Company is advocating for a sizable change to the basic charge without any substantiated evidence that their proposal will not negatively affect low-income customers.

Further, as I state in my Opening Testimony, many academic studies have found a positive relationship between energy consumption and income in absolute terms.[43] As such, this is typically the baseline assumption made when discussing the issue of the equity impacts of higher basic charges. While Staff notes there is a lot of heterogeneity in the residential customer

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40 *Id.*
41 *Id.* at 16.
42 Staff/1900, Stevens/20-21.
43 Raphael Branch. Short Run Income Elasticity of Demand for Residential Electricity Using Consumer Expenditure Survey Data. Energy Economics, 14(4):111–121, 1993; Elisabetta Pellini, Estimating income and price elasticities of residential electricity demand with Autometrics, Energy Economics, Volume 101, 2021; Jacqueline M. Doremus, Irene Jacqz, Sarah Johnston, Sweating the energy bill: Extreme weather, poor households, and the energy spending gap, Journal of Environmental Economics and Management, Volume 112, 2022.

class, enacting a substantial change to the basic charge may increase the financial strain on the majority of low-income households.

PGE's assertion in UE 416 that low-income customers have a consumption distribution that is shifted slightly right to the consumption distribution of their non-low-income customers[44] was a novel assertion and is still being investigated by Staff. Further, PAC has presented no evidence that this, still shaky, result applies to their service territory. As such, it is still reasonable to assume with some degree of confidence that low-income customers in PacifiCorp's territory consume less on average than non-low-income customers.

Staff has requested customer usage data via OPUC DR 281 but was not able to complete a full analysis of the relationship between income and consumption in this case. However, Staff plans to continue their analysis and present any results in a later docket where appropriate.

Q. How does Staff respond to PacifiCorp's position on the cost components of the basic charge?

A. Staff generally agrees with CUB on this issue. Staff's long-standing position on the basic charge is in line with the description given by CUB in UE 294:

> Fixed cost recovery is limited to the direct costs of a particular customer; the line drop, the meter and billing, etc. Costs that are shared by customers, whether those costs are line transformers, conductors, or the call center, should not be included in a fixed monthly charge.

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[44] Docket No. UE 416, PGE 1300, Macfarlane-Pleasant/17.

Staff agrees with the Company's statement that without the consideration of the costs of poles, conductors, and transformers, there would be no cause for a differential basic charge between multi- and single-family customers under the current framework. However, it is Staff's position that the differential basic charge is meant to reflect the difference in the cost to serve these dwelling types through a streamlined means rather than through a differential per kWh rate. As such, the total basic charge should be based on the costs categories discussed above, with the differential set on the differential in the cost to serve each dwelling type.

Q. How does Staff respond to PacifiCorp's position on the relevancy of COU basic charges?

A. The Company argues that because COU service areas are often in rural areas, they are a more relevant comparison group than other local and regional IOUs as rural areas have higher fixed costs.[45] Staff agrees with CUB on this issue and also agrees that the list of IOUs displayed in Table 1 of CUB's Opening Testimony[46] is a more relevant comparison group than in Table 2 of PAC's Opening Testimony.[47]

IOUs are regulated, governed, and operated in completely different ways than COUs. While some COUs may have more similar service territory to PAC than some other IOUs, there are many IOUs displayed in CUB's comparison group that also have largely rural service territories, such as Avista's

45 PAC/3500, Meredith/13.
46 CUB/200, Wochelle-Jenks/11.
47 PAC/1900, Meredith/23.

Washington service territory. That said, Staff does not view the comparison of PAC's basic charge to peer utilities as having a lot of weight on this issue. PacifiCorp, and Staff for that matter, made similar arguments in UE 399.[48] As stated in that case, this comparison would only be relevant if it was clear that PacifiCorp's basic charge was seemingly singled-out or wildly out of line with other IOUs overseen by the Commission. This is obviously not the case. Instead Staff puts more weight on gradualism, cost causation, and equity concerns when making any basic charge recommendations.

Q. How does Staff respond to PacifiCorp's position on price signals sent by a higher basic charge?

A. PacifiCorp argued that since the majority of the price increase is proposed to be coming through the volumetric charge, that customers will have a stronger incentive to invest in energy efficiency and DSM due to this rate case.[49] While it is true that quantitatively both the basic and volumetric charge are increasing as proposed, it is not relevant to CUB's initial point. CUB argued that *compared to maintaining the current basic charge*, if the Commission approved the Company's request for a $16 basic charge that investments in energy efficiency and DSM may decrease.

The Company also argued that too low of a basic charge can actually hinder decarbonization efforts by encouraging fuel switching away from electricity towards natural gas. While the basic charges for all Oregon natural

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[48] Docket No. UE 399, Staff/700, Dlouhy, 26.
[49] PAC/3500, Meredith,15.

gas utilities are lower or near PacifiCorp's current basic charge, Staff agrees that, all else equal, an inordinately low basic charge could incent customers to fuel switch or prevent customers from fuel switching. However, a customer's ultimate decision to switch fuels is likely based on many factors, not just the volumetric price of energy alone. Staff disagrees that the $12/$8 basic charges proposed by Staff in this case are inordinately low and argues that they are in line with past Commission precedent.

Q. How does Staff respond to CUB and PacifiCorp's discussion on pricing in competitive industries?

A. Staff largely does not have a position on this issue. Different competitive industries price goods in many different ways. Two-part tariffs for electricity are used almost ubiquitously across the country for pricing electricity. While there has been much advocacy, and practice, of using alternative or many different pricing models to better fit consumer preferences, Staff does not believe that retail pricing reform is the most pressing matter facing the Commission at this time.

ISSUE 5. EPIS RATE BASE CALCULATION

Q. Please summarize your position on rate base calculation methodology.

A. In Opening Testimony, Staff recommended that the Company utilize a 13-month average of monthly averages (AMA) methodology excluding non-growth-related Test Year capital additions when calculating its Electric Plant in Service (EPIS) Test Year rate base.

Q. Did any other parties discuss PacifiCorp's rate base calculation methodology in their Opening Testimony?

A. No.

Q. How did PAC respond to Staff's position?

A. PacifiCorp disagreed with Staff's recommendation. PacifiCorp argued that Staff's characterization of PAC's EPIS Test Year calculation is incomplete as they annualize depreciation for 2024 capital additions. Further, associated deferred tax balances are also consistently established on this annualized basis.[50] The Company also argued that their current methodology was implemented in response to Staff's concerns around ORS 757.355 in UE 210.[51] PacifiCorp took issue with Staff's estimated adjustment stating that it is overly simplistic.[52] The Company argued that Staff's recommendation breaks the matching principle as it carries forward accumulated depreciation in the Test Year, but not gross plant.[53] PacifiCorp

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[50] PAC/3300, Cheung/98-101.
[51] *Id.,* at 102.
[52] *Id.,* at 103.
[53] *Id.,* at 104-105.

also argued that customers are partially seeing the benefit of incremental depreciation expense because of the annualization of 2024 capital additions.[54] PacifiCorp also claimed that using a traditional AMA calculation would lead to a higher Test Year rate base assuming a "realistic" level of capital additions.[55] The Company argued that Staff's proposal may violate IRS 168(i)(10) and Treasury 1.167(l)-1(h)(6)(ii) because Staff's method is not a comprehensive adjustment as it does not contemplate the necessary corresponding adjustment to tax balances that would ensure compliance.[56] Lastly, the Company argued that revising all the pertinent cost elements in this filing to reflect an AMA rate base, even one excluding capital additions, would take time beyond what is available under the procedural schedule.[57]

Q. How does Staff respond to PacifiCorp's claim that it did not completely describe the Company's Test Year EPIS rate base calculation?

A. Staff agrees that its description was not complete. However, this omission was not intentional. Further, PacifiCorp's practice of annualizing the depreciation, amortization, and accumulated depreciation for capital additions placed into service the year prior to the Test Year does not assuage Staff's concerns about the Company's rate base calculation methodology. This adjustment to the EOP rate base calculation is similar to PGE's methodology in UE 416 and UE 435 where Staff has also raised

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54 *Id.,* at 106.
55 *Id.*, at 106-110.
56 *Id.*, at 110.
57 *Id.*, at 113.

concern about that Company's rate base calculation methodology. The Company argues that ratepayers do see some of the benefit of depreciation expense that they pay in the Test Year reflected through this annualization adjustment. However, the Company failed to highlight that ratepayers do not see this same benefit for depreciation expense paid in the Test Year for all assets placed into service prior to 2024, which makes up the vast majority of the Company's Test Year depreciation expense.

Q. How does Staff respond to PacifiCorp's argument that its current methodology was developed to satisfy Staff's concerns around ORS 757.355 in UE 210?

A. Staff agrees that PacifiCorp's current methodology does not elicit any potential violations with ORS 757.355. However, Staff's concern revolves around the fact that the future Test Year is meant to reflect the cost to serve customers in that year. Staff's methodology reflects this by effectively valuing the utility's rate base at the mid-point of the Test Year while staying in compliance with Staff's understanding of ORS 757.355.

Q. How does Staff respond to PacifiCorp's argument that Staff's proposed adjustment is overly simplistic?

A. Staff agrees that its adjustment is not accurate and stated in its Opening Testimony that Staff is not proposing that this number be used as the final revenue requirement adjustment, but that the Commission recommend that Staff's preferred methodology be adopted and that the Company perform this analysis to arrive at the actual revenue requirement adjustment.[58] Staff welcomes the Company to provide its own estimation in its next round of testimony. This is a complicated issue and Staff does not have the resources to complete the analysis needed in this rate case to make an accurate adjustment. The complicated nature of this adjustment is further evidenced by the Company's own statements claiming that it does not have the adequate time to recalculate the full effect of this adjustment in this rate case.[59]

Q. How does Staff respond to PacifiCorp's argument that Staff's proposed method violates the matching principle?

A. The future test year is meant to set rates such that the Company's prudently incurred costs are recovered in that future year. A faithful adherence to ORS 757.355 implies that no Test Year capital additions can be included in rates. As such, the combination of a future test year and compliance with ORS 757.355 inherently violates a strict interpretation of the matching principle. If the Company is concerned with satisfying the matching principle, one potential solution is to submit its next rate case using a historical test year with an AMA rate base calculation. If the Company did so, Staff would likely be supportive of this approach. Staff's primary goal in this recommendation is to ensure that, for the purposes of establishing the required return in this rate case, the value of PacifiCorp's rate base reflects

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[58] Staff/1900, Stevens/35.
[59] PAC/3300, Cheung/113.

the depreciation of its assets over the course of the Test Year while complying with ORS 757.355. Staff is open to any methodology that satisfies this goal.

Q. How does Staff respond to PacifiCorp's argument that using a traditional AMA rate base calculation would likely increase PacifiCorp's Test Year EPIS rate base?

A. Staff agrees that in some years this may be true and in others it may be false. It simply depends on the amount of capital additions placed into service in a given year. In PacifiCorp's constructed example, they conveniently used numbers that made their case; however, these numbers are not necessarily indicative of past or future capital addition levels. That said, Staff does not necessarily give much weight to the potential results of an "appropriately calculated"[60] AMA. As stated, Staff does not believe the inclusion of Test Year capital additions are legal under ORS 757.355. Further, under this interpretation it seems misleading to describe a method including these additions as "appropriately calculated" under Oregon law.

Q. How does Staff respond to PacifiCorp's positions that Staff's approach to the rate base calculation violates IRS tax normalization rules and treasury regulations?

A. It does not. The Commission has followed the statutory prohibition on including Test Year investment in rate base for many years and PacifiCorp has not prevailed on an argument that the statute creates a normalization

[60] *Id.*, at 106, line 21.

issue for the Company that requires a regulatory change. Further, Staff's methodology would be narrowly applied to the calculation of the required net operating income in this case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 3900

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Steph Yamada. I am a Senior Utility Analyst employed in the Water, Telecom, Safety and Consumers Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. My Opening Testimony is found in Exhibit Staff/2000 and my witness qualifications statement is provided in Exhibit Staff/2001.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address PacifiCorp's (PAC or Company) Reply Testimony regarding salaries and incentives.

Q. Did any intervenors provide specific arguments regarding the items addressed in your Opening Testimony?

A. No.

Q. Did you prepare any new exhibits for this docket?

A. No. I have not prepared any additional exhibits beyond those included with my Opening Testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. SALARIES AND WAGES

Q. Please summarize the Company's initial proposal for salaries and wages.

A. The Company proposed to include salaries, wages, and overtime totaling $605,601,394 at the system level in the Test Year,[1] as summarized in Figure 1.

FIGURE 1: TEST YEAR SALARIES, WAGES, OVERTIME

Category	Base Salaries & Wages	Overtime
Officers	$1,451,918	$0
Exempt	$221,901,352	$2,519,898
Non-Exempt/Non-Union	$19,637,447	$1,294,497
Union	$263,599,995	$95,196,289
Total	**$506,590,711**	**$99,010,683**

Q. Please describe Staff's analysis and recommendations as described in its Opening Testimony.

A. Staff applied its standard Wage & Salary (W&S) Model to the Company's proposed wages. As a result of that analysis, Staff recommended no adjustment. However, since two of the Company's nine collective bargaining agreements were in or soon to be in negotiations as of February 2024, Staff recommended that the Test Year inclusion for union wages be updated to reflect actual amounts once those amounts become known.

Q. Please summarize PAC's Reply Testimony position.

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1 Staff/2002, PAC's second Revised Response to Staff's DR 92, Attachment SDR-OPUC 092 2nd REVISED.

A. The Company proposes to increase its Test Year wage inclusion by $8,000, stating that this amount was previously inadvertently excluded due to a formula error.[2] Regarding union wages, the Company states that one of the active bargaining negotiations has been finalized, and that the finalized increase matches the projection included in PAC's initial filing.[3] Consequently, no additional wage change is needed at this time. The Company agrees to update the inclusion for the other agreement currently in negotiation if the finalized increase becomes known during the pendency of this case.[4]

Q. Does Staff agree to increase the Company's Test Year wage inclusion by $8,000?

A. No. Staff agrees to an increase of $5,000. Staff's initial application of the W&S Model resulted in a $3,000 Oregon-allocated wage decrease in the Officer category; Staff deemed this amount to be immaterial and did not include it in its Opening Testimony. Offsetting the Company's proposed increase by this amount results in a net increase of $5,000 to the Company's Test Year wages.

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[2] PAC/3300, Cheung/6, lines 13-17.
[3] PAC/3300, Cheung/6, lines 4-9.
[4] PAC/3300, Cheung/6, lines 9-11.

ISSUE 2. INCENTIVES

Q. Please summarize the Company's initial proposal for employee incentives.

A. The Company proposed to include incentives attributable to the Annual Incentive Plan (AIP) as well as Bonuses totaling $18,553,131 at the system level, as summarized in the following table.[5]

FIGURE 2: COMPANY PROPOSED INCENTIVES

	AIP	Bonus	Total
Officers	$0	$0	**$0**
Exempt	$16,693,314	$1,137,738	**$17,831,052**
Non-Exempt/Non-Union	$0	$19,612	**$19,612**
Union	$0	$702,467	**$702,467**
Total	**$16,693,314**	**$1,859,817**	**$18,553,131**

Q. Please describe Staff's recommendations as described in your Opening Testimony.

A. Regarding the inclusion for Test Year incentives, I made two recommendations. First, I recommended an adjustment of ($293,540) at the system level to correct an error in the Company's AIP calculation that inappropriately included officer salaries where only exempt employee salaries should have been included. Second, I recommended an additional system-level adjustment of ($929,908) to exclude 50 percent of the "Bonus" category shown in the previous table. Specifically, I argued that incentives included in the Bonus category should be considered "merit-based incentives," which

[5] Staff/2002, PAC's second Revised Response to Staff's DR 92, Attachment SDR-OPUC 092 2nd REVISED.

equally benefit customers and shareholders and are subject to 50 percent exclusion. The combined total of these adjustments was allocated 28.88 percent, or ($353,387) to Oregon, and further allocated 63.29 percent, or ($223,642) to O&M, and 36.71 percent, or ($129,745) to capital.

Additionally, I recommended an Oregon-allocated rate base adjustment of ($18,721,813) to remove the estimated portion of capitalized incentives that are not eligible for inclusion in rates (specifically, 100 percent of capitalized officer incentives and 50 percent of capitalized non-officer incentives). In the absence of available data regarding the actual amount of capitalized incentives present in the Test Year rate base, I estimated the currently undepreciated portion of officer and non-officer incentives capitalized since 2004 and adjusted these figures in accordance with the Commission's regulatory principles regarding the inclusion of incentives costs. My specific estimation methodology is described in detail in my Opening Testimony in Exhibit Staff/2000, Yamada/14-16.

Finally, I recommended an O&M adjustment of ($555,508) to reflect the effect on depreciation expense associated with my proposed rate base reductions for capitalized incentives and the capital-allocated portion of my Test Year incentives adjustment.

Q. Please summarize PAC's Reply Testimony position.

A. Regarding Staff's error correction related to officer salaries, the Company "agrees the Test Year wage total used as the basis to calculate Test Year AIP should only reflect the exempt category wages."[6] Regarding Staff's Bonus adjustment, the Company argues that this adjustment is not warranted because the "Company's proposed calculation of labor expenses already properly removes 50 percent of…merit-based components of Bonus expenses from Test Year projections."[7] Additionally, the Company argues that Staff's capital-allocated adjustment of ($129,745) is not necessary because "the Company does not adjust the capitalized components of labor expenses in its Wages & Employee benefits adjustment,"[8] stating that "there should be no reduction necessary for the portion of the AIP adjustment presumed to be capitalized as that cost was not reflected in the Company's direct filing to begin with."[9]

Regarding Staff's adjustment for capitalized incentives, the Company disagrees with Staff in two ways. First, PAC disagrees with the number of years included in Staff's analysis, which reaches back to 2004. PAC argues that only incentives capitalized since the last rate case are eligible for exclusion, citing past rate cases. Second, PAC disagrees with Staff's removal of 50 percent of capitalized non-officer incentives, arguing that only capitalized incentives associated with officers should be excluded from rate base. PAC proposes a net revenue requirement decrease of approximately $10,000 in Oregon to account for capitalized officers' incentives.[10]

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6 PAC/3300, Cheung/13, lines 9-10.
7 PAC/3300, Cheung/12, lines 11-13.
8 PAC/3300, Cheung/13, lines 15-16.
9 PAC/3300, Cheung/13, lines 16-18.
10 PAC/3300, Cheung/97.

Q. Have Staff's recommendations changed since its Opening Testimony?

A. No. Staff continues to recommend the adjustments described in its Opening Testimony with regard to incentives.

Q. Please respond to the Company's argument that 100 percent of the Bonus incentive category should be included in customer rates.

A. The Company's proposal does not align with the Commission's established regulatory principles regarding employee incentives. As discussed in my Opening Testimony, the Commission typically disallows incentives at three levels in accordance with the anticipated ratio of benefits to shareholders. Officer incentives are 100 percent disallowed, performance-based incentives are 75 percent disallowed, and merit-based incentives are 50 percent disallowed. The Company's Bonus incentives should be categorized as "merit-based," which equally benefit customers and shareholders and are subject to 50 percent exclusion.

Q. Does Staff agree that its proposed exclusion is unnecessary because the Company has already properly excluded 50 percent of merit-based incentives?

A. No. The Company argues that it has already categorized merit-based incentives into the "AIP" category shown in the previous table, and that the Bonus category reflects only those items that are eligible for full rate recovery. Staff disagrees; the Bonus category should also be classified as "merit-based," and 50 percent of this category should be excluded.

Q. Why does Staff consider the Bonus category to be merit-based incentives?

A. The Company states that the "balance in this Bonus account reflects safety awards, hire-in bonuses, referral awards, [and] training awards[.]"[11] These items clearly fall into the category of employee incentives because they reflect compensation that is provided in addition to base compensation in exchange for completing certain tasks or meeting certain metrics. These incentives may benefit both customers and shareholders and should be categorized as "merit-based" incentives, which are subject to 50 percent exclusion—the lowest exclusion level typically applied to incentives. The Commission does not typically allow 100 percent recovery of incentives.[12]

Q. Please respond to the Company's assertion that the capital allocation portion of Staff's recommended adjustment is not necessary.

A. The Company argues that its filing includes only the expensed portion of incentives costs and ignores the capitalized portion. This appears to be false. The incentives totals requested by the Company and used in Staff's analysis are shown in DR 92, which reflects the total amount anticipated to be paid to employees in the Test Year, after certain Commission-ordered exclusions.[13] Some portion of that amount will ultimately be capitalized. Staff proposes an adjustment to reduce the Company's overall incentives cost; it is appropriate to assign a portion of that reduction to expense and a portion to capital. This

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11 PAC/3300, Cheung/11, lines 8-9.
12 Order No. 20-473, Page 104.
13 Staff/2002, Yamada/1, PAC's Response to Staff's DR 92.

allocation to expense and capital is consistent with Staff's standard methodology for applying its incentives adjustment, including the methodology used in the Company's last rate case.[14]

Q. Regarding Staff's adjustment for capitalized incentives, please briefly explain why this adjustment is necessary.

A. This adjustment is necessary to align with the Commission's established regulatory principles regarding incentives. As discussed previously, the Commission has adopted a standard treatment for incentives, excluding 50, 75, or 100 percent of the cost from customer rates depending on the nature of the incentives. This principle must be applied not only to incentives anticipated to be awarded in the Test Year, but also to the portion of incentive costs that were awarded and capitalized in previous years. If not removed, those costs would remain in the Company's rate base and the Company would inappropriately earn a return on those costs. Consequently, an adjustment is needed to remove from rate base the portion of incentive costs that the Commission would not typically deem to be includable in rates. As discussed in my Opening Testimony, the Company's rate request does not include an appropriate adjustment to account for this.

Q. Please respond to the Company's assertion that Staff's capitalized incentives adjustment reaches too far back in time.

A. The Company's position is inconsistent with the Commission's established regulatory principles regarding incentives. To support its position, the

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[14] Docket No. UE 399, Staff/600, Cohen/15, Figure 10: Incentives Adjustment.

Company cites the handling of its incentives costs in its last two rate cases, quoting past testimony in which Staff stated that it "typically disallows the total number of officer incentives capitalized in plant since the last rate case."[15]

In response, Staff notes that its recommendations in this case are guided by the Commission's established broad regulatory principles, not Staff's handling of specific items in past cases. As discussed in my Opening Testimony, Staff can reasonably assume PAC's proposed Test Year rate base to include costs associated with incentives that were capitalized decades ago and have not yet fully depreciated. While Staff's estimation methodology reached back to 2004, it may have been appropriate to go back even further. To align with the Commission's established principles, costs that the Commission would typically exclude from rates must be removed from rate base, regardless of their age. By limiting this exclusion to only those incentives capitalized since the last rate case, PAC is effectively arguing that the undepreciated value of otherwise excludable incentives becomes includable once the Company files a new rate case, which is false.

Q. Is it true that Staff typically disallows incentives capitalized in plant since the last rate case, as indicated in the past Staff testimony quoted by PAC? If so, why is Staff recommending different treatment in this case?

A. In some cases, yes. The distinguishing difference is whether a permanent rate base reduction to account for previously capitalized incentives has been

[15] Docket No. UE 374, Staff/400, Cohen/10.

applied. For example, in Docket No. UE 283, the Commission approved a $10 million rate base reduction for Portland General Electric "in recognition of past capitalized financial performance based incentives" and amortized that adjustment over 20 years.[16] In Docket No. UG 435, the Commission approved a similar rate base reduction of $4.5 million for Northwest Natural, which was amortized over 15 years and would carry over to following rate cases.[17] In such cases, since the cost of past capitalized incentives has been addressed, only the incentives newly capitalized since the most recent rate case need to be adjusted going forward. As discussed in my Opening Testimony, PAC has not previously been subject to a permanent rate base reduction for past capitalized incentives. Consequently, Staff's recommended Oregon-allocated rate base adjustment of ($18,721,813) in this case is appropriate.

Q. What is Staff's recommended amortization period for its rate base adjustment attributable to past capitalized incentives?

A. This adjustment should be amortized over 20 years and carried forward into future rate cases until fully amortized. Staff invites the Company to consider this and other amortization periods, and to recommend a term with its justification therefor.

Q. Please respond to the Company's assertion that only capitalized incentives associated with officers should be removed from rate base.

[16] Order No. 14-442, Appendix B, Page 2.
[17] Order No. 22-388, Appendix A, Page 5.

A. Again, the Company's position in this area does not align with the Commission's established regulatory principles. As discussed previously and in my Opening Testimony, it is Staff's position that all of the Company's non-officer incentives should be treated as "merit-based" and subject to 50 percent exclusion. Consequently, 50 percent of capitalized non-officer incentives should be removed from rate base in addition to 100 percent of capitalized officer incentives.

In support of its argument to fully include non-officer incentives, the Company states that "there is no way to accurately determine how much of non-officer employees' incentives and merit-based bonuses have been capitalized over time."[18] While that may be the case, the absence of readily available data does not mean that no adjustment is warranted. As discussed in my Opening Testimony, Staff's recommended rate base reduction is based on actuals where such figures are known, reasonable assumptions to estimate missing data, and adjustments to account for the effects of inflation over time. The methodology used by Staff to calculate its rate base adjustment for past capitalized incentives is reasonable and Staff's recommended adjustment should be adopted.

Q. Please summarize the adjustments described in your testimony.

A. My recommended adjustments, as compared to the Company's opening position, are shown in the following table.

[18] PAC/3300, Cheung/96.

FIGURE 3: SUMMARY OF STAFF'S ADJUSTMENTS – OREGON

Description	O&M	Capital
Salaries & Wages	$5,000	$0
Overtime	$0	$0
Incentives	($223,642)	($129,745)
Capitalized Incentives		($18,721,813)
FTE Adjustment	$0	$0
Payroll Taxes	$0	$0
Depreciation Expense	($555,508)	$0
Total	**($774,150)**	**($18,851,558)**

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 4000

REDACTED
Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Madison Bolton. I am a Senior Energy and Policy Analyst in the Policy and Economic Analysis Section at the Oregon Public Utility Commission (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. I previously sponsored Staff Exhibit 2100. My Witness Qualification Statement can be found in Staff Exhibit 2101.

Q. What is the purpose of your testimony?

A. I respond to the Association of Western Energy Consumers' (AWEC) Opening Testimony and PacifiCorp's Reply Testimony regarding coal decommissioning costs. I also respond to PacifiCorp's Reply Testimony on Staff's pass-through proposal for qualifying facilities (QFs).

Q. Please summarize your testimony and conclusions.

A. In Opening Testimony, AWEC proposed to address coal decommissioning costs, which are currently the subject of Docket No. UM 2183, by realigning Exit Dates for PacifiCorp's coal plants with common closures before 2030 and adopting decommissioning cost estimates in the Kiewit Study for coal units that will close after 2030. Staff generally supports AWEC's proposal because it allows Oregon customers to receive any potential power cost benefits from extending coal plants' use in Oregon's resource mix until 2030 and limits rate shock in the near future while still meeting HB 2021 targets. In addition to adopting AWEC's proposal to address coal decommissioning costs, Staff is making a new recommendation that the Commission impose a ten percent management disallowance for the decommissioning costs outlined in the Kiewit Studies due to the lack of transparency into Kiewit's underlying assumptions and the inability to verify the accuracy of those costs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits for this testimony?

A. Yes. I prepared Staff Exhibit 4001 showing a timeline of events related to PacifiCorp's coal decommissioning costs, Staff Exhibit 4002 containing PacifiCorp's reply to Staff's Data Request, and Confidential Staff Exhibit 4003 containing PacifiCorp's reply to AWEC's Data Request.

ISSUE 1. DOCKET NO. UM 2183 AND COAL DECOMMISSIONING STUDIES

Q. Can you please describe the issues being litigated in Docket No. UM 2183?

A. Staff will defer to counsel for any legal analysis of these issues, but for the purpose of this testimony, Staff understands that Oregon law requires electric companies to "eliminate coal-fired resources from [their] allocation of electricity" by January 1, 2030.[1] PacifiCorp's service territory spans six states, and other states may continue to take costs and benefits from coal-fired resources after Oregon exits these plants. As such, it is necessary to determine Oregon's allocated share of decommissioning costs for the coal-fired resources Oregon will exit before the plant common closure dates.

The 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol)[2] includes provisions addressing states' decisions to exit coal-fueled resources, reassignment of coal-fueled resources, and decommissioning costs.[3] One of these provisions dictate that PacifiCorp undertake "a contractor-assisted engineering study of decommissioning costs."[4] To meet this provision, PacifiCorp hired Kiewit to conduct an Association of the Advancement of Cost

1 O.R.S. § 757.518(2).

2 The 2020 Protocol is a multistate agreement, which sets forth how PacifiCorp's system costs are allocated among the Company's service territories in six states (Oregon, Washinton, California, Utah, Idaho, and Wyoming). This is the fifth multi-state agreement. *See In the Matter of PacifiCorp Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 05-021 (January 12, 2005); Order No. 11-244 (Jul 5, 2011); Order No. 16-319 (August 23, 2016); Order No. 17-124 (March 29, 2017); and Order No. 20-024 (January 23, 2020).

3 Order No. 20-024 at 6.

4 2020 Protocol § 4.3.1.1.

Engineering (AACE) Class 3 cost estimate for coal decommissioning costs for Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, Hayden, and Colstrip (Kiewit Studies).[5]

PacifiCorp first filed the Kiewit Studies in Docket No. UM 1968, a PacifiCorp depreciation docket, and Docket No. UE 374, PacifiCorp's 2020 general rate case. However, PacificCorp would not provide critical assumptions because PacifiCorp claimed that the underlying data was confidential proprietary information belonging to Kiewit. As a result, parties were unable to fully review underlying analyses, inputs, or methodology of the Kiewit Studies.[6] Staff, AWEC, and CUB argued that because parties could not access or test the underlying data, PacifiCorp failed to meet its burden of proof to demonstrate the costs in the Kiewit Study should be allowed into base rates.[7]

The Commission agreed and found the UE 374 record to be lacking to establish final decommissioning costs.[8] The Commission noted "robust review and verification of these costs is critical," and opened a separate proceeding, UM 2183, to determine final decommissioning cost estimates.[9]

Staff has included a timeline of events related to the coal decommissioning costs in Exhibit 4001.

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5 *In the matter of PacifiCorp's Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism*, Docket No. UM 2183, PacifiCorp Application at 9 (July 8, 2021).
6 Order No. 20-473 at 15-16.
7 Order No. 20-473 at 15-16.
8 Order No. 20-473 at 17.
9 Order No. 20-473 at 17.

Q. Did the Commission provide any expectations for PacifiCorp in Docket No. UM 2183?

A. Yes. The Commission made clear that there must be "transparency" and a "thorough review" of the coal decommissioning studies that inform what PacifiCorp will recover in Oregon rates.[10] The Commission clearly outlined its expectations as follows:

> We expect significant IE involvement in this proceeding, which includes providing an evaluation of the Kiewit Studies, and developing an alternate, independent AACE Class 3 estimate as originally contemplated. This process will be structured to provide the IE and parties with an opportunity for full review, including review of all PacifiCorp-supplied inputs and assumptions, with the opportunity for direct communication between the IE and all parties. We remind the company that it bears the burden of demonstrating the costs are sufficiently reliable to be included in rates. Finally, we expect that this process will include interim status reports to facilitate timely involvement by the Commission with any further issues regarding access to information.[11]

Q. Do you believe the Company has met these expectations?

A. No. Staff does not believe that the Company has met these expectations and finds that PacifiCorp has made very little progress in UM 2183 in the last two years. The Commission approved a Draft Request for Proposal for an Independent Evaluator (IE) on April 25, 2022.[12] In that Order, the Commission reiterated the need to move quickly because of "the limited amount of time to absorb any additional decommissioning costs that may

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[10] Order No. 20-473 at 17.
[11] Order No. 20-473 at 18.
[12] *In the* Matter *of PacifiCorp, dba Pacific Power, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism*, Docket No. UM 2183, Order No. 22-187 (May 26, 2022).

emerge after a full examination in docket UM 2183."[13] The Administrative Law Judge approved a motion for a modified protective order on June 26, 2023.[14] Since that time, there has not been any updates or other filings from the Company or reports from the IE.

Q. Can you speak more specifically to what the 2020 Protocol provides regarding the allocation of coal decommissioning costs and further Commission directives regarding the coal decommissioning provisions?

A. Section 4 of the 2020 Protocol sets forth a number of provisions regarding states' decisions to exit coal-fueled resources.[15] A number of these are relevant for purposes of this discussion. Section 4.1 discusses allocation of costs at closure and Exit Orders. Section 4.3 addresses decommission costs.

Q. What is an Exit Order?

A. The 2020 Protocol provides that "an Exit Order establishes the Exit Date that PacifiCorp will use to propose the allocation of Decommissioning Costs, allocation of capital additions costs, and any other associated costs related to the exit from a coal-fueled Interim Period Resource as outlined in the 2020 Protocol."[16] The Commission "may issue an Exit Order specifying an Exit Date in a proceeding for approval of this Agreement, a depreciation docket, a rate

[13] Order No. 22-187 at 1.
[14] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement a* Decommissioning *Cost Recovery Adjustment and Coal Removal Mechanism*, Docket No. UM 2183, Order No. 22-218 (June 26, 2022).
[15] Order No. 20-024, Appendix B at 15-32.
[16] 2020 Protocol § 4.1.2.

case, or any other appropriate proceeding."[17] In other words, an Exit Order sets "an end date for Oregon's allocation of the costs and benefits of each coal-fueled plant."[18]

Q. Has the Commission issued Exit Orders for PacifiCorp's coal plants?

A. Yes. The Commission has issued Exit Orders with the following Exit Dates in Table 1. AWEC's proposed changes to some Exit Dates are discussed later in this testimony and are included in Table 1 for comparison.[19]

Table 1. Coal Plant Exit Dates

Plant	Current Exit Date	AWEC Proposed Exit Date
Cholla Unit 4	December 31, 2020	N/A
Jim Bridger Unit 1	December 31, 2023	N/A
Jim Bridger Unit 3 and 4	N/A	**December 31, 2028**
Craig Unit 1	December 31, 2025	N/A
Craig Unit 2	September 30, 2028	N/A
Naughton Unit 1 and 2	December 31, 2025	**Revoke Exit Order**
Colstrip Unit 3	December 31, 2027	**December 31, 2025**
Colstrip Unit 4	December 31, 2027	**December 31, 2029**
Dave Johnston Unit 1 and 2	December 31, 2027	**December 31. 2028**
Dave Johnston Unit 3 and 4	December 31, 2027	N/A
Hayden Unit 1	December 31, 2028	N/A
Hayden Unit 2	December 31, 2027	N/A

[17] 2020 Protocol § 4.1.2. A Commission determination that a coal-fueled resource will reach the end of its depreciable life without a specific order that the state will exit the resource does not constitute an exit order. *Id.*

[18] *In the* Matter *of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 8 (December 18, 2020).

[19] Exit Orders were adopted in Order No. 20-473 in Docket No. UE 374. Order No. 22-491 in UE 399 included modifications to Craig Unit 2 and Jim Bridger Unit 1, and added an Exit Date for Hayden.

Q. What has changed since the Commission issued these Exit Orders?

A. These Exit Orders were issued in Docket No. UE 374 in December of 2020. Since then, there have been considerable changes to PacifiCorp's coal outlook and other actions in its Integrated Resource Plan (IRP). The Company pivoted to implementing coal-to-gas conversion for Jim Bridger and Naughton units in its 2023 IRP.[20] PacifiCorp also cancelled its 2022 All Source Request for Proposals (AS RFP) in light of many events, including a finding of liability in the 2020 wildfires, limitations in capital for resource investment, and increased coal availability in other states due to a stay on the EPA's Ozone Transport Rule.[21]

PacifiCorp's Oregon customers continue to face upward rate pressure while the changes to the IRP and cancellation of the RFP raise further questions about the economic analysis underlying the Company's change in resource strategy and ability to make continual progress towards HB 2021 emission targets at reasonable costs. Given the magnitude of change surrounding PacifiCorp's resource planning and coal planning in particular, it is timely to evaluate the costs and benefits of coal decommissioning allocations for Oregon customers. Staff notes that this does not fundamentally change how long coal assets are actually on PacifiCorp's system or Staff's argument that the Company's economic analysis for coal unit planning is flawed.[22]

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[20] Docket No. LC 82, PacifiCorp's 2023 IRP, Chapter 1, Page 5, March 31, 2023.
[21] Docket No. LC 82, Staff's Comments, Page 2, June 14, 2024.
[22] In Exhibit Staff/3300, Pal/10, Staff raises concerns regarding the Company's economic analysis for coal units and how it has undermined emissions reduction benefits and lower costs for Oregon customers.

Q. What does the 2020 Protocol provide regarding decommissioning studies?

A. The 2020 Protocol provides that the Company will "undertake a contractor-assisted engineering study of decommissioning costs."[23] As Staff understands it, PacifiCorp intended for the Kiewit Studies to be this engineering study. PacifiCorp also stated it intended to complete an update "by no later than June 30, 2024."[24] PacifiCorp has not yet completed this update and states in Reply Testimony that the Company does not intend to prepare an updated decommissioning study any longer due to Oregon parties' ongoing review of the Kiewit Studies.[25]

Q. What does AWEC propose in this docket regarding coal decommissioning costs?

A. AWEC proposes to:

- Align existing coal plant Exit Dates with updated retirement dates for units that have Exit Orders and whose retirement dates precede 2030;
- Issue Exit Orders for Bridger Units 3 and 4, with an exit date of December 31, 2028;
- Revoke Exit Orders for Naughton Units 1 and 2;
- Adopt the Kiewit Study estimates for Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 and recover these costs over 12 years;

[23] 2020 Protocol § 4.3.1.1.
[24] 2020 Protocol § 4.3.1.2.
[25] PAC/2000, McVee/65 at 15-18.

- Apply the allocation methods described in Section 6.5 of the 2020 Protocol to plants with Exit Orders for capital investments in coal plants; and
- Align the depreciable life of plants with Exit Orders with the Exit Dates and align the depreciable life of gas converted plants with the economic life used to justify the prudence of the conversion.[26]

Q. How does PacifiCorp respond to AWEC's proposals?

A. PacifiCorp states that AWEC's proposal is premature given that the Company is actively evaluating the best course of action in its 2025 IRP and Clean Energy Plan (CEP) processes to determine a least-risk, least-cost portfolio.[27] PacifiCorp also takes the following positions:

- The Exit Orders for Naughton Units 1 and 2 should not be revoked due to conversion to natural gas, but modified so that they only apply to the units as coal-fired units;
- Jim Bridger Units 3 and 4 should not have a 2028 Exit Date because the Company is not seeking cost recovery for carbon capture technology in this case; and
- The Kiewit Studies no longer reflect an accurate depiction of inflation or risk for Oregon utilities and a depreciation study in 2025 is required to update these costs. Because of this, the Company recommends closing UM 2183.[28]

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[26] AWEC/200, Kaufman/1-2.
[27] PAC/2000, McVee/62 at 1-13.
[28] PAC/2000, McVee/62-67.

Q. How does Staff respond to AWEC's proposal regarding updated Exit Orders?

A. Staff believes most of AWEC's proposals are appropriate. As stated previously, the Commission has highlighted concerns over the limited timeframe available to settle on final Exit Dates without creating substantial rate shock to Oregon customers. Acting on AWEC's proposal aligns the costs and benefits associated with PAC's coal plants in a way that may mitigate more rate shock than if the Commission waits to act on this issue in PAC's 2025 IRP or another future process while still preserving the Company's ability to make meaningful progress towards is HB 2021 targets at reasonable costs. Furthermore, aligning Exit Dates with actual retirement dates allows customers to receive the benefits of these coal plants for a longer period of time before Oregon must exit all coal operations.

Q. What are the rate impacts of AWEC's proposals?

A. AWEC requested that the Company calculate the rate impact of the proposed changes to coal plant Exit Dates depreciable lives in its next round of testimony.[29] However, the Company did not include any estimate in its reply. While Staff does not have all the necessary information to verify an estimate yet, Staff anticipates AWEC's proposal is likely to produce some power cost benefits in addition to reducing the potential for rate shock as described above.

Q. What are the impacts to the depreciable life estimates as a result of AWEC's proposals?

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[29] AWEC/200, Kaufman/15 at 11-16.

A. Staff requested that the Company calculate the impact to revenue requirement based on AWEC's proposed changes to the coal plants' depreciable lives. The Company provided analysis showing an approximate $31.3 million reduction in revenue requirement. If customers receive generation from Jim Bridger Units through 2028, PacifiCorp states that revenue requirement would be reduced by an additional $3.8 million due to amortizing Bridger Mine reclamation costs.[30]

Q. Does Staff agree that the depreciable lives in Exit Orders should be aligned with the proposed Exit Dates?

A. Yes. Staff supports updating the depreciable lives now, as further delay poses greater rate shock to customers.

Q. How does Staff respond to AWEC's proposal regarding the adoption of the Kiewit Study estimates as Oregon's final decommissioning responsibility for DJ unit 4 and Jim Bridger Units 3 and 4 and to recover these costs over 12 years?

A. Staff supports using the Kiewit Study estimates for DJ Unit 4 and Jim Bridger Units 3 and 4 despite some concerns discussed in the following Q&A.

The Kiewit Studies are currently the only third-party decommissioning study available to estimate costs for these coal units. With the lack of progress in UM 2183 over the previous year, Staff agrees that using the Kiewit Studies is the timeliest option to begin recovering decommissioning costs and limit rate impacts. Additionally, the Kiewit Studies are the only available decommissioning estimate for Jim Bridger, as AWEC highlights in Opening

30 Exhibit Staff/4002, PacifiCorp Response to OPUC DR 738.

Testimony.[31] At this time, Staff also agrees that the 12-year period is reasonable for these units' cost recovery.

Q. Does Staff have concerns about the Kiewit Studies estimated decommissioning costs for DJ unit 4 and Jim Bridger Units 3 and 4?

A. Yes. The Commission's concerns regarding transparency and a thorough review of the Kiewit Study have not been addressed. Neither Staff, nor any other party, has been able to review the underlying data of the Kiewit Study, and there have been no updates from the UM 2183 IE within any meaningful timeframe. Allowing PacifiCorp to shield underlying data for analyses or studies that form the basis for rates from discovery through third party non-disclosure agreements could set dangerous precedent for regulated utilities to evade regulatory oversight.

Q. What hurdles have Staff and stakeholders faced in fully evaluating the reasonableness of the Kiewit study?

A. As stated previously, Staff is unable to review the underlying data for the Kiewit study to assess whether the conclusions are reasonable. This is despite the fact that the study was submitted over four years ago. Further, the Commission approved a request for an IE over two years ago, which was supposed to give Staff at least some ability to independently assess whether the study is reasonable. As described previously in this testimony though, Staff has still not seen any progress towards a full IE report. Given that this issue was raised in the Company's rate case from over four years ago and the

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[31] AWEC/200, Kaufman/11.

Commission greenlit over two years ago, it is Staff's assessment that the Company is either intentionally obfuscating the Commission's ability to conduct an independent review of the decommissioning study or has been willfully negligent in responding to Staff's requests to close out the process in a fair and transparent manner.

Q. What is Staff's recommendation regarding how best to address this?

A. Based on the dangerous precedent that the Company's unwillingness to engage in a transparent process and the intentional or negligent delays caused by the process, Staff recommends that the Commission impose a ten percent management disallowance for the estimated decommissioning costs for DJ Unit 4 and Jim Bridger Units 3 and 4 in the Kiewit Studies. Staff attempted to estimate the decommissioning costs by adding the grand totals for DJ and Jim Bridger from the Kiewit Studies and allocating using the System Generation (SG) factor for Oregon from PacifiCorp's 2025 TAM in UE 434. This results in a total of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for DJ and Jim Bridger. Factoring in Staff's ten percent disallowance brings the total to approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[32]

However, the estimates in the Kiewit Studies break down decommissioning costs by total plant, not by individual unit. Further analysis may be necessary to ensure these estimated costs are specific to DJ Unit 4

[32] Exhibit Staff/4003, PacifiCorp Response to AWEC DR 161, Attach AWEC 161-2 CONF. "CONF OR UM 1968 Decommissioning Study Workpapers".

and Jim Bridger Units 3 and 4 instead of the entirety of the plant. Staff recommends that PacifiCorp describe a methodology for parsing out the decommissioning costs by unit in the Company's next round of testimony.

Q. What is the appropriate treatment for the Exit Orders for Naughton Units 1 and 2?

A. Staff agrees with PacifiCorp that the Exit Orders should not be completely revoked for these units but modified to note that Oregon only exits these units as coal-fired units. Staff recommends that the Naughton Exit Orders are treated in a manner consistent with the Jim Bridger gas conversion units.

Q. Does Staff agree with AWEC's Exit Date proposal for Jim Bridger Units 3 and 4?

A. Yes. The 2028 Exit Date ensures that Oregon does not pay for the carbon capture technology installed on these units. Staff agrees that Oregon customers should not pay for carbon capture technology installation that is intended to lengthen coal units' lives past 2030 when the plant cannot be included in Oregon rates. PacifiCorp argues that the costs for carbon capture technology are not being included for recovery yet; therefore, AWEC's proposal is outside the scope of the current rate case.[33] However, Staff again notes that finalizing Exit Dates now is important to prevent the rate shock that customers face by continuing to push out a decision on Exit Dates into the future.

Q. How does Staff respond to AWEC's proposal regarding capital investments in coal plants, application of the allocation methods in

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[33] PAC/2000, McVee/63 at 10-15.

Section 6.5 of the 2020 Protocol for capital investments in plants with Exit Orders?

A. Staff agrees that the allocation methods in Section 6.5 are sufficient in this context. While section 6.5 is a straw proposal that was not officially agreed to by all parties, it is the most robust multi-state framework available.

Q. What is Staff's recommendation related to Docket No. UM 2183?

A. Staff recommends adopting AWEC's proposal to use the Kiewit Studies' estimates for DJ Unit 4 and Jim Bridger Units 3 and 4, closing Docket No. UM 2183, and applying a managerial disallowance to the decommissioning estimates of ten percent. With the state of progress in UM 2183, Staff is concerned that the docket will not reach resolution in time to mitigate rate shock to Oregon customers. However, Staff recommends the disallowance due to the transparency concerns stated earlier, noting the importance of being able to verify the inputs and basic assumptions in such a study.

ISSUE 2. JIM BRIDGER COAL TO GAS CONVERSION

Q. Please summarize Staff's position on the Jim Bridger coal-to-gas conversions in Opening Testimony.

A. Staff did not have any recommendations regarding the Jim Bridger coal-to-gas conversions in Opening Testimony. These units came online in March and April 2024.[34] These conversion plans were acknowledged in PacifiCorp's 2021 IRP in Docket No. LC 77 and as part of PacifiCorp's last General Rate Case UE 399.[35]

Q. Please summarize CUB's position on the Jim Bridger coal-to-gas conversions in Opening Testimony.

A. CUB recommends that the Commission either disallow ten percent of the rate base for this investment or disallow cost recovery starting in 2030. CUB argues that the Company "failed to show that this investment is prudent and in the best interest of Oregon customers in the context of HB 2021."[36] While HB 2021 requires the Company to reduce emissions by 80 percent by 2030 and 100 percent by 2040, CUB notes that converting Jim Bridger from coal to gas will result in carbon emissions until its exit date in 2037. Given that the Company could not serve Oregon load with coal generation after 2030, if Jim Bridger had not been converted to gas, there would not be additional emissions from Units 1 and 2 after 2030. CUB argues that in the 2023 IRP and CEP, the Company again included Jim Bridger as a part of its long-term Clean Energy

34 Exhibit Staff/1002, PAC response to Staff DR 460.
35 See UE 399, Opening Testimony, Staff/300, Anderson/5-8.
36 CUB/100, Jenks/22, at 23.

Plan along with other resources but did not follow through on other key components of the plan to reduce carbon emissions, such as carrying out the 2022 All-Source RFP. By invalidating key components of the CEP, the Commission chose not to acknowledge the 2023 IRP and CEP. CUB notes that these conversions were proposed in the 2021 IRP, which preceded any CEP filings.[37]

Q. Please summarize PAC's response to CUB's recommendations.

A. The Company argues that the conversions are "significantly more beneficial to customers than retirement" across all carbon price scenarios tested, and addressing a need for capacity at a relatively low cost of $9.3 million Oregon-allocated.[38] Retirement in contrast would increase the cost of serving Oregon customers in the form of higher net power costs and reduced system reliability The Company argues that customers will receive the benefits of these conversions starting with the 2024 Transition Adjustment Mechanism (to which CUB was a party) and thus should bear the costs. The Commission acknowledged these conversions in the 2021 IRP where Staff discussed implications for the CEP. The final Commission Order on the 2023 IRP and CEP was issued in March 2024 as the conversion projects were wrapping up. PAC adds that it acquired additional generating resources to reduce greenhouse gas emissions and continues to add wind and solar to address HB 2021 goals. In UE 399, PacifiCorp's last rate case, the Commission

[37] CUB/100 Jenks/21-23.
[38] PAC/2000, McVee/56, at 15-16.

approved two partial stipulations that included these conversions, with CUB as a signing party.[39]

Q. What is Staff's interpretation of this issue?

A. Staff believes these gas conversion plans were acknowledged well in advance of this docket and are expected to provide benefits to customers in 2024. Staff acknowledges that all stakeholders would have a better view of the impact of coal-to-gas conversions in the context of an overall Clean Energy Plan. However, the decision to proceed with the conversions of Jim Bridger Unit 1 and Unit 2 was decided long before this docket. This is further demonstrated in the Company's 2023 IRP, where Staff recommended removing the conversions of Naughton 1 and 2 and Jim Bridger 1 and 2 from the Company's action plan "because the Company has already taken these actions".[40]

Q. Did Staff expect to review the prudency of these decisions in the GRC?

A. Yes. Prior acknowledgement and action taken to execute these projects does not address the prudency of these decisions. Staff expected and addressed prudency in the current GRC.[41] Details regarding converting these units were also addressed in Commission Order No. 22-491 in PacifiCorp's previous GRC, UE 399.

Q. Has Staff found reason to find these conversions to be imprudent?

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[39] PAC/2000 McVee/53-59.

[40] LC 82, PacifiCorp 2023 Integrated Resource Plan, Staff's Round 2 Comments and Recommendations, pp. 8-9.

[41] Staff/100, Kim/7-8.

A. Not at this time. Staff has not found evidence to suggest these gas conversions were not prudent, nor have other parties provided such evidence. While Staff holds many of the same concerns about the Company's unwillingness to update its action plan or carry out an RFP to acquire non-emitting resources, Staff finds that the decision to convert Jim Bridger 1 and 2 to gas plants is in customers' best interests when the Company's decarbonization obligations are weighed against other relevant concerns, such as cost pressures.

Staff would like to reiterate that finding the conversion to be prudent does not mean that Staff agrees with the decision to cancel the 2022 RFP and otherwise delay the acquisition of resources that would further the Company's progress towards HB 2021 targets. Staff has serious concerns about the Company's decarbonization strategy, or lack thereof. However, Staff believes that these issues are best addressed in other spaces.

ISSUE 3. FLY ASH DEFERRAL

Q. Please summarize Staff's position on this issue.

A. Staff analyzed the Company's Opening Testimony proposal to reduce Test Year Fly Ash Revenue by $1.4 million, on an Oregon-allocated basis, and concluded that the reduction is reasonable based on the conversion of Jim Bridger Units 1 and 2 from coal to natural gas.

Q. Did PacifiCorp propose any adjustments to Fly Ash Revenue in Rebuttal Testimony?

A. Yes. PAC proposes to decrease Fly Ash Revenue for the Test Year by approximately $269,000, compared to Opening Testimony.[42] The updated proposal serves to increase the revenue requirement and reflects the underlying generation assumptions and adjustments agreed upon in the settlement of the 2025 Transition Adjustment Mechanism (TAM) in Docket No. UE 434.

Q. Does Staff agree with PAC's adjustment to Fly Ash Revenue proposed in Rebuttal Testimony?

A. Yes. PAC's adjustment reflects projected Fly Ash revenues consistent with the forecasted generation in TAM UE 434. Staff supports the synchronization of the generation assumptions and stipulations agreed upon in UE 434 with this filing.

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[42] PAC/3300, Cheung/5.

ISSUE 4. QF PASS-THROUGH

Q. Has Staff provided testimony on this issue previously?

A. Yes, Staff Exhibit 2100 outlines a pass-through mechanism for qualifying facilities (QF).

Q. Please summarize the Company's response to Staff's proposal.

A. Exhibit PAC/3100, Mitchell/2-19 addresses Staff's pass-through proposal. PacifiCorp does not agree with the pass-through mechanism and takes the following positions:

- PacifiCorp has routinely over-forecasted generation that is typically cheaper than market prices. Since QF's have been lower than market prices recently, the Company claims it is not incentivized to over-forecast QF generation as Staff suggests.[43]
- Staff's estimate of QF costs as a portion of net variable power costs (NVPC) is incorrect because the Company uses the 2020 Protocol energy price for non-Oregon jurisdictional QFs. This results in QFs accounting for 3.6 percent of NVPC, not 12.5 percent.[44]
- The Company claims that natural gas prices, market spot prices, unexpected weather conditions, and transmission outages on non-Company lines are all examples of risks that the Company must take that are similar to mandated QF generation.[45]

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[43] PAC/3100, Mitchell10-12.
[44] PAC/3100, Mitchell/12, at 14-22.
[45] PAC/3100, Mitchell/13-14.

- The QF forecast error percentage is lower than the total Company NPC forecast error and the Company considers Staff's proposal too narrow because it isolates a single component of NPC for pass-through recovery.[46]
- If QF volumes are under-forecasted, the Company claims the variance in QF volumes is valued at a Mid-C price without consideration of the QF price.[47]
- Staff's proposal only uses forecast market prices. The Company claims that market price actuals should be treated the same as a "must take" where neither party is completely responsible for the risks associated with the cost.[48]
- PacifiCorp has several Oregon solar QFs that do not generate at night and therefore the market price to value them should be hourly-scaled similar to Official Forward Price Curve (OFPC) used in the TAM.[49]
- The Company operates in in multiple power trading hubs and using only Mid-C forecasts is not appropriate.[50]

Q. Does Staff agree that its proposal is flawed because QF prices have not been higher than market prices in recent years?

A. No. The current trend between market and QF prices may not continue. The Company has consistently over-forecasted QF volume over periods when QF prices were higher than the market and vice versa. Just because the

[46] PAC/3100, Mitchell/14-15.
[47] PAC/3100, Mitchell/17, at 6-17.
[48] PAC/3100, Mitchell/18-19.
[49] PAC/3100, Mitchell/18, at 1-3.
[50] PAC/3100, Mitchell/18. at 4-9.

conditions currently pose less impact to customers' NPC does not mean Staff's proposal is unreasonable. A pass-through approach results in fair treatment of QF costs regardless of the current market condition and does not incentivize the Company to hedge for forecasting risk in more specific scenarios.

Q. Does the Company's claim that QFs account for 3.6 percent of NPC and not 12.5 percent impact the merits of Staff's proposal?

A. No. Staff's proposal intends to implement fair allocation of risk. While the impact on NPC may not be as large as originally stated, it does not change the fact that QF forecasting has been problematic. As the Company's QF portfolio grows, proper forecasting and pass-through treatment will continue to become even more important. Under the current methodology, over or under forecasting continues to present risk for under or over-collection that can harm customers or the Company.

Q. Do you agree with PacifiCorp's logic equating QFs as a must-take resource along with market purchases, transmission outages, and weather events?

A. No. The events contemplated by PacifiCorp can be much more random or unexpected than forecasting for QF generation. These events vary greatly from QFs in predictability and severity. A wildfire or a storm's impacts are quite different than a federally-mandated policy to take forecasted generation. Staff's pass-through proposal intends to target the inherent risk associated with forecasting for a generating resource that the Company must purchase. It is not intended to address outages or events that pose more severe ramifications in terms of safety, reliability, or market failure.

Q. How does Staff respond regarding the Company's assertion that a QF pass-through is too narrow since it focuses on one element of NPC?

A. The pass-through proposal is narrow because QFs differ from the utility's own generation and other purchases. As a must-take resource, QFs are unique and therefore may require unique rate treatment.

Q. Do you agree with the claim that Staff's pass-through methodology does not take the QF price into consideration and only considers the market price when QF volume is under-forecasted?

A. No. Staff 's methodology factors in the QF price compared to the Mid C forecast price regardless of whether the QF is over or under-forecasted. As an example, if the QF price is less than Mid C and is under-forecasted, the result would be a credit to customers. For the equation below, let "s" stand for supplier, "f" stand for forecast, "A" stand for actual, "p" stand for cost or price of the QF project, and "j" for hours (1 to 8760 hours).

$$(QFf_{sj} - QFA_{j}) * (\text{Mid } Cf_{j} - QF_{spj})$$

Q. The Company disagrees with using forecasts for market prices in the pass-through. Why does Staff use forecasted market prices in the calculation instead of actuals?

A. As stated in Staff's Opening Testimony, the pass-through is not intended to pass wholesale market price risk to customers. If using actuals, a small change in QF output could be completely overshadowed by a large change in market prices in the pass-through calculation. The pass-through proposal's primary goal is to address variance in QF volume.

Q. Is Staff amenable to using multiple power trading hubs for the market price component of the pass-through calculation?

A. Staff is not opposed to incorporating multiple market hubs in lieu of using Mid-C prices exclusively. Using a blend of hubs may be more representative of PacifiCorp's system and less volatile than when a single market experiences large changes in prices. Staff assumes the Company would use the Official Forward Price Curve (OFPC) instead of Mid-C prices. If this is incorrect, Staff requests that PacifiCorp outline what price forecast the Company would propose in its Surrebuttal Testimony. If the OFPC is used, Staff understands that the Company would propose hourly scaling instead of monthly weighted averages for heavy and light load hours in order to account for solar QFs that do not generate at night.

Q. What is Staff's recommendation for QFs after reviewing PacifiCorp's reply?

A. Staff continues to recommend that PacifiCorp implement the QF pass-through contemplated in Staff Exhibit 2100 but is amenable to considering a blend of multiple power trading hubs in the calculation in place of Mid-C. Staff believes that pass-through treatment for QFs is not overly narrow as PacifiCorp suggests, and that continuing with PacifiCorp's current forecasting methodology presents risk to customers at any point when QF prices are higher than market prices.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 4001

Timeline of Coal Decommissioning Events

August 16, 2024

Timeline of Coal Decommissioning Events

Date	Docket	Event
July 18, 2023	UM 2183	PAC Signatory Pages
June 26, 2023	UM 2183	ALJ Grants PAC Motion for MPO
June 22, 2023	UM 2183	PAC Motion for MPO
May 26, 2022	UM 2183	Order 22-187 authorizing RFP for IE for Review of Coal Plant Decommission Costs, Commission: (includes RFP)
May 5, 2022	UM 2183	Public Meeting Commission authorized RFP for IE to review Decommissioning Studies, Staff Report, Staff Presentation
July 8, 2021	UM 2183	PacifiCorp Application for Authority to Implement a Decommission Cost Recovery Adjustment and Coal Removal Mechanism
Aug 17, 2020	UE 374	Parties file partial stipulation
July 17, 2020	UE 374	Staff (Steve Storm) testimony on coal plant decommissioning costs and Kiewit studies
June 21, 2020	UE 374	Dr. Ranajit Sahu files confidential Narrative Report and Spreadsheets of IE Evaluation of Decommissioning Study
June 4, 2020	UE 374	Opening Testimony Filed, including Staff
May 28, 2020	UE 374	PAC files Supplemental Direct Testimony Regarding Depreciation Rates for Coal-Fired Resources
May 7, 2020	UE 374	Staff Recommendation to appoint IE (*Dr. Ranajit Sahu*) to evaluate Kiewit Studies
April 13, 2020	UM 1968	ALJ Grants Motions to segregate coal issues and suspend proceeding
April 2, 2020	UE 374	ALJ grants PAC motion to expand UE 374
March 31, 2020	UM 1968	PAC Motion to segregate coal fired resources from depreciation rates, expand scope of UE 374 to include coal decommissioning,
March 31, 2020	UE 374	PAC Motion to expand UE 374 "to include a determination of the depreciation rates for PacifiCorp's coal-fired resources" "If granted, all depreciation issues for PacifiCorp's coal-fired resources will be substantively addressed in docket UE 374."
Feb 14, 2020	UE 374	PAC files Request for General Rate Revision
Feb 14, 2020	UM 1968	PAC files supplemental testimony updating depreciable lives to align with the 2019 IRP and the 2020 Protocol, revised decommissioning rates to reflect information in PAC's Decommission Study
Jan 16, 2020	UM 1968	PAC files Decommissioning Study, "designed to implement provisions of the 2020 Protocol" – includes Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, and Hayden plants

Feb 15, 2019	UM 1968	Commission Order holding UM 1968 in abeyance (in response to PAC's unopposed motion)
Sept 13, 2018	UM 1968	PAC Filed application for revised depreciation rates, effective Jan 1, 2021

CASE: UE 433
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 4002

PacifiCorp Reply to Staff DR 738

August 16, 2024

UE 433 / PacifiCorp
August 9, 2024
OPUC Data Request 738

OPUC Data Request 738 Depreciation

Please calculate the revenue requirement if the depreciable lives of the Company's coal plants reflect the exit dates contained in Table 2 of AWEC/200, Kaufman/14-15. In your response, please also provide a workpaper that support the calculations and demonstrate the change to revenue requirement when compared to the Company's Reply Testimony revenue requirement.

Response to OPUC Data Request 738

Please refer to Attachment OPUC 738 which provides requested calculation of revenue requirement impact on test year results in this general rate case (GRC) if the depreciable lives of the Company's coal plants reflect exit dates contained in the Direct Testimony of Alliance of Western Energy Consumers' (AWEC) witness, Lance D. Kaufman, specifically Table 2 of Exhibit AWEC/200, Kaufman/14-15. The estimated impact to the Company's Reply Testimony revenue requirement of updating depreciation parameters to match Kaufman's proposed depreciable lives is a reduction of approximately $31.3 million.

This calculated revenue requirement impact in Attachment OPUC 738 does not consider the potential necessity to begin unwinding the Bridger Mine reclamation and accelerated depreciation regulatory liability originally approved in docket No. UE 374, the Company's 2021 GRC, which currently is approved to recover Bridger Mine reclamation and accelerated depreciation expenses over an assumed remaining depreciable life for Oregon customers of the Jim Bridger plant, through 2025, deferred to a regulatory liability. If Oregon customers were to continue relying on generation from the Jim Bridger plant through 2028, and thus be paying their share of mine reclamation and depreciation costs through amounts embedded in fuel cost through 2028, then the accumulated balance in the Bridger Mine reclamation and accelerated depreciation regulatory liability will also need to be amortized over 2025 through 2028 (i.e. four years). The projected regulatory liability balance as of December 2024 is approximately $58 million on a system basis, or approximately $15.3 million on an Oregon-allocated basis. Amortizing this amount over a four-year amortization period would result in a further reduction to revenue requirement of approximately $3.8 million annually in this GRC, in addition to the $31.3 million supported in Attachment OPUC 738.

CASE: UE 433
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
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CONFIDENTIAL
STAFF EXHIBIT 4003

PacifiCorp Reply to AWEC DR 161, Attach 161-2 CONF: CONF OR UM 1968 Decommissioning Study Workpapers

August 16, 2024

CONFIDENTIAL EXHIBIT 4003 FILED IN ELECTRONIC FORMAT

CASE: UE 433
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 4100

Rebuttal Testimony

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Eric Shierman. I am a Senior Utility Analyst in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. No.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/4101.

Q. What is the purpose of your testimony?

A. In this testimony I respond to Walmart's opening testimony regarding PacifiCorp's Schedule 45.

Q. How is your testimony organized?

A. My testimony briefly covers a single issue.

Q. Did you prepare additional exhibits for this testimony?

A. No.

ISSUE 1. SCHEDULE 45

Q. What is Schedule 45?

A. Schedule 45 is PacifiCorp's optional tariff for nonresidential customers operating public charging stations for electric vehicles that contain at least one direct current fast charger (DCFC) port.

Q. If these customers don't opt for Schedule 45, what service would they take?

A. These customers would most likely either be under Schedule 28 General Service Large Nonresidential 31 KW to 200 KW Delivery Service or Schedule 30 General Service Large Nonresidential 201 KW to 999 KW Delivery Service.

Q. What does the choice of taking service under Schedule 45 offer these customers?

A. Schedule 45 allows these customers to pay less than the full demand charge that other customers in their rate class must pay. The intent when this transitional rate was established back in 2017 was to incent the early construction of public DCFC charging sites by temporarily reducing the amount of capacity cost that these customers pay for a decade until an expected larger number of EVs operate in the Company's service territory by 2026.

Schedule 45 does so on a time-based sliding scale; that is to say, the percentage of the demand charge they must pay gradually increases over the ten-year period. Schedule 45 customers are currently paying only 80 percent of their demand charge. On May 15, 2025, this will go up to 90 percent. The demand charge will be fully phased in on May 15, 2026.

Q. What is Walmart's proposal?

A. Walmart wants PacifiCorp to work with stakeholders to develop a new EV retail rate specific for public-facing EV chargers within six months following the issuance of a final order in this docket.[1] Walmart articulated specific recommendations for that rate, such as allowing the 10-year transition to start anew with each new customer rather than remain just a transition from 2017 to 2026. Walmart's goal is to see more third-party investment in public DCFC at its stores, and Walmart sees the payment of these chargers' capacity cost as a remaining barrier to development.

Q. Does Staff support this proposal?

A. Partially. Staff supports engagement between PacifiCorp and stakeholders on this topic, but Staff does not necessarily support further subsidization of EV charging through rates. Staff notes that public charging businesses are also eligible for a rebate.[2] Discussion of what additional subsidies high speed public charging should get from other ratepayers should be conducted wholistically in the context of transportation electrification (TE) planning.

PacifiCorp is due to file a third TE Plan on May 1, 2025, in Docket No. UM 2056. That other proceeding fits within the six-month time frame Walmart has proposed. Staff thanks Walmart for raising this issue in this

[1] See Walmart/100, Austin/20.
[2] Schedule 118.

proceeding, but Staff finds the TE Plan docket to be the more appropriate forum to decide to what degree other customers should be subsiding the capacity cost of the very high-speed chargers that are being sited in Walmart parking lots.

Only the newest and most expensive EVs can charge at 350 kW. The older models of Chevy Bolts max out at 55 kW and older Nissan Leaves at 62.5 kW. These are the EVs low-income customers are more likely to own. Therefore, this cross subsidy could be expected to disproportionately benefit wealthy EV owners. The focus of TE planning in recent years has been on Level 2 charging (7 kW) for residents of multifamily housing.

This does not necessarily mean Walmart's effort to get PacifiCorp's ratepayers to provide a more permanent subsidy for public DCFC charging has no merit. It means Walmart's proposal is best considered within the context of other EV program priorities with the input of other EV advocates that do not participate in rate case dockets.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 433
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 4101

Witness Qualifications Statement

August 16, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Eric Shierman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	MS Economics; Portland State University; Portland, Oregon BA Political Economy; Hillsdale College; Hillsdale, Michigan
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since June 2019. I was previously employed by McCullough Research as a Research Associate for two years.

CASE: UE 433
WITNESSES: LUZ MONDRAGON, NICOLA PETERSON, and BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 4200

REDACTED
Rebuttal Testimony
Wildfire Restoration Costs
Wildfire Liability Insurance
Insurance Cost Adjustment

August 16, 2024

Q. Please state your name, occupation, and business address.

A. My name is Luz Mondragon. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Commission's Energy Program.

My name is Nicola Peterson. I am a Senior Telecommunications Analyst employed in the Water, Telecom, Safety and Consumers Program of the Public Utility Commission of Oregon (OPUC).

My name is Bret Stevens. I am a Senior Economist employed in the Commission's Regulatory Strategy section of Energy Rate and Regulatory Strategy Division.

Our business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. Our Opening Testimonies can be found in Staff/1100, Staff/1600, and Staff/1900. Our witness qualification statements are found in Exhibit Staff/1101, Staff/1601, and Staff/1901.

Q. What is the purpose of your testimony?

A. We consolidate three issues: recovery of the UM 2116 deferral, recovery of the UM 2301 deferral, and the Insurance Cost Adjustment (ICA). We also broadly discuss the similarities between Staff's recommendations on these issues and the Company's response to Staff's recommendations.

Q. Did you prepare any exhibits for this docket?

A. Yes, we prepared Exhibit 4201, which lists a non-confidential data request.

Q. How is your testimony organized?

A. Our testimony is organized as follows:

ISSUE 1. SHARING OF WILDFIRE RESTORATION AND LIABILITY COSTS

Q. Please discuss the structure of this testimony.

A. In Opening Testimony, Staff submitted three exhibits which, in part, recommended some level of cost sharing for both wildfire restoration costs and wildfire liability costs.[1] These proposals revolved around the Company's Insurance Cost Adjustment (ICA) proposal and the amortization of two deferrals: one for wildfire restoration costs due to fires occurring in 2020 and the other for incremental liability insurance premium costs in 2023. In the Company's Reply Testimony, witnesses McVee,[2] Steward,[3] and Coleman[4] responded to Staff's recommendations on these issues.

Staff decided to consolidate the record by submitting rebuttal on these issues under one heading for ease of reference and understanding. In this first section, Staff will respond to the common threads throughout both Staff's proposals and the Company's responses. In the subsequent sections, Staff will respond to any points specific to a particular issue.

Q. Please discuss the commonalities between Staff's proposals on these issues.

A. In all three of Staff's Opening Testimony positions, Staff proposed some level of sharing between ratepayers and shareholders. In particular, Staff proposed 30/70 sharing for the wildfire restoration cost deferral,[5] 80/20 sharing for the

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1 Staff/1900, Stevens/38-40; Staff/1100, Mondragon/42-52; and Staff/1600, Peterson/26-27.
2 PAC/2000, McVee/26-45.
3 PAC/2300, Steward/11-19.
4 PAC/2400, Colman/2-8.
5 Staff/1100, Mondragon/52.

liability cost deferral,[6] and 80/20 sharing for all liability insurance premiums on a going forward basis,[7] respectively.

Q. Please discuss Staff's rationale for proposing these sharing mechanisms.

A. For wildfire restoration costs, Staff argued that because of the jury's findings in *James v. PacifiCorp*—which included findings of negligence, gross negligence, recklessness, willfulness, private nuisance, public nuisance, and trespass—[8] the Company could reasonably be seen to have acted imprudently during the 2020 fires and should share the majority of burden of the wildfire restoration costs.[9] For the liability insurance deferral, Staff argued that a sharing mechanism was appropriate to incentivize the Company to purchase in a least cost manner and to recognize that the 2020 fires play a role in the increase in insurance costs.[10] Lastly, in Staff's recommendation to apply a sharing mechanism to all liability insurance costs, either through self-insurance or commercially obtained, Staff explained its reasoning as being meant to provide incentive for the Company to manage its network in a safe and responsible manner and to ensure that there is no incentive for the Company to prefer one insurance source over the other.[11]

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[6] Staff/1600, Peterson/26-27.
[7] Staff/1900, Stevens/40.
[8] *Jeanyne James, et. al. v. PacifiCorp*, In the Circuit Court of the State Oregon for the County of Multnomah, Case No. 20CV33885, Final Verdict (June 9, 2023); See also *Jeanyne James, et. al. v. PacifiCorp*, In the Circuit Court of the State Oregon for the County of Multnomah, Case No. 20CV33885, Final Jury Instructions, Trial Date February 26, 2024 (filed March 5, 2024).
[9] Staff/1100, Mondragon/50-52.
[10] Staff/1600, Peterson/26-27.
[11] Staff/1900, Stevens/40.

The common thread between Staff's positions on these issues is that a court of law has found that PacifiCorp was grossly negligent, reckless, and willful in causing wildfires in 2020. The consequences of PacifiCorp's actions led to destruction of Company property and increased liability insurance costs. Ratepayers should not bear the costs of a Company's grossly negligent, reckless, or willful behavior.

Q. Please expand on the slight differences between Staff's rationale for recommending the sharing mechanism for the wildfire restoration costs and the liability insurance costs.

A. While the rationale for each sharing mechanism may share some commonalities, there are some slight differences between them. For wildfire restoration costs, Staff's recommendation is largely based on the logic that through its grossly negligent actions, PacifCorp contributed, at least in part, to the damage done to its own system. As such, they should share the burden of the reconstruction costs.

Staff's recommendation for sharing costs for both the UM 2301 deferral and future liability insurance costs is related to the impacts of the *James* case finding on the Company's current and ongoing liability insurance costs but also for reasons not associated with the *James* finding. First, Staff argues that regardless of the finding in the *James* case, PacifiCorp should be sharing its liability insurance costs. The fallout from this case has highlighted the material benefit received by shareholders from liability insurance. The stoppage of dividends due to liability claims in excess of the Company's insurance coverage underscores the direct benefit received by shareholders by liability in years where claims did not exceed the Company's coverage level. PacifiCorp witness Steward argues that ratepayers benefit from liability insurance, stating:

> Utilities incur insurance costs not to boost profits, but to protect themselves and their customers from exposure to large claims that could impact the utility's financial stability and its rates.[12]

While Staff agrees that ratepayers do, in fact, benefit from liability insurance coverage and that liability insurance is generally a prudent business expense, it is undeniable that shareholders also benefit from this expense that, to date, has been exclusively paid for by ratepayers. Staff is not arguing that insurance costs "boost profits" *per se*, but instead that liability insurance *shields* profits and ensures that dividends are paid out in years where liability claims do not wildly outstrip coverage levels. Staff argues that this reality should be reflected in how and who pays for liability insurance.

Second, as Staff explained in Opening Testimony,[13] with the Company's forthcoming Insurance Mechanism proposal, it will be important for the Company to share the costs of commercially obtained insurance. Staff strongly supports a sharing mechanism in any potential self-insurance mechanism. Without one, the Company has no incentive to fight frivolous claims as there is no threat of increased insurance rates from a self-insurance mechanism and there would be little to no risk of recovery if a case was settled. In this setting, the Company has little to no incentive to shrewdly arbitrate settlements or fight

12 PAC/2300, Steward/16.
13 Staff/1900, Stevens/40.

claims at all. A sharing mechanism for self-insurance would incentivize the Company to minimize its liability costs. However, if this sharing mechanism only applies to self-insurance, then the Company has an incentive to purchase commercial insurance to skirt the self-insurance sharing mechanism even if the commercial insurance rates are inordinately high. Further, a sharing mechanism for both self-insurance and commercial insurance would further incentivize the Company to safely and responsibly operate its system.

Lastly, the gross negligence finding in the *James* case further heightens the need for a liability insurance sharing mechanism. Insurance companies determine the price offered to organizations based on their perceived riskiness. The exact reasoning for the drastic increase in the Company's liability insurance costs is the product of internal actuarial models that can only truly be known by the insurance providers themselves. However, a gross negligence finding or even a prolonged court case determining gross negligence tied to a catastrophic fire is *undeniably* going to have a sizable impact on the perceived riskiness of a prospective insurance client, which would likely affect the insurance rate offered or whether insurance is offered at all. Recovering from the finding of the *James* case, in terms of liability premium costs, will likely take years of conservative and prudent decision making by the Company. This long-lasting effect is another reason why Staff has recommended an indefinite sharing of liability insurance costs.

Q. Did any other Parties propose some sort of cost sharing for any of these issues?

A. Yes, The Alliance of Western Energy Consumers (AWEC) recommended to exclude all amortization of the UM 2116 deferral from rates. Additionally, they made the following recommendations in the event that the Commission approve amortization of some or all of the deferred amount:[14]

- Aligning the cost of capital calculations for capital accrual with the effective cost of capital in the period of accrual.
- Either compounding interest annually or adjusting the calculation of the monthly interest rate to account for monthly compounding.
- Deferral be reduced to reflect assets embedded in base rates as discussed in Response to OPUC Data Request 584.
- Amortizing any authorized recovery over five years rather than three years.

AWEC's recommendation would reduce the Oregon allocated amortization expense by $18.9 million, depreciation expense by $1.5 million, and rate base by $86.8 million.

Q. Why did AWEC make the recommendations?

A. AWEC's testimony finds that PacifiCorp's gross negligence and willful and reckless conduct are inconsistent with prudent utility management and that the Company has not offered evidence of prudency in spite of the court findings.[15] This general argument aligns with Staff's thinking on this issue.

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[14] AWEC/200, Kaufman/2.
[15] AWEC/2000 Kaufman/17.

Q. What was the Company's response to Staff's proposed sharing mechanisms?

A. PacifiCorp states that the basis for all three sharing mechanisms is not identified.[16] The Company also states that "Without additional evidence, Staff's decision to advocate for a monumental disallowance "[i]n light of court findings," does not withstand analysis and certainly does not constitute a proper finding of imprudence."[17] The Company also argues that the exact levels of sharing proposed by Staff are arbitrary.[18,19]

For the restoration cost issue, the Company also references Portland General Electric's Docket No. UE 394, which sought to amortize deferred costs associated with the restoration of services related to the 2020 wildfires and 2021 ice storms, and the Commission's decision to reject a sharing mechanism. PacifiCorp states that, "In this situation, the *James* jury decision referenced by Staff provides no assistance to the Commission because the jury was focused on whether it was reasonable to turn off the power, not whether it was prudent to repair and restore PacifiCorp's system after the wildfire."[20] The Company also argues for both restoration costs and liability insurance that sharing mechanisms would incent the Company to not restore power in a timely manner or buy less liability insurance than is necessary.[21]

16 PAC/2000, McVee/30; PAC/2400, Coleman/2.
17 PAC/2000, McVee/33.
18 PAC/2400, Coleman/2.
19 PAC/2000, McVee/30.
20 PAC/2000, McVee/33.
21 PAC/2000, McVee/31, McVee/42.

The Company argues that “a jury’s negligence finding does not make a utility’s action *per se* imprudent...” and that pointing to a jury’s negligence finding, without more, does not demonstrate that the utility failed to meet the Commission’s prudence standard.[22] Additionally, the Company points to PacifiCorp’s recent Docket No. UE 428 and cites the following two Commission comments:

> …[W]e emphasize that Oregon needs to find appropriate policy and regulatory solutions to the serious problems wildfire liability creates for PacifiCorp and, indeed, all utilities and their customers. The James verdicts are an example of the risk utilities may face in adjudication of wildfire actions in civil courts, where juries evaluate whether the company met an unclear and rapidly changing duty of care and engaged in willful misconduct. It may be impossible for a utility to avoid a civil court finding of gross negligence, regardless of actions the utility took.
>
> …Maintaining affordable electric service in the face of mounting liability is problem with which the state as a whole will need to reckon. In doing so, the state must grapple with the appropriate balance between affordability, reliability, and reducing-but not completely eliminating-the risk of utility wildfire ignitions, which are just one source among many sources of wildfire ignition.[23]

Lastly, PacifiCorp states that the *James* finding is not the cause of the 2023 increase in insurance premiums[24] and that Staff has not provided evidence proving the contrary.[25] The Company argues that this is partially due to the fact that the Company has not, and will not, file any *James* related claims with its excess liability insurance providers. Further, they argue that any claims

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22 PAC/2000, McVee/32.
23 *In the Matter of PacifiCorp, dba Pacific Power*, Advice No. 23-018 (ADV 1545), Modifications to Rule 4, Application for Electrical Service, Docket No. UE 428, Order No. 24-155, at 7 (May 30, 2024).
24 PAC/2000, McVee/42; PAC/2400, Coleman/6.
25 *Id. at 2.*

arising from the *James* litigation that are recoverable from excess liability insurance would have to be paid by the Company's excess liability policies that were in effect during 2020.[26]

Q. How did the Company respond to the AWEC's proposal?

A. PacifiCorp responds to AWEC's testimony by stating that AWEC conflates prudence with a jury's finding of negligence and that relying solely on the negligence findings in a jury verdict without further independent analysis does not provide sufficient evidence to support a finding that the Company acted imprudently or that documented costs of repairing its system to restore service to its customers after wildfires should be disallowed.[27]

Q. How does Staff respond to the Company's statement that "sharing" is contrary to the recent Commission decision in UE 394?

A. The Commission decision PacifiCorp references is Docket No. UE 394 where PGE sought to recover costs associated with the 2020 wildfires and 2021 ice storms. While these are indeed recovery costs that arose from the same wildfire event, PGE was not found grossly negligent for causing the wildfires that burnt down the equipment that PGE replaced.

Q. How does Staff respond to the Company's statement that Staff's basis for its sharing mechanisms is not identified and arbitrary?

A. Staff would like to point to the quote referenced by the Company and presented above, to respond.

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[26] PAC/2400, Coleman/6.
[27] PAC/2000, McVee/35.

> Maintaining affordable electric service in the face of mounting liability is problem with which the state as a whole will need to reckon. In doing so, the state must grapple with the appropriate balance between affordability, reliability, and reducing-but not completely eliminating-the risk of utility wildfire ignitions, which are just one source among many sources of wildfire ignition.

Staff's recommendation was based on the exact grappling mentioned in the Commission statement. Staff is attempting to find the appropriate balance between affordability, reliability, and reduction of risk. In doing so, Staff tried to arrive at a sharing number that held PacifiCorp accountable for imprudent decision making, while still allowing them to recover costs that are appropriate for Company to recover.

In the case of the deferred reconstruction costs, Staff feels that asking Oregon customers, some of whom suffered losses in various ways, to front the full recovery of millions of dollars in costs that were incurred as a direct result of the Company's grossly negligent actions, is not in line with accountability for the Company nor affordability for the customer. In the case of the liability insurance costs, Staff again points out that PacifiCorp's grossly negligent behavior has contributed to the substantial increase in liability insurance premiums the Company is now facing.

PacifiCorp's argument that Staff's exact sharing proposals are "arbitrary" pretends as though there is some scientific way to measure the Company's precise level of guilt in either of these issues. The truth is that there is not. As stated above, the exact reasoning for the drastic increase in the Company's liability insurance costs can only truly be known by the insurance providers themselves. Staff recognizes the heightened fire risk in the west is leading to higher regional insurance premiums. However, any attempt to claim that a gross negligence finding would not contribute to higher liability insurance costs should be seen as a thinly veiled attempt by the Company to minimize their role in both the Labor Day wildfires and the ensuing insurance market price increases. The closest measure Staff has for understanding the role the Company played in the severity of the fires in the *James* case is the gross negligence finding itself. The strong finding paired with the punitive damages handed out by the judge in the case are a strong indication of the Company's role, thus informing Staff's strong sharing proposal.

Q. How does Staff respond to the Company's argument that the ruling in the *James* case is not relevant to the restoration cost issue?

A. Staff strongly disagrees. The Company states that since the *James* case was focused on the Company's actions or inaction at the start of the fires, and not about its decisions during the reconstruction process, it has no bearing on the recovery of this deferral. In other words, PacifiCorp argues that it's irrelevant whether the Company was held to be responsible for starting the fires that burnt down their equipment in the first place. Staff disagrees that if the Company's grossly negligent, reckless, or willful misconduct destroys its own plant or equipment, that ratepayers should bear the costs of replacing such plant or equipment. If, for instance, PacifiCorp was found to be willfully negligent in the maintenance or operation of a gas power plant that resulted in major damage to the unit, it would not be appropriate for ratepayers to compensate the Company for the reconstruction of the plant. The same logic can be applied in this case.

Q. How does Staff respond to the Company invoking the Commission's language from the Order in UE 428?

A. Staff interprets the Commission's language differently within the context of the record in UE 428 and the Commission's order as a whole. Staff assumes that the Commission will interpret their own words as they intended.

Q. Do you have any other evidence to support your claim that the *James* ruling played a role in the Company's elevated insurance rates.

A. Yes. In DR 279, Staff asked for the Company's cost of liability insurance per dollar of coverage for the years: 2010, 2014, 2019, 2021, and 2023. Staff asked for years 2010, 2014, and 2019 to establish a baseline cost and to observe whether insurance premiums had been rising due to climate change induced fire risk prior to 2020. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff asked for the cost of coverage in 2021 to observe the price change post the 2020 wildfires. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff asked for 2023 insurance cost information to see what rates were offered after the *James* case was ruled on. To be clear, the *James* case ended roughly two months prior to PacifiCorp's August policy renewal deadline. **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL]

While Staff agrees that the *exact* reason for PacifiCorp's elevated liability insurance rates is unknown, both to Staff and the Company, it is reasonable to expect that *some* portion of this increase is attributable to the gross negligence finding in the *James* case.

Q. Does Staff feel that its liability insurance sharing mechanism is aggressive?

A. No. Based on the data provided above, Staff has reason to believe that the *James* verdict may be attributable to **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL] of the increase in the Company's insurance premiums. Staff chose the 20 percent sharing amount as it seemed to be a conservative estimate of the attributable increase from the *James* case.

Q. What does PacifiCorp say about the effect of the *James* case on insurance costs?

A. In Utah Docket No. 23-035-40, PacifiCorp's Application quotes an insurance industry trade publication that suggests the *James* verdict has strongly impacted insurance premiums: "insurers have taken note of the fact that, [l]iability on the scale imposed by the Oregon jury presents an existential threat to an industry that faces increasing wildfire risk from more extreme weather…."[28]

Q. Does Staff have any other justification for a sharing mechanism for commercially purchased insurance?

A. Yes. As stated in Opening Testimony,[29] if PacifiCorp's forthcoming Insurance Mechanism is approved, Staff is strongly supportive of a sharing mechanism to align managerial incentives with prudent use of the self-insurance fund. Applying the sharing provision to both commercially obtained and self-insurance would ensure that there is no incentive for the Company to prefer one insurance source over the other.

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[28] *Application of Rocky Mountain Power for a Deferred Accounting Order Regarding Insurance Costs*, Order Denying Application, Utah Docket No. 23-035-40, page 5 (March 9, 2024) available at: https://pscdocs.utah.gov/electric/23docs/2303540/3330962303540oda3-29-2024.pdf (citing PacifiCorp Application at 2 which cites Joel Rosenblatt, Utility Investors Wary of Exposures After Buffet's PacifiCorp Held Liable for Wildfires, Insurance Journal (July 19, 2023)).

[29] Staff/1900, Stevens/40.

Q. How does Staff respond to the Company's statement that a sharing mechanism for these costs would incent the Company to make imprudent decisions?

A. Specifically, PacifiCorp said about the sharing mechanism for the 2020 wildfire restoration costs:

> Such a drastic disallowance of system restoration costs certainly does not "promote [restoration] efforts" after emergencies like wildfires.[30]

While this sentence is a bit vague in its meaning, Staff's interpretation of this statement is that if a sharing mechanism is applied to the UM 2116, that the Company may be less incentivized to swiftly restore power after future emergencies as they may risk a disallowance. More explicitly, the Company stated that Staff's proposed sharing mechanism "incentivizes the purchase of less insurance than may be needed, at exactly the time when increasing wildfire risk and skyrocketing costs make obtaining adequate insurance coverage critical to the Company and customers."[31]

Staff finds both of these statements concerning. It is the Company's duty to provide safe and reliable service to its customers, and Staff expects that any intentional delay by the Company to restore power would be seen as imprudent actions that put customers at risk. Any implication that that sense of duty may be compromised by a sharing of costs when the Company acts imprudently is not something that should be taken lightly. Further, the Company's argument

[30] PAC/2000, McVee/31.
[31] PAC/2000, McVee/42.

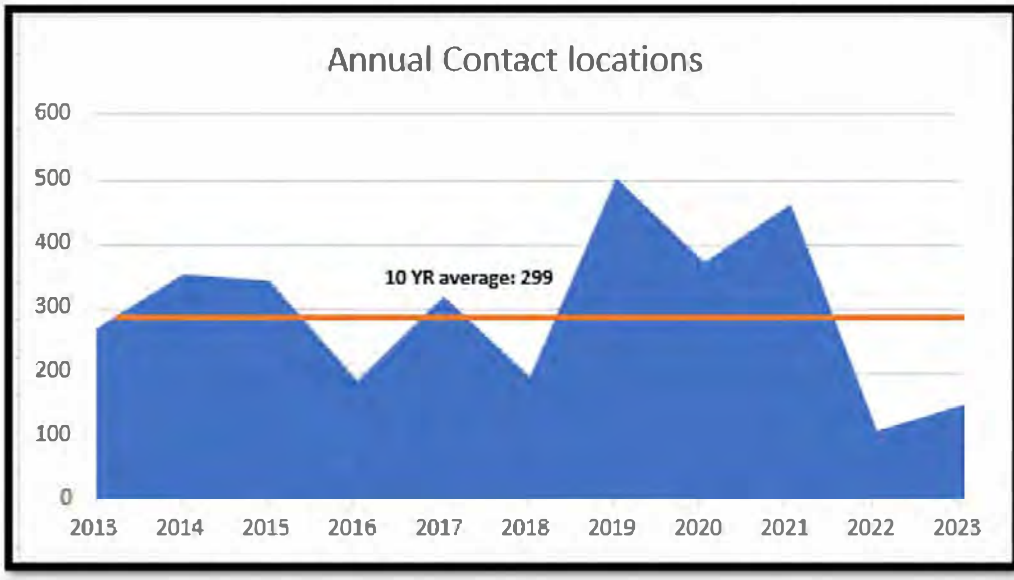
that a sharing of liability insurance premium costs will potentially lead to the imprudent purchase of a lower than necessary amount of liability insurance is alarming. It is the Company's duty to make prudent decisions regardless of the amount of recovery they are authorized.

Q. How does Staff respond to the Company's statement that a jury's negligence finding does not demonstrate that the utility failed to meet the Commission's prudence standard?

A. Staff agrees that in some cases, a *negligence* finding in civil court does not necessitate a finding of imprudence. As noted above, the jury in the *James* case found the Company's actions constituted gross negligence, recklessness, willful misconduct, private nuisance, public nuisance, and trespass. However, this is a legal issue that Staff Counsel will discuss further in legal briefs.

Q. Did Staff do any additional analysis that might support the courts findings?

A. Yes, Staff reviewed PUC Vegetation Management Audit Results, since 2005, in Staff Exhibit 1100. In 2019, just prior to the 2020 Labor Day fires, we see the number of contact locations are at their highest point with 504 contact locations. This is well above the ten-year average of 299 contact locations.



Q. Has Staff's position been supported in other cases in other states?

A. Yes. In June of 2023, Rocky Mountain Power (RMP), a division of PacifiCorp, filed an application requesting the Public Service Commission (PSC) of Utah authorize deferred accounting for incremental costs associated with third-party liability due to 2020 Wildfires in Oregon.[32] The request was later withdrawn without prejudice by the Company to allow the appeal process in the *James* proceeding to move forward and allows the Company an opportunity to refile at a later date when the costs and impacts of the *James* proceeding are more fully known.[33]

However, before the withdrawal, the Utah Division of Public Utilities published their Statement of Position in which they state:

> It is apparent from the Division's initial review that the Application seeks to establish a deferral account for expenses which the Company would not be entitled to collect from

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32 *Application of Rocky Mountain Power for a Deferred Accounting Order Regarding Wildfire Claims*, Application for Deferred Accounting Order, Utah Docket No. 23-035-30 (June 21, 2023).

33 *Id.*

> ratepayers. The Application relies upon James v. PacifiCorp as grounds to establish the deferral account, but the Company should not be able to recover expenses caused by its own negligence, gross negligence, and reckless and willful conduct.[34]

Q. Does Staff have another example?

A. Yes. In August of 2023, RMP filed Docket No. 23-035-40 asking the Utah PSC to issue a Deferred Accounting Order (DAO) for the costs associated with the increase in Excess Liability Insurance (ELI). In Discussion, the PSC noted:

> A jury has found RMP acted in a manner sufficiently tortious as to impose punitive damages. RMP has declined to offer any meaningful evidence concerning its conduct underlying the James verdict or to otherwise make any serious attempt to demonstrate its tortious conduct is not a substantial or primary cause of its increased premiums. On the contrary, as noted above, RMP quotes an insurance industry trade publication in its Application that expressly suggests the James verdict is, in fact, a primary driver of its increased premiums.[35]

The docket resulted in a denial of the application with the PSC stating,

> RMP has seen exorbitant increases in its ELI premiums immediately subsequent to an unprecedently large jury verdict finding PacifiCorp was grossly negligent, reckless, and willful in causing the Oregon wildfires and awarding plaintiffs significant punitive damages. We do not prejudge whether RMP might ultimately demonstrate the increased ELI premiums are a prudent expense, but no reasonable person could conclude that such an outcome is likely…"[36]

Q. What is Staff's conclusion on the Utah dockets?

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[34] *Application of Rocky Mountain Power for a Deferred Accounting Order*, Docket No. 23-035-30, Statement of Position of the Utah Division of Public Utilities, page 3 (August 11, 2023).

[35] *Application of Rocky Mountain Power for a Deferred Accounting Order Regarding Insurance Costs*, Order Denying Application, Utah Docket No. 23-035-40, page 12.

[36] *Id.* at 12-13.

A. In the two Utah dockets, the Utah Staff and the Commission share Oregon's Staff's sentiment that PacifiCorp's imprudent decisions should not penalize ratepayers.

ISSUE 2. WILDFIRE RESTORATION COST DEFERRAL

Q. Please summarize Staff's initial recommendation regarding the sharing of UM 2116-Amortization of 2020 Wildfire Costs?

A. In Opening Testimony, Staff proposed a sharing mechanism of 30/70 (70/30) for restoration costs. In Staff's preliminary calculations the sharing mechanism adjustment decreases amortization by $13.3 million.

Q. Did intervenors address UM 2116 in their testimony?

A. Yes. AWEC witness Kaufman addressed this subject. AWEC's positions are discussed above.

Q. Did Staff complete any other analysis?

A. Yes. In order to try to produce a sharing mechanism based on a scientific method, Staff summed up restoration costs based on how PacifiCorp treated the specific fire. For example, costs associated with the wildfires that resulted in the *James* case where PacifiCorp was found to have been grossly negligent make up 39 percent of O&M costs and 19 percent of new plant. Costs associated with the Archie Creek and Slater fires, both of which have reached settlements, make up 47 percent of O&M costs and 75 percent of new plant.

If Staff proposes a sharing mechanism based on the costs associated with wildfires in which PacifiCorp was found to be grossly negligent, this would not account for costs associated with wildfires where PacifiCorp settled with wildfire victims. This would create an incentive for the Company to settle future lawsuits, regardless of whether they were frivolous or not. On the other hand, there have been no findings of gross negligence for the Archie Creek and

Slater fires because they were settled. Staff is uncomfortable with recommending a sharing mechanism that would either incentivize or disincentivize settlement of wildfire litigation instead of basing decisions on the strength of the claims against the Company. As such, there does not seem to be an answer in the scientific method. Here, Staff attempts to both allow the Company to recover wildfire restoration costs for wildfires it was not found to have caused while protecting ratepayers from paying the costs to replace equipment that was damaged in a fire that a jury found PacifiCorp to have caused.

Restoration Costs

District	Wildfire	O&M Totals		James Case		Settled		Other
Medford	Almeda	$ 317,071		-		-	x	317,071
Meldford	South Obenchain	$ -	x	-		-		
Lincoln City	Echo Mountain	$ 400,236	x	400,236		-		
Roseburg	Archie Creek	$ 883,788		-	x	883,788		
Stayton	Beachie Creek	$ 250,846	x	250,846		-		
Grants Pass	Slater	$ 199,614		-	x	199,614		
Klamath Falls	Two Four Two Fire	$ 245,658	x	245,658		-		
		$ 2,297,213		$ 896,740		$ 1,083,402		$ 317,071
				39%		47%		14%

District	Wildfire	Plant Totals		James Case		Settled		Other
Medford	Almeda	$ 13,370,029		-		-	x	13,370,029
Meldford	South Obenchain	$ 1,051,456	x	1,051,456		-		
Lincoln City	Echo Mountain	$ 28,039,013	x	28,039,013		-		
Roseburg	Archie Creek	$107,073,709		-	x	107,073,709		
Stayton	Beachie Creek	$ 3,952,017	x	3,952,017		-		
Grants Pass	Slater	$ 58,156,203		-	x	58,156,203		
Klamath Falls	Two Four Two Fire	$ 8,967,181	x	8,967,181		-		
		$220,609,608		$ 42,009,667		$ 165,229,912		$ 13,370,029
				19%		75%		6%

Q. Does Staff have an update to the original recommendation?

A. Yes. Based on further analysis, Staff would like to update the original recommendation of 30 percent customer and 70 percent Company (30/70) to 50 percent customer/50 percent Company (50/50). This would result in a decrease of $9.4 million in amortization. Staff further recommends that if the Commission disagrees with Staff's or AWEC's proposals, to suggest a fair and just sharing mechanism that is mindful of the effect to the ratepayer.

Moving forward Staff will continue to evaluate restoration costs of these and future wildfires to ensure fair treatment between shareholders and ratepayers.

ISSUE 3. WIDLFIRE LIABILITY COST DEFERRAL

Q. Please summarize Staff's initial recommendation for the UM 2301 Deferral in Opening Testimony.

A. In Opening Testimony, Staff had recommended that 20 percent of excess insurance costs deferred through the Insurance Cost Adjustment should be shared with the Company. PacifiCorp addressed this cost sharing in their Reply Testimony. Staff addressed the Company's points in testimony above.

Q. Did intervenors address UM 2301 in their testimony?

A. Yes. CUB witness Jenks addressed this subject and concluded that "before amortization, the Commission needs to address the prudence of these costs, apply an earnings test, and decide whether the costs should be subject to sharing."[37] CUB did not suggest a percentage rate for said sharing.

Q. Does Staff have an update to the original recommendation?

A. No.

[37] CUB/100, Jenks/78-79.

ISSUE 4. INSURANCE COST ADJUSTMENT

Q. Please summarize Staff's initial recommendation for the Insurance Cost Adjustment in Opening Testimony.

A. In Opening Testimony, Staff recommended that PacifiCorp continue to track insurance costs in excess of the amount in base rates as was done in UM 2301. These deferrals would be amortized via Schedule 80. If, and when, the Insurance Mechanism and its vehicle for cost recovery is established, either through a surcharge or base rates, the Company would end filing these deferrals. Staff also recommended that all insurance, either commercially obtained or self-insurance, be shared 20 percent by the utility on a going forward basis.

Q. Did other Parties address this issue in Opening Testimony?

A. Yes. AWEC, CUB, and Kroger all commented on the proposal. AWEC argued that since the Insurance Mechanism is not fully formed, the creation of Schedule 80 is premature.[38] CUB argued that Schedule 80 is not needed to recover the UM 2301 costs and as such should not be created.[39] Further, CUB argues that this must be done in order to address UM 2301 with the typical scrutiny for amortizing a deferral prior to its incorporation into rates.[40] Kroger did not recommend that the Commission approve the proposed ICA, but

38 AWEC/100, Wilcox/16-17.
39 CUB/100, Jenks/78.
40 *Id.* at 78-79.

argued that if the Commission were to accept the proposal, that the surcharge be recovered through a percent of bill charge.[41]

Q. Did the Company address Staff's and Intervenor's proposals in its Reply Testimony?

A. Yes. The Company's response to Staff's proposal for sharing 20 percent of all liability insurance costs is addressed in Testimony above. The Company also addressed Staff's recommendation to continue to defer the difference between its insurance premiums and the amount currently in rates by arguing that creates a "concerning precedent" and denies PAC recovery of prudently incurred costs.[42] PAC also argues that Staff "offers no basis for its proposal".[43]

The Company addressed AWEC and CUB's recommendation to remove Schedule 80 by arguing that the ICA is meant to begin the process of futureproofing its insurance portfolio. PacifiCorp states that in 2025 the ICA would only recover costs traditionally recoverable cost items. The Company states that the creation of Schedule 80 would have two advantages over recovering insurance costs through base rates. The first is that it would allow the Commission and Company more flexibility if the insurance market becomes untenable. Second, approving Schedule 80 in this rate case would facilitate Commission approval of a self-insurance vehicle in a future proceeding.[44] Lastly, the Company disagrees with Kroger's percent of bill proposal. The

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[41] FM/100, Bieber/15.
[42] PAC/2000, McVee/40.
[43] *Id.*
[44] PAC/2300, Steward/12-14.

Company argues that nearly all of the Company's adjustment schedules in its Oregon service territory are billed on a per kWh basis. This is partially done to so that per kWh prices are non-bypassable by direct access customers.

Q. How does Staff respond to the Company's position on continuing to defer insurance premium costs?

A. Staff maintains its Opening Testimony position. The Company is proposing to introduce a docket in the near future that has the potential to radically change how its insurance costs are recovered. If the investigation into the Company's Insurance Mechanism continues past the Company's next renewal period, rates may be dramatically different than they are even this year. The same logic holds if the self-insurance mechanism is not approved. By continuing to defer the difference between the insurance costs already in base rates and those faced by the Company, the Commission can both make a decision on the Company's self-insurance proposal and the amortization of commercial insurance premiums simultaneously.

Q. How does Staff respond to the Intervenors' positions?

A. Staff is sympathetic to AWEC and CUB's proposals. Staff continues to advocate for its Opening Testimony position but prefers AWEC and CUB's position to eliminate Schedule 80 and recover actual liability insurance premiums in base rates as an alternative option. Staff agrees that a new rate schedule can be created in a future proceeding that addresses PacifiCorp's Insurance Mechanism proposal.

Staff does agree with PacifiCorp regarding Kroger's rate design proposal for the ICA.

SUMMARY

Q. Please summarize your recommendations.

A. Staff strives to balance an appropriate sharing of wildfire restoration costs and to incentivize the Company to prudently control costs. With this in mind, Staff makes the following recommendations:

- UM 2116 2020 Wildfire Restoration Cost Amortization: A 50 percent sharing of restoration costs.
- UM 2301 Wildfire Liability Cost Deferral: A 20 percent sharing of excess insurance costs. 20 percent the Company and 80 percent ratepayer.
- Insurance Cost Adjustment: PacifiCorp continue to track insurance costs in excess of the amount in base rates. Additionally, that all insurance, either commercially obtained or self-insurance, be shared 20 percent by the utility on a going forward basis

Q. Does this conclude your testimony?

A. Yes

CASE: UE 433
WITNESS: LUZ MONDRAGON, NICOLA PETERSON, and BRET STEVENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 4201

Non-Confidential Discovery in Support of Opening Testimony

August 16, 2024

Staff Data Request 279

In an Excel spreadsheet please provide the following data regarding the company's commercial liability insurance policies for each year between 2010-2023:

a. The sum of all coverage of policies taken out by the Company.
b. The cents per dollar of insurance per coverage for liability insurance.
c. The total annual premiums paid for liability insurance.
d. The deductibles for each claim.
e. The dollars paid by insurance each year.

PAC Response to Data Request 279

Please refer to Confidential Attachment OPUC 279.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.