Oregon

Tina Kotek, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

June 13, 2023

Via Electronic Filing

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

RE: Docket No. UE 416 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

Attached for filing are the following:
Exhibit 400- 412 Muldoon with Highly-Confidential
Exhibit 500-501 Chipanera with Highly-Confidential
Exhibit 600-602 Scala
Exhibit 700-702 Ahmed
Exhibit 800-802 Stevens_Young
Exhibit 900-902 Beitzel
Exhibit 1000-1104 Bolton
Exhibit 1100-1103 Dlouhy with Confidential
Exhibit 1200-1213 Farrell
Exhibit 1300-1303 Jent with Confidential
Exhibit 1400-1404 Lockwood with Confidential
Exhibit 1500-1502 Mondragon
Exhibit 1600-1603 Moore
Exhibit 1700-1702 Peng
Exhibit 1800 not included with this filing
Exhibit 1900-1909 with Confidential
Exhibit 2000-2002 Stevens with Confidential
Exhibit 2100-2115 Young with Highly-Confidential
Exhibit 2200-2201 Dloughy_Muldoon_Scala_Stevens
Exhibit 2300-2303 Ahmed_Dlouhy_Jent_Pileggi with Confidential
Exhibit 2400-2403 Nottingham_Shearer
Exhibit 2500-2501 Gorsuch
Exhibit 2600-2603 Lundquist with Confidential
Exhibit 2700-2710 Ankum_Fischer with Highly-Confidential

/s/ Kay Barnes
Oregon Public Utility Commission
(971) 375-5079
Kay.barnes@puc.oregon.gov

CERTIFICATE OF SERVICE

UE 416

I certify that I have, this day, served the foregoing document upon all parties 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, to the following parties or attorneys of parties.

Dated this 13th day of June, 2023 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

UE 416
SERVICE LIST

GUILERMO CASTILLO **(C)** SMALL BUSINESS UTILITY ADVOCATES	guillermo@utilityadvocates.org
STEVE CHRISS WALMART	stephen.chriss@wal-mart.com
TONIA L MORO **(C)** ATTORNEY AT LAW PC	106 TALENT AVE STE 6 TALENT OR 97540 tonia@toniamoro.com
BENEDIKT SPRINGER **(C)** COMMUNITY ACTION PARTNERSHIP OF OREGON	2475 CENTER ST NE SALEM OR 97301 benedikt@caporegon.org
AWEC	
BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY, SUITE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com
CORRINE OLSON **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY, STE. 450 PORTLAND OR 97201 coo@dvclaw.com
CALPINE SOLUTIONS GREGORY M. ADAMS **(C)** RICHARDSON ADAMS PLLC	515 N 27TH ST BOISE ID 83702 greg@richardsonadams.com
GREG BASS CALPINE ENERGY SOLUTIONS, LLC	401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
COMMUNITY ENERGY PROJECT	
CHARITY FAIN **(C)** COMMUNITY ENERGY PROJECT	2900 SE STARK ST STE A PORTLAND OR 97214 charity@communityenergyproject.org
CUB	

WILLIAM GEHRKE **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97206 will@oregoncub.org
MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
Share OREGON CITIZENS' UTILITY BOARD OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
FRED MEYER	
JUSTIN BIEBER **(C)** FRED MEYER/ENERGY STRATEGIES LLC	215 SOUTH STATE STREET, STE 200 SALT LAKE CITY UT 84111 jbieber@energystrat.com
KURT J BOEHM **(C)** BOEHM KURTZ & LOWRY	36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
JODY KYLER COHN BOEHM KURTZ & LOWRY	36 E SEVENTH ST STE 1510 CINCINNATI OH 45202 jkylercohn@bkllawfirm.com
NEWSUN ENERGY	
MARIE P BARLOW **(C)** NEWSUN ENERGY LLC	550 NW FRANKLIN AVE STE 408 BEND OR 97703 mbarlow@newsunenergy.net
LESLIE SCHAUER **(C)** NEWSUN ENERGY LLC	550 NW FRANKLIN AVE STE 408 BEND OR 97703 leslie@newsunenergy.net
JACOB (JAKE) STEPHENS **(C)** NEWSUN ENERGY LLC	550 NW FRANKLIN AVE STE 408 BEND OR 97703 jstephens@newsunenergy.net
NRDC	
RALPH CAVANAGH **(C)** **(HC)** NATURAL RESOURCES DEFENSE COUNCIL	111 SUTTER ST FL 20 SAN FRANCISCO CA 94104 rcavanagh@nrdc.org
CAROLINE CILEK **(C)** **(HC)** GREEN ENERGY INSTITUTE	carolinecilek@lclark.edu
NW ENERGY COALITION	
F. DIEGO RIVAS **(C)** **(HC)** NW ENERGY COALITION	1101 8TH AVE HELENA MT 59601 diego@nwenergy.org
PARSONS BEHLE & LATIMER	

JUSTINA A CAVIGLIA PARSONS BEHLE & LATIMER	50 WEST LIBERTY ST STE 750 RENO NV 89501 jcaviglia@parsonsbehle.com
PGE	
PORTLAND GENERAL ELECTRIC	pge.opuc.filings@pgn.com
KIM BURTON **(C)** **(HC)** PORTLAND GENERAL ELECTRIC	121 SW SALMON STREET PORTLAND OR 97204 kim.burton@pgn.com
JAKI FERCHLAND **(C)** **(HC)** PORTLAND GENERAL ELECTRIC	121 SW SALMON ST. 1WTC0306 PORTLAND OR 97204 jacquelyn.ferchland@pgn.com
SMALL BUSINESS UTILITY ADVOCATES	
DIANE HENKELS **(C)** SMALL BUSINESS UTILITY ADVOCATES	621 SW MORRISON ST. STE 1025 PORTLAND OR 97205 diane@utilityadvocates.org
SBUA SBUA SMALL BUSINESS UTILITY ADVOCATES	9450 SW GEMINI DR. #11200 BEAVERTON OR 97008 britt@utilityadvocates.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** Oregon Department of Justice	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@doj.state.or.us
MATTHEW MULDOON **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308-1088 matt.muldoon@puc.oregon.gov
NATASCHA SMITH **(C)** **(HC)** Oregon Department of Justice	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301 natascha.b.smith@doj.state.or.us
WALMART	
ALEX KRONAUER **(C)** WALMART	alex.kronauer@walmart.com

CASE: UE 416
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

REDACTED
OPENING TESTIMONY
Overview, Public Comments,
Overall Rate of Return, and Return on Equity

This Exhibit is Highly Confidential and Subject to Protective Order No. 23-039, and Modified Protective Order No. 23-138

You Must Have Signed Appendix B of each of the Modified Protective Order and the Protective Order to Receive the Highly Confidential Version of this Exhibit.

June 13, 2013

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 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. Please describe your educational background and work experience.

A. My witness qualifications statement is provided in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. I introduce Staff-sponsored adjustments and issues regarding the Portland General Electric Company (PGE, or Company) request for a general rate revision, docketed as Docket No. UE 416. Please refer to Exhibit No. Staff/500, the testimony of Itayi Chipanera, for additional detail about revenue, expense, and rate base components of Staff's proposed adjustments.

In addition, I articulate some of Staff's overarching concerns and summarize public comments received by the Commission in this rate case, pointing to Staff testimony where these issues are examined.

I offer a Staff proposal to apply deferred revenues in Docket No. UM 2217 from PGE's transmission rate case before the Federal Energy Regulatory Commission (FERC) as a credit to mitigate the impact of this general rate increase Docket No. UE 416 on PGE's utility Customers.

I next introduce the escalation methodology utilized by Staff to reflect inflation's impact on historical costs in projects for Test Year revenue requirement. Please also refer to Exhibit No. Staff/500, the testimony of Itayi

Chipanera, for additional detail and examples of how Staff applies its escalation methodology to specific issues in this general rate case.

Lastly, I address Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE). Further detail on Capital Structure and Cost of Long-Term (LT) Debt are found in Rose Pileggi's testimony in Exhibit Staff/1800.

Q. Will other Staff witnesses submit testimony on these same issues?

A. Yes. Each Staff assigned to Docket No. UE 416 is submitting separate and/or joint testimonies. This testimony introduces the Staff witnesses and their respective assignments and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. Staff testimony represents issues identified to date. Staff's recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits for this docket?

A. Yes. In addition to my witness qualifications statement, I prepared the following exhibits:

Other Supporting Exhibits

1. REVENUE REQUIREMENT IMPACT BY STAFF TOPIC

Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.

A. See Table 1 below:

TABLE 1 – STAFF RATE CASE TOPICS

Revenue Requirement (Rev. Req) Effects			Twelve Months Ended 12/31/24	($000)
			* PGE Requested $337.807M - (NVPV $109M Request) = M Base Cost:	$ 228,807
Testimony	**Staff**	**Issue**	**Proposed Staff Adjustments by Issue**	**Rev. Req.**
400	Muldoon	1	Revenue Requirement by Staff Topic	0
		2	Intro to Other Staff's Opening Testimony	0
		3	Key Concerns	0
		4	Summary of Public Comments Received	0
		5	UM 2217 Deferral vs. Revenue Requirement	Proposal
		6	Intro to Staff's Escalation Methodology	0
		7	Overall Rate of Return Summary	0
		8	Return on Equity (ROE) w Interest Synch.	(34,540)
500	Chipanera	1	Revenue Requirement	
		2	Overall Rate Base	
		3	Esclations on Miscellaneous Accounts	(112)
		4	Income Taxes	
600	Scala	1	Energy Justice	0
700	Ahmed	1	Schedule 125 Guidelines Update	0
		2	Extended Day Ahead Market (EDAM)	0
800	Young/Stevens	1	Accumulated Depreciation, Accumulated Deferred Tax and Depreciation Expense	0
		2	Change from average of monthly averages to year end in rate base calculation	(21,703)
900	Beitzel	1	Administrative and General (A&G) Expense Employee Health and Dental	(3,736)
		2	A&G Expense Non-Labor (NL) Memberships	Sum Above
1000	Bolton	1	Franchise Fees	0
		2	Amortization - Trojan Nuclear Decommissioning	0
1100	Dlouhy	1	Grid Modernization Adminstrative and General (A&G) Salary	(1,035)
		2	Proposed Schedule 122 Update	0
1200	Farrell	1	Uncollectible Expense	(5,473)
		2	Level III Outage Accrual Mechanism	0
		3	Research and Development (R&D)	0
1300	Jent	1	Wages & Salaries	[redacted]
		2	QF Pass Through Proposal in NVPC	0
		3	Full-Time-Equivalents (FTE)	0
		4	Generation Expenses NL	0
1400	Lockwood	1	Advertising and Marketing	0
		2	Promotional Activities and Concessions	0

Continued on Next Page

1500	Mondragon	1	Customer Service Expense - Operations and Maintenance (O&M) NL	(2,127)
		2	Customer Assistance Expense - O&M NL	0
1600	Moore	1	Non-Fuel Material and Supplies	(121)
		2	Miscellaneous Operating Revenues	(13,700)
		3	Miscellaneous Deferred Debits	0
		4	Affiliated Interest (AI) Transactions	0
1700	Peng	1	Accumulated Depreciation, Computing Licensing and Hosting Fees	0
		2	Amortization Expense	0
		3	Depreciation Reserve	0
		4	Amortization Reserve	0
		5	Allowance for Funds Used During Construction (AFUDC)	0
1800	Pileggi	1	Faraday Resiliency and Repowering Project	[redacted]
		2	Faraday Cost of Equity Adjustment	[redacted]
		3	Capital Structure	0
		4	Cost of Long-Term Debt w Interest Synchronizaton	1,214
1900	Shierman	1	Fleet Electrification - Fleet Charging	(594)
		2	Stranded Chargng Infrastructure	(146)
		3	P36394 – Vintage Vehicle Replacement, P36412 – Incremental Added Vehicles and Fleet Charging	(1,049)
		4	Line Extension (LE) Allowances	(18)
		5	Capital Expenditures on LE Allowances	(64)
		6	Capital Expenditures on Transportation Electrification (TE) Investments	(34)
		7	Capital Expenditure on Electric Island	(138)
		8	Capital Expenditure on TE Database	(11)
		9	TE Operating Expenses	(3,263)
2000	Stevens	1	Vegetation Management	[redacted]
2100	Young	1	Transmission and Distribution (T&D) Plant, Non Information Technology (IT)	(2,887)
		2	OH FITNES, T&D Plant	(2,053)
		3	T&D Plant, IT / Cloud Expenses	(712)
2200	Dlouhy/Muldoon/ Scala/Stevens	1	Role of Automatic Adjustment Clauses (AAC)	0
		2	The Need for Deferrals with AACs	0
2300	Ahmed/Dlouhy/ Jent/Pileggi	1	Power Cost Adjustment Mechanism (PCAM) Changes	0
2400	Nottingham/ Schearer	1	Changes to Schedules, Rules, Regulations	0
2500	Gorsuch	1	Physical Security	0
		2	Service Quality Measures (SQM)	0
2600	Lundquist	1	Cyber Security	0
2700	Ankum/Fischer	1	Plant Additions (Other than Faraday Repowering Project, Cyber-Security IT)	0
		2	Fuel Stock (Major only)	(1,497)
		3	Maintenance of Generation and Electric Plant	(1,050)
		4	Major Maintenance Accruals (MMA) Deferral Balance Adjustment+F13:F46	8
		5	CO_2 Allowances	0
Staff-Proposed Base Cost Adjustments (Excluding NVPC adjustments)				[redacted]
Base Cost Revenue Requirement (after Staff-Proposed Adjustments)				[redacted]
NVPC Revenue Requirements (after Staff Adjustments) **				[redacted]
Total Revenue Requirement (After Staff Base Cost and NVPAC Adjustments)				[redacted]

* ** Staff/100 Jent, Staff 200 Dlouhy, Staff 300 Ahmed proposed a additional $10.521M reduction to NVPC.

2. INTRODUCTION TO OTHER STAFF'S OPENING TESTIMONY

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

A. Following a brief recap of the Staff's earlier published Net Variable Power Cost (NVPC) testimony, the Staff exhibit number, respective Staff witness, and topic published on this date are presented below.

Recap of Staff NVPC Opening Testimony published on May 24, 2023:

In Exhibit 100, Julie Jent, Senior Economist, provides an overview of PGE's Annual Update Tariff (AUT) and discusses trading margin refinement at the California Oregon Border (COB).

In Exhibit 200, Dr. Ishraq Ahmed Ph.D., Senior Utility Analyst, reviews PGE's interactions with Washington State's Cap and Invest Program.

In Exhibit 300, Dr. Curtis Dlouhy, Ph.D., Economist and Senior Utility Analyst, discusses PGE's gas resale, storage, and optimization model updates, as well as a gas physical call option contract. Further, Dr. Dlouhy reviews PGE's capacity planning.

Topics addressed in Opening Testimony published June 13, 2023:

In Exhibit 500, Itayi Chipanera, Senior Financial Analyst, discusses revenue requirement, overall rate base, Staff escalation adjustments, and income taxes.

In Exhibit 600, Michell Scala, Energy Justice Program Manager, provides an Energy Justice overview for this general rate case and discusses five energy justice foci.

In Exhibit 700, Dr. Ahmed analyzes PGE's proposed modifications to Schedule 125 guidelines to include NVPC forecast modeling enhancements in non-general rate case (GRC) years. In addition, Dr. Ahmed discusses impacts on customer rates from PGE compliance with requirements to participate in the Extended Day Ahead Market (EDAM).

In Exhibit 800 Joint Testimony, Dr. Bret Stevens, Ph.D., Senior Economist, and **Robert Young**, Managing Director, of economists.com**,** discuss the use of the average of monthly averages in calculations of test year rate base.

In Exhibit 900, Russ Beitzel, Senior Utility Analyst, reviews Administrative and General (A&G) Expenses – Non-Labor (NL).

In Exhibit 1000, Madison Bolton, Senior Energy and Policy Analyst, examines the Trojan Nuclear Decommissioning Trust (NDT), and unbundling and franchise fees.

In Exhibit 1100, Dr. Dlouhy analyzes reviews Grid Modernization Operations and Maintenance (O&M), and a proposed Schedule 122 update.

In Exhibit 1200, Bret Farrell, Senior Utility and Energy Analyst, reviews PGE's proposals for uncollectible expense, Level III Outage Accrual Mechanism expense, and research and development (R&D) expense.

In Exhibit 1300, Julie Jent reviews PGE's Qualifying Facility (QF) pass through proposal for Net Variable Power Costs (NVPC), the Company's total compensation and Full Time Equivalents (FTE), as well as generation expenses – non-labor (NL).

In Exhibit 1400, Charles Lockwood, Utility Analyst, analyzes expense for advertising and marketing, and promotional activities and concessions.

In Exhibit 1500, Luz Mondragon, Senior Financial Analyst, reviews non-labor (NL) customer service and related information and sales expenses.

In Exhibit 1600, Mitch Moore, Senior Economist, analyzes miscellaneous operating revenue, non-fuel materials and supplies, deferred debits, and affiliated transactions.

In Exhibit 1700, Ming Peng, Senior Economist, analyzes depreciation expense, amortization expense, depreciation reserve, amortization reserve, and Allowance for Funds Used During Construction (AFUDC).

In Exhibit 1800, Rose Pileggi, Senior Utility Analyst, analyzes PGE's capital structure and cost of long-term (LT) debt, and the Company's investment and management of PGE's Faraday Repowering Project.

In Exhibit 1900, Eric Shierman, Senior Utility Analyst, examines fleet electrification – breaking out new fleet electrification, line extension (LE) allowances – also separately considering new LE allowances and prior rate case Docket No. UE 394, Order No. 19-385 budget violations. Mr. Shierman also considers UE 394 Electric Island issues, transportation electrification (TE) database, and TE operational expenses, as well as stranded charging infrastructure.

In Exhibit 2000, Dr. Stevens analyzes PGE's load forecast, routine vegetation management, marginal cost study and rate spread, and rate design.

In Exhibit 2100, Mr. Young examines transmission and distribution (T&D) plant additions and information technology (IT) issues – focusing on cloud computing.

In Exhibit 2200 Joint Testimony, Dr. Dlouhy, Mr. Muldoon, **Ms. Scala,** and **Mr. Stevens** consider the role of Automatic Adjustment Clauses (AAC) in energy utility regulation and the need for deferrals for AACs.

In Exhibit 2300 Joint Testimony, Dr. Ahmed, Dr. Dlouhy, **Ms. Jent,** and **Ms. Pileggi** discuss PGE's proposed changes to its Power Cost Adjustment Mechanism (PCAM).

In Exhibit 2400 Joint Testimony, Melissa Nottingham, Consumer Services and Residential Service Protection Fund (RSPF) Manager, and **Scott Shearer**, Analyst, discuss Schedule 300 billing rates, submersible transformers, and Reconnection Fees.

In Exhibit 2500 Joint Testimony, Lisa Gorsuch, Emergency Preparedness Manager, discuss Service Quality Measures (SQM) and physical security.

In Exhibit 2600 Scott Lundquist, Consultant of **QSI Consulting, Inc**, examines PGE's cyber security.

In Exhibit 2700 Joint Testimony, August Ankum, Chief Economist, and **Warren R. Fisher**, Chief Financial Officer (CFO), both with **QSI Consulting, Inc**, discuss PGE's Major Maintenance Accrual Mechanism (MMA), Fuel Stock, CO2 issues and plant additions (other than T&D, Faraday, and certain IT investments).

3. KEY CONCERNS

Q. Are there any issues that appear in the case that you would like to highlight?

A. Yes. Staff is concerned that the aggregate rate impacts of this general rate case, deferrals, and power costs may constitute rate shock for PGE's Oregon utility customers outpacing Oregon wages.[1] Further, the U.S. Federal Reserve (Fed) is tightening monetary policy to control high inflation.[2] This increases the cost of borrowing for utility rate payers as well as the cost of debt for utilities.

Q. Please show the approximate impact on residential customer rates were PGE's rate increase implemented as requested.

A. Staff cautions that it is still early in this proceeding and the following depiction reflects a point estimate just prior to this testimony:

Table 2

	Current	Residential Avg. Bill $/Mo.		
	Single Family	$ 141.65		
	Multi-Family	$ 95.35		
PGE Proposed	**Jan. 1, 2024 Increase**	**Scenario if increase were $338 M***		
With Power Costs	**$338 Million***	**$/Mo.**	**Increase $/Mo**	**% Increase**
Single Family		$ 164.12	$ 22.47	15.90%
Multi-Family		$ 110.92	$ 15.57	16.30%

* After errata, requested increase is about $340M, early in rate case

1 See Exhibit Staff/409 Muldoon/5, /14, /17, /26, /40, /50, /55, /59, and /70 for the inflation customers are experiencing.

2 See Exhibit Staff/409 Muldoon/7, /10, /32, and /72 for Fed activity on interest rates.

This information does not yet reflect recommendations offered by Staff and intervenors for Commission consideration, which if adopted, would reduce the impact of PGE's proposed rate increase.

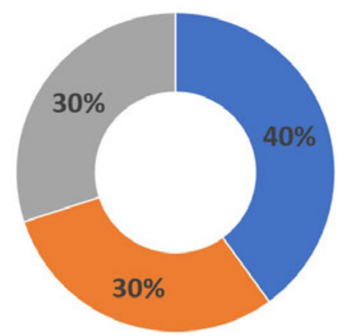
Q. What does PGE identify as key cost drivers when describing this rate case to investors and analysts?

A. With the caution that this is at a very general level, PGE indicates that capital investments represent about 40 percent, or about $135 million, purchased natural gas and electricity represent about 30 percent, and higher operations and maintenance costs also represent about 30 percent of the overall increase in this general rate case.

Staff's testimony will go into greater detail.

Table 3

Cost Driver	%
Capital Investments	**40%**
Cost of Purchased Natural Gas and Electricity	**30%**
Higher Operations and Maintenance Costs (Inflation)	**30%**



Driver	PGE Revenue Requirement Impact
Capital Projects (Examples Below) Current Rate Base $6.3 Billion PGE Proposed Increase $859 Million +16%	$135 Million
Example: **Faraday Dam Repowering Project** (Clackamas River) in service	
Example: **Transmission & Distribution** T&D Improvements	
Higher Operations and Maintenance Costs	$100 Million
Cost of Purchased Natural Gas & Electricity	$100 Million
Total Approximately	$335 Million

CAPITAL PROJECT MANAGEMENT

Q. Please describe any concerns Staff has with PGE's proposed capital project management.

A. Historically, Staff has viewed PGE as focused on efficient capital project management with strict attention applied to control of cost and risk, while applying best financial and operational practices. However, in this case Staff is concerned that PGE is not exercising the same level of risk and cost management.

Q. Can you provide examples of where PGE managed cost and risk in prior projects?

A. When building its 440 MW Carty gas fired Generation Station, PGE had performance guarantees from its primary contractor, a unit of Abengoa, S.A. and reinforced those obligations with insurance. When Abengoa filed for bankruptcy and stopped work on December 14, 2022, PGE had to assume responsibility for engineering, procurement, and construction (EPC). Because PGE had proactively controlled risk well, and forced insurance to pay out, the Company and its Oregon utility ratepayers were protected from much of the cost impact of the Abengoa bankruptcy.

Another example is PGE's use of turn-key contracts is when it installed 12 reciprocating internal combustion engines at Port Westward. On January 21, 2014, one of these power plant engines tumbled off the truck as contractors were preparing rigging to install the reciprocating engine at Unit 2. The primary contractor and subcontractors were responsible for cost and logistics of installing a replacement engine. Again PGE proactively took actions to control cost and risk.

Q. What is different about PGE's management of capital projects for which the Company is seeking cost recovery in this general rate case?

A. In Staff/1800, Rose Pileggi discusses the Faraday Dam Repowering Project. Because those details include highly confidential information, they are not duplicated herein. However, Staff is concerned that PGE did not apply the same good management practices described above in the planning and oversight of the Faraday Repowering Project.

Q. Do public comments received by the Commission mirror Staff's concerns described above?

A. Yes. The next section of this testimony summarizes public comments, which also express concern about the frequency and magnitude of PGE's general rate increases, and question whether PGE is managing cost and risk appropriately. The testimony offered by Robert Young also discusses the lack of PGE's use of software packages typically used by utilities to track capital projects and the rapid growth in planned spending for transmission and distribution projects without considering alternatives that may be less costly and if not controlled will further cause pressures on the Company to continue raising rates.

CALCULATION OF TEST YEAR RATE BASE

Q. Please describe any concerns Staff's has regarding the test year rate base calculations.

A. Staff is concerned with the change in rate base value from the average-of monthly-test-period-averages to beginning-of-test-period. In Staff/800, Dr. Stevens and Mr. Young's testimony raises a significant issue that involves over $20 million in revenue requirement from a ratemaking change that occurred in a 2014 where rate base value was changed from the average-of monthly-test-period-averages to beginning-of-test-period. The Commission has supported the average-of-monthly-averages for decades, and yet PGE made this substantive change with no testimony or briefing. The order adopting rate base calculated with a beginning-of-test period method was based on a stipulated resolution of issues, as were each of the orders for PGE's rate cases since that time.

Staff strongly supports reverting to the average-of-monthly-averages in this general rate case, as it represents the average rate base value over the test period when rates are in effect. Otherwise, customers are paying for depreciation in rates without those payments being reflected in rate base. Consequently, there is no corresponding benefit for having paid for depreciation during the test period.

4. SUMMARY OF PUBLIC COMMENTS RECEIVED

Q. Please summarize the public comments received to date in this rate case.

A. In addition to public comments received at the Commission's Hearing on the evening of May 3, 2023, the OPUC has received 196 other public comments regarding this general rate case as of May 19, 2023. These comments demonstrate that PGE's residential and small business customers are very concerned about the large size of the increase. Many residential customers who are working and on fixed incomes, or of limited means worry about energy utility increases outpacing their income and express concerns about having to balance paying for utilities, shelter, medications, food, and other essentials. As an example, commenter Matthew Hale shared that, according to a U.S. Federal Reserve study released this May, American families did worse financially last year than they did the year before. Most persons offering public comments urge the Commission to reduce the pace and size of PGE's rate increases where possible.

TABLE 4 – PRIMARY CONCERNS

Size of Increase	Investors' Share of Risk and Costs	Green & Sustainable Service	Cost Control Needed at PGE
1st	2nd	3rd	4th

Certain public comments provided insights into energy justice challenges utility customers are facing. Michelle Scala will address these in her Staff/600 testimony including conflicts between apartments that charge tenants a fixed utilities charges each month, even though some low-income tenants could qualify for PGE's bill discount program.

Commenters are also concerned whether utility customers are picking up risks and costs that commenters feel previously were more evenly split between investors and customers. Staff opening testimony addresses the concern that PGE's proposals seeking more certainty and faster cost recovery for the Company can leave PGE's utility customers carrying a higher than historical share of risk and costs. Prudent management on the Company's part is necessary to control cost and risk to achieve favorable cash flows to the firm.

Commenters also urge the Commission to "reign in PGE officers' pay and benefits to incentivize senior management to control costs and associated utility rates". A common theme is commenters noting that customers must live within their means and asking the Commission to see that PGE does as well – through controlling expenses and the pace of new spending. Commenters say they understand that there is a need for modest amounts of construction but ask whether the rate of increase in PGE's new capital costs is excessive. A few commenters suggest that without PGE controlling its own costs, PGE should become a government run utility.

Both small businesses and residential customers are also concerned that they do not subsidize other classes of customers. Dr. Stevens in Exhibit Staff/2000 explains how he works to develop a fair and equitable rate spread and rate design that incorporates cost causation principles while addressing commenters' concerns. The owners of Café Zamora also shared that small

Oregon businesses like themselves with limited liquidity are struggling to keep the doors open, and don't have the resources of large corporations to ride out an economic downturn.

Commenters expected solar and wind power to help control rates by avoiding purchases of natural gas and electricity on the market. Staff appreciate these questions and Staff's power cost team is looking into these issues.

Commenters practicing conservation and using less electricity also asked why they were not seeing lower rates. In this scenario, the total bill for electricity will go down. But the price of electricity could go up. That is generally how conservation works rates wise and why the OPUC, years ago, rejected a rate impact test for conservation. Those who do not take advantage of conservation opportunities (non-participants) will see their total bill go up.

Several commenters also asked whether the Commission was acting effectively to limit the City of Portland and Multnomah County growing utility taxes and fees shifting unrelated maintenance and social services costs to utility ratepayers.

Participants in the May 3 Commission Public Comment Hearing were interested in how low-income renters could access solar power without the responsibility for repairs and maintenance of solar panels. To learn more about the **Oregon Community Solar Program**, including how low-income renters can participate, please visit www.oregoncsp.org.

Finally, some commenters suggested that the Commission ask utilities to post upcoming Commission Public Comment Hearings on utility bills so that customers are aware of opportunities to provide feedback out, or to put an insert in bills that highlights when and how to participate. One commenter also shared that it would be helpful for the Commission to provide a link to the Commission's webpage showing filings for a general rate case on the notice for Public Comment Hearings

Q. Please explain the reasoning behind the inclusion of public comments in Staff's testimony.

A. Consistent with the Commission's Internal Operating Guidelines adopted in Order No. 20-065 in Docket No. UM 2055, in order to provide more transparency about the public comments in contested cases, public comments received are now made part of the Staff's Opening Testimony.

The Commission will post a link or instructions on how the public can see all public comments received, as well as the public comments from the edited transcript for the Public Informational Hearing on Tuesday, May 3, 2023, at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23617.

Written comments received after preparation of Staff's Opening Testimony will be included in subsequent Staff testimony. However, Staff will not be able to testify regarding comments received after Staff prepares its final round of UE 416 testimony.

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. Does Staff Opening Testimony address comments received?

A. Yes.

5. USE OF UM 2217 DEFERRAL TO REDUCE REVENUE REQUIREMENT

Q. Has Staff considered how PGE might reduce the rate shock when rates likely increase in January 2024, following a Commission decision in this general rate case?

A. Yes. Staff analyzed how deferred balances might be used to reduce rate shock. To that end, Staff asked PGE to provide the Company's best estimate of the dollar value of PGE's deferral as authorized in Docket No. UM 2217, by month from January 1, 2023, through December 31, 2023, considering interest thereon.[3] PGE returned the following table in the Company's response.

Table 5

PGE UE 2217 TRC Revenue Deferral					
Month	Year	Accrual / Deferral	Amortization	Interest on Avg Balance	Balance
January	2022	-		.	-
February	2022	(846,919.95)		(642.25)	(847,562.20)
March	2022	(770,524.15)		(1,869.78)	(1,619,956.13)
April	2022	(820,042.68)		(3,078.80)	(2,443,077.61)
May	2022	(875,391.61)		(4,369.17)	(3,322,838.39)
June	2022	(567,551.00)		(5,470.03)	(3,895,859.42)
July	2022	(435,523.25)		(6,238.99)	(4,337,621.66)
August	2022	(613,057.66)		(7,043.63)	(4,957,722.95)
September	2022	(810,774.60)		(8,134.05)	(5,776,631.60)
October	2022	(781,071.77)		(9,353.54)	(6,567,056.91)
November	2022	(648,409.82)		(10,451.75)	(7,225,918.48)
December	2022	(754,955.84)		(11,531.82)	(7,992,406.14)
January	2023	(1,328,236.47)		(37,006.64)	(9,357,649.25)
February	2023	(780,171.70)		(41,671.57)	(10,179,492.52)
March	2023	(544,248.72)		(44,680.66)	(10,768,421.90)
April	2023	(569,201.39)		(47,251.67)	(11,384,874.96)
May (Estimated)	2023	(755,491.37)		(50,285.20)	(12,190,651.53)
June (Estimated)	2023	(755,491.37)		(53,729.90)	(12,999,872.80)
July (Estimated)	2023	(755,491.37)		(57,189.32)	(13,812,553.49)
August (Estimated)	2023	(755,491.37)		(60,663.53)	(14,628,708.39)
September (Estimated)	2023	(755,491.37)		(64,152.59)	(15,448,352.35)
October (Estimated)	2023	(755,491.37)		(67,656.57)	(16,271,500.29)
November (Estimated)	2023	(755,491.37)		(71,175.53)	(17,098,167.19)
December (Estimated)	2023	(755,491.37)		(74,709.53)	(17,928,368.09)

[3] PGE provided this information in in response to Staff Data Requests (DR) 785 and 786. See Exhibit No. Staff/41**X for PGE's response to these DRs.**

The table above provides actual amounts deferred from February 2022 through April 2023 and a monthly estimate from May 2023 through December 2023. PGE notes that May 2023 through December 2023 are rough estimates and that actual amounts will change.

Q. How could the deferral balance in UM 2217 reduce rate shock?

A. Staff looked at applying the deferral balance as a credit towards the revenue requirement in this rate case. PGE indicates that assuming an amortization period of one year and using the 2023 blended treasury rate, the estimated December 31, 2023, deferred balance provided in in the table above would reduce PGE's 2024 test year request by $18,391,138 for one year. Staff is considering whether this deferral should be credited to customers over a one-year or two-year period.

Staff cautions that both Staff and PGE are making assumptions to generate estimates for deferred account future values, and that actual numbers will change.

Q. Is this the best or only way to utilize funds represented above or to reduce the rate impact of an increase in rates January 1, 2024?

A. No. Staff invites PGE and intervenors to consider these questions and in subsequent testimony to offer their innovation suggestions on how best to mitigate what may be one of PGE's largest ever general rate increases.

6. STAFF ESCALATION METHODOLOGY

Q. Please introduce Staff's escalation methodology for this rate case.

A. First, Staff's escalation methodology excludes wages and salaries, these rely on a different Commission preferred approach. In this rate case, Staff relies on U.S. All Urban Consumer Price Index (CPI) information, using the following three steps.

1. For July thru December 2022, Staff escalates actual data by 1.5 percent based on the U.S. Bureau of Labor Statistics (BLS) (Seasonally Adjusted Monthly Data).
2. Then for January thru December 2023, Staff relies on the 3.9 percent CPI projected by the OR Dept Econ Analysis Pg 44 March 2023 Release.
3. Finally for January through June 2024, Staff uses 1.1 percent CPI, representing half of projected OR Dept Econ Analysis Pg 44 March Release for 2024.

Q. What is the overall escalation from mid-year 2022 through mid-year 2024?

A. Staff's aggregate escalation is 6.6 percent.

Q. Why does Staff escalate to the middle of the 2024 test year?

A. PGE will make utility purchases and expenditures throughout 2024. Using the midpoint of 2024 avoids over-escalation from presuming that PGE will make all purchases in 2024 on the last day of the calendar year. For example, some of PGE's expenditures will be made in January 2024. In addition, we are basing the overall escalation rate on the amount of inflation from the mid-year of 2022 through the mid-year of 2024 to reflect the average amount over the test period. We note that PGE in most cases bases its 2024 forecasts by taking 2022 budgets and escalating those to 2024 values.

Please see Staff/500 for Itayi Chipanera's examples of Staff escalations.

7. OVERALL RATE OF RETURN (ROR)

Q. Did you prepare tables showing PGE's current Commission-authorized, Company-proposed, and Staff-calculated RORs?

A. Yes. The following three tables provide that information.

TABLE 6

PGE Current OPUC Authorized (UE 394 Order Nos. 22-129)			PGE
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	50%	4.125%	2.063%
Preferred Stock	0%	0.0%	0.000%
Common Stock	50%	9.50%	4.750%
100%			**6.813%**

TABLE 7[4]

PGE Requested – UE 416		PGE Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	50%	**4.317%**	2.159%	**0.246%**
Preferred Stock	0%	0.0%	0.000%	
Common Stock	50%	**9.80%**	4.900%	
100%			**7.059%**	

TABLE 8

Staff Proposed – UE 416		Staff Opening Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	50%	**4.293%**	2.147%	**-0.166%**
Preferred Stock	0%	0.0%	0.000%	
Common Stock	50%	**9.00%**	4.500%	
100%			**6.647%**	

Note: See Staff/1800 for Staff's analysis of PGE's Cost of Long-Term (LT) Debt.

4 See PGE/1000, Liddle-Villadsen/2.

CAPITAL STRUCTURE

Q. Has the Commission recently considered a preferred target capital structure?

A. Yes. In Order No. 20-473 at 24, the Commission adopted a notional 50 percent equity capital structure: "We consider all components to the company's cost of capital that will result in a fair and reasonable rate of return, 'to strike a balance between the interests of ratepayers and the interests of investors.'"

Q. What are the currently authorized capital structures of the other five Commission jurisdictional energy IOUs?

A. All five are within 10 basis points (bps) of a 50 percent Equity and 50 percent Long-Term Debt Capital Structure. See below for their equity layers.[5]

AVA	CNG	IPC	NWN	PAC
50.0 %	50.0 %	49.9 %	50.0 %	49.9 %

Q. Does PGE target a 50 percent Common Equity / 50 percent LT Debt capital structure?

A. Yes. Both Staff and PGE recommend the Commission authorize a PGE capital structure with a balanced 50 percent equity layer as described further in Staff/1800.

5 Avista Corp. (AVA); Cascade Natural Gas (CNG); Idaho Power Company (IPC); Northwest Natural Gas (NWN) and PGE (PAC).

8. RETURN ON EQUITY (ROE)

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

A. Staff recommends a **point ROE** estimate of **9.0 percent** within a range of reasonable ROEs of 8.83 percent to 9.10 percent derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models. The Commission has traditionally relied on the Three-Stage DCF models for its authorized ROE decisions.

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. A Single-Stage DCF or Gordon Growth Model; and,
2. A Capital Asset Pricing Model (CAPM).

Q. What results did these models generate?

A. The Gordon Growth Model generated a mean ROE of 8.8 percent using Staff's peer electric utilities and 8.5 percent with the Company's peer electric utilities.

The CAPM generated a mean ROE of 9.1 percent using Staff's peer electric utilities and 9.1 percent as well with the Company's peer electric utilities.

Based on these conflicting checks, one pointing to top of range and one pointing to bottom of range, Staff finds that the point estimate for ROE in Staff's range of reasonable ROEs generated by its two separate Three-Stage DCF models should be near the top of modeling results reflective of the above checks on reasonableness.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.0 percent ROE 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 Oregon Revised Statute (ORS) 756.040.[6] Staff 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."[7]

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate PGE's ROE?

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

1. Covered by Value Line (VL) as an electric utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating from A1 to Baa2 inclusive from Moody's and from A to BBB- inclusive from S&P;

---

6 *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).

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

4. No decline in annual dividend in last five years based on VL;
5. Has heavily regulated electric utility revenue;
6. Has LT Debt from 45 percent to 55 percent inclusive in VL Capital Structure; and[8]
7. Has no recent merger and acquisition activity.

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

A. The Company and Staff recommended regulated electric utility peer groups both drew from pertinent electric utilities covered by VL. In Staff Exhibit 402, Page 2, Staff flags electric utilities not selected due to merger activity as it shows how each element of its screening was applied. Table 9 shows a fair amount of overlap between PGE's and Staff's peer groups.

Q. Did the Company apply some different criteria?

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

[8] 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.

TABLE 9[9]

Abbreviated Utility	UE 416 PGE	UE 416 Staff
Allete	Yes	No
Alliant	Yes	Yes
Ameren	Yes	Yes
AEP	Yes	No
Avista	Yes	Yes
Black Hills	Yes	No
CenterPoint	Yes	No
CMS	Yes	No
Consol Ed	No	Yes
Dominion	Yes	No
Duke	Yes	No
Edison Int'l	Yes	No
Entergy	Yes	No
Evergy	Yes	Yes
Eversource	No	Yes
Exelon	Yes	No
IDACORP	Yes	Yes
MGE	Yes	No
NextEra	Yes	No
NorthWestern	Yes	Yes
OGE	Yes	Yes
Otter Tail	Yes	No
Pinnacle	Yes	Yes
Public Serv.	Yes	No
Sempra	Yes	Yes
Southern	Yes	No
WEC	Yes	Yes
Xcel	Yes	No
No. of Peers:	**26**	**12**

A comparison of the peer groups used by Staff and PGE are set forth in Table 9 above. Staff excluded sixteen of the companies used by PGE based

9 See Exhibit Staff 102, Muldoon/2 for the full peer screening table.

on its screening criteria described above. PGE excludes two of the companies used by Staff. Ten companies were relied upon by both Staff and PGE.

Q. Are there some elements of PGE's peer screening that Staff does not agree with.

A. Yes. For example, PGE comparable utilities for modeling purposes need only have an investment grade credit rating.[10] In contrast, Staff requires credit ratings within two notches of PGE's S&P or Moody's credit ratings as a criteria for inclusion in Staff's peer group. Presuming investors require a higher return over time for holding riskier stocks as determined by credit ratings, PGE's method would select riskier peer utilities than PGE, which would inflate modeling returns. Instead Staff tries to select peer utilities most like PGE, including consideration of PGE's credit ratings.

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

A. See Table 10 below for the results from Staff's three stage DCF modeling.

TABLE 10 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[11]

Best Fit Range of Reasonable ROEs	8.70%	**to**	8.97%	**ROE**	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				**12.5**	bps
	8.83%	**to**	9.10%	**ROE**	
	Midpoint	9.0%	**ROE**	**Testimony**	
Staff Point ROE Recommendation:		**9.0%**			

CAPM and Single Stage DCF point to top and bottom respectively of Staff's Three Stage DCF Modeling Results

Supporting Exhibit Staff/404, Muldoon/1 shows step-by-step how Staff's Hamada adjusted Three-Stage DCF modeling results, using Staff peers and growth rates, generates a higher recommended ROE than using PGE's peer electric utility group.

---

10 See PGE/1000, Liddle-Villadsen/52.
11 See Exhibit Staff/404, Muldoon/1 for the results of Staff three-stage DCF modeling.

Q. Does Staff Agree with PGE's assertion that the Company's requested ROE of 9.8 percent is reasonable?

A. No. Averaging its Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), and Risk Premium, PGE comes up with an average range of 9.7 percent to 10.4 percent with a midpoint of 10 percent.[12] Then PGE suggests that its requested point ROE of 9.8 percent is reasonable. PGE inflates its results while averaging in modeling results from CAPM, and Single Stage DCF that the Commission accepts only as checks on recommendations. Further PGE uses extreme or unreasonable inputs which push modeling results upward.

Q. Please provide an example of an extreme input used in PGE's modeling.

A. In its CAPM modeling PGE overstates its market risk premium estimate.

Example 1 – NOT a Staff Recommendation:

PGE	4.05%	Rf Rate as shown in Exhibit PGE/1000 PGE Staff Liddle - Villadsen/56 -- Top Current Table	
Direct	11.51%	Mkt Return as shown in Exhibit PGE/1000 PGE Staff Liddle - Villadsen/61 -- Top Current Table	
Testimony	7.46%	PGE Mkt Risk Premium (MRP)	
Staff	3.961%	R_f May 26, 2023 30-Yr UST Yield /WSJ	www.wsj.com/market-data/bonds
	9.75%	30-Year S&P 500 Proxy Market Return	Geometric Return
	5.79%	Staff 30-Yr Mkt Risk Premium (MRP)	
	3.806%	R_f May 26, 2023 10-Yr UST Yield /WSJ	www.wsj.com/market-data/bonds
	10.41%	10-Year S&P 500 Proxy Market Return	Geometric Return
	6.60%	Staff 10-Yr Mkt Risk Premium (MRP)	

Note that PGE does not identify its "extreme" market risk premiums as such.

[12] See PGE/1000 Liddle-Villadsen 61.

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

Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	LT Debt UE 416 Sensitivity	Ticker	VL Q4 2022 Beta	Staff MRP 30 Yr ROE w VL Beta CAPM	Staff MRP 10 Yr ROE w VL Beta CAPM	PGE MRP PGE/1000 ROE w VL Beta CAPM
1	Allete	Yes	No	No	ALE	0.90	9.17%	9.75%	10.76%
2	Alliant	Yes	Yes	Yes	LNT	0.85	8.88%	9.42%	10.39%
3	Ameren	Yes	Yes	Yes	AEE	0.85	8.88%	9.42%	10.39%
4	AEP	Yes	No	Yes	AEP	0.75	8.30%	8.76%	9.65%
6	Avista	Yes	Yes	Yes	AVA	0.90	9.17%	9.75%	10.76%
7	Black Hills	Yes	No	Yes	BKH	0.95	9.46%	10.08%	11.14%
8	CenterPoint	Yes	No	No	CNP	1.10	10.33%	11.07%	12.26%
9	CMS	Yes	No	No	CMS	0.80	8.59%	9.09%	10.02%
10	Consol Ed	No	Yes	Yes	ED	0.75	8.30%	8.76%	9.65%
11	Dominion	Yes	No	No	D	0.85	8.88%	9.42%	10.39%
13	Duke	Yes	No	Yes	DUK	0.85	8.88%	9.42%	10.39%
14	Edison Int'l	Yes	No	No	EIX	0.95	9.46%	10.08%	11.14%
15	Entergy	Yes	No	No	ETR	0.95	9.46%	10.08%	11.14%
16	Evergy	Yes	Yes	Yes	EVRG	0.90	9.17%	9.75%	10.76%
17	Eversource	No	Yes	Yes	ES	0.90	9.17%	9.75%	10.76%
18	Exelon	Yes	No	No	EXC	0.95	9.46%	10.08%	11.14%
22	IDACORP	Yes	Yes	Yes	IDA	0.80	8.59%	9.09%	10.02%
23	MGE	Yes	No	No	MGEE	0.75	8.30%	8.76%	9.65%
24	NextEra	Yes	No	No	NEE	0.90	9.17%	9.75%	10.76%
25	NorthWestern	Yes	Yes	Yes	NWE	0.90	9.17%	9.75%	10.76%
26	OGE	Yes	Yes	Yes	OGE	1.00	9.75%	10.41%	11.51%
27	Otter Tail	Yes	No	Yes	OTTR	0.85	8.88%	9.42%	10.39%
30	Pinnacle	Yes	Yes	Yes	PNW	0.90	9.17%	9.75%	10.76%
33	Public Serv.	Yes	No	No	PEG	0.90	9.17%	9.75%	10.76%
34	Sempra	Yes	Yes	Yes	SRE	0.95	9.46%	10.08%	11.14%
35	Southern	Yes	No	No	SRE	0.95	9.46%	10.08%	11.14%
36	WEC	Yes	Yes	Yes	SO	0.95	9.46%	10.08%	11.14%
37	Xcel	Yes	No	Yes	WEC	0.80	8.59%	9.09%	10.02%
	No. of Peers:	26	12	17			VL Betas	VL Betas	VL Betas
				Company Screen		Mean	9.1%	9.7%	10.7%
				Staff Screen		Mean	9.1%	9.7%	10.7%
				Staff Sensitivity Screen		Mean	9.0%	9.6%	10.6%

Above is an example of how PGE generates ROE modeling results above average authorized electric utility ROEs over the last 12 months.

Staff usually relies on a U.S. Treasury (UST) thirty-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 of 11.5% (from 1926 to 2023) generating a 7.46% risk premium,** one can inflate the results of a CAPM model with few inputs[13] to **an extreme result of 10.70 percent**, which is a **full percent above average authorized ROEs** in rates cases across the U.S. over the last year.

[13] See PGE/1000, Liddle-Villadsen where PGE uses the yield on a 20-year U.S. Government Bond as a modeling risk-free rate for purposes of the Company's analysis.

Q. Is calculation of a market risk premium calculated from 1926-2003 a good predictor of future U.S. stock returns?

A. No. Since returns over the last thirty years are lower than those experienced earlier in PGE's date range, which includes post-World-War II economic expansion in the U.S, expectations should mirror the recent 30 years returns. According to Ibbotson, reliance on a date range like PGE's would overstate likely future market returns.[14] The combination of a 20-year UST as a risk-free rate and a very long (almost 100-year) arithmetic market return is an odd choice, which Staff notes inflates PGE's CAPM output.

Q. Is Staff suggesting that CAPM is not a good model to check results of other modeling Staff performs, as advised by the Commission?

A. No. Rather, Staff shows why the Commission accepts CAPM only as a check on ROE modeling and demonstrates how one can abuse the model. If one eliminates unreasonable modeling inputs, selects only peer electric utilities most like PGE using Staff's standard screening methods, and eliminates the Company's Risk Premium Modeling, you arrive at a result equal to Staff's ROE recommendations.[15]

According to Regulatory Research Associates (RRA), an affiliate of S&P, the average ROE authorized for electric utilities rose to 9.54 percent for rate cases decided in 2022 from the 9.38 percent average for cases decided in

[14] See "The Equity Risk Premium" by William N. Goetzmann and Roger G. Ibbotson available on Amazon.com.

[15] Exhibits Staff/402 – /406 show how Staff's recommendations are generated.

2021.[16] PGE's recommendations do not seem to have any correlation whatsoever to prevailing state commission decisions regarding authorized ROE in rate case decisions in the last year.[17]

GROWTH RATES USED IN THIRD STAGE OF DCF MODELS[18,19]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[20,21]

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

The first method uses the U.S. Congressional Budget Office's (CBO) 4.05 percent nominal 20-year GDP growth rate estimate.

Staff's second Composite Growth Rate applies a 50 percent weight to the average annual growth rate resulting from estimates of long-term GDP by the U.S. Energy Information Administration (EIA), the Organization for Economic Co-operation and Development (OECD), the U.S. Social Security Administration (SSA), and the Congressional Budget Office's (CBO), with each

---

16 See Exhibit Staff/409, Muldoon for "Average Authorized ROEs in 2022" by Lisa Fontanella, RRA.

17 The ROE determinations authorized by state public utility commissions for electric utilities in 2022 ranged from 7.85% to 10.80%, with an average of 9.54% and a median of 9.50%, according to Regulatory Research Associates (RRA) an affiliate of S&P Global Market Intelligence. CIQ Pro: RRA Regulatory Focus: Electric authorized ROEs rebound in 2022 as interest rates bounce higher (spglobal.com)

18 See Exhibit Staff/406, Muldoon1 for BEA historical GDP growth rates.

19 See Exhibit Staff/407, Muldoon1 for TIPS implied long-run inflation rates.

20 Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. *See*, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, Exhibit Staff/800, Storm/46 – 52. Growth rates relied upon by Staff are also shown in Exhibit Staff/104, Muldoon/1

21 See three-stage DCF models X and Y in Exhibit Staff/403.

receiving one-quarter of that 50 percent weight.[22] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis of U.S. Bureau of Economic Analysis (BEA) Nominal Historical,1980 Q1 – 2022 Q4, for the period 1980 through 2021 to which we apply a TIPS implied inflation forecast.

Staff's third "Near Historical" Stage 3 annual growth rate, is the earlier BEA derived projection which presumes the future will look much like the past. Table 7 below captures LT GDP growth rates Staff used.

TABLE 11
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)	2.20%	2.33%	4.58%	12.50%	0.57%	
Organization for Economic Co-operation and Development (OECD)	1.49%	2.33%	3.85%	12.50%	0.48%	
Social Security Administration (SSA)	2.00%	2.33%	4.38%	12.50%	0.55%	
Congressional Budget Office CBO)	1.75%	2.33%	4.12%	12.50%	0.52%	
BEA Nominal Historical,1980 Q1 – 2022 Q4	2.64%	2.33%	5.03%	50.0%	2.52%	
Composite				100%	4.63%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.05%	100.0%	4.05%	CBO
BEA Nominal Historical,1980 Q1 – 2022 Q4	2.64%	2.33%	5.03%	100.0%	5.03%	Near Historical

Q. Did your analysis reflect a synthetic forward curve?

A. Yes. Staff utilized synthetic forward curve using UST Treasury Inflation Protected Securities (TIPS) break-even points. This reflects implied market-

[22] The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. We applied to CBO's estimate of real GDP as an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities method described by Staff in testimony in multiple recent general rate case proceedings.

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

Staff assumes for purposes of its three-stage DCF modeling that LDC 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. Assuming that future U.S. GDP growth will mirror the growth experienced in the past 30 years, would a ROE based on that assumption still fall within Staff's recommended range?

A. Yes. Staff extracted and ran regression on data from the U.S. Bureau of Economic Analysis (BEA) to generate the annual real historical GDP growth rate. Staff recommended range of ROEs includes values that presume GDP growth over the next 30 years would look like that of the past 30 years informed by other federal projections.

Q. How do your growth rates compare to the Company's?

A. Staff's 20-year GDP growth rate estimates of 4.50 percent from the CBO; 4.58 percent aggregated from the EIA, 4.38 percent from the SSA, and 5.03 percent from Staff's regression analysis of BEA historical data of 4.95 percent are all higher than the Company's proposed 3.90 percent – which is closer to Staff's 3.85 percent EIA values. Because higher growth rates typically result in higher estimates of ROE, the fact that Staff uses a higher growth rate than PGE means that Staff is using more favorable assumptions for PGE than PGE itself assumes.

Q. How do your methods employed in this case differ from those utilized by Staff in recent general rate cases?

A. Staff's methods and modeling parallel those employed by Staff in recent electric utility general rate cases. Staff continues to look primarily to referent federal sources for long-term GDP growth rates which weight long-run population, workforce participation, and productivity higher than current financial market events and global events with shorter if not transitory effects. Nevertheless, Staff monitors current financial news, and this testimony is informed by such.[23]

Q. Describe the two three-stage DCF models on which you primarily rely.

A. Staff's first model is a conventional three-stage discounted dividend model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (referred to as "Model X"). This model captures the thinking of a money manager at a pension fund or insurance company, or other institutional investor, who expects to keep the Company's stock indefinitely and use the dividend cash flow to meet future obligations.

Staff's second model is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (referred to as "Model Y"). This model best fits the investor who has a goal they are working toward. In addition to the income stream from dividends, this investor intends to sell the

[23] See Exhibit Staff/408, Muldoon/23, /30, /43, /45, and /50 for news that investors in electric utilities are seeing.

stock as the goal is reached.

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per share to be received over the next five years calculated from information provided by Value Line, and a long-term growth rate applicable to dividends 10- to 30-years out. On this last point, Staff always recommends the Commission be particularly vigilant for any substitution of a short-term growth rate for a long-term 20- to 30-year growth rate. Some growth rates labeled "long" may be supported by information looking at the next ten years or less into the future.

For a smooth transition, Staff steps the rate of dividend growth between the near-term (the next five years) and that of long-run expectations.

Q. How does Model X calculate the terminal value of dividends as a perpetual cash flow into the future?

A. Model X includes a terminal value calculation, in which Staff assumes dividends per share grow indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast, Model Y terminates in a sale of stock where the price is determined by our escalated price/earnings (P/E) ratio.

Q. Why is thirty years the primary horizon for financial decision-making?

A. Investors focus on the 30-year U.S. Treasury (UST) Bond against alternate investment opportunities. Thirty years is a generally accepted period for economists to ascribe to one generation. It is a common length of time for mortgages of plants, equipment, and homes. Many institutional holders of utility securities match the cash flows from utility dividends to future obligations, such as the payout of life insurance, preparing to meet future pension and post-retirement obligations, and interest service for borrowing. Individuals plan for the education of their children, ownership of their home, and provision for their retirement on this same multi-decade timeframe.

Staff uses five years for Stage One, as that is the timeframe for which Value Line estimates of future dividends are available. This is as far as Value Line projects near-future trends. Staff also uses five years for Stage Two as a reasonable length of time for individual company's dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all electric utilities.

Q. How do you address dividend timing?[24]

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values to generate an Internal Rate of Return (IRR) produced with each set of calculations for each peer utility. This approach accounts for the time value of money, closely replicating actual quarterly receipt of dividends by investors.

---

[24] See Exhibit Staff/409 for Value Line (VL) information relied on in this testimony regarding publicly traded electric utilities.

Q. What price do you use for each peer utility's stock?

A. Staff used the average of closing prices for each utility from the first trading day in January, February, and March 2023, to represent a reasonable snapshot of utility stock prices.

Q. Do you capture both the perspective of a buy and hold investor and an investor who plans to sell in the future?

A. Yes. Staff's recommended 9.0 percent point ROE is consistent with findings modeling the perspectives of both types of investors through Staff's two different three-stage DCF models.

Q. Does this approach capture a reasonable set of investor expectations similar to Staff's analysis in other recent general rate cases?

A. Yes. Staff modeling captures the expectations of investors who think that: A) the non-partisan CBO is reliable; B) blended federal agency expert analysis also informs the historical track record; and C) one should be optimistic about the economy's long-run growth, provided there are still enough non-retired adult Americans to make it happen 20 years from now.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for electric utilities?

A. Yes. In many of the Company's prior rate cases, Staff has shared plots of U.S. electric demand growth since 1950 on a three-year moving average. This downward trending consumption curve allows GDP growth to be a conservative proxy for both electric utility sales and dividend growth rates.

Q. Can relying on a long-term GDP growth rate overstate required ROE?

A. Yes. It is possible that Staff modeling anticipates greater growth than may be realized and so overstates required ROE to attract investors. Our highest growth rate presumes return to near historical U.S. GDP growth rates.

Q. Is it important to distinguish between long-run 20- to 30-year rates and rates over the next five years?

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results. For example, Value Line, Blue Chip, and a variety of other financial resources focus primarily on the next five years. The next five years may be affected by recent events. Over the long run, population and productivity are the key drivers of economic growth. This is of concern with declines in the rate of growth of America's population.[25]

Q. In Staff's two different three-stage DCF models, Staff is looking for growth rates for a period between 10 and 30 years in the future, or an average of 20-years out. Why not just use a five- or ten-year projection?

A. Staff could use a five- or ten-year projection, but there is better information available. If a primary concern is whether enough Americans are both working and highly productive to support a robustly growing economy 30 years from now, 10-year data will not be the most useful. This is because 10-year data is not yet impacted by retirement of persons born in 1960 or persons not

---

[25] See Exhibit Staff/408, Muldoon/1 and /43 for long-run concerns about birth rate declines.

immigrating and not being born to U.S. families now. A better solution is to use data that is projected with those difficulties in mind, i.e., 30-year data.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at PGE's target capital structure increases required ROE. Why is this adjustment reasonable?

A. Staff employs the Hamada Equation to better compare companies with different capital structures driven by differing amounts of outstanding debt. As earlier discussed, Staff applied screening criteria already identify peers that have a very close capital structure to the Company. Use of the Hamada-adjusted results helps ensure that Staff has captured all material risk in our analysis because it captures additional risk associated with varying capital structure.

Within the confines of Staff's testimony, one can see the steps to un-lever and re-lever a peer company's capital structure as the equivalent of removing debt of peer companies with varying capital structures, and then adding enough debt back to equal the Company's balanced target capital structure in this general rate case.

Q. What accounts for differences in peer capital structures?

A. Each of the two models employs the Hamada equation[26] to calculate an adjustment for differences in capital structure between each peer utility and the

---

[26] Dr. Robert Hamada's Equation as used in Staff/404 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental

Staff-proposed capital structure for the Company. When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. Why is it important to consider capital structure when modeling ROE?

A. Different amounts of debt financing along with different tax rates result in disparate risk profiles among peer utilities used in ROE modeling to approximate the unknown appropriate ROE for the utility examined. All else equal, with more debt in a capital structure, investors require higher expected equity returns to compensate for the increased risk. Debt has a higher call on the company's available cash, and so less cash is available for equity holders. Staff uses the Hamada's equation, named after Robert Hamada, to separate the financial risk of a levered firm from its business risk, and adjust the results of peer utilities to have results as though they had the same capital structure as the utility for whom an appropriate ROE is sought.

Q. Did Staff consider what modeling outcomes would result from using a larger peer capital structure screen with a sensitivity peer group with 40 percent to 60 percent debt, carrying more interest rate risk than PGE?

A. Yes. Inclusive of Hamada adjustments, the higher debt sensitivity peer group would decrease Staff's recommended ROE by 24 basis points. While the

business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

Hamada equation addresses the capital structure itself to a certain degree, Companies taking on more debt may also be taking on more risk in other areas than finance. In general, Staff screens to select companies most like the utility it seeks to identify a best range of reasonable ROEs and point ROE for.

Q. Did Staff use robust and proven analytical methodologies?

A. Yes. Staff's methods are robust, proven, and parallel Staff's work for many years. The Commission, for example, expressly relies on the multi-stage DCF to determine the range of ROEs and relies on CAPM and risk premium models to check the reasonableness of results. This can be seen in Order No. 22-129 in PGE Docket No. UE 394 as well as in Order No. 20-473 in PAC Docket No. UE 374.

Q. Describe how you performed your analysis.

A. Using the cohort of proxy companies that met our screens, Staff ran each of Staff's two three-stage DCF models three times, each time using a different long-term growth rate.

Q. Was your analysis consistent with a top supportable finding of 9.1 percent ROE?

A. Yes.

Q. Would applying Hamada adjustments like Staff does with three stage discounted cash flow modeling increase the outputs of CAPM and Single Stage DCF models?

A. Yes. PGE does so in this rate case, and the Company also performs after-tax Hamada adjustments to CAPM and Single Stage modeling. PGE also uses

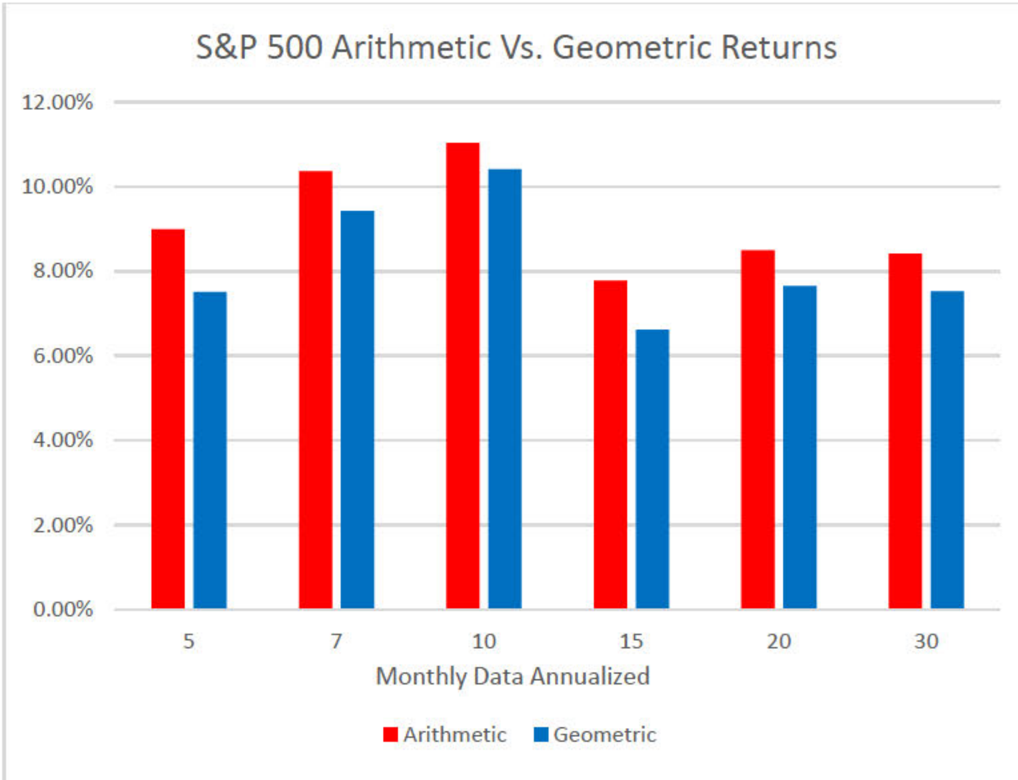
ECAPM, a variant of CAPM not recognized by the Commission, combined with what look like arithmetic 10-year market returns to boost results of these models.

Q. Does use of arithmetic returns rather than geometric returns for a referent market index like the S&P 500 make much difference?

A. Yes. PGE used arithmetic returns in this rate case and also performs after taxes Hamada adjustments straining CAPM and single stage modeling. As seen in Chart 1 below, inappropriate use of arithmetic market returns can inflate modeling inputs by different amounts depending on the number of years one measures returns over.[27]

[27] *See e.g., In re Pacific Northwest Bell Company*, et al., UT 43, Order No. 87-406, (March 31, 1987) ("A geometric average should be used to derive the market risk premium when CAPM is focused on a holding period greater than one year."); *In re GTE Northwest, Inc.*, UT 113, Order No. 94-336 (February 22, 1994)(" The arithmetic mean provides a better measure of typical performance over a single historical period (e.g. one year). The geometric mean, however, is the best estimate of the ending value of an investment over multiple periods.").

Chart 1



c

PGE also uses empirical (ECAPM), a variant of CAPM not recognized by the Commission, combined with what look like arithmetic 10-year market returns to boost results of these models. PGE makes what it calls direct empirical adjustments to CAPM.[28] By effectively pivoting results upward, PGE generates results of 11.3 percent to 11.5 percent ROE. Though such results do not seem to have much relation to authorized ROEs in the last year in the U.S. on average, PGE indicates that manipulating its modeling in this manner somehow makes the Company's requested 9.8 percent ROE reasonable.[29]

---

[28] See PGE/1000, Liddle-Villadsen/58.

[29] See Figure 11 of PGE/1000, Liddle-Villadsen/61.

Q. Is Staff's point recommendation herein immalleable?

A. Staff will continue to analyze analysis and testimony as well as incremental data requests and the work of intervenors and the Company's response thereto. At this time, Staff has shown how use of a 10-year geometric market risk premium can increase certain modeling results to +/- 20 bps of PGE's currently authorized ROE. While Staff does not agree with this approach and has concerns with much of PGE's methodology, Staff will continue to be informed by ongoing work of participants in this rate case and Staff may update its positions based on new information or analysis, including that from financial market conditions. The use of geometric results is further supported by the fact that PGE receives a continuous stream of revenues over the year and can reinvest those revenues. This is consistent with using a geometric calculation.[30]

BALANCED APPROACH TO ROE

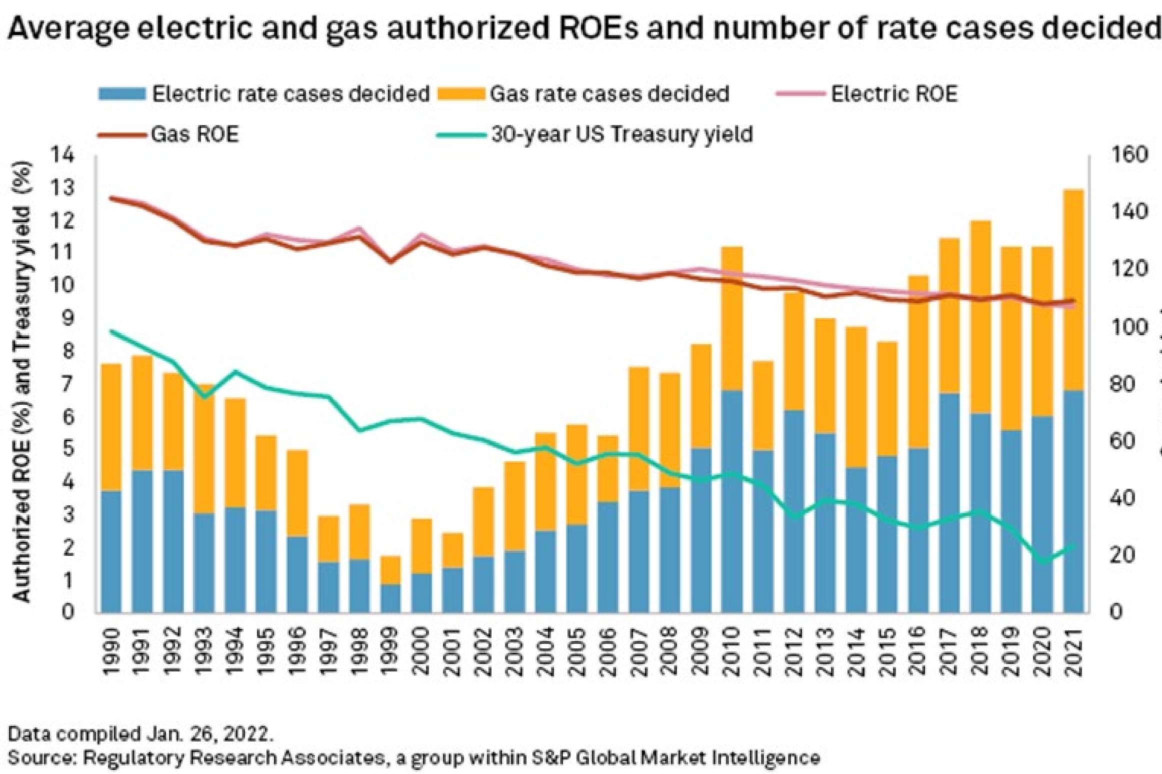
Q. Are your results robust given uncertainty around COVID-19, high inflation, U.S. Federal Reserve (Fed) intent to raise interest rates, and a major war in Eastern Europe further disrupting global supply chains?

---

[30] See *In re Pacific Northwest Bell Company*, Order No. 87-406 ("The yield to maturity on the Treasury Notes used by the Commissioner in development of the risk-free rate is a geometric average that reflects the benefits of compounding interim returns. To develop a consistent model, the method used in estimating the market risk premium also must reflect compounding. Staff's geometric average model does that and does it for the appropriate holding period. PNB's arithmetic average contemplates no reinvestment of short-term earnings. As a result, it overstates the market risk premium.").

A. Yes. The downward glide path for ROE in 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.[31]

FIGURE 1 – Downward Glide Path of Utility ROES[32]



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 is now raising interest rates, there is

---

[31] See Exhibit Staff/408, Muldoon/1, 20 for pertinent population growth rates.

[32] Published by Regulatory Research Associates (RRA), an affiliate of S&P Global Market Intelligence on Feb. 10, 2022.

considerable uncertainty whether the Fed may need to decrease interest rates as soon as inflation is under better control, or the U.S. economy experiences duress due to such a rapid tightening cycle.

Q. When will updated growth forecasts be available from referent federal agencies?

A. Staff expects federal agencies to update long-run (20-year out and longer) forecasts this summer. Staff intends to update its modeling in its next round of testimony to incorporate updated information available then.

<u>GORDON GROWTH MODEL – As Check on ROE Findings</u>

Q. What is the Gordon Growth model?

A. The Gordon Growth model (or Single Stage DCF model), similarly to the Three-Stage DCF model, is based on the principle that a company's value is equal to the net present value (NPV) of all its future cash flows and the company's current stock price. The Single-Stage DCF uses simpler assumptions than other models however, with dividend payments representing the only cash flow, and an assumption that growth will remain constant in perpetuity.[33]

Q. What are the positive aspects and potential shortfalls of the DCF model?

A. The most positive aspect of the Single-Stage model is its simplicity. An analyst can use this model to calculate a rudimentary cost of equity

[33] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of the Single-Stage DCF model, and the Commission's historical treatment of its results.

valuations without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividends. In fact, after some algebraic simplification, the return can be expressed by:

$$R = \frac{D_1}{P_0} + g$$

Where $\boldsymbol{R}$ is estimated ROE, $\boldsymbol{D_1}$ is the first dividend paid after stock purchase, $\boldsymbol{P_0}$ is the stock price, and $\boldsymbol{g}$ is the growth rate.

Caution and discretion must be used when sourcing inputs to the model, for example, growth rates should be based on well vetted and reliable sources, as opposed to sell-side marketing information used by investment advisors to entice new investors. This is important to bear in mind when considering the results of any Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

The Single-Stage model is based on simple principles and serves as a rough estimation of investor required ROE. It cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis. For this reason, Staff, consistent with Commission precedent, has traditionally only relied on it as a sensitivity check when rate making.

Q. How does Staff determine the dividend flow and growth rate for the single-stage DCF?

A. Much like Staff's Multi-Stage DCF, Staff sources its expected dividends from Value Line. We calculate the average dividend growth rate by comparing the expected dividend by Value Line and actual dividend for each for each company in the peer screen.

Q. What inputs does Staff use to build Staff's single-stage DCF model?

A. Staff uses the same representative draw of stock prices to build its single-stage DCF model as it uses in the three-stage DCF model. Current dividends and anticipated dividend growth are sourced from Value Line.

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 8.5 percent.

TABLE 12[34]

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 Upper End of Staff's 3-Stage DCF Modeling Results**

	Screen #	Abbreviated Utility (1)	UE 416 PGE (2)	UE 416 Staff (3)	LT Debt UE 416 Sensitivity (4)	Ticker (5)	Recent Stock $ Price (6)	Current Dividend Yield (7)	Next VL Annual Dividend (8)	Anticipated Dividend Yield (9)	VL Dividend Growth (10)	Investor Required ROE (11) = 9 + 10	Screen # (12)	(13)
1	1	Allete	Yes	No	No	ALE	62.92	4.1%	2.70	4.3%	3.5%	7.7%	1	1
2	2	Alliant	Yes	Yes	Yes	LNT	53.45	3.2%	1.81	3.4%	6.0%	9.4%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	85.61	2.8%	2.52	2.9%	7.2%	10.2%	3	3
4	4	AEP	Yes	No	Yes	AEP	91.96	3.4%	3.35	3.6%	5.8%	9.5%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	42.16	4.2%	1.83	4.3%	4.0%	8.3%	6	5
6	7	Black Hills	Yes	No	Yes	BKH	68.02	3.5%	2.53	3.7%	5.2%	9.0%	7	6
7	8	CenterPoint	Yes	No	No	CNP	29.01	2.4%	0.77	2.7%	1.9%	4.6%	8	7
8	9	CMS	Yes	No	No	CMS	61.74	3.0%	1.94	3.1%	5.9%	9.0%	9	8
9	10	Consol Ed	No	Yes	Yes	ED	93.12	3.4%	3.24	3.5%	2.5%	6.0%	10	9
10	11	Dominion	Yes	No	No	D	60.27	4.4%	2.83	4.7%	0.9%	5.6%	11	10
11	13	Duke	Yes	No	Yes	DUK	99.38	4.0%	4.06	4.1%	2.0%	6.1%	13	11
12	14	Edison Int'l	Yes	No	No	EIX	65.58	4.3%	2.95	4.5%	5.4%	9.9%	14	12
13	15	Entergy	Yes	No	No	ETR	106.59	3.8%	4.30	4.0%	5.2%	9.3%	15	13
14	16	Evergy	Yes	Yes	Yes	EVRG	61.29	3.8%	2.48	4.0%	6.8%	10.9%	16	14
15	17	Eversource	No	Yes	Yes	ES	80.03	3.2%	2.70	3.4%	6.4%	9.8%	17	15
16	18	Exelon	Yes	No	No	EXC	41.74	3.2%	1.45	3.5%	2.6%	6.0%	18	16
17	22	IDACORP	Yes	Yes	Yes	IDA	105.73	2.9%	3.25	3.1%	6.6%	9.7%	22	17
18	23	MGE	Yes	No	No	MGEE	71.56	2.2%	1.66	2.3%	4.6%	7.0%	23	18
19	24	NextEra	Yes	No	No	NEE	75.98	2.2%	1.87	2.5%	10.2%	12.7%	24	19
20	25	NorthWestern	Yes	Yes	Yes	NWE	58.05	4.3%	2.56	4.4%	1.9%	6.3%	25	20
21	26	OGE	Yes	Yes	Yes	OGE	38.16	4.3%	1.70	4.5%	2.9%	7.4%	26	21
22	27	Otter Tail	Yes	No	Yes	OTTR	64.83	2.5%	1.76	2.7%	6.8%	9.5%	27	22
23	30	Pinnacle	Yes	Yes	Yes	PNW	74.82	4.6%	3.48	4.7%	2.4%	7.1%	30	23
24	33	Public Serv.	Yes	No	No	PEG	60.80	3.6%	2.28	3.8%	5.6%	9.4%	33	24
25	34	Sempra	Yes	Yes	Yes	SRE	153.82	3.0%	4.80	3.1%	6.1%	9.2%	34	25
26	35	Southern	Yes	No	No	SO	67.69	4.0%	2.78	4.1%	3.4%	7.5%	35	26
27	36	WEC	Yes	Yes	Yes	SO	67.69	4.0%	3.11	4.6%	7.0%	11.6%	36	27
28	37	Xcel	Yes	No	Yes	WEC	91.88	3.2%	2.07	2.3%	6.8%	9.1%	37	28
		No. of Peers:	26	12	17							Mean		
											Company Screen	8.5%	ROE	
											Staff Screen	8.8%	ROE	
											Staff Sensitivity Screen	8.8%	ROE	

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

The average required ROE increased to 8.8 percent if the Company's larger peer screen is used. Staff's sensitivity peer group allowing for Debt up to 60 percent of capital structure also increases the modeling result to 8.8 percent. Findings in Table 12 above support Staff's recommended ROE of 9.0 percent being within a range of reasonable ROEs.

34 See Exhibit Staff/405, Muldoon/4 for Staff's full Gordon Growth Model.

CAPM – As Check on ROE Findings

Q. What is the Capital Asset Pricing Model (CAPM)?

A. The CAPM assumes that a stock's return on equity is a function of a risk-free return and a risk premium and that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by Beta or β. All told, CAPM takes the form:

$$\boldsymbol{Required\ Return} = \boldsymbol{r_f} + \boldsymbol{\beta}(\boldsymbol{r_m} - \boldsymbol{r_f})$$

Where $\boldsymbol{r_f}$ is the risk-free rate and $\boldsymbol{r_m}$ is the market return. Generally, the risk-free rate is assumed to be the rate of return on bonds. Taking cues from long-standing financial modelling, Staff calculates its CAPM using the yield on 30-year and 10-year US Treasury bonds as stand-ins the risk-free rate.

Q. Should the Commission scrutinize CAPM carefully?

A. Yes. CAPM only relies on a few inputs. In this case, there are three inputs: the risk-free rate, the market return, and the choice of Beta. Although it is generally agreed that the rate of return on US Treasury bond is the proper choice for the risk-free rate, there is much discussion about what maturity should be used for Beta and the market return.

There are a variety of sources to find or calculate both Beta and the market return. Because there are so many sources for two inputs into this simple model, an uninformed or malicious investigator could use unrepresentative values to motivate abnormal required returns. It is therefore of the utmost importance to be thoughtful and consistent in choosing CAPM parameters. In Commission activities, we have standardized on Value Line

(VL) Betas that are broadly used to give apples-to-apples modeling output comparisons. Staff has used CAPM for validation rather than rate setting in past cases.

Q. Where do you find information on companies' Beta estimates?

A. Estimates of Beta can be found from many sources including Bloomberg, Yahoo Finance, and VL. Traditionally, the Commission has relied on Value Line's Beta estimates to conduct analysis to maintain consistency in regulation between rate cases. The perils of switching between Beta estimates, known as "Beta shopping," will be addressed later in this testimony.

Q. Where do you find information on market returns?

A. Market returns can also be found or calculated from a variety of places. Two common sources for market returns are historical returns on stock market indices and projections for future growth. As earlier discussed, care should be taken in selecting a market return due to the volatile nature of the stock market.

Q. What issues can arise from an improper market return selection?

A. For any company with a positive Beta, a higher market return translates directly into a higher required return according to the CAPM formula. Overstating market returns, a required return estimate can vary by up to three percent for a typical regulated utility.

Q. How does Staff recommend that market returns be calculated?

A. Staff recommends that market returns be calculated based off the historic long-run growth rates of stocks and an up-to-date measure of the risk-free rate. By using historical averages, a modeler does not run the risk of a large shock in one period unnecessarily augmenting estimated returns, much like the large negative shock caused by the COVID-19 pandemic, the roaring economic recovery post-pandemic, or the ongoing conflict in Ukraine.

As has been done in past rate cases, Staff uses the market risk premium calculated by Ibbotson and the implied market risk premium from Morningstar's Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook, which measures average returns since 1926. These two sources imply that the risk premium would be 4.5 percent and 6.0 percent, respectively. Staff also calculates market risk premiums as described herein using annualized monthly data for 30 years of geometric S&P 500 returns paired with current 30-year UST yields.

Q. What recommendations do you have for the maximum authorized ROE according to CAPM?

A. As stated previously, Staff only uses CAPM for validation rather than rate setting due to its historic unreliability. Within Staff's peer utility screen, the estimated ROEs from Staff's CAPM under Staff assumptions average 9.1 percent. Using the Company's peer screen and Staff's methods, the average estimated ROE observed is 9.1 percent. If one uses a nearly 100-year arithmetic return combined with a 20-year UST risk free rate, one can boost results to 10.7 percent similar to that found in PGE's testimony.

Q. Has the Commission determined that CAPM should not be relied upon as a stand-alone modeling method?

A. Yes. The Commission made this determination in two general rate cases in 2001 with the issuance of Order No. 01-777 and Order No. 01-787, but still permits use of the CAPM as a check on other modeling methods employed.[35]

[35] *In the Matter of Portland General Electric*, Docket No. UE 115, Order No. 01-777 at 32 (August 31, 2001). *In the Matter of PGE*, Docket No. UE 116, Order No. 01-787 at 21 (September 7, 2001).

9. CONCLUSION

Q. What primary summary recommendation do those offering public comments make to the Commission?

A. The frequency and magnitude of PGE's rate increases is straining Oregon utility customers' means and appears unsustainable to those sharing their personal experiences with the Commission.

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission adopt a point ROE of 9.0 percent consistent with the findings herein within a range of reasonable ROEs between 8.83 percent and 9.1 percent.

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's calculations generate a 6.647 percent Overall Rate of Return (ROR). Though 17 bps lower than the Company last authorized ROR, this is a fair and reasonable recommendation to the Commission.

Q. Does Staff offer one possible way to mitigate some of the impact of this general rate increase?

A. Yes. Applying deferred monies in Docket No. UM 2217 from PGE's transmission rate case before FERC as a credit against the revenue requirement herein in UE 416 could lessen the immediate shock of PGE's largest ever proposed general rate increase, by reducing PGE's 2024 test year request by $18,391,138 for one year.

Staff cautions that both Staff and PGE are making assumptions to generate the approximate above future values, and that actual numbers will change. Staff will work with Company and intervenors to consider not just specific issues raised in this general rate case, but also how the Commission might mitigate some of the immediate impact of an increase of the potential magnitude requested by PGE in UE 416 effective January 1, 2024.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement
Staff: Muldoon

June 13, 2023

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew (Matt) J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Manager, Accounting and Finance Section of Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC)
ADDRESS:	201 High Street SE, Suite 100, Salem, OR 97301
EDUCATION:	In 1981, I received a Bachelor of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration (MBA) from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial analysis with an emphasis on Cost of Capital (CoC). I have worked on CoC in the following general rate case dockets: AVA UG 186; UG 201, UG 246, UG 284, UG 288, UG 325, UG 366, UG 389, UG 433 and current UG 461; CNG UG 287, UG 305, UG 347, and UG 390; NWN UG 221, UG 344, UG 388, and UG 435; PAC UE 246, UE 263, UG 374, and UE 399; and PGE UE 262, UE 283, UE 294, UE 319, UE 335, UE 394, and current UE 416. From 2002 to 2008, I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to ensure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

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

June 13, 2023

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)		High grade
Aa2		AA		AA		AA	R-1M	
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		

Source: http://en.wikipedia.org/wiki/Credit_rating

S	Small Cap	Under 2 Billion	
M	Mid Cap	2 to 10 Billion	1 PGE Peer Group
L	Large Cap	Over 10 Billion	2 Staff Peer Group

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	18	19	20	21	22	23
											LT Debt Sensitivity	VL	VL $B 2/1/2023	VL 2/1/2023	Covered by Value Line 2/1/2023	VL 2/1/2023 No Div	Moody's 2/7/2023 A1 to Baa2 Local LT	S&P 2/7/2023 A to BBB- Local LT	+ / - 2 Notches	SEC 10-K 2/10/2023 Percentage
VL #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	VL Corporate Name Electric Utility	SEC Edgar CIK	SEC Edgar SIC	SEC File #	IRS EIN #	Ticker	VL Region	UE 416 Staff	2/1/2023 Beta	Mkt Cap $ Billions	S,M,L CAP	(VL)	Declines 5 years	Unsecured Debt Rating	Rating	S&P & Moody's	Regulated Revenue
1	Allete	Yes	No	Allete, Inc.	0000066756	4931	1-3548	41-0418150	ALE	Central	No	0.90	3.80	M	Yes	Pass	Baa1	BBB	Pass	87%
2	Alliant	Yes	Yes	Alliant Energy Corporation	0000352541	4931	1-9894	39-1380265	LNT	Central	Yes	0.85	14.00	L	Yes	Pass	Baa2	A-	Pass	97%
3	Ameren	Yes	Yes	Ameren Corporation	0001002910	4931	1-14756	43-1723446	AEE	Central	Yes	0.85	23.00	L	Yes	Pass	Baa1	BBB+	Pass	100%
4	AEP	Yes	No	American Electric Power Company, Inc.	0000004904	4911	1-3525	13-4922640	AEP	Central	Yes	0.75	48.90	L	Yes	Pass	Baa2	A-	Pass	83%
5	Avangrid	No	No	Avangrid, Inc. (ex merger: *Iberdrola USA & UIL*)	0001634997	4911	1-37660	14-1798693	AGR	East	No	0.85	15.70	L	Yes	Pass	Baa2	BBB+	Pass	N/A
6	Avista	Yes	Yes	Avista Corporation	0000104918	4931	1-3701	91-0462470	AVA	West	Yes	0.90	3.20	M	Yes	Pass	Baa2	BBB	Pass	99%
7	Black Hills	Yes	No	Black Hills Corporation	0001130464	4911	1-31303	46-0458824	BKH	West	Yes	0.95	4.60	M	Yes	Pass	Baa2	BBB+	Pass	100%
8	CenterPoint	Yes	No	CenterPoint Energy, Inc.	0001130310	4911	1-31447	74-0694415	CNP	Central	No	1.10	19.40	L	Yes	Fail	Baa2	BBB+	Pass	80%
9	CMS	Yes	No	CMS Energy Corporation	0000811156	4931	1-9513	38-2726431	CMS	Central	No	0.80	17.60	L	Yes	Pass	Baa2	BBB+	Pass	94%
10	Consol Ed	No	Yes	Consolidated Edison, Inc.	0001047862	4931	1-14514	13-3965100	ED	East	Yes	0.75	31.20	L	Yes	Pass	Baa2	A-	Pass	84%
11	Dominion	Yes	No	Dominion Energy, Inc.	0000715957	4911	1-08489	54-1229715	D	East	No	0.85	58.30	L	Yes	Fail	Baa2	BBB+	Pass	95%
12	DTE	No	No	DTE Energy Company	0000936340	4911	1-11607	38-3217752	DTE	Central	No	0.95	22.30	L	Yes	Fail	Baa2	BBB+	Pass	52%
13	Duke	Yes	No	Duke Energy Corporation	0001326160	4931	1-32853	20-2777218	DUK	East	Yes	0.85	84.60	L	Yes	Pass	Baa2	BBB+	Pass	100%
14	Edison Int'l	Yes	No	Edison International	0000827052	4911	1-9936	95-4137452	EIX	West	No	0.95	25.90	L	Yes	Pass	Baa3	BBB	Fail	100%
15	Entergy	Yes	No	Entergy Corporation	0000065984	4911	1-11299	72-1229752	ETR	Central	No	0.95	23.00	L	Yes	Pass	Baa2	BBB+	Pass	98%
16	Evergy	Yes	Yes	Evergy, Inc. (Holds Great Plains & Westar)	0001711269	4931	1-38515	82-2733395	EVRG	Central	Yes	0.90	13.50	L	Yes	Pass	Baa2	A-	Pass	100%
17	Eversource	No	Yes	Eversource Energy (formerly: *Northeast Utilities*)	0000072741	4911	1-5324	04-2147929	ES	East	Yes	0.90	26.40	L	Yes	Pass	Baa1	A-	Pass	100%
18	Exelon	Yes	No	Exelon Corporation	0001109357	4931	1-16169	23-2990190	EXC	East	No	0.95	37.80	L	Yes	Fail	Baa2	BBB+	Pass	67%
19	First Energy	No	No	FirstEnergy Corporation (Formerly in part: Allegheny)	0001031296	4911	333-21011	34-1843785	FE	East	No	0.85	21.60	L	Yes	Fail	Ba1	BBB-	Fail	100%
20	Fortis	No	No	Fortis, Inc.	001666175	4911	1-37915	98-0352146	FTS	Central	No	0.70	25.90	L	Yes	Pass	Baa3	A-	Fail	55%
21	Hawaiian	No	No	Hawaiian Electric Industries, Inc.	0000354707	4911	1-8503	99-0208097	HE	West	No	0.85	4.60	M	Yes	Pass	Baa1	BBB-	Pass	77%
22	IDACORP	Yes	Yes	IDACORP, Inc.	0001057877	4911	1-14465	82-0505802	IDA	West	Yes	0.80	5.50	M	Yes	Pass	Baa2	BBB	Pass	99%
23	MGE	Yes	No	MGE Energy, Inc. (Madison Gas & Electric Co.)	0001161728	4900	0-49965	39-2040501	MGEE	Central	No	N/A	N/A	M	No	Pass	A1	AA-	Fail	99%
24	NextEra	Yes	No	NextEra Energy, Inc. (Formerly: FPL Group, Inc.)	0000753308	4911	1-8841	59-2449419	NEE	East	No	0.90	152.30	L	Yes	Pass	Baa1	A-	Pass	70%
25	NorthWestern	Yes	Yes	NorthWestern Corporation	0000073088	4931	1-10499	46-0172280	NWE	West	Yes	0.90	3.40	M	Yes	Pass	Baa2	BBB	Pass	99%
26	OGE	Yes	Yes	OGE Energy Corporation	0001021635	4911	1-12579	73-1481638	OGE	Central	Yes	1.00	8.00	M	Yes	Pass	Baa1	BBB+	Pass	100%
27	Otter Tail	Yes	No	Otter Tail Corporation	0001466593	4911	0-53713	27-0383995	OTTR	Central	Yes	0.85	2.40	M	Yes	Pass	A3	BBB	Pass	80%
28	PG&E	No	No	PG&E Corporation	0001004980	4931	1-12609	94-3234914	PCG	West	No	N/A	N/A	L	No	Fail	Ba2	BB-	Fail	N/A
29	PGE	No	No	Portland General Electric Company	0000784977	4911	1-5532-99	93-0256820	POR	West	No	0.85	4.40	M	Yes	Pass	A3	BBB+	Pass	100%
30	Pinnacle	Yes	Yes	Pinnacle West Capital Corporation	0000764622	4911	1-8962	86-0512431	PNW	West	Yes	0.90	8.50	M	Yes	Pass	Baa1	BBB+	Pass	100%
31	PNM	No	No	PNM Resources, Inc.	0001108426	4911	1-32462	85-0468296	PNM	West	No	0.90	4.20	M	Yes	Pass	Baa3	BBB	Fail	100%
32	PPL	No	No	PPL Corporation	0000922224	4911	1-11459	23-2758192	PPL	East	No	1.10	19.50	L	Yes	Pass	Baa1	A-	Pass	100%
33	Public Serv.	Yes	No	Public Serv. Enterprise Group, Inc.	0000788784	4931	1-09120	22-2625848	PEG	East	No	0.90	28.00	L	Yes	Pass	Baa2	BBB+	Pass	64%
34	Sempra	Yes	Yes	Sempra Energy	0001032208	4932	1-14201	33-0732627	SRE	West	Yes	0.95	49.40	L	Yes	Pass	Baa2	BBB+	Pass	80%
35	Southern	Yes	No	Southern Company (Southern Company Gas)	0000092122	4911	1-3526	58-0690070	SO	East	No	0.95	71.30	L	Yes	Pass	Baa2	BBB+	Pass	96%
36	WEC	Yes	Yes	WEC Energy Group (formerly Wisconsin Energy)	0000783325	4931	1-09057	39-1391525	WEC	Central	Yes	0.80	30.50	L	Yes	Pass	Baa1	A-	Pass	100%
37	Xcel	Yes	No	Xcel Energy, Inc.	0000072903	4931	1-3034	41-0448030	XEL	West	Yes	0.80	39.40	L	Yes	Pass	Baa1	A-	Pass	100%
	No. of Peers:	26	12							AVG:	17	0.89								

	Moody's	S&P
PGE	A3	A
Range	A1 to Baa2	AA- to BBB+

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

1	2	3	4	24	25	26 (Sensitivity)	27	28	
				EEI 1/31/2023	VL 2/1/2023	VL 2/1/2023	VL 2/2/2023		
VL #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	80%+ Regulated Assets	LT Debt 45% - 55% of Capital	LT Debt 40% - 60% of Capital	Div. Growth 5 Yr Rate Forecast > 0%	No M&A Executed in Last 5 Years	#
1	Allete	Yes	No	50% to 80%	39.5%	39.5%	Yes		1
2	Alliant	Yes	Yes	80% +	54.0%	54.0%	Yes		2
3	Ameren	Yes	Yes	80% +	53.5%	53.5%	Yes		3
4	AEP	Yes	No	80% +	58.0%	58.0%	Yes	Sale of KY Power Subsidiary for $1.45 Billion expected to be completed in 2022 Q2	4
5	Avangrid	No	No	50% to 80%	33.0%	33.0%	Fail	Proposes to by PNM for $4.3 Billion, Has financed acquisition / VL. Companies appealed to the state Supreme Court.	5
6	Avista	Yes	Yes	80% +	49.5%	49.5%	Yes	H1 Failed to Buy Avista 2019	6
7	Black Hills	Yes	No	80% +	56.5%	56.5%	Yes		7
8	CenterPoint	Yes	No	80% +	59.0%	59.0%	Fail	CenterPoint Acquired Vectren Feb 2019 $6 B Deal, Sold 2 Gas Utilities in AR and OK 2022 Now Exiting position in Enable Mistream Partners	8
9	CMS	Yes	No	80% +	62.0%	62.0%	Yes		9
10	Consol Ed	No	Yes	80% +	53.0%	53.0%	Yes		10
11	Dominion	Yes	No	80% +	56.5%	56.5%	Fail	2019 Purchase of Scana, 2020 Sale gas pipeline / storage $9.7B to Berkshire Energy	11
12	DTE	No	No	50% to 80%	61.5%	61.5%	Fail	2021 Spun Off subsidiary into DT Midstream NYSE:DTM	12
13	Duke	Yes	No	80% +	58.5%	58.5%	Yes	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	Yes	No	80% +	56.5%	56.5%	Yes	Aug **2000** Bought Citizens Power, Nuclear Gen w San Onofre Nuclear Generation Station (SONGS)	14
15	Entergy	Yes	No	80% +	66.5%	66.5%	Yes		15
16	Evergy	Yes	Yes	80% +	51.5%	51.5%	Yes		16
17	Eversource	No	Yes	80% +	55.0%	55.0%	Yes		17
18	Exelon	Yes	No	50% to 80%	61.0%	61.0%	Fail	Exelon completed Spin Off of Nonutility Opertions on Feb. 1, 2022	18
19	First Energy	No	No	80% +	70.0%	70.0%	Fail		19
20	Fortis	No	No	N/A	53.5%	53.5%	Yes		20
21	Hawaiian	No	No	50% to 80%	50.5%	50.5%	Yes	Failed Attempt by Next Era to Buy HECO for $17B in 2017	21
22	IDACORP	Yes	Yes	80% +	46.5%	46.5%	Yes		22
23	MGE	Yes	No	80% +	38.1%	38.1%	Yes		23
24	NextEra	Yes	No	50% to 80%	56.5%	56.5%	Yes	Next Era Failed to Buy HECO for $17B in 2017, Next Era Failed to Buy Oncor for $17B in 2017	24
25	NorthWestern	Yes	Yes	80% +	49.5%	49.5%	Yes		25
26	OGE	Yes	Yes	80% +	52.0%	52.0%	Yes		26
27	Otter Tail	Yes	No	80% +	41.5%	41.5%	Yes		27
28	PG&E	No	No	80% +	N/A	N/A	Fail	2019 Chapter 11 bankruptcy liability for 2017 and 2018 wildfires in CA	28
29	PGE	No	No	80% +	55.0%	55.0%	Yes		29
30	Pinnacle	Yes	Yes	80% +	54.5%	54.5%	Yes		30
31	PNM	No	No	80% +	59.0%	59.0%	Yes	Avangrid Proposal to Purchase PNM, now more viable with newly constituted NW PRC	31
32	PPL	No	No	80% +	47.5%	47.5%	Fail	2021 Sold operations in UK, Buying Narragansett Electric for $3.8B	32
33	Public Serv.	Yes	No	50% to 80%	55.5%	55.5%	Yes		33
34	Sempra	Yes	Yes	80% +	47.0%	47.0%	Yes	Bought Oncor March 2018 for $9.5 B	34
35	Southern	Yes	No	80% +	64.0%	64.0%	Yes	2016 AGL Resources merged with Southern Company	35
36	WEC	Yes	Yes	80% +	55.0%	55.0%	Yes		36
37	Xcel	Yes	No	80% +	58.0%	58.0%	Yes		37
	No. of Peers:	26	12						

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.

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	21	22	23	24	25	26	27	28	29	30	31	32	33	34		
					Staff Sensitivity																						Value Line Estimated Dividends						VL	VL % Div Growth		
	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	UE 416 LT Debt	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2018 Yr	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2019 Yr	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2019-21 Average	2022 Yr	2023 Yr	2024 Yr	2025 Yr	2026 Yr	2027 Yr	2025 - 27 Average	2025 - 27 vs. 2019 - 21	Screen #	
1	1	Allete	Yes	No	No	0.560	0.560	0.560	0.560	2.24	0.5875	0.5875	0.5875	0.5875	2.35	0.6175	0.6175	0.6175	0.6175	2.47	0.630	0.630	0.630	0.630	2.52	2.45	2.60	2.70	2.80	2.90	3.00	3.10	3.00	3.5%	1	1
2	2	Alliant	Yes	Yes	Yes	0.335	0.335	0.335	0.335	1.34	0.355	0.355	0.355	0.355	1.42	0.380	0.380	0.380	0.380	1.52	0.4025	0.4025	0.4025	0.4025	1.61	1.52	1.71	1.81	1.92	2.03	2.15	2.27	2.15	6.0%	2	2
3	3	Ameren	Yes	Yes	Yes	0.4575	0.4575	0.4575	0.475	1.85	0.475	0.475	0.475	0.495	1.92	0.4950	0.4950	0.4950	0.515	2.00	0.550	0.550	0.550	0.550	2.20	2.04	2.36	2.52	2.70	2.89	3.10	3.31	3.10	7.2%	3	3
4	4	AEP	Yes	No	Yes	0.620	0.620	0.620	0.670	2.53	0.670	0.670	0.670	0.700	2.71	0.700	0.700	0.700	0.740	2.84	0.740	0.740	0.740	0.780	3.00	2.85	3.17	3.35	3.55	3.77	4.00	4.23	4.00	5.8%	4	4
5	6	Avista	Yes	Yes	Yes	0.3725	0.3725	0.3725	0.3725	1.49	0.3875	0.3875	0.3875	0.3875	1.55	0.405	0.405	0.405	0.405	1.62	0.4225	0.4225	0.4225	0.4225	1.69	1.62	1.76	1.83	1.90	1.97	2.05	2.13	2.05	4.0%	6	5
6	7	Black Hills	Yes	No	Yes	0.475	0.475	0.475	0.505	1.93	0.505	0.505	0.505	0.535	2.05	0.535	0.535	0.535	0.5650	2.17	0.565	0.565	0.565	0.596	2.29	2.17	2.41	2.53	2.66	2.80	2.95	3.10	2.95	5.2%	7	6
7	8	CenterPoint	Yes	No	No	0.2775	0.2775	0.2775	0.2775	1.11	0.2875	0.2875	0.2875	0.2875	1.15	0.29	0.15	0.15	0.15	0.74	0.16	0.16	0.16	0.17	0.65	0.85	0.71	0.77	0.83	0.89	0.95	1.01	0.95	1.9%	8	7
8	9	CMS	Yes	No	No	0.358	0.358	0.358	0.358	1.43	0.383	0.383	0.383	0.383	1.53	0.408	0.408	0.408	0.408	1.63	0.44	0.44	0.44	0.44	1.74	1.63	1.84	1.94	2.05	2.17	2.30	2.43	2.30	5.9%	9	8
9	10	Consol Ed	No	Yes	Yes	0.7150	0.7150	0.7150	0.7150	2.86	0.740	0.740	0.740	0.740	2.96	0.7650	0.7650	0.7650	0.7650	3.06	0.7750	0.7750	0.7750	0.7750	3.1	3.04	3.16	3.24	3.33	3.42	3.52	3.62	3.52	2.5%	10	9
10	11	Dominion	Yes	No	No	0.835	0.835	0.835	0.835	3.34	0.9175	0.9175	0.9175	0.9175	3.67	0.94	0.94	0.94	0.63	3.45	0.63	0.63	0.63	0.63	2.52	3.21	2.67	2.83	3.01	3.20	3.40	3.60	3.40	0.9%	11	10
11	13	Duke	Yes	No	Yes	0.890	0.890	0.928	0.928	3.64	0.928	0.928	0.945	0.945	3.75	0.945	0.945	0.965	0.965	3.82	0.965	0.965	0.985	0.985	3.90	3.82	3.98	4.06	4.14	4.22	4.30	4.38	4.30	2.0%	13	11
12	14	Edison Int'l	Yes	No	No	0.605	0.605	0.605	0.605	2.42	0.6125	0.6125	0.6125	0.6125	2.45	0.6375	0.6375	0.6375	0.6375	2.55	0.6625	0.6625	0.6625	0.6625	2.65	2.55	2.80	2.95	3.12	3.31	3.50	3.69	3.50	5.4%	14	12
13	15	Entergy	Yes	No	No	0.8900	0.8900	0.8900	0.9100	3.58	0.9100	0.9100	0.9100	0.9300	3.66	0.930	0.930	0.930	0.950	3.74	0.950	0.950	0.950	1.010	3.86	3.75	4.10	4.30	4.55	4.82	5.10	5.38	5.10	5.2%	15	13
14	16	Evergy	Yes	Yes	Yes	0.400	0.400	0.460	0.475	1.74	0.475	0.475	0.475	0.505	1.93	0.505	0.505	0.505	0.535	2.05	0.535	0.535	0.535	0.573	2.18	2.05	2.33	2.48	2.66	2.85	3.05	3.25	3.05	6.8%	16	14
15	17	Eversource	No	Yes	Yes	0.505	0.505	0.505	0.505	2.02	0.535	0.535	0.535	0.535	2.14	0.568	0.568	0.568	0.568	2.27	0.603	0.603	0.603	0.603	2.41	2.27	2.55	2.70	2.89	3.09	3.30	3.51	3.30	6.4%	17	15
16	18	Exelon	Yes	No	No	0.345	0.345	0.345	0.345	1.38	0.3625	0.3625	0.3625	0.3625	1.45	0.3825	0.3825	0.3825	0.3825	1.53	0.3825	0.3825	0.3825	0.3825	1.53	1.50	1.35	1.45	1.54	1.64	1.75	1.86	1.75	2.6%	18	16
17	22	IDACORP	Yes	Yes	Yes	0.590	0.590	0.590	0.6300	2.40	0.630	0.630	0.630	0.670	2.56	0.670	0.670	0.670	0.710	2.72	0.710	0.710	0.710	0.750	2.88	2.72	3.04	3.25	3.48	3.73	4.00	4.27	4.00	6.6%	22	17
18	23	MGE	Yes	No	No	0.3225	0.3225	0.3225	0.3375	1.31	0.3375	0.3375	0.3525	0.3525	1.38	0.3525	0.3525	0.370	0.370	1.45	0.370	0.370	0.3875	0.3875	1.52	1.45	1.59	1.66	1.74	1.82	1.90	1.98	1.90	4.6%	23	18
19	24	NextEra	Yes	No	No	0.2775	0.2775	0.2775	0.2775	1.11	0.313	0.313	0.313	0.313	1.25	0.3500	0.3500	0.3500	0.3500	1.40	0.3850	0.3850	0.3850	0.3850	1.54	1.40	1.70	1.87	2.06	2.27	2.50	2.73	2.50	10.2%	24	19
20	25	NorthWestern	Yes	Yes	Yes	0.550	0.550	0.550	0.550	2.20	0.575	0.575	0.575	0.575	2.30	0.600	0.600	0.600	0.600	2.40	0.620	0.6200	0.6200	0.6200	2.48	2.39	2.52	2.56	2.60	2.64	2.68	2.72	2.68	1.9%	25	20
21	26	OGE	Yes	Yes	Yes	0.3325	0.3325	0.3325	0.365	1.36	0.365	0.365	0.365	0.388	1.48	0.3875	0.3875	0.3875	0.4025	1.57	0.4025	0.4025	0.4025	0.41	1.62	1.56	1.64	1.70	1.75	1.80	1.85	1.90	1.85	2.9%	26	21
22	27	Otter Tail	Yes	No	Yes	0.335	0.335	0.335	0.3350	1.34	0.350	0.350	0.350	0.350	1.40	0.370	0.370	0.370	0.370	1.48	0.390	0.390	0.390	0.390	1.56	1.48	1.65	1.76	1.90	2.04	2.20	2.36	2.20	6.8%	27	22
23	30	Pinnacle	Yes	Yes	Yes	0.695	0.695	0.695	0.737	2.82	0.737	0.738	0.738	0.782	3.00	0.783	0.783	0.783	0.830	3.18	0.83	0.83	0.83	0.85	3.34	3.17	3.42	3.48	3.54	3.60	3.66	3.72	3.66	2.4%	30	23
24	33	Public Serv.	Yes	No	No	0.45	0.45	0.45	0.45	1.80	0.47	0.47	0.47	0.47	1.88	0.49	0.49	0.49	0.49	1.96	0.51	0.51	0.51	0.51	2.04	1.96	2.16	2.28	2.42	2.56	2.72	2.88	2.72	5.6%	33	24
25	34	Sempra	Yes	Yes	Yes	0.8225	0.895	0.895	0.895	3.51	0.8950	0.9675	0.9675	0.9675	3.80	0.968	1.045	1.045	1.045	4.10	1.045	1.10	1.10	1.10	4.35	4.08	4.58	4.80	5.12	5.46	5.82	6.18	5.82	6.1%	34	25
26	35	Southern	Yes	No	No	0.580	0.600	0.600	0.600	2.38	0.600	0.620	0.620	0.620	2.46	0.620	0.640	0.640	0.640	2.54	0.64	0.66	0.66	0.66	2.62	2.54	2.70	2.78	2.88	2.99	3.10	3.21	3.10	3.4%	35	26
27	36	WEC	Yes	Yes	Yes	0.5525	0.5525	0.5525	0.5525	2.21	0.590	0.590	0.590	0.590	2.36	0.6325	0.6325	0.6325	0.6325	2.53	0.6775	0.6775	0.6775	0.6775	2.71	2.53	2.91	3.11	3.32	3.55	3.80	4.05	3.80	7.0%	36	27
28	37	Xcel	Yes	No	Yes	0.360	0.380	0.380	0.380	1.50	0.380	0.405	0.405	0.405	1.60	0.405	0.430	0.430	0.430	1.70	0.430	0.4575	0.4575	0.4575	1.80	1.70	1.95	2.07	2.21	2.36	2.52	2.68	2.52	6.8%	37	28
		No. of Peers:	26	12	17																															

Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet

	Mean
Company Screen	4.9%
Staff Screen	5.0%
Staff LT Screen	5.1%

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	21
					Staff Sensitivity											Value Line Estimated EPS					
	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	UE 416 LT Debt	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2019 Yr	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2019-21 Average
1	1	Allete	Yes	No	No	1.18	0.64	0.60	0.92	3.34	1.28	0.39	0.78	0.90	3.35	0.99	0.53	0.53	1.18	3.23	3.31
2	2	Alliant	Yes	Yes	Yes	0.53	0.40	0.94	0.46	2.33	0.72	0.54	0.94	0.26	2.46	0.68	0.57	1.02	0.35	2.62	2.47
3	3	Ameren	Yes	Yes	Yes	0.78	0.72	1.47	0.38	3.35	0.59	0.98	1.47	0.46	3.50	0.91	0.80	1.65	0.48	3.84	3.56
4	4	AEP	Yes	No	Yes	1.16	0.93	1.48	0.51	4.08	1.00	1.05	1.50	0.87	4.42	1.15	1.15	1.59	1.07	4.96	4.49
5	6	Avista	Yes	Yes	Yes	1.76	0.38	0.08	0.76	2.98	0.72	0.26	0.07	0.85	1.90	0.98	0.20	0.20	0.71	2.09	2.32
6	7	Black Hills	Yes	No	Yes	1.73	0.24	0.44	1.13	3.54	1.59	0.33	0.58	1.23	3.73	1.54	0.40	0.70	1.11	3.75	3.67
7	8	CenterPoint	Yes	No	No	0.28	0.33	0.47	0.41	1.49	0.56	0.17	0.29	0.27	1.29	0.41	0.29	0.21	0.03	0.94	1.24
8	9	CMS	Yes	No	No	0.75	0.33	0.73	0.58	2.39	0.85	0.48	0.76	0.55	2.64	1.09	0.55	0.54	0.40	2.58	2.54
9	10	Consol Ed	No	Yes	Yes	1.39	0.58	1.54	0.86	4.37	1.35	0.60	1.48	0.74	4.17	1.44	0.53	1.41	1.00	4.38	4.31
10	11	Dominion	Yes	No	No	1.10	0.77	1.18	1.18	4.23	0.92	0.73	1.08	0.81	3.54	1.09	0.76	1.11	0.90	3.86	3.88
11	13	Duke	Yes	No	Yes	1.24	1.12	1.79	0.91	5.06	1.14	1.08	1.87	1.03	5.12	1.26	1.15	1.88	0.94	5.23	5.14
12	14	Edison Int'l	Yes	No	No	0.64	1.57	1.35	0.45	4.01	0.50	0.85	-0.76	1.13	1.72	0.68	0.84	-0.90	1.38	2.00	2.58
13	15	Entergy	Yes	No	No	1.32	1.22	1.82	1.94	6.30	0.59	1.79	2.59	1.93	6.90	1.66	1.30	2.63	1.28	6.87	6.69
14	16	Evergy	Yes	Yes	Yes	0.39	0.57	1.56	0.28	2.80	0.31	0.59	1.60	0.22	2.72	0.84	0.81	1.95	0.23	3.83	3.12
15	17	Eversource	No	Yes	Yes	0.97	0.74	0.98	0.76	3.45	1.02	0.76	1.01	0.85	3.64	1.15	0.79	1.02	0.91	3.87	3.65
16	18	Exelon	Yes	No	No	0.87	0.60	0.92	0.83	3.22	0.87	0.55	1.04	0.76	3.22	-0.06	0.89	1.09	0.90	2.82	3.09
17	22	IDACORP	Yes	Yes	Yes	0.84	1.05	1.78	0.93	4.60	0.74	1.19	2.02	0.74	4.69	0.89	1.38	1.93	0.65	4.85	4.71
18	23	MGE	Yes	No	No	0.69	0.45	0.88	0.48	2.50	0.75	0.53	0.88	0.44	2.60	0.97	0.63	0.97	0.36	2.93	2.68
19	24	NextEra	Yes	No	No	0.35	0.64	0.45	0.50	1.94	0.59	0.65	0.67	0.40	2.31	0.67	0.71	0.75	0.41	2.54	2.26
20	25	NorthWestern	Yes	Yes	Yes	1.44	0.49	0.42	1.18	3.53	1.00	0.43	0.58	1.21	3.22	1.24	0.59	0.70	0.97	3.50	3.42
21	26	OGE	Yes	Yes	Yes	0.24	0.50	1.25	0.26	2.25	0.23	0.51	1.04	0.30	2.08	0.26	0.56	1.26	0.27	2.35	2.23
22	27	Otter Tail	Yes	No	Yes	0.66	0.39	0.62	0.51	2.18	0.60	0.42	0.87	0.45	2.34	0.73	1.01	1.26	1.23	4.23	2.92
23	30	Pinnacle	Yes	Yes	Yes	0.16	1.28	2.77	0.57	4.78	0.27	1.71	3.07	-0.17	4.88	0.32	1.91	3.00	0.24	5.47	5.04
24	33	Public Serv.	Yes	No	No	1.08	0.58	0.98	0.64	3.28	1.03	0.79	0.96	0.65	3.43	1.26	0.70	0.98	0.69	3.63	3.45
25	34	Sempra	Yes	Yes	Yes	1.78	0.85	2.00	1.34	5.97	2.53	1.58	1.31	1.88	7.30	2.95	1.63	1.70	2.16	8.44	7.24
26	35	Southern	Yes	No	No	0.75	0.85	1.25	0.32	3.17	0.81	0.75	1.18	0.51	3.25	1.09	0.67	1.22	0.44	3.42	3.28
27	36	WEC	Yes	Yes	Yes	1.33	0.74	0.74	0.77	3.58	1.43	0.76	0.84	0.76	3.79	1.61	0.87	0.92	0.71	4.11	3.83
28	37	Xcel	Yes	No	Yes	0.61	0.46	1.01	0.56	2.64	0.56	0.54	1.14	0.54	2.78	0.67	0.58	1.13	0.58	2.96	2.79
		No. of Peers:	26	12	17																

Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet

	2	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37		
																VL	VL EPS Growth		
	Abbreviated Utility	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2024 Yr	2025 Yr	2026 Yr	2027 Yr	2025 - 27 Average	2025 - 27 vs. 2019 - 21	Screen #	
1	Allete	1.24	0.67	0.59	1.25	3.75	1.30	0.65	0.90	1.10	3.95	4.20	4.47	4.75	5.03	4.75	6.2%	1	1
2	Alliant	0.77	0.63	0.90	0.40	2.70	0.80	0.65	1.05	0.45	2.95	3.12	3.31	3.50	3.69	3.50	6.0%	2	2
3	Ameren	0.97	0.80	1.74	0.59	4.10	1.00	0.90	1.80	0.65	4.35	4.63	4.93	5.25	5.57	5.25	6.7%	3	3
4	AEP	1.41	1.02	1.33	1.24	5.00	1.30	1.25	1.75	1.05	5.35	5.71	6.09	6.50	6.91	6.50	6.4%	4	4
5	Avista	0.99	0.16	-0.08	0.83	1.90	1.15	0.25	0.15	0.80	2.35	2.51	2.67	2.85	3.03	2.85	3.5%	6	5
6	Black Hills	1.82	0.52	0.54	1.17	4.05	1.75	0.60	0.65	1.20	4.20	4.52	4.87	5.25	5.63	5.25	6.1%	7	6
7	CenterPoint	0.52	0.28	0.30	0.30	1.40	0.55	0.30	0.35	0.30	1.50	1.59	1.69	1.80	1.91	1.80	6.4%	8	7
8	CMS	1.20	0.50	0.56	0.64	2.90	1.25	0.55	0.60	0.70	3.10	3.30	3.52	3.75	3.98	3.75	6.7%	9	8
9	Consol Ed	1.47	0.64	1.47	0.97	4.55	1.53	0.67	1.53	1.02	4.75	4.99	5.24	5.50	5.76	5.50	4.2%	10	9
10	Dominion	1.18	0.77	1.13	1.02	4.10	1.25	0.82	1.20	1.08	4.35	4.65	4.96	5.30	5.64	5.30	5.4%	11	10
11	Duke	1.30	1.14	1.86	1.15	5.45	1.30	1.20	2.00	1.10	5.60	5.89	6.18	6.50	6.82	6.50	4.0%	13	11
12	Edison Int'l	1.07	0.94	1.48	1.11	4.60	1.05	1.00	1.55	1.20	4.80	5.26	5.75	6.30	6.85	6.30	16.1%	14	12
13	Entergy	1.36	1.78	2.84	0.67	6.65	1.40	1.75	2.90	0.75	6.80	7.33	7.89	8.50	9.11	8.50	4.1%	15	13
14	Evergy	0.53	0.84	1.86	0.32	3.55	0.60	0.80	2.05	0.30	3.75	4.06	4.39	4.75	5.11	4.75	7.3%	16	14
15	Eversource	1.30	0.86	1.03	0.91	4.10	1.35	0.92	1.11	1.02	4.40	4.68	4.98	5.30	5.62	5.30	6.4%	17	15
16	Exelon	0.64	0.44	0.70	0.47	2.25	0.64	0.49	0.77	0.50	2.40	2.56	2.90	2.90	2.90	2.90	-1.0%	18	16
17	IDACORP	0.91	1.27	2.10	0.82	5.10	0.65	1.40	2.20	0.95	5.20	5.48	5.78	6.10	6.42	6.10	4.4%	22	17
18	MGE	0.95	0.60	0.95	0.50	3.00	1.00	0.65	1.00	0.50	3.15	3.26	3.38	3.50	3.62	3.50	4.6%	23	18
19	NextEra	0.74	0.81	0.85	0.50	2.90	0.80	0.88	0.92	0.55	3.15	3.44	3.76	4.10	4.44	4.10	10.4%	24	19
20	NorthWestern	1.08	0.58	0.47	1.22	3.35	1.15	0.59	0.58	1.23	3.55	3.69	3.84	4.00	4.16	4.00	2.7%	25	20
21	OGE	0.33	0.36	1.31	0.25	2.25	0.32	0.33	1.25	0.20	2.10	2.43	2.81	3.25	3.69	3.25	6.5%	26	21
22	Otter Tail	1.72	2.05	2.01	0.82	6.60	1.40	1.35	1.20	0.80	4.75	4.39	4.06	3.75	3.44	3.75	4.3%	27	22
23	Pinnacle	0.15	1.45	2.88	-0.23	4.25	0.20	1.50	2.70	0.00	4.40	4.67	4.95	5.25	5.55	5.25	0.7%	30	23
24	Public Serv.	1.33	0.64	0.86	0.65	3.48	1.20	0.70	0.95	0.75	3.60	3.83	4.08	4.35	4.62	4.35	4.0%	33	24
25	Sempra	2.91	1.98	1.97	1.99	8.85	3.00	2.10	2.10	2.10	9.30	9.91	10.56	11.25	11.94	11.25	7.6%	34	25
26	Southern	0.97	1.07	1.31	0.20	3.55	1.00	0.85	1.35	0.50	3.70	4.02	4.37	4.75	5.13	4.75	6.4%	35	26
27	WEC	1.79	0.91	0.96	0.74	4.40	1.80	0.95	1.05	0.90	4.70	4.95	5.22	5.50	5.78	5.50	6.2%	36	27
28	Xcel	0.70	0.60	1.18	0.67	3.15	0.75	0.65	1.25	0.70	3.35	3.55	3.77	4.00	4.23	4.00	6.2%	37	28

	Mean
Company Screen	5.7%
Staff Screen	5.2%
Staff Sensitivity Screen	5.2%

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

	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						2023		Hamada		
	Screen #	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	Ticker	Jan 1/3/2022	Feb 2/1/2023	Mar 3/1/2023	3-Day Avg $ Stock Price	Div Yield at Recent Price	2023 Return on Common Equity	2023 % LT Debt	2023 Common Equity	2023 Preferred Stock	VL Beta	VL 2023 Tax Rate	2023 Unlevered Beta	Relevered Beta Equity at 50.0%	Equity Risk Premium	2023 Adjustment Equity at 50.0%	Screen #	
1	1	Allete	Yes	No	No	ALE	65.13	62.41	61.22	62.92	4.1%	8.0%	39.5	60.5	0.0	0.90	0.0%	0.54	109%	4.50%	0.85%	1	1
2	2	Alliant	Yes	Yes	Yes	LNT	55.37	54.74	50.25	53.45	3.2%	11.5%	54.0	46.0	0.0	0.85	4.0%	0.40	78%	4.50%	-0.30%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	88.49	87.29	81.04	85.61	2.8%	10.0%	53.5	46.0	0.5	0.85	12.0%	0.42	79%	4.50%	-0.29%	3	3
4	4	AEP	Yes	No	Yes	AEP	94.87	94.65	86.36	91.96	3.4%	10.5%	58.0	42.0	0.0	0.75	7.0%	0.33	63%	4.50%	-0.52%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	44.79	41.10	40.59	42.16	4.2%	7.5%	49.5	50.5	0.0	0.90	15.0%	0.49	91%	4.50%	0.04%	6	5
6	7	Black Hills	Yes	No	Yes	BKH	70.45	72.47	61.14	68.02	3.5%	8.0%	56.5	43.5	0.0	0.95	8.5%	0.43	83%	4.50%	-0.53%	7	6
7	8	CenterPoint	Yes	No	No	CNP	29.56	30.10	27.36	29.01	2.4%	10.0%	59.0	38.0	3.0	1.10	20.0%	0.48	86%	4.50%	-1.08%	8	7
8	9	CMS	Yes	No	No	CMS	63.73	63.72	57.78	61.74	3.0%	12.0%	62.0	37.0	1.0	0.80	18.0%	0.33	61%	4.50%	-0.87%	9	8
9	10	Consol Ed	No	Yes	Yes	ED	95.76	95.45	88.15	93.12	3.4%	8.0%	53.0	47.0	0.0	0.75	18.0%	0.39	71%	4.50%	-0.18%	10	9
10	11	Dominion	Yes	No	No	D	62.97	63.1	54.74	60.27	4.4%	12.5%	56.5	41.0	2.5	0.85	17.0%	0.39	71%	4.50%	-0.64%	11	10
11	13	Duke	Yes	No	Yes	DUK	103.70	102.54	91.91	99.38	4.0%	9.0%	58.5	40.0	1.5	0.85	9.0%	0.36	69%	4.50%	-0.74%	13	11
12	14	Edison Int'l	Yes	No	No	EIX	64.28	67.87	64.59	65.58	4.3%	12.5%	56.5	33.5	10.0	0.95	5.0%	0.33	64%	4.50%	-1.39%	14	12
13	15	Entergy	Yes	No	No	ETR	109.13	109.21	101.42	106.59	3.8%	10.5%	66.5	33.0	0.5	0.95	23.0%	0.37	66%	4.50%	-1.32%	15	13
14	16	Evergy	Yes	Yes	Yes	EVRG	62.93	62.89	58.05	61.29	3.8%	9.0%	51.5	48.5	0.0	0.90	9.0%	0.46	87%	4.50%	-0.12%	16	14
15	17	Eversource	No	Yes	Yes	ES	84.22	82.71	73.17	80.03	3.2%	9.5%	55.0	44.5	0.5	0.90	24.0%	0.46	81%	4.50%	-0.39%	17	15
16	18	Exelon	Yes	No	No	EXC	43.16	42.30	39.75	41.74	3.2%	9.5%	61.0	39.0	0.0	0.95	15.0%	0.41	75%	4.50%	-0.88%	18	16
17	22	IDACORP	Yes	Yes	Yes	IDA	108.23	107.59	101.36	105.73	2.9%	9.0%	46.5	53.5	0.0	0.80	13.0%	0.46	85%	4.50%	0.23%	22	17
18	23	MGE	Yes	No	No	MGEE	70.68	74.04	69.95	71.56	2.2%	10.0%	41.0	59.0	0.0	0.75	16.0%	0.47	87%	4.50%	0.55%	23	18
19	24	NextEra	Yes	No	No	NEE	83.83	74.24	69.87	75.98	2.2%	13.5%	56.5	43.5	0.0	0.90	15.0%	0.43	79%	4.50%	-0.49%	24	19
20	25	NorthWestern	Yes	Yes	Yes	NWE	59.79	57.54	56.83	58.05	4.3%	7.5%	49.5	50.5	0.0	0.90	3.0%	0.46	91%	4.50%	0.04%	25	20
21	26	OGE	Yes	Yes	Yes	OGE	39.51	39.83	35.14	38.16	4.3%	12.0%	52.0	48.0	0.0	1.00	12.0%	0.51	96%	4.50%	-0.17%	26	21
22	27	Otter Tail	Yes	No	Yes	OTTR	59.01	65.09	70.40	64.83	2.5%	13.5%	41.5	58.5	0.0	0.85	20.0%	0.54	98%	4.50%	0.57%	27	22
23	30	Pinnacle	Yes	Yes	Yes	PNW	74.63	76.53	73.29	74.82	4.6%	8.0%	54.5	45.5	0.0	0.90	13.5%	0.44	82%	4.50%	-0.34%	30	23
24	33	Public Serv.	Yes	No	No	PEG	62.05	61.81	58.54	60.80	3.6%	12.5%	55.5	44.5	0.0	0.90	20.0%	0.45	81%	4.50%	-0.40%	33	24
25	34	Sempra	Yes	Yes	Yes	SRE	153.71	159.88	147.86	153.82	3.0%	11.0%	47.0	51.0	2.0	0.95	19.0%	0.53	97%	4.50%	0.08%	34	25
26	35	Southern	Yes	No	No	SO	71.90	68.86	62.32	67.69	4.0%	13.0%	64.0	36.0	0.0	0.95	15.0%	0.38	70%	4.50%	-1.13%	35	26
27	36	WEC	Yes	Yes	Yes	WEC	94.16	94.90	86.57	91.88	3.2%	12.5%	55.0	44.5	0.5	0.80	19.0%	0.40	72%	4.50%	-0.36%	36	27
28	37	Xcel	Yes	No	Yes	XEL	70.07	69.61	63.27	67.65	2.9%	10.5%	58.0	42.0	0.0	0.80	0.0%	0.34	67%	4.50%	-0.58%	37	28
		No. of Peers:	26	9	12																		

	Mean (Common Equity)		Mean (Hamada Adjustment)
Company Screen	45.2%	Company Screen	-0.38%
Staff Screen	48.0%	Staff Screen	-0.15%
Staff Sensitivity Screen	47.1%	Staff Sensitivity Screen	-0.21%

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

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

Note: MGE Was Not Covered by VL as of Mar 1, 2023, VL Data Shown is from March 11, 2022 VL Sheet

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

ROE – Three-Stage DCF: Models X and Y

June 13, 2023

4.05% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows Staff Model X

	Screen # (1)	Abbreviated Utility (2)	PGE Yes (3)	Staff No (4)	LT Debt Staff Sensitivity	IRR (5)	Terminal Value as % of NPV_{DIV} (6)	NPV @ IRR (7)	Recent Price* (8)	2020 (9) Initial Stage	2021 (10)	2022 (11)	2023 (12)	2024 (13)	2025 (14) Transition Stage	2026 (15)	2027 (16)	2028 (17)	2029 (18)
1	1	Allete	Yes	No	No	8.3%	31.9%	0.00	(62.92)	2.60	2.70	2.80	2.90	3.00	3.10	3.31	3.51	3.68	3.83
2	2	Alliant	Yes	Yes	Yes	7.8%	37.1%	0.00	(53.45)	1.71	1.81	1.92	2.03	2.15	2.27	2.47	2.64	2.79	2.90
3	3	Ameren	Yes	Yes	Yes	7.5%	40.4%	0.00	(85.61)	2.36	2.52	2.70	2.89	3.10	3.31	3.63	3.91	4.14	4.30
4	4	AEP	Yes	No	Yes	8.0%	34.4%	0.00	(91.96)	3.17	3.35	3.55	3.77	4.00	4.23	4.59	4.91	5.19	5.40
5	6	Avista	Yes	Yes	Yes	8.4%	31.0%	0.00	(42.16)	1.76	1.83	1.90	1.97	2.05	2.13	2.28	2.42	2.54	2.64
6	7	Black Hills	Yes	No	Yes	8.0%	34.7%	0.00	(68.02)	2.41	2.53	2.66	2.80	2.95	3.10	3.35	3.57	3.77	3.92
7	8	CenterPoint	Yes	No	No	7.0%	45.7%	0.00	(29.01)	0.71	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22
8	9	CMS	Yes	No	No	7.5%	39.9%	0.00	(61.74)	1.84	1.94	2.05	2.17	2.30	2.43	2.64	2.82	2.98	3.10
9	10	Consol Ed	No	Yes	Yes	7.3%	40.5%	0.00	(93.12)	3.16	3.24	3.33	3.42	3.52	3.62	3.83	4.04	4.23	4.40
10	11	Dominion	Yes	No	No	8.9%	26.8%	0.00	(60.27)	2.67	2.83	3.01	3.20	3.40	3.60	3.77	3.95	4.11	4.28
11	13	Duke	Yes	No	Yes	7.8%	35.8%	(0.00)	(99.38)	3.98	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29
12	14	Edison Int'l	Yes	No	No	8.9%	27.4%	0.00	(65.58)	2.80	2.95	3.12	3.31	3.50	3.69	4.00	4.27	4.50	4.69
13	15	Entergy	Yes	No	No	8.4%	31.2%	0.00	(106.59)	4.10	4.30	4.55	4.82	5.10	5.38	5.82	6.21	6.55	6.81
14	16	Evergy	Yes	Yes	Yes	8.7%	29.5%	0.00	(61.29)	2.33	2.48	2.66	2.85	3.05	3.25	3.56	3.83	4.05	4.21
15	17	Eversource	No	Yes	Yes	7.9%	36.1%	0.00	(80.03)	2.55	2.70	2.89	3.09	3.30	3.51	3.83	4.11	4.34	4.52
16	18	Exelon	Yes	No	No	7.8%	36.7%	0.00	(41.74)	1.35	1.45	1.54	1.64	1.75	1.86	1.97	2.07	2.17	2.26
17	22	IDACORP	Yes	Yes	Yes	7.6%	39.1%	(0.00)	(105.73)	3.04	3.25	3.48	3.73	4.00	4.27	4.66	5.01	5.29	5.51
18	23	MGE	Yes	No	No	N/A	N/A	N/A	(71.56)	1.59	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49
19	24	NextEra	Yes	No	No	7.3%	42.7%	0.00	(75.98)	1.70	1.87	2.06	2.27	2.50	2.73	3.06	3.34	3.56	3.70
20	25	NorthWestern	Yes	Yes	Yes	8.0%	33.4%	0.00	(58.05)	2.52	2.56	2.60	2.64	2.68	2.72	2.87	3.02	3.15	3.28
21	26	OGE	Yes	Yes	Yes	8.3%	31.4%	0.00	(38.16)	1.64	1.70	1.75	1.80	1.85	1.90	2.02	2.13	2.24	2.33
22	27	Otter Tail	Yes	No	Yes	7.2%	42.8%	0.00	(64.83)	1.65	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05
23	30	Pinnacle	Yes	Yes	Yes	8.3%	31.2%	0.00	(74.82)	3.42	3.48	3.54	3.60	3.66	3.72	3.94	4.15	4.34	4.52
24	33	Public Serv.	Yes	No	No	8.1%	33.5%	0.00	(60.80)	2.16	2.28	2.42	2.56	2.72	2.88	3.12	3.33	3.52	3.66
25	34	Sempra	Yes	Yes	Yes	7.6%	39.2%	0.00	(153.82)	4.58	4.80	5.12	5.46	5.82	6.18	6.72	7.21	7.61	7.92
26	35	Southern	Yes	No	No	8.1%	33.3%	0.00	(67.69)	2.70	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96
27	36	WEC	Yes	Yes	Yes	7.9%	35.9%	0.00	(91.88)	2.91	3.11	3.32	3.55	3.80	4.05	4.43	4.77	5.04	5.25
28	37	Xcel	Yes	No	Yes	7.5%	39.6%	0.00	(67.65)	1.95	2.07	2.21	2.36	2.52	2.68	2.93	3.15	3.33	3.47
		No. of Peers:	26	12	17		Mean												
						7.95%	35.39%	0.00%	Company Screen										
						7.93%	35.41%	0.00%	Staff Screen										
						7.87%	36.01%	0.00%	Staff Sensitivity Screen										

Abbreviated Utility	2030 (19) Final Stage	2031 (20)	2032 (21)	2033 (22)	2034 (23)	2035 (24)	2036 (25)	2037 (26)	2038 (27)	2039 (28)	2040 (29)	2041 (30)	2042 (31)	2043 (32)	2044 (33)	2045 (34)	2046 (35)	2047 (36)	2048 (37)	2046 Terminal Value (38)	2049 Div (39)	2049 Perpetuity (40)	Screen #	
Allete	3.98	4.14	4.31	4.49	4.67	4.86	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.52	7.82	8.14	217.39	8.47	208.92	1	1
Alliant	3.02	3.14	3.27	3.40	3.54	3.68	3.83	3.99	4.15	4.32	4.49	4.67	4.86	5.06	5.27	5.48	5.70	5.93	6.17	186.76	6.42	180.34	2	2
Ameren	4.48	4.66	4.85	5.04	5.25	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	299.94	9.52	290.42	3	3
AEP	5.61	5.84	6.08	6.32	6.58	6.85	7.12	7.41	7.71	8.03	8.35	8.69	9.04	9.41	9.79	10.18	10.60	11.03	11.47	322.78	11.94	310.84	4	4
Avista	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	146.32	5.85	140.47	6	5
Black Hills	4.08	4.24	4.42	4.59	4.78	4.97	5.18	5.39	5.60	5.83	6.07	6.31	6.57	6.83	7.11	7.40	7.70	8.01	8.33	237.34	8.67	228.67	7	6
CenterPoint	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	99.65	2.71	96.94	8	7
CMS	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.80	4.99	5.19	5.40	5.62	5.85	6.09	6.33	6.59	214.68	6.86	207.83	9	8
Consol Ed	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	7.08	7.37	7.66	7.98	8.30	8.63	8.98	9.35	316.54	9.73	306.81	10	9
Dominion	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.89	7.17	7.46	7.77	8.08	8.41	8.75	9.10	210.98	9.47	201.50	11	10
Duke	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	337.34	11.70	325.64	13	11
Edison Int'l	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.20	9.58	9.96	232.60	10.37	222.23	14	12
Entergy	7.09	7.37	7.67	7.98	8.31	8.64	8.99	9.36	9.74	10.13	10.54	10.97	11.41	11.87	12.35	12.85	13.38	13.92	14.48	375.02	15.07	359.95	15	13
Evergy	4.38	4.56	4.74	4.93	5.13	5.34	5.56	5.78	6.02	6.26	6.52	6.78	7.05	7.34	7.64	7.95	8.27	8.60	8.95	218.94	9.31	209.63	16	14
Eversource	4.70	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	281.55	10.00	271.55	17	15
Exelon	2.35	2.45	2.55	2.65	2.76	2.87	2.98	3.10	3.23	3.36	3.50	3.64	3.79	3.94	4.10	4.27	4.44	4.62	4.81	144.85	5.00	139.85	18	16
IDACORP	5.73	5.96	6.20	6.46	6.72	6.99	7.27	7.57	7.87	8.19	8.52	8.87	9.23	9.60	9.99	10.40	10.82	11.26	11.71	370.74	12.19	358.55	22	17
MGE	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	#VALUE!	5.51	#VALUE!	23	18
NextEra	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	5.73	5.96	6.20	6.45	6.72	6.99	7.27	7.56	7.87	269.65	8.19	261.46	24	19
NorthWestern	3.41	3.55	3.70	3.84	4.00	4.16	4.33	4.51	4.69	4.88	5.08	5.28	5.50	5.72	5.95	6.19	6.44	6.70	6.97	196.97	7.26	189.71	25	20
OGE	2.42	2.52	2.62	2.73	2.84	2.95	3.07	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.39	4.57	4.76	4.95	131.20	5.15	126.05	26	21
Otter Tail	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	226.48	6.75	219.73	27	22
Pinnacle	4.70	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	255.04	10.00	245.04	30	23
Public Serv.	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	5.23	5.44	5.66	5.89	6.13	6.38	6.64	6.90	7.18	7.47	7.78	213.58	8.09	205.49	33	24
Sempra	8.24	8.57	8.92	9.28	9.66	10.05	10.45	10.88	11.32	11.78	12.25	12.75	13.27	13.80	14.36	14.95	15.55	16.18	16.84	537.13	17.52	519.61	34	25
Southern	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	233.45	8.75	224.70	35	26
WEC	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	9.90	10.31	10.72	11.16	323.98	11.61	312.38	36	27
Xcel	3.61	3.75	3.91	4.06	4.23	4.40	4.58	4.76	4.96	5.16	5.37	5.58	5.81	6.04	6.29	6.54	6.81	7.09	7.37	236.76	7.67	229.09	37	28

B.O.Y. Cash Flows Staff Model X

	Screen # (1)	Abbreviated Utility (2)	PGE Yes (3)	Staff No (4)	LT Debt Staff Sensitivity	IRR (5)	Terminal Value as % of NPV_{DIV} (6)	NPV @ IRR (7)	Recent Price* (8)	2020 (9) Initial Stage	2021 (10)	2022 (11)	2023 (12)	2024 (13)	2025 (14) Transition Stage	2026 (15)	2027 (16)	2028 (17)	2029 (18)
1	1	Allete	Yes	No	No	8.4%	30.4%	0.00	(62.92)	2.70	2.80	2.90	3.00	3.10	3.31	3.51	3.68	3.83	3.98
2	2	Alliant	Yes	Yes	Yes	7.9%	35.4%	0.00	(53.45)	1.81	1.92	2.03	2.15	2.27	2.47	2.64	2.79	2.90	3.02
3	3	Ameren	Yes	Yes	Yes	7.6%	38.6%	0.00	(85.61)	2.52	2.70	2.89	3.10	3.31	3.63	3.91	4.14	4.30	4.48
4	4	AEP	Yes	No	Yes	8.2%	32.7%	0.00	(91.96)	3.35	3.55	3.77	4.00	4.23	4.59	4.91	5.19	5.40	5.61
5	6	Avista	Yes	Yes	Yes	8.6%	29.5%	0.00	(42.16)	1.83	1.90	1.97	2.05	2.13	2.28	2.42	2.54	2.64	2.75
6	7	Black Hills	Yes	No	Yes	8.2%	33.0%	0.00	(68.02)	2.53	2.66	2.80	2.95	3.10	3.35	3.57	3.77	3.92	4.08
7	8	CenterPoint	Yes	No	No	7.1%	43.9%	0.00	(29.01)	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27
8	9	CMS	Yes	No	No	7.6%	38.2%	(0.00)	(61.74)	1.94	2.05	2.17	2.30	2.43	2.64	2.82	2.98	3.10	3.22
9	10	Consol Ed	No	Yes	Yes	7.5%	39.1%	0.00	(93.12)	3.24	3.33	3.42	3.52	3.62	3.83	4.04	4.23	4.40	4.57
10	11	Dominion	Yes	No	No	9.2%	25.2%	0.00	(60.27)	2.83	3.01	3.20	3.40	3.60	3.77	3.95	4.11	4.28	4.46
11	13	Duke	Yes	No	Yes	7.9%	34.5%	0.00	(99.38)	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50
12	14	Edison Int'l	Yes	No	No	9.1%	25.8%	0.00	(65.58)	2.95	3.12	3.31	3.50	3.69	4.00	4.27	4.50	4.69	4.88
13	15	Entergy	Yes	No	No	8.6%	29.5%	0.00	(106.59)	4.30	4.55	4.82	5.10	5.38	5.82	6.21	6.55	6.81	7.09
14	16	Evergy	Yes	Yes	Yes	8.9%	27.6%	0.00	(61.29)	2.48	2.66	2.85	3.05	3.25	3.56	3.83	4.05	4.21	4.38
15	17	Eversource	No	Yes	Yes	8.1%	34.3%	0.00	(80.03)	2.70	2.89	3.09	3.30	3.51	3.83	4.11	4.34	4.52	4.70
16	18	Exelon	Yes	No	No	7.9%	35.0%	0.00	(41.74)	1.45	1.54	1.64	1.75	1.86	1.97	2.07	2.17	2.26	2.35
17	22	IDACORP	Yes	Yes	Yes	7.7%	37.2%	0.00	(105.73)	3.25	3.48	3.73	4.00	4.27	4.66	5.01	5.29	5.51	5.73
18	23	MGE	Yes	No	No	N/A	N/A	N/A	(71.56)	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59
19	24	NextEra	Yes	No	No	7.5%	40.6%	0.00	(75.98)	1.87	2.06	2.27	2.50	2.73	3.06	3.34	3.56	3.70	3.85
20	25	NorthWestern	Yes	Yes	Yes	8.2%	32.2%	0.00	(58.05)	2.56	2.60	2.64	2.68	2.72	2.87	3.02	3.15	3.28	3.41
21	26	OGE	Yes	Yes	Yes	8.5%	30.0%	0.00	(38.16)	1.70	1.75	1.80	1.85	1.90	2.02	2.13	2.24	2.33	2.42
22	27	Otter Tail	Yes	No	Yes	7.4%	40.9%	0.00	(64.83)	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17
23	30	Pinnacle	Yes	Yes	Yes	8.5%	30.0%	0.00	(74.82)	3.48	3.54	3.60	3.66	3.72	3.94	4.15	4.34	4.52	4.70
24	33	Public Serv.	Yes	No	No	8.3%	31.7%	0.00	(60.80)	2.28	2.42	2.56	2.72	2.88	3.12	3.33	3.52	3.66	3.81
25	34	Sempra	Yes	Yes	Yes	7.7%	37.5%	0.00	(153.82)	4.80	5.12	5.46	5.82	6.18	6.72	7.21	7.61	7.92	8.24
26	35	Southern	Yes	No	No	8.3%	31.8%	0.00	(67.69)	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12
27	36	WEC	Yes	Yes	Yes	8.1%	34.0%	0.00	(91.88)	3.11	3.32	3.55	3.80	4.05	4.43	4.77	5.04	5.25	5.46
28	37	Xcel	Yes	No	Yes	7.7%	37.7%	0.00	(67.65)	2.07	2.21	2.36	2.52	2.68	2.93	3.15	3.33	3.47	3.61
		No. of Peers:	26	12	17		Mean												
						8.12%	33.72%	0.00%	Company Screen										
						8.10%	33.78%	0.00%	Staff Screen										
						8.04%	34.37%	0.00%	Staff Sensitivity Screen										

Abbreviated Utility	2030 (19) Final Stage	2031 (20)	2032 (21)	2033 (22)	2034 (23)	2035 (24)	2036 (25)	2037 (26)	2038 (27)	2039 (28)	2040 (29)	2041 (30)	2042 (31)	2043 (32)	2044 (33)	2045 (34)	2046 (35)	2047 (36)	2048 (37)	2046 Terminal Value (38)	2049 Div (39)	2049 Perpetuity (40)	Screen #	
Allete	4.14	4.31	4.49	4.67	4.86	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.52	7.82	8.14	8.47	217.62	8.81	208.81	1	1
Alliant	3.14	3.27	3.40	3.54	3.68	3.83	3.99	4.15	4.32	4.49	4.67	4.86	5.06	5.27	5.48	5.70	5.93	6.17	6.42	186.29	6.68	179.61	2	2
Ameren	4.66	4.85	5.04	5.25	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	298.80	9.91	288.90	3	3
AEP	5.84	6.08	6.32	6.58	6.85	7.12	7.41	7.71	8.03	8.35	8.69	9.04	9.41	9.79	10.18	10.60	11.03	11.47	11.94	321.91	12.42	309.48	4	4
Avista	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	5.85	146.40	6.08	140.32	6	5
Black Hills	4.24	4.42	4.59	4.78	4.97	5.18	5.39	5.60	5.83	6.07	6.31	6.57	6.83	7.11	7.40	7.70	8.01	8.33	8.67	236.97	9.02	227.95	7	6
CenterPoint	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	2.71	99.38	2.82	96.56	8	7
CMS	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.80	4.99	5.19	5.40	5.62	5.85	6.09	6.33	6.59	6.86	214.21	7.13	207.08	9	8
Consol Ed	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	7.08	7.37	7.66	7.98	8.30	8.63	8.98	9.35	9.73	317.23	10.12	307.11	10	9
Dominion	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.89	7.17	7.46	7.77	8.08	8.41	8.75	9.10	9.47	210.56	9.86	200.71	11	10
Duke	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	11.70	338.62	12.18	326.45	13	11
Edison Int'l	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.20	9.58	9.96	10.37	231.98	10.79	221.20	14	12
Entergy	7.37	7.67	7.98	8.31	8.64	8.99	9.36	9.74	10.13	10.54	10.97	11.41	11.87	12.35	12.85	13.38	13.92	14.48	15.07	374.18	15.68	358.50	15	13
Evergy	4.56	4.74	4.93	5.13	5.34	5.56	5.78	6.02	6.26	6.52	6.78	7.05	7.34	7.64	7.95	8.27	8.60	8.95	9.31	217.95	9.69	208.26	16	14
Eversource	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	10.00	280.55	10.41	270.15	17	15
Exelon	2.45	2.55	2.65	2.76	2.87	2.98	3.10	3.23	3.36	3.50	3.64	3.79	3.94	4.10	4.27	4.44	4.62	4.81	5.00	144.48	5.20	139.28	18	16
IDACORP	5.96	6.20	6.46	6.72	6.99	7.27	7.57	7.87	8.19	8.52	8.87	9.23	9.60	9.99	10.40	10.82	11.26	11.71	12.19	369.33	12.68	356.65	22	17
MGE	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	#VALUE!	5.73	#VALUE!	23	18
NextEra	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	5.73	5.96	6.20	6.45	6.72	6.99	7.27	7.56	7.87	8.19	267.85	8.52	259.33	24	19
NorthWestern	3.55	3.70	3.84	4.00	4.16	4.33	4.51	4.69	4.88	5.08	5.28	5.50	5.72	5.95	6.19	6.44	6.70	6.97	7.26	197.89	7.55	190.34	25	20
OGE	2.52	2.62	2.73	2.84	2.95	3.07	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.39	4.57	4.76	4.95	5.15	131.48	5.36	126.12	26	21
Otter Tail	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	6.75	225.60	7.02	218.58	27	22
Pinnacle	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	10.00	256.20	10.41	245.79	30	23
Public Serv.	3.96	4.12	4.29	4.46	4.64	4.83	5.03	5.23	5.44	5.66	5.89	6.13	6.38	6.64	6.90	7.18	7.47	7.78	8.09	213.02	8.42	204.60	33	24
Sempra	8.57	8.92	9.28	9.66	10.05	10.45	10.88	11.32	11.78	12.25	12.75	13.27	13.80	14.36	14.95	15.55	16.18	16.84	17.52	535.65	18.23	517.43	34	25
Southern	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	8.75	233.74	9.10	224.63	35	26
WEC	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	9.90	10.31	10.72	11.16	11.61	322.71	12.08	310.63	36	27
Xcel	3.75	3.91	4.06	4.23	4.40	4.58	4.76	4.96	5.16	5.37	5.58	5.81	6.04	6.29	6.54	6.81	7.09	7.37	7.67	235.97	7.98	227.99	37	28

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

	1	2	3	4		5	6	7	8	9		
	Screen #	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2020- 2024 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	Allete	Yes	No	No	8.4%	31.1%	3.6%	3.5%	3.6%	1	1
2	2	Alliant	Yes	Yes	Yes	7.8%	36.3%	5.9%	5.8%	5.9%	2	2
3	3	Ameren	Yes	Yes	Yes	7.5%	39.5%	7.1%	7.0%	7.0%	3	3
4	4	AEP	Yes	No	Yes	8.1%	33.5%	6.0%	6.0%	6.0%	4	4
5	6	Avista	Yes	Yes	Yes	8.5%	30.3%	3.9%	3.8%	3.9%	6	5
6	7	Black Hills	Yes	No	Yes	8.1%	33.9%	5.2%	5.2%	5.2%	7	6
7	8	CenterPoint	Yes	No	No	7.0%	44.8%	7.6%	7.1%	7.3%	8	7
8	9	CMS	Yes	No	No	7.6%	39.0%	5.7%	5.8%	5.7%	9	8
9	10	Consol Ed	No	Yes	Yes	7.4%	39.8%	2.7%	2.8%	2.8%	10	9
10	11	Dominion	Yes	No	No	9.1%	26.0%	6.2%	6.2%	6.2%	11	10
11	13	Duke	Yes	No	Yes	7.9%	35.1%	2.0%	1.9%	1.9%	13	11
12	14	Edison Int'l	Yes	No	No	9.0%	26.6%	5.7%	5.8%	5.8%	14	12
13	15	Entergy	Yes	No	No	8.5%	30.4%	5.6%	5.8%	5.7%	15	13
14	16	Evergy	Yes	Yes	Yes	8.8%	28.5%	7.0%	7.0%	7.0%	16	14
15	17	Eversource	No	Yes	Yes	8.0%	35.2%	6.7%	6.8%	6.7%	17	15
16	18	Exelon	Yes	No	No	7.9%	35.9%	6.7%	6.4%	6.5%	18	16
17	22	IDACORP	Yes	Yes	Yes	7.7%	38.2%	7.1%	7.0%	7.1%	22	17
18	23	MGE	Yes	No	No	N/A	N/A	4.6%	4.6%	4.6%	23	18
19	24	NextEra	Yes	No	No	7.4%	41.7%	10.1%	9.9%	10.0%	24	19
20	25	NorthWestern	Yes	Yes	Yes	8.1%	32.8%	1.6%	1.5%	1.5%	25	20
21	26	OGE	Yes	Yes	Yes	8.4%	30.7%	3.1%	2.8%	2.9%	26	21
22	27	Otter Tail	Yes	No	Yes	7.3%	41.9%	7.5%	7.6%	7.5%	27	22
23	30	Pinnacle	Yes	Yes	Yes	8.4%	30.6%	1.7%	1.7%	1.7%	30	23
24	33	Public Serv.	Yes	No	No	8.2%	32.6%	5.9%	6.0%	6.0%	33	24
25	34	Sempra	Yes	Yes	Yes	7.6%	38.3%	6.2%	6.5%	6.4%	34	25
26	35	Southern	Yes	No	No	8.2%	32.6%	3.5%	3.7%	3.6%	35	26
27	36	WEC	Yes	Yes	Yes	8.0%	34.9%	6.9%	6.8%	6.8%	36	27
28	37	Xcel	Yes	No	Yes	7.6%	38.7%	6.6%	6.7%	6.6%	37	28
		No. of Peers:	26	12	17	Mean						
						8.04%	34.56%	5.49%	Company Screen			
						8.02%	34.59%	4.97%	Staff Screen			
						7.95%	35.19%	5.11%	Staff Sensitivity Screen			

4.05% 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	PGE Yes	Staff No	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Sale	2050	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	Yes	No	No	8.6%	34.4%	0.00	(62.92)	2.60	2.70	2.80	2.90	3.00	3.10	3.31	3.51	3.68	3.83	3.98	4.14	4.31	4.49	4.67	4.86	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.52	7.82	8.14	257.92	8.47	249.45		1	1
				e	e					3.75	3.95	4.20	4.47	4.75	5.03	5.48	5.88	6.21	6.46	6.72	6.99	7.28	7.57	7.88	8.20	8.53	8.87	9.23	9.61	10.00	10.40	10.82	11.26	11.72	12.19	12.68	13.20	13.73		14.29		14.87		
2	2	Alliant	Yes	Yes	Yes	8.1%	39.8%	0.00	(53.45)	1.71	1.81	1.92	2.03	2.15	2.27	2.47	2.64	2.79	2.90	3.02	3.14	3.27	3.40	3.54	3.68	3.83	3.99	4.15	4.32	4.49	4.67	4.86	5.06	5.27	5.48	5.70	5.93	6.17	221.69	6.42	215.27		2	2
				e	e					2.70	2.95	3.12	3.31	3.50	3.69	4.01	4.30	4.54	4.72	4.92	5.11	5.32	5.54	5.76	5.99	6.24	6.49	6.75	7.03	7.31	7.61	7.91	8.24	8.57	8.92	9.28	9.65	10.04		10.45		10.87		
3	3	Ameren	Yes	Yes	Yes	7.8%	43.1%	0.00	(85.61)	2.36	2.52	2.70	2.89	3.10	3.31	3.63	3.91	4.14	4.30	4.48	4.66	4.85	5.04	5.25	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	355.16	9.52	345.64		3	3
				e	e					4.10	4.35	4.63	4.93	5.25	5.57	6.08	6.54	6.91	7.19	7.48	7.79	8.10	8.43	8.77	9.13	9.50	9.88	10.28	10.70	11.13	11.58	12.05	12.54	13.05	13.57	14.12	14.70	15.29		15.91		16.55		
4	4	AEP	Yes	No	Yes	8.4%	37.3%	0.00	(91.96)	3.17	3.35	3.55	3.77	4.00	4.23	4.59	4.91	5.19	5.40	5.61	5.84	6.08	6.32	6.58	6.85	7.12	7.41	7.71	8.03	8.35	8.69	9.04	9.41	9.79	10.18	10.60	11.03	11.47	388.04	11.94	376.11		4	4
				e	e					5.00	5.35	5.71	6.09	6.50	6.91	7.53	8.08	8.54	8.88	9.24	9.62	10.01	10.41	10.83	11.27	11.73	12.20	12.70	13.21	13.75	14.31	14.88	15.49	16.11	16.77	17.45	18.15	18.89		19.65		20.45		
5	6	Avista	Yes	Yes	Yes	9.0%	35.4%	0.00	(42.16)	1.76	1.83	1.90	1.97	2.05	2.13	2.28	2.42	2.54	2.64	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	196.60	5.85	190.75		6	5
				e	e					1.90	2.35	2.51	2.67	2.85	3.03	3.23	3.42	3.59	3.73	3.89	4.04	4.21	4.38	4.55	4.74	4.93	5.13	5.34	5.55	5.78	6.01	6.26	6.51	6.77	7.05	7.33	7.63	7.94		8.26		8.60		
6	7	Black Hills	Yes	No	Yes	8.4%	37.7%	0.00	(68.02)	2.41	2.53	2.66	2.80	2.95	3.10	3.35	3.57	3.77	3.92	4.08	4.24	4.42	4.59	4.78	4.97	5.18	5.39	5.60	5.83	6.07	6.31	6.57	6.83	7.11	7.40	7.70	8.01	8.33	287.43	8.67	278.76		7	6
				e	e					4.05	4.20	4.52	4.87	5.25	5.63	6.12	6.56	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	9.91	10.31	10.72	11.16	11.61	12.08	12.57	13.08	13.61	14.16	14.73	15.33		15.95		16.60		
7	8	CenterPoint	Yes	No	No	7.4%	48.5%	0.00	(29.01)	0.71	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	119.67	2.71	116.96		8	7
				e	e					1.40	1.50	1.59	1.69	1.80	1.91	2.08	2.23	2.36	2.45	2.55	2.66	2.76	2.87	2.99	3.11	3.24	3.37	3.51	3.65	3.80	3.95	4.11	4.28	4.45	4.63	4.82	5.01	5.21		5.43		5.65		
8	9	CMS	Yes	No	No	7.9%	42.9%	0.00	(61.74)	1.84	1.94	2.05	2.17	2.30	2.43	2.64	2.82	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.80	4.99	5.19	5.40	5.62	5.85	6.09	6.33	6.59	258.99	6.86	252.13		9	8
				e	e					2.90	3.10	3.30	3.52	3.75	3.98	4.35	4.68	4.94	5.14	5.35	5.57	5.80	6.03	6.27	6.53	6.79	7.07	7.35	7.65	7.96	8.28	8.62	8.97	9.33	9.71	10.10	10.51	10.94		11.38		11.84		
9	10	Consol Ed	No	Yes	Yes	7.6%	42.0%	(0.00)	(93.12)	3.16	3.24	3.33	3.42	3.52	3.62	3.83	4.04	4.23	4.40	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	7.08	7.37	7.66	7.98	8.30	8.63	8.98	9.35	347.97	9.73	338.25		10	9
				e	e					4.55	4.75	4.99	5.24	5.50	5.76	6.18	6.56	6.90	7.18	7.47	7.77	8.09	8.42	8.76	9.11	9.48	9.86	10.26	10.68	11.11	11.56	12.03	12.52	13.02	13.55	14.10	14.67	15.27		15.88		16.53		
10	11	Dominion	Yes	No	No	9.3%	29.3%	0.00	(60.27)	2.67	2.83	3.01	3.20	3.40	3.60	3.77	3.95	4.11	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.89	7.17	7.46	7.77	8.08	8.41	8.75	9.10	251.26	9.47	241.78		11	10
				e	e					4.10	4.35	4.65	4.96	5.30	5.64	6.10	6.51	6.87	7.15	7.43	7.74	8.05	8.38	8.71	9.07	9.43	9.82	10.21	10.63	11.06	11.51	11.97	12.46	12.96	13.49	14.03	14.60	15.19		15.81		16.45		
11	13	Duke	Yes	No	Yes	8.0%	37.1%	0.00	(99.38)	3.98	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	367.33	11.70	355.63		13	11
				e	e					5.45	5.60	5.89	6.18	6.50	6.82	7.30	7.75	8.14	8.47	8.82	9.17	9.54	9.93	10.33	10.75	11.19	11.64	12.11	12.60	13.11	13.64	14.20	14.77	15.37	15.99	16.64	17.31	18.01		18.74		19.50		
12	14	Edison Int'l	Yes	No	No	9.6%	32.9%	0.00	(65.58)	2.80	2.95	3.12	3.31	3.50	3.69	4.00	4.27	4.50	4.69	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.20	9.58	9.96	339.65	10.37	329.28		14	12
				e	e					4.60	4.80	5.26	5.75	6.30	6.85	7.97	8.93	9.64	10.03	10.44	10.86	11.30	11.76	12.24	12.73	13.25	13.79	14.34	14.92	15.53	16.16	16.81	17.49	18.20	18.94	19.71	20.50	21.33		22.20		23.10		
13	15	Entergy	Yes	No	No	8.7%	33.4%	0.00	######	4.10	4.30	4.55	4.82	5.10	5.38	5.82	6.21	6.55	6.81	7.09	7.37	7.67	7.98	8.31	8.64	8.99	9.36	9.74	10.13	10.54	10.97	11.41	11.87	12.35	12.85	13.38	13.92	14.48	433.30	15.07	418.23		15	13
				e	e					6.65	6.80	7.33	7.89	8.50	9.11	9.77	10.37	10.89	11.34	11.79	12.27	12.77	13.29	13.82	14.38	14.97	15.57	16.20	16.86	17.54	18.25	18.99	19.76	20.56	21.40	22.26	23.16	24.10		25.08		26.09		
14	16	Evergy	Yes	Yes	Yes	9.1%	32.8%	0.00	(61.29)	2.33	2.48	2.66	2.85	3.05	3.25	3.56	3.83	4.05	4.21	4.38	4.56	4.74	4.93	5.13	5.34	5.56	5.78	6.02	6.26	6.52	6.78	7.05	7.34	7.64	7.95	8.27	8.60	8.95	273.78	9.31	264.47		16	14
				e	e					3.55	3.75	4.06	4.39	4.75	5.11	5.60	6.04	6.40	6.65	6.92	7.20	7.50	7.80	8.12	8.44	8.79	9.14	9.51	9.90	10.30	10.72	11.15	11.60	12.07	12.56	13.07	13.60	14.15		14.72		15.32		
15	17	Eversource	No	Yes	Yes	8.2%	38.8%	0.00	(80.03)	2.55	2.70	2.89	3.09	3.30	3.51	3.83	4.11	4.34	4.52	4.70	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	334.77	10.00	324.77		17	15
				e	e					4.10	4.40	4.68	4.98	5.30	5.62	6.12	6.57	6.95	7.23	7.52	7.83	8.14	8.47	8.81	9.17	9.54	9.93	10.33	10.75	11.19	11.64	12.11	12.60	13.11	13.64	14.19	14.77	15.37		15.99		16.64		
16	18	Exelon	Yes	No	No	7.8%	37.1%	0.00	(41.74)	1.35	1.45	1.54	1.64	1.75	1.86	1.97	2.07	2.17	2.26	2.35	2.45	2.55	2.65	2.76	2.87	2.98	3.10	3.23	3.36	3.50	3.64	3.79	3.94	4.10	4.27	4.44	4.62	4.81	147.89	5.00	142.89		18	16
				e	e					2.25	2.40	2.56	2.90	2.90	2.90	2.99	3.10	3.22	3.35	3.48	3.62	3.77	3.92	4.08	4.25	4.42	4.60	4.78	4.98	5.18	5.39	5.61	5.83	6.07	6.32	6.57	6.84	7.12		7.40		7.70		
17	22	IDACORP	Yes	Yes	Yes	7.7%	40.1%	(0.00)	######	3.04	3.25	3.48	3.73	4.00	4.27	4.66	5.01	5.29	5.51	5.73	5.96	6.20	6.46	6.72	6.99	7.27	7.57	7.87	8.19	8.52	8.87	9.23	9.60	9.99	10.40	10.82	11.26	11.71	394.96	12.19	382.77		22	17
				e	e					5.10	5.20	5.48	5.78	6.10	6.42	6.89	7.33	7.71	8.02	8.35	8.68	9.04	9.40	9.78	10.18	10.59	11.02	11.47	11.93	12.41	12.92	13.44	13.98	14.55	15.14	15.75	16.39	17.05		17.75		18.46		
18	23	MGE	Yes	No	Yes	6.6%	52.7%	0.00	(71.56)	1.59	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	254.68	5.51	249.17		23	18
				e	e					3.00	3.15	3.26	3.38	3.50	3.62	3.90	4.15	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.49	6.75	7.02	7.31	7.60	7.91	8.23	8.57	8.91	9.27	9.65		10.04		10.45		
19	24	NextEra	Yes	No	No	8.1%	47.9%	0.00	(75.98)	1.70	1.87	2.06	2.27	2.50	2.73	3.06	3.34	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	5.73	5.96	6.20	6.45	6.72	6.99	7.27	7.56	7.87	372.71	8.19	364.52		24	19
				e	e					2.90	3.15	3.44	3.76	4.10	4.44	4.98	5.45	5.81	6.04	6.29	6.54	6.81	7.08	7.37	7.67	7.98	8.30	8.64	8.99	9.35	9.73	10.13	10.54	10.96	11.41	11.87	12.35	12.85		13.37		13.91		
20	25	NorthWestern	Yes	Yes	Yes	8.2%	34.3%	0.00	(58.05)	2.52	2.56	2.60	2.64	2.68	2.72	2.87	3.02	3.15	3.28	3.41	3.55	3.70	3.84	4.00	4.16	4.33	4.51	4.69	4.88	5.08	5.28	5.50	5.72	5.95	6.19	6.44	6.70	6.97	209.38	7.26	202.13		25	20
				e	e					3.35	3.55	3.69	3.84	4.00	4.16	4.41	4.65	4.87	5.07	5.27	5.49	5.71	5.94	6.18	6.43	6.69	6.96	7.24	7.54	7.84	8.16	8.49	8.83	9.19	9.56	9.95	10.35	10.77		11.21		11.66		
21	26	OGE	Yes	Yes	Yes	9.1%	37.0%	0.00	(38.16)	1.64	1.70	1.75	1.80	1.85	1.90	2.02	2.13	2.24	2.33	2.42	2.52	2.62	2.73	2.84	2.95	3.07	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.39	4.57	4.76	4.95	190.76	5.15	185.61		26	21
				e	e					2.25	2.10	2.43	2.81	3.25	3.69	4.03	4.32	4.57	4.75	4.95	5.15	5.36	5.57	5.80	6.03	6.28	6.53	6.80	7.07	7.36	7.66	7.97	8.29	8.62	8.97	9.34	9.72	10.11		10.52		10.94		
22	27	Otter Tail	Yes	No	Yes	5.7%	30.2%	0.00	(64.83)	1.65	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	103.91	6.75	97.16		27	22
				e	e					6.60	4.75	4.39	4.06	3.75	3.44	3.70	3.93	4.13	4.30	4.47	4.65	4.84	5.04	5.24	5.45	5.67	5.90	6.14	6.39	6.65	6.92	7.20	7.49	7.79	8.11	8.44	8.78	9.14		9.51		9.89		
23	30	Pinnacle	Yes	Yes	Yes	8.5%	32.4%	0.00	(74.82)	3.42	3.48	3.54	3.60	3.66	3.72	3.94	4.15	4.34	4.52	4.70	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	276.27	10.00	266.27		30	23
				e	e					4.25	4.40	4.67	4.95	5.25	5.55	5.80	6.06	6.32	6.57	6.84	7.11	7.40	7.70	8.01	8.34	8.68	9.03	9.39	9.77	10.17	10.58	11.01	11.46	11.92	12.40	12.90	13.43	13.97		14.54		15.13		
24	33	Public Serv.	Yes	No	No	8.4%	35.2%	0.00	(60.80)	2.16	2.28	2.42	2.56	2.72	2.88	3.12	3.33	3.52	3.66	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	5.23	5.44	5.66	5.89	6.13	6.38	6.64	6.90	7.18	7.47	7.78	238.72	8.09	230.63		33	24
				e	e					3.48	3.60	3.83	4.08	4.35	4.62	4.94	5.25	5.51	5.73	5.97	6.21	6.46	6.72	6.99	7.28	7.57	7.88	8.20	8.53	8.87	9.23	9.61	10.00	10.40	10.82	11.26	11.72	12.19		12.69		13.20		
25	34	Sempra	Yes	Yes	Yes	8.0%	42.1%	0.00	######	4.58	4.80	5.12	5.46	5.82	6.18	6.72	7.21	7.61	7.92	8.24	8.57	8.92	9.28	9.66	10.05	10.45	10.88	11.32	11.78	12.25	12.75	13.27	13.80	14.36	14.95	15.55	16.18	16.84	642.81	17.52	625.29		34	25
				e	e					8.85	9.30	9.91	10.56	11.25	11.94	13.13	14.17	15.02	15.63	16.26	16.92	17.61	18.32	19.06	19.83	20.64	21.47	22.34	23.25	24.19	25.17	26.19	27.25	28.35	29.50	30.69	31.94	33.23		34.58		35.98		
26	35	Southern	Yes	No	No	8.6%	37.0%	0.00	(67.69)	2.70	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	298.25	8.75	289.50		35	26
				e	e					3.55	3.70	4.02	4.37	4.75	5.13	5.59	6.00	6.34	6.60	6.86	7.14	7.43	7.73	8.04	8.37	8.71	9.06	9.43	9.81	10.21	10.62	11.05	11.50	11.96	12.45	12.95	13.48	14.02		14.59		15.18		
27	36	WEC	Yes	Yes	Yes	8.2%	37.9%	0.00	(91.88)	2.91	3.11	3.32	3.55	3.80	4.05	4.43	4.77	5.04	5.25	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	9.90	10.31	10.72	11.16	368.20	11.61	356.59		36	27
				e	e					4.40	4.70	4.95	5.22	5.50	5.78	6.29	6.75	7.13	7.42	7.72	8.03	8.36	8.70	9.05	9.41	9.80	10.19	10.61	11.03	11.48	11.95	12.43	12.93	13.46	14.00	14.57	15.16	15.77		16.41		17.08		
28	37	Xcel	Yes	No	Yes	7.9%	42.0%	0.00	(67.65)	1.95	2.07	2.21	2.36	2.52	2.68	2.93	3.15	3.33	3.47	3.61	3.75	3.91	4.06	4.23	4.40	4.58	4.76	4.96	5.16	5.37	5.58	5.81	6.04	6.29	6.54	6.81	7.09	7.37	275.77	7.67	268.10		37	28
				e	e					3.15	3.35	3.55	3.77	4.00	4.23	4.60	4.93	5.21	5.42	5.64	5.87	6.11	6.36	6.61	6.88	7.16	7.45	7.75	8.07	8.39	8.73	9.09	9.45	9.84	10.24	10.65	11.08	11.53		12.00		12.48		
		No. of Peers:	26	12	17																																							

Mean			
8.18%	38.09%	0.00%	Company Screen
8.28%	37.97%	0.00%	Staff Screen
8.10%	37.64%	0.00%	Staff Sensitivity Screen

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

	#	Abbreviated Utility	PGE Yes	Staff No	LT Debt Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2046 Terminal Value	2049 Div	2049 Sale	2050	#	
	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	Yes	No	No	8.8%	32.9%	0.00	(62.92)	2.70	2.80	2.90	3.00	3.10	3.31	3.51	3.68	3.83	3.98	4.14	4.31	4.49	4.67	4.86	5.05	5.26	5.47	5.69	5.92	6.16	6.41	6.67	6.94	7.22	7.52	7.82	8.14	8.47	258.26	8.81	249.45		1	1
				e	e					3.75	3.95	4.20	4.47	4.75	5.03	5.48	5.88	6.21	6.46	6.72	6.99	7.28	7.57	7.88	8.20	8.53	8.87	9.23	9.61	10.00	10.40	10.82	11.26	11.72	12.19	12.68	13.20	13.73		14.29		14.87		
2	2	Alliant	Yes	Yes	Yes	8.3%	38.1%	0.00	(53.45)	1.81	1.92	2.03	2.15	2.27	2.47	2.64	2.79	2.90	3.02	3.14	3.27	3.40	3.54	3.68	3.83	3.99	4.15	4.32	4.49	4.67	4.86	5.06	5.27	5.48	5.70	5.93	6.17	6.42	221.95	6.68	215.27		2	2
				e	e					2.70	2.95	3.12	3.31	3.50	3.69	4.01	4.30	4.54	4.72	4.92	5.11	5.32	5.54	5.76	5.99	6.24	6.49	6.75	7.03	7.31	7.61	7.91	8.24	8.57	8.92	9.28	9.65	10.04		10.45		10.87		
3	3	Ameren	Yes	Yes	Yes	8.0%	41.3%	0.00	(85.61)	2.52	2.70	2.89	3.10	3.31	3.63	3.91	4.14	4.30	4.48	4.66	4.85	5.04	5.25	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	355.55	9.91	345.64		3	3
				e	e					4.10	4.35	4.63	4.93	5.25	5.57	6.08	6.54	6.91	7.19	7.48	7.79	8.10	8.43	8.77	9.13	9.50	9.88	10.28	10.70	11.13	11.58	12.05	12.54	13.05	13.57	14.12	14.70	15.29		15.91		16.55		
4	4	AEP	Yes	No	Yes	8.6%	35.5%	0.00	(91.96)	3.35	3.55	3.77	4.00	4.23	4.59	4.91	5.19	5.40	5.61	5.84	6.08	6.32	6.58	6.85	7.12	7.41	7.71	8.03	8.35	8.69	9.04	9.41	9.79	10.18	10.60	11.03	11.47	11.94	388.53	12.42	376.11		4	4
				e	e					5.00	5.35	5.71	6.09	6.50	6.91	7.53	8.08	8.54	8.88	9.24	9.62	10.01	10.41	10.83	11.27	11.73	12.20	12.70	13.21	13.75	14.31	14.88	15.49	16.11	16.77	17.45	18.15	18.89		19.65		20.45		
5	6	Avista	Yes	Yes	Yes	9.1%	33.9%	0.00	(42.16)	1.83	1.90	1.97	2.05	2.13	2.28	2.42	2.54	2.64	2.75	2.86	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.79	4.99	5.19	5.40	5.62	5.85	196.83	6.08	190.75		6	5
				e	e					1.90	2.35	2.51	2.67	2.85	3.03	3.23	3.42	3.59	3.73	3.89	4.04	4.21	4.38	4.55	4.74	4.93	5.13	5.34	5.55	5.78	6.01	6.26	6.51	6.77	7.05	7.33	7.63	7.94		8.26		8.60		
6	7	Black Hills	Yes	No	Yes	8.6%	36.0%	0.00	(68.02)	2.53	2.66	2.80	2.95	3.10	3.35	3.57	3.77	3.92	4.08	4.24	4.42	4.59	4.78	4.97	5.18	5.39	5.60	5.83	6.07	6.31	6.57	6.83	7.11	7.40	7.70	8.01	8.33	8.67	287.79	9.02	278.76		7	6
				e	e					4.05	4.20	4.52	4.87	5.25	5.63	6.12	6.56	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	9.91	10.31	10.72	11.16	11.61	12.08	12.57	13.08	13.61	14.16	14.73	15.33		15.95		16.60		
7	8	CenterPoint	Yes	No	No	7.5%	46.8%	0.00	(29.01)	0.77	0.83	0.89	0.95	1.01	1.07	1.12	1.18	1.22	1.27	1.32	1.38	1.43	1.49	1.55	1.62	1.68	1.75	1.82	1.89	1.97	2.05	2.13	2.22	2.31	2.40	2.50	2.60	2.71	119.78	2.82	116.96		8	7
				e	e					1.40	1.50	1.59	1.69	1.80	1.91	2.08	2.23	2.36	2.45	2.55	2.66	2.76	2.87	2.99	3.11	3.24	3.37	3.51	3.65	3.80	3.95	4.11	4.28	4.45	4.63	4.82	5.01	5.21		5.43		5.65		
8	9	CMS	Yes	No	No	8.0%	41.1%	0.00	(61.74)	1.94	2.05	2.17	2.30	2.43	2.64	2.82	2.98	3.10	3.22	3.35	3.49	3.63	3.78	3.93	4.09	4.26	4.43	4.61	4.80	4.99	5.19	5.40	5.62	5.85	6.09	6.33	6.59	6.86	259.27	7.13	252.13		9	8
				e	e					2.90	3.10	3.30	3.52	3.75	3.98	4.35	4.68	4.94	5.14	5.35	5.57	5.80	6.03	6.27	6.53	6.79	7.07	7.35	7.65	7.96	8.28	8.62	8.97	9.33	9.71	10.10	10.51	10.94		11.38		11.84		
9	10	Consol Ed	No	Yes	Yes	7.7%	40.6%	0.00	(93.12)	3.24	3.33	3.42	3.52	3.62	3.83	4.04	4.23	4.40	4.57	4.76	4.95	5.15	5.36	5.58	5.80	6.04	6.28	6.54	6.80	7.08	7.37	7.66	7.98	8.30	8.63	8.98	9.35	9.73	348.37	10.12	338.25		10	9
				e	e					4.55	4.75	4.99	5.24	5.50	5.76	6.18	6.56	6.90	7.18	7.47	7.77	8.09	8.42	8.76	9.11	9.48	9.86	10.26	10.68	11.11	11.56	12.03	12.52	13.02	13.55	14.10	14.67	15.27		15.88		16.53		
10	11	Dominion	Yes	No	No	9.5%	27.7%	0.00	(60.27)	2.83	3.01	3.20	3.40	3.60	3.77	3.95	4.11	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.89	7.17	7.46	7.77	8.08	8.41	8.75	9.10	9.47	251.64	9.86	241.78		11	10
				e	e					4.10	4.35	4.65	4.96	5.30	5.64	6.10	6.51	6.87	7.15	7.43	7.74	8.05	8.38	8.71	9.07	9.43	9.82	10.21	10.63	11.06	11.51	11.97	12.46	12.96	13.49	14.03	14.60	15.19		15.81		16.45		
11	13	Duke	Yes	No	Yes	8.1%	35.8%	0.00	(99.38)	4.06	4.14	4.22	4.30	4.38	4.63	4.86	5.08	5.29	5.50	5.73	5.96	6.20	6.45	6.71	6.98	7.27	7.56	7.87	8.19	8.52	8.86	9.22	9.59	9.98	10.39	10.81	11.25	11.70	367.80	12.18	355.63		13	11
				e	e					5.45	5.60	5.89	6.18	6.50	6.82	7.30	7.75	8.14	8.47	8.82	9.17	9.54	9.93	10.33	10.75	11.19	11.64	12.11	12.60	13.11	13.64	14.20	14.77	15.37	15.99	16.64	17.31	18.01		18.74		19.50		
12	14	Edison Int'l	Yes	No	No	9.8%	31.2%	0.00	(65.58)	2.95	3.12	3.31	3.50	3.69	4.00	4.27	4.50	4.69	4.88	5.07	5.28	5.49	5.72	5.95	6.19	6.44	6.70	6.97	7.25	7.55	7.85	8.17	8.50	8.85	9.20	9.58	9.96	10.37	340.07	10.79	329.28		14	12

				e	e					4.60	4.80	5.26	5.75	6.30	6.85	7.97	8.93	9.64	10.03	10.44	10.86	11.30	11.76	12.24	12.73	13.25	13.79	14.34	14.92	15.53	16.16	16.81	17.49	18.20	18.94	19.71	20.50	21.33		22.20		23.10		
13	15	Entergy	Yes	No	No	8.9%	31.7%	0.00	######	4.30	4.55	4.82	5.10	5.38	5.82	6.21	6.55	6.81	7.09	7.37	7.67	7.98	8.31	8.64	8.99	9.36	9.74	10.13	10.54	10.97	11.41	11.87	12.35	12.85	13.38	13.92	14.48	15.07	433.91	15.68	418.23		15	13
										6.65	6.80	7.33	7.89	8.50	9.11	9.77	10.37	10.89	11.34	11.79	12.27	12.77	13.29	13.82	14.38	14.97	15.57	16.20	16.86	17.54	18.25	18.99	19.76	20.56	21.40	22.26	23.16	24.10		25.08		26.09		
14	16	Evergy	Yes	Yes	Yes	9.3%	30.9%	0.00	(61.29)	2.48	2.66	2.85	3.05	3.25	3.56	3.83	4.05	4.21	4.38	4.56	4.74	4.93	5.13	5.34	5.56	5.78	6.02	6.26	6.52	6.78	7.05	7.34	7.64	7.95	8.27	8.60	8.95	9.31	274.16	9.69	264.47		16	14
				e	e					3.55	3.75	4.06	4.39	4.75	5.11	5.60	6.04	6.40	6.65	6.92	7.20	7.50	7.80	8.12	8.44	8.79	9.14	9.51	9.90	10.30	10.72	11.15	11.60	12.07	12.56	13.07	13.60	14.15		14.72		15.32		
15	17	Eversource	No	Yes	Yes	8.4%	37.0%	0.00	(80.03)	2.70	2.89	3.09	3.30	3.51	3.83	4.11	4.34	4.52	4.70	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	10.00	335.18	10.41	324.77		17	15
				e	e					4.10	4.40	4.68	4.98	5.30	5.62	6.12	6.57	6.95	7.23	7.52	7.83	8.14	8.47	8.81	9.17	9.54	9.93	10.33	10.75	11.19	11.64	12.11	12.60	13.11	13.64	14.19	14.77	15.37		15.99		16.64		
16	18	Exelon	Yes	No	No	8.0%	35.4%	0.00	(41.74)	1.45	1.54	1.64	1.75	1.86	1.97	2.07	2.17	2.26	2.35	2.45	2.55	2.65	2.76	2.87	2.98	3.10	3.23	3.36	3.50	3.64	3.79	3.94	4.10	4.27	4.44	4.62	4.81	5.00	148.10	5.20	142.89		18	16
				e	e					2.25	2.40	2.56	2.90	2.90	2.90	2.99	3.10	3.22	3.35	3.48	3.62	3.77	3.92	4.08	4.25	4.42	4.60	4.78	4.98	5.18	5.39	5.61	5.83	6.07	6.32	6.57	6.84	7.12		7.40		7.70		
17	22	IDACORP	Yes	Yes	Yes	7.9%	38.3%	0.00	######	3.25	3.48	3.73	4.00	4.27	4.66	5.01	5.29	5.51	5.73	5.96	6.20	6.46	6.72	6.99	7.27	7.57	7.87	8.19	8.52	8.87	9.23	9.60	9.99	10.40	10.82	11.26	11.71	12.19	395.45	12.68	382.77		22	17
				e	e					5.10	5.20	5.48	5.78	6.10	6.42	6.89	7.33	7.71	8.02	8.35	8.68	9.04	9.40	9.78	10.18	10.59	11.02	11.47	11.93	12.41	12.92	13.44	13.98	14.55	15.14	15.75	16.39	17.05		17.75		18.46		
18	23	MGE	Yes	No	No	6.7%	51.3%	0.00	(71.56)	1.66	1.74	1.82	1.90	1.98	2.14	2.27	2.39	2.49	2.59	2.69	2.80	2.92	3.04	3.16	3.29	3.42	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	254.90	5.73	249.17		23	18
										3.00	3.15	3.26	3.38	3.50	3.62	3.90	4.15	4.36	4.54	4.72	4.91	5.11	5.32	5.53	5.76	5.99	6.23	6.49	6.75	7.02	7.31	7.60	7.91	8.23	8.57	8.91	9.27	9.65		10.04		10.45		
19	24	NextEra	Yes	No	No	8.2%	45.8%	0.00	(75.98)	1.87	2.06	2.27	2.50	2.73	3.06	3.34	3.56	3.70	3.85	4.01	4.17	4.34	4.51	4.70	4.89	5.09	5.29	5.51	5.73	5.96	6.20	6.45	6.72	6.99	7.27	7.56	7.87	8.19	373.04	8.52	364.52		24	19
				e	e					2.90	3.15	3.44	3.76	4.10	4.44	4.98	5.45	5.81	6.04	6.29	6.54	6.81	7.08	7.37	7.67	7.98	8.30	8.64	8.99	9.35	9.73	10.13	10.54	10.96	11.41	11.87	12.35	12.85		13.37		13.91		
20	25	NorthWestern	Yes	Yes	Yes	8.3%	33.1%	0.00	(58.05)	2.56	2.60	2.64	2.68	2.72	2.87	3.02	3.15	3.28	3.41	3.55	3.70	3.84	4.00	4.16	4.33	4.51	4.69	4.88	5.08	5.28	5.50	5.72	5.95	6.19	6.44	6.70	6.97	7.26	209.68	7.55	202.13		25	20
				e	e					3.35	3.55	3.69	3.84	4.00	4.16	4.41	4.65	4.87	5.07	5.27	5.49	5.71	5.94	6.18	6.43	6.69	6.96	7.24	7.54	7.84	8.16	8.49	8.83	9.19	9.56	9.95	10.35	10.77		11.21		11.66		
21	26	OGE	Yes	Yes	Yes	9.2%	35.5%	0.00	(38.16)	1.70	1.75	1.80	1.85	1.90	2.02	2.13	2.24	2.33	2.42	2.52	2.62	2.73	2.84	2.95	3.07	3.20	3.33	3.46	3.60	3.75	3.90	4.06	4.22	4.39	4.57	4.76	4.95	5.15	190.97	5.36	185.61		26	21
				e	e					2.25	2.10	2.43	2.81	3.25	3.69	4.03	4.32	4.57	4.75	4.95	5.15	5.36	5.57	5.80	6.03	6.28	6.53	6.80	7.07	7.36	7.66	7.97	8.29	8.62	8.97	9.34	9.72	10.11		10.52		10.94		
22	27	Otter Tail	Yes	No	Yes	5.9%	28.6%	(0.00)	(64.83)	1.76	1.90	2.04	2.20	2.36	2.58	2.77	2.93	3.05	3.17	3.30	3.44	3.58	3.72	3.87	4.03	4.19	4.36	4.54	4.72	4.91	5.11	5.32	5.54	5.76	5.99	6.24	6.49	6.75	104.18	7.02	97.16		27	22
				e	e					6.60	4.75	4.39	4.06	3.75	3.44	3.70	3.93	4.13	4.30	4.47	4.65	4.84	5.04	5.24	5.45	5.67	5.90	6.14	6.39	6.65	6.92	7.20	7.49	7.79	8.11	8.44	8.78	9.14		9.51		9.89		
23	30	Pinnacle	Yes	Yes	Yes	8.6%	31.1%	0.00	(74.82)	3.48	3.54	3.60	3.66	3.72	3.94	4.15	4.34	4.52	4.70	4.89	5.09	5.30	5.51	5.74	5.97	6.21	6.46	6.72	7.00	7.28	7.57	7.88	8.20	8.53	8.88	9.24	9.61	10.00	276.68	10.41	266.27		30	23
										4.25	4.40	4.67	4.95	5.25	5.55	5.80	6.06	6.32	6.57	6.84	7.11	7.40	7.70	8.01	8.34	8.68	9.03	9.39	9.77	10.17	10.58	11.01	11.46	11.92	12.40	12.90	13.43	13.97		14.54		15.13		
24	33	Public Serv.	Yes	No	No	8.6%	33.5%	0.00	(60.80)	2.28	2.42	2.56	2.72	2.88	3.12	3.33	3.52	3.66	3.81	3.96	4.12	4.29	4.46	4.64	4.83	5.03	5.23	5.44	5.66	5.89	6.13	6.38	6.64	6.90	7.18	7.47	7.78	8.09	239.05	8.42	230.63		33	24
				e	e					3.48	3.60	3.83	4.08	4.35	4.62	4.94	5.25	5.51	5.73	5.97	6.21	6.46	6.72	6.99	7.28	7.57	7.88	8.20	8.53	8.87	9.23	9.61	10.00	10.40	10.82	11.26	11.72	12.19		12.69		13.20		
25	34	Sempra	Yes	Yes	Yes	8.1%	40.3%	0.00	######	4.80	5.12	5.46	5.82	6.18	6.72	7.21	7.61	7.92	8.24	8.57	8.92	9.28	9.66	10.05	10.45	10.88	11.32	11.78	12.25	12.75	13.27	13.80	14.36	14.95	15.55	16.18	16.84	17.52	643.51	18.23	625.29		34	25
				e	e					8.85	9.30	9.91	10.56	11.25	11.94	13.13	14.17	15.02	15.63	16.26	16.92	17.61	18.32	19.06	19.83	20.64	21.47	22.34	23.25	24.19	25.17	26.19	27.25	28.35	29.50	30.69	31.94	33.23		34.58		35.98		
26	35	Southern	Yes	No	No	8.8%	35.5%	0.00	(67.69)	2.78	2.88	2.99	3.10	3.21	3.42	3.62	3.80	3.96	4.12	4.28	4.46	4.64	4.82	5.02	5.22	5.43	5.65	5.88	6.12	6.37	6.63	6.90	7.17	7.47	7.77	8.08	8.41	8.75	298.61	9.10	289.50		35	26
				e	e					3.55	3.70	4.02	4.37	4.75	5.13	5.59	6.00	6.34	6.60	6.86	7.14	7.43	7.73	8.04	8.37	8.71	9.06	9.43	9.81	10.21	10.62	11.05	11.50	11.96	12.45	12.95	13.48	14.02		14.59		15.18		
27	36	WEC	Yes	Yes	Yes	8.4%	36.0%	0.00	(91.88)	3.11	3.32	3.55	3.80	4.05	4.43	4.77	5.04	5.25	5.46	5.68	5.91	6.15	6.40	6.66	6.93	7.21	7.50	7.81	8.12	8.45	8.79	9.15	9.52	9.90	10.31	10.72	11.16	11.61	368.67	12.08	356.59		36	27
				e	e					4.40	4.70	4.95	5.22	5.50	5.78	6.29	6.75	7.13	7.42	7.72	8.03	8.36	8.70	9.05	9.41	9.80	10.19	10.61	11.03	11.48	11.95	12.43	12.93	13.46	14.00	14.57	15.16	15.77		16.41		17.08		
28	37	Xcel	Yes	No	Yes	8.0%	40.2%	0.00	(67.65)	2.07	2.21	2.36	2.52	2.68	2.93	3.15	3.33	3.47	3.61	3.75	3.91	4.06	4.23	4.40	4.58	4.76	4.96	5.16	5.37	5.58	5.81	6.04	6.29	6.54	6.81	7.09	7.37	7.67	276.08	7.98	268.10		37	28
				e	e					3.15	3.35	3.55	3.77	4.00	4.23	4.60	4.93	5.21	5.42	5.64	5.87	6.11	6.36	6.61	6.88	7.16	7.45	7.75	8.07	8.39	8.73	9.09	9.45	9.84	10.24	10.65	11.08	11.53		12.00		12.48		
		No. of Peers:	26	12	17	Mean																																						
						8.35%	36.45%	0.00%	Company Screen																																			
						8.44%	36.35%	0.00%	Staff Screen																																			
						8.27%	36.02%	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	PGE Yes	Staff No	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	Yes	No	No	8.7%	33.7%	3.6%	3.5%	3.6%	1	1
2	2	Alliant	Yes	Yes	Yes	8.2%	39.0%	5.9%	5.8%	5.9%	2	2
3	3	Ameren	Yes	Yes	Yes	7.9%	42.2%	7.1%	7.0%	7.0%	3	3
4	4	AEP	Yes	No	Yes	8.5%	36.4%	6.0%	6.0%	6.0%	4	4
5	6	Avista	Yes	Yes	Yes	9.1%	34.6%	3.9%	3.8%	3.9%	6	5
6	7	Black Hills	Yes	No	Yes	8.5%	36.8%	8.0%	5.2%	6.6%	7	6
7	8	CenterPoint	Yes	No	No	7.5%	47.7%	7.6%	7.1%	7.3%	8	7
8	9	CMS	Yes	No	No	8.0%	42.0%	5.7%	5.8%	5.7%	9	8
9	10	Consol Ed	No	Yes	Yes	7.6%	41.3%	2.7%	2.8%	2.8%	10	9
10	11	Dominion	Yes	No	No	9.4%	28.5%	6.2%	6.2%	6.2%	11	10
11	13	Duke	Yes	No	Yes	8.0%	36.4%	2.0%	1.9%	1.9%	13	11
12	14	Edison Int'l	Yes	No	No	9.7%	32.1%	5.7%	5.8%	5.8%	14	12
13	15	Entergy	Yes	No	No	8.8%	32.6%	5.6%	6.6%	6.1%	15	13
14	16	Evergy	Yes	Yes	Yes	9.2%	31.9%	7.0%	4.5%	5.7%	16	14
15	17	Eversource	No	Yes	Yes	8.3%	37.9%	6.7%	8.2%	7.4%	17	15
16	18	Exelon	Yes	No	No	7.9%	36.2%	6.7%	1.9%	4.3%	18	16
17	22	IDACORP	Yes	Yes	Yes	7.8%	39.2%	7.1%	5.8%	6.4%	22	17
18	23	MGE	Yes	No	No	6.6%	52.0%	4.6%	5.8%	5.2%	23	18
19	24	NextEra	Yes	No	No	8.1%	46.9%	10.1%	7.0%	8.6%	24	19
20	25	NorthWestern	Yes	Yes	Yes	8.2%	33.7%	1.6%	6.8%	4.2%	25	20
21	26	OGE	Yes	Yes	Yes	9.1%	36.3%	3.1%	6.3%	4.7%	26	21
22	27	Otter Tail	Yes	No	Yes	5.8%	29.4%	7.5%	7.6%	7.5%	27	22
23	30	Pinnacle	Yes	Yes	Yes	8.5%	31.7%	1.7%	6.6%	4.2%	30	23
24	33	Public Serv.	Yes	No	No	8.5%	34.3%	5.9%	6.6%	6.2%	33	24
25	34	Sempra	Yes	Yes	Yes	8.0%	41.2%	6.2%	4.6%	5.4%	34	25
26	35	Southern	Yes	No	No	8.7%	36.3%	3.5%	6.4%	4.9%	35	26
27	36	WEC	Yes	Yes	Yes	8.3%	36.9%	6.9%	7.0%	7.0%	36	27
28	37	Xcel	Yes	No	Yes	7.9%	41.1%	6.6%	6.7%	6.6%	37	28
		No. of Peers:	26	12	17	Mean						
						8.27%	37.27%	5.60%	Company Screen			
						8.36%	37.16%	4.97%	Staff Screen			
						8.18%	36.83%	5.27%	Staff Sensitivity Screen			

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

ROE – Three-Stage DCF:
Summary and Recommendation

June 13, 2023

UE 416 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)	2.20%	2.33%	4.58%	12.50%	0.57%	
Organization for Economic Co-operation and Development (OECD)	1.49%	2.33%	3.85%	12.50%	0.48%	
Social Security Administration (SSA)	2.00%	2.33%	4.38%	12.50%	0.55%	
Congressional Budget Office CBO)	1.75%	2.33%	4.12%	12.50%	0.52%	
BEA Nominal Historical,1980 Q1 – 2022 Q4	2.64%	2.33%	5.03%	50.0%	2.52%	
Composite				100%	4.63%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.05%	100.0%	4.05%	CBO
BEA Nominal Historical,1980 Q1 – 2022 Q4	2.64%	2.33%	5.03%	100.0%	5.03%	Near Historical

Though shown below for comparison purposes - Staff disagrees with the Company's third Stage Growth Rate **3.90%**

	Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity							
	X	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE 3.90%
1	Company Peer Screen	7.98%		8.49%		9.02%		7.91%
2	Staff Peer Screen	8.02%		8.51%		8.85%		7.89%
3	Staff Sensitivity Peer Screen	7.95%		8.45%		8.79%		7.83%

Hamada →

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)								
X	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE 3.90%	
Company Peer Screen	7.61%		8.11%		8.64%		7.54%	1
Staff Peer Screen	7.87%		8.36%		8.70%		7.74%	2
Staff Sensitivity Peer Screen	7.74%		8.24%		8.58%		7.62%	3

	Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale							
	Y	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE 3.90%
1	Company Peer Screen	8.27%		8.72%		9.02%		8.15%
2	Staff Peer Screen	8.36%		8.81%		9.12%		8.25%
3	Staff Sensitivity Peer Screen	8.18%		8.63%		8.94%		8.07%

Hamada →

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)								
Y	CBO	4.05%	Composite	4.63%	Historical	5.03%	PGE 3.90%	
Company Peer Screen	7.89%		8.34%		8.65%		7.78%	1
Staff Peer Screen	8.21%		8.66%		8.97%		8.10%	2
Staff Sensitivity Peer Screen	7.97%		8.42%		8.73%		7.86%	3

Best Fit Range of Reasonable ROEs	8.70%	to	8.97%	ROE	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
	8.83%	to	9.10%	ROE	
	Midpoint	9.0%	ROE	Testimony	
Staff Point ROE Recommendation:		9.0%			

CAPM and Single Stage DCF point to top and bottom respectively of Staff's Three Stage DCF Modeling Results

Note: Staff disagrees with a potential upper limit of 9.68% relying on an excessive GDP growth rate.
Pacificorp reaches back to 1929 to pull in years with higher growth rates than have been experiences since 1980.
Staff provides this illustration to show how excessive inputs can distort modeling results.

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

ROE:
Capital Asset Pricing Model (CAPM)

June 13, 2023

Staff's CAPM Modeling Results

PGE	4.05%	Rf Rate as shown in Exhibit PGE/1000 PGE Staff Liddle - Villadsen/56 -- Top Current Table
Direct	11.51%	Mkt Return as shown in Exhibit PGE/1000 PGE Staff Liddle - Villadsen/61 -- Top Current Table
Testimony	7.46%	PGE Mkt Risk Premium (MRP)
Staff	3.961%	R_f May 26, 2023 30-Yr UST Yield /WSJ www.wsj.com/market-data/bonds
	9.75%	30-Year S&P 500 Proxy Market Return Geometric Return
	5.79%	Staff 30-Yr Mkt Risk Premium (MRP)
	3.806%	R_f May 26, 2023 10-Yr UST Yield /WSJ www.wsj.com/market-data/bonds
	10.41%	10-Year S&P 500 Proxy Market Return Geometric Return
	6.60%	Staff 10-Yr Mkt Risk Premium (MRP)

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

	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	LT Debt UE 416 Sensitivity	Ticker	VL Q4 2022 Beta	Staff MRP 30 Yr ROE w VL Beta CAPM	Staff MRP 10 Yr ROE w VL Beta CAPM	PGE MRP PGE/1000 ROE w VL Beta CAPM	Screen #	
1	1	Allete	Yes	No	No	ALE	0.90	9.17%	9.75%	10.76%	1	1
2	2	Alliant	Yes	Yes	Yes	LNT	0.85	8.88%	9.42%	10.39%	2	2
3	3	Ameren	Yes	Yes	Yes	AEE	0.85	8.88%	9.42%	10.39%	3	3
4	4	AEP	Yes	No	Yes	AEP	0.75	8.30%	8.76%	9.65%	4	4
5	6	Avista	Yes	Yes	Yes	AVA	0.90	9.17%	9.75%	10.76%	6	5
6	7	Black Hills	Yes	No	Yes	BKH	0.95	9.46%	10.08%	11.14%	7	6
7	8	CenterPoint	Yes	No	No	CNP	1.10	10.33%	11.07%	12.26%	8	7
8	9	CMS	Yes	No	No	CMS	0.80	8.59%	9.09%	10.02%	9	8
9	10	Consol Ed	No	Yes	Yes	ED	0.75	8.30%	8.76%	9.65%	10	9
10	11	Dominion	Yes	No	No	D	0.85	8.88%	9.42%	10.39%	11	10
11	13	Duke	Yes	No	Yes	DUK	0.85	8.88%	9.42%	10.39%	13	11
12	14	Edison Int'l	Yes	No	No	EIX	0.95	9.46%	10.08%	11.14%	14	12
13	15	Entergy	Yes	No	No	ETR	0.95	9.46%	10.08%	11.14%	15	13
14	16	Evergy	Yes	Yes	Yes	EVRG	0.90	9.17%	9.75%	10.76%	16	14
15	17	Eversource	No	Yes	Yes	ES	0.90	9.17%	9.75%	10.76%	17	15
16	18	Exelon	Yes	No	No	EXC	0.95	9.46%	10.08%	11.14%	18	16
17	22	IDACORP	Yes	Yes	Yes	IDA	0.80	8.59%	9.09%	10.02%	22	17
18	23	MGE	Yes	No	No	MGEE	0.75	8.30%	8.76%	9.65%	23	18
19	24	NextEra	Yes	No	No	NEE	0.90	9.17%	9.75%	10.76%	24	19
20	25	NorthWestern	Yes	Yes	Yes	NWE	0.90	9.17%	9.75%	10.76%	25	20
21	26	OGE	Yes	Yes	Yes	OGE	1.00	9.75%	10.41%	11.51%	26	21
22	27	Otter Tail	Yes	No	Yes	OTTR	0.85	8.88%	9.42%	10.39%	27	22
23	30	Pinnacle	Yes	Yes	Yes	PNW	0.90	9.17%	9.75%	10.76%	30	23
24	33	Public Serv.	Yes	No	No	PEG	0.90	9.17%	9.75%	10.76%	33	24
25	34	Sempra	Yes	Yes	Yes	SRE	0.95	9.46%	10.08%	11.14%	34	25
26	35	Southern	Yes	No	No	SRE	0.95	9.46%	10.08%	11.14%	35	26
27	36	WEC	Yes	Yes	Yes	SO	0.95	9.46%	10.08%	11.14%	36	27
28	37	Xcel	Yes	No	Yes	WEC	0.80	8.59%	9.09%	10.02%	37	28
		No. of Peers:	26	12	17			VL Betas	VL Betas	VL Betas		
					Company Screen		Mean	9.1%	9.7%	10.7%	ROE	
					Staff Screen		Mean	9.1%	9.7%	10.7%	ROE	
					Staff Sensitivity Screen		Mean	9.0%	9.6%	10.6%	ROE	

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

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 406

ROE:
Gordon Growth – Single Stage DCF

June 13, 2023

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 Upper End of Staff's 3-Stage DCF Modeling Results

	Screen #	Abbreviated Utility	UE 416 PGE	UE 416 Staff	LT Debt UE 416 Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #
		1	2	3	4	5	6	7	8	9	10	11 = 9 + 10	12
1	1	Allete	Yes	No	No	ALE	62.92	4.1%	2.70	4.3%	3.5%	7.7%	1
2	2	Alliant	Yes	Yes	Yes	LNT	53.45	3.2%	1.81	3.4%	6.0%	9.4%	2
3	3	Ameren	Yes	Yes	Yes	AEE	85.61	2.8%	2.52	2.9%	7.2%	10.2%	3
4	4	AEP	Yes	No	Yes	AEP	91.96	3.4%	3.35	3.6%	5.8%	9.5%	4
5	6	Avista	Yes	Yes	Yes	AVA	42.16	4.2%	1.83	4.3%	4.0%	8.3%	6
6	7	Black Hills	Yes	No	Yes	BKH	68.02	3.5%	2.53	3.7%	5.2%	9.0%	7
7	8	CenterPoint	Yes	No	No	CNP	29.01	2.4%	0.77	2.7%	1.9%	4.6%	8
8	9	CMS	Yes	No	No	CMS	61.74	3.0%	1.94	3.1%	5.9%	9.0%	9
9	10	Consol Ed	No	Yes	Yes	ED	93.12	3.4%	3.24	3.5%	2.5%	6.0%	10
10	11	Dominion	Yes	No	No	D	60.27	4.4%	2.83	4.7%	0.9%	5.6%	11
11	13	Duke	Yes	No	Yes	DUK	99.38	4.0%	4.06	4.1%	2.0%	6.1%	13
12	14	Edison Int'l	Yes	No	No	EIX	65.58	4.3%	2.95	4.5%	5.4%	9.9%	14
13	15	Entergy	Yes	No	No	ETR	106.59	3.8%	4.30	4.0%	5.2%	9.3%	15
14	16	Evergy	Yes	Yes	Yes	EVRG	61.29	3.8%	2.48	4.0%	6.8%	10.9%	16
15	17	Eversource	No	Yes	Yes	ES	80.03	3.2%	2.70	3.4%	6.4%	9.8%	17
16	18	Exelon	Yes	No	No	EXC	41.74	3.2%	1.45	3.5%	2.6%	6.0%	18
17	22	IDACORP	Yes	Yes	Yes	IDA	105.73	2.9%	3.25	3.1%	6.6%	9.7%	22
18	23	MGE	Yes	No	No	MGEE	71.56	2.2%	1.66	2.3%	4.6%	7.0%	23
19	24	NextEra	Yes	No	No	NEE	75.98	2.2%	1.87	2.5%	10.2%	12.7%	24
20	25	NorthWesterr	Yes	Yes	Yes	NWE	58.05	4.3%	2.56	4.4%	1.9%	6.3%	25
21	26	OGE	Yes	Yes	Yes	OGE	38.16	4.3%	1.70	4.5%	2.9%	7.4%	26
22	27	Otter Tail	Yes	No	Yes	OTTR	64.83	2.5%	1.76	2.7%	6.8%	9.5%	27
23	30	Pinnacle	Yes	Yes	Yes	PNW	74.82	4.6%	3.48	4.7%	2.4%	7.1%	30
24	33	Public Serv.	Yes	No	No	PEG	60.80	3.6%	2.28	3.8%	5.6%	9.4%	33
25	34	Sempra	Yes	Yes	Yes	SRE	153.82	3.0%	4.80	3.1%	6.1%	9.2%	34
26	35	Southern	Yes	No	No	SO	67.69	4.0%	2.78	4.1%	3.4%	7.5%	35
27	36	WEC	Yes	Yes	Yes	SO	67.69	4.0%	3.11	4.6%	7.0%	11.6%	36
28	37	Xcel	Yes	No	Yes	WEC	91.88	3.2%	2.07	2.3%	6.8%	9.1%	37
		No. of Peers:	26	12	17							Mean	
											Company Screen	8.5%	ROE
											Staff Screen	8.8%	ROE
											Staff Sensitivity Screen	8.8%	ROE

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

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 407

ROE: BEA Historical
GDP Growth

June 13, 2023

Bureau of Economic Analysis (BEA)

Staff Accessed February 18, 2022

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

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 2012 dollars
1947	249.616	2465.461817
1948	274.468	2638.784425
1949	272.475	2668.443116
1950	299.827	2775.272168
1951	346.914	3030.366528
1952	367.341	3179.968303
1953	389.218	3349.288246
1954	390.549	3373.295866
1955	425.478	3661.311821
1956	449.353	3760.399928
1957	474.039	3849.939291
1958	481.229	3840.878516
1959	521.654	4101.236298
1960	542.382	4206.981161
1961	562.209	4331.707004
1962	603.922	4596.426885
1963	637.45	4773.051375
1964	684.46	5064.368821
1965	742.289	5388.785082
1966	813.414	5713.19558
1967	859.959	5848.252351
1968	940.651	6109.501822
1969	1017.615	6241.219043
1970	1073.303	6235.431984
1971	1164.85	6553.230702
1972	1279.11	6958.990431
1973	1425.376	7118.290801
1974	1545.243	6884.251093
1975	1684.904	7006.927838
1976	1873.412	7417.332124
1977	2081.826	7726.515081
1978	2351.599	8007.93921
1979	2627.333	7899.799266
1980	2857.307	7646.636364
1981	3207.041	7880.289342
1982	3343.789	7913.554108
1983	3634.038	8286.645961
1984	4037.613	8849.108204
1985	4338.979	9162.219757
1986	4579.631	9556.921114
1987	4855.215	9711.312003
1988	5236.438	10031.27117
1989	5641.58	10328.20086
1990	5963.144	10274.24828
1991	6158.129	10303.10236
1992	6520.327	10594.77533
1993	6858.559	10839.66419
1994	7287.236	11225.59624
1995	7639.749	11478.04031
1996	8073.122	11732.71742
1997	8577.552	12257.78833
1998	9062.817	12746.43315
1999	9631.172	13192.70866
2000	10250.952	13575.23123
2001	10581.929	13792.35741
2002	10929.108	13900.10606
2003	11456.45	14280.17157
2004	12217.196	14735.90128
2005	13039.197	15219.26385
2006	13815.583	15728.47325
2007	14474.228	15827.97168
2008	14769.862	16154.8466
2009	14478.067	15402.25138
2010	15048.97	15782.67486
2011	15599.731	15874.20904
2012	16253.97	16253.97
2013	16843.196	16592.18309
2014	17550.687	17176.94411
2015	18206.023	17705.23696
2016	18695.106	17815.50672
2017	19477.337	18175.97671
2018	20533.058	18793.47233
2019	21380.976	19134.71842
2020	21060.474	18469.94557
2021	23315.081	18979.22134
2022	25464.463	20015.4

1980 through 2022 Q4

Quarter	GDP in billions of current dollars	GDP in billions of chained 2012 dollars	Qtr#	Average	Ln(Real GDP)	
1947Q1	243.164	2034.450	1	1	8.831	1980
1947Q2	245.968	2029.024	2	2	8.810	
1947Q3	249.585	2024.834	3	3	8.809	
1947Q4	259.745	2056.508	4	4	8.827	
1948Q1	265.742	2087.442	5	5	8.847	1981
1948Q2	272.567	2121.899	6	6	8.839	
1948Q3	279.196	2134.056	7	7	8.851	
1948Q4	280.366	2136.440	8	8	8.840	
1949Q1	275.034	2107.001	9	9	8.825	1982
1949Q2	271.351	2099.814	10	10	8.829	
1949Q3	272.889	2121.493	11	11	8.825	
1949Q4	270.627	2103.688	12	12	8.826	
1950Q1	280.828	2186.365	13	13	8.839	1983
1950Q2	290.383	2253.045	14	14	8.861	
1950Q3	308.153	2340.112	15	15	8.881	
1950Q4	319.945	2384.920	16	16	8.902	
1951Q1	336.000	2417.311	17	17	8.921	1984
1951Q2	344.090	2459.196	18	18	8.938	
1951Q3	351.385	2509.880	19	19	8.948	
1951Q4	356.178	2515.408	20	20	8.956	
1952Q1	359.820	2542.286	21	21	8.966	1985
1952Q2	361.030	2547.762	22	22	8.974	
1952Q3	367.701	2566.153	23	23	8.990	
1952Q4	380.812	2650.431	24	24	8.997	
1953Q1	387.980	2699.699	25	25	9.006	1986
1953Q2	391.749	2720.566	26	26	9.011	
1953Q3	391.171	2705.258	27	27	9.020	
1953Q4	385.970	2664.302	28	28	9.026	
1954Q1	385.345	2651.566	29	29	9.033	1987
1954Q2	386.121	2654.456	30	30	9.044	
1954Q3	390.996	2684.434	31	31	9.052	
1954Q4	399.734	2736.960	32	32	9.069	
1955Q1	413.073	2815.134	33	33	9.075	1988
1955Q2	421.532	2860.942	34	34	9.088	
1955Q3	430.221	2899.578	35	35	9.093	
1955Q4	437.092	2916.985	36	36	9.107	
1956Q1	439.746	2905.656	37	37	9.117	1989
1956Q2	446.010	2929.666	38	38	9.124	
1956Q3	451.191	2927.034	39	39	9.132	
1956Q4	460.463	2975.209	40	40	9.134	
1957Q1	469.779	2994.259	41	41	9.145	1990
1957Q2	472.025	2987.699	42	42	9.148	
1957Q3	479.490	3016.979	43	43	9.149	
1957Q4	474.864	2985.775	44	44	9.140	
1958Q1	467.540	2908.281	45	45	9.135	1991
1958Q2	471.978	2927.395	46	46	9.143	
1958Q3	485.841	2995.112	47	47	9.148	
1958Q4	499.555	3065.141	48	48	9.151	
1959Q1	510.330	3123.978	49	49	9.163	1992
1959Q2	522.653	3194.429	50	50	9.174	
1959Q3	525.034	3196.683	51	51	9.184	
1959Q4	528.600	3205.790	52	52	9.194	
1960Q1	542.648	3277.847	53	53	9.196	1993
1960Q2	541.080	3260.177	54	54	9.202	
1960Q3	545.604	3276.133	55	55	9.207	
1960Q4	540.197	3234.087	56	56	9.220	
1961Q1	545.018	3255.914	57	57	9.230	1994
1961Q2	555.545	3311.181	58	58	9.243	
1961Q3	567.664	3374.742	59	59	9.249	
1961Q4	580.612	3440.924	60	60	9.260	
1962Q1	594.013	3502.298	61	61	9.264	1995
1962Q2	600.366	3533.947	62	62	9.267	
1962Q3	609.027	3577.362	63	63	9.275	
1962Q4	612.280	3589.128	64	64	9.282	
1963Q1	621.672	3628.306	65	65	9.290	1996
1963Q2	629.752	3669.020	66	66	9.306	
1963Q3	644.444	3749.681	67	67	9.315	
1963Q4	653.938	3774.264	68	68	9.325	
1964Q1	669.822	3853.835	69	69	9.332	1997
1964Q2	678.674	3895.793	70	70	9.348	
1964Q3	692.031	3956.657	71	71	9.361	
1964Q4	697.319	3968.878	72	72	9.369	
1965Q1	717.790	4064.915	73	73	9.379	1998
1965Q2	730.191	4116.267	74	74	9.388	
1965Q3	749.323	4207.782	75	75	9.401	
1965Q4	771.857	4304.731	76	76	9.417	
1966Q1	795.734	4409.518	77	77	9.426	1999
1966Q2	804.981	4424.581	78	78	9.435	
1966Q3	819.638	4462.053	79	79	9.448	
1966Q4	833.302	4498.660	80	80	9.464	
1967Q1	844.170	4538.498	81	81	9.468	2000
1967Q2	848.983	4541.280	82	82	9.486	
1967Q3	865.233	4584.246	83	83	9.487	
1967Q4	881.439	4618.812	84	84	9.493	
1968Q1	909.387	4713.013	85	85	9.489	2001
1968Q2	934.344	4791.758	86	86	9.496	
1968Q3	950.825	4828.892	87	87	9.492	
1968Q4	968.030	4847.885	88	88	9.494	
1969Q1	993.337	4923.760	89	89	9.503	2002
1969Q2	1009.020	4938.728	90	90	9.509	
1969Q3	1029.956	4971.349	91	91	9.513	
1969Q4	1038.147	4947.104	92	92	9.514	
1970Q1	1051.200	4939.759	93	93	9.519	2003
1970Q2	1067.375	4946.770	94	94	9.528	
1970Q3	1086.059	4992.357	95	95	9.545	
1970Q4	1088.608	4938.857	96	96	9.556	
1971Q1	1135.156	5072.996	97	97	9.562	2004
1971Q2	1156.271	5100.447	98	98	9.570	
1971Q3	1177.675	5142.422	99	99	9.579	
1971Q4	1190.297	5154.547	100	100	9.589	
1972Q1	1230.609	5249.337	101	101	9.600	2005
1972Q2	1266.369	5368.485	102	102	9.605	
1972Q3	1290.566	5419.184	103	103	9.613	
1972Q4	1328.904	5509.926	104	104	9.619	
1973Q1	1377.490	5646.286	105	105	9.632	2006
1973Q2	1413.887	5707.755	106	106	9.634	
1973Q3	1433.838	5677.738	107	107	9.636	
1973Q4	1476.289	5731.632	108	108	9.644	
1974Q1	1491.209	5682.353	109	109	9.647	2007
1974Q2	1530.056	5695.859	110	110	9.654	
1974Q3	1560.026	5642.025	111	111	9.660	
1974Q4	1599.679	5620.126	112	112	9.666	
1975Q1	1616.116	5551.713	113	113	9.662	2008
1975Q2	1651.853	5591.382	114	114	9.667	
1975Q3	1709.820	5687.087	115	115	9.662	
1975Q4	1761.831	5763.665	116	116	9.640	
1976Q1	1820.487	5893.276	117	117	9.628	2009
1976Q2	1852.332	5936.515	118	118	9.627	
1976Q3	1886.558	5969.089	119	119	9.630	
1976Q4	1934.273	6012.356	120	120	9.641	
1977Q1	1988.648	6083.391	121	121	9.646	2010
1977Q2	2055.909	6201.659	122	122	9.655	
1977Q3	2118.473	6313.559	123	123	9.663	
1977Q4	2164.270	6313.697	124	124	9.668	
1978Q1	2202.760	6333.848	125	125	9.666	2011
1978Q2	2331.633	6578.605	126	126	9.673	
1978Q3	2395.053	6644.754	127	127	9.672	
1978Q4	2476.949	6734.069	128	128	9.683	
1979Q1	2526.610	6746.176	129	129	9.692	2012
1979Q2	2591.247	6753.389	130	130	9.696	
1979Q3	2667.565	6803.558	131	131	9.698	
1979Q4	2723.883	6820.572	132	132	9.699	
1980Q1	**2789.842**	**6842.024**	133	133	9.708	2013
1980Q2	2797.352	6701.046	134	134	9.709	
1980Q3	2856.483	6693.082	135	135	9.717	
1980Q4	2985.557	6817.903	136	136	9.724	
1981Q1	3124.206	6951.495	137	137	9.720	2014
1981Q2	3162.532	6899.980	138	138	9.733	
1981Q3	3260.609	6982.609	139	139	9.745	
1981Q4	3280.818	6906.529	140	140	9.749	
1982Q1	3274.302	6799.233	141	141	9.757	2015
1982Q2	3331.972	6830.251	142	142	9.763	
1982Q3	3366.322	6804.139	143	143	9.766	
1982Q4	3402.561	6806.857	144	144	9.768	
1983Q1	3473.413	6896.561	145	145	9.774	2016
1983Q2	3578.848	7053.500	146	146	9.777	
1983Q3	3689.179	7194.504	147	147	9.783	
1983Q4	3794.706	7344.597	148	148	9.788	
1984Q1	3908.054	7488.167	149	149	9.792	2017
1984Q2	4009.601	7617.547	150	150	9.797	
1984Q3	4084.250	7690.985	151	151	9.805	

Long Run Historical GDP Growth Rate

Annualized Real LN GPD Q

2.64%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.98800266
R Square	0.976149257
Adjusted R Square	0.976008958
Standard Error	0.051022521
Observations	172

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	18.11286112	18.11286112	6957.660463	7.5669E-140
Residual	170	0.4425606	0.002603298		
Total	171	18.55542172			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.857256013	0.007814914	1133.378626	0	8.841829243	8.872682783	8.841829243	8.872682783
X Variable 1	0.006535801	7.83551E-05	83.41259176	7.5669E-140	0.006381127	0.006690475	0.006381127	0.006690475

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)

1984Q4	4148.551	7754.117	152
1985Q1	4230.168	7829.260	153
1985Q2	4294.887	7898.194	154
1985Q3	4386.773	8018.809	155
1985Q4	4444.094	8078.415	156
1986Q1	4507.894	8153.829	157
1986Q2	4545.340	8190.552	158
1986Q3	4607.669	8268.935	159
1986Q4	4657.627	8313.338	160
1987Q1	4722.156	8375.274	161
1987Q2	4806.160	8465.630	162
1987Q3	4884.555	8539.075	163
1987Q4	5007.994	8685.694	164
1988Q1	5073.372	8730.569	165
1988Q2	5190.036	8845.280	166
1988Q3	5282.835	8897.107	167
1988Q4	5399.509	9015.661	168
1989Q1	5511.253	9107.314	169
1989Q2	5612.463	9176.827	170
1989Q3	5695.365	9244.816	171
1989Q4	5747.237	9263.033	172
1990Q1	5872.701	9364.259	173
1990Q2	5960.028	9398.243	174
1990Q3	6015.116	9404.494	175
1990Q4	6004.733	9318.876	176
1991Q1	6035.178	9275.276	177
1991Q2	6126.862	9347.597	178
1991Q3	6205.937	9394.834	179
1991Q4	6264.540	9427.581	180
1992Q1	6363.102	9540.444	181
1992Q2	6470.763	9643.893	182
1992Q3	6566.641	9739.185	183
1992Q4	6680.803	9840.753	184
1993Q1	6729.459	9857.185	185
1993Q2	6808.939	9914.565	186
1993Q3	6882.098	9961.873	187
1993Q4	7013.738	10097.362	188
1994Q1	7115.652	10195.338	189
1994Q2	7246.931	10333.495	190
1994Q3	7331.075	10393.898	191
1994Q4	7455.288	10512.962	192
1995Q1	7522.289	10550.251	193
1995Q2	7580.997	10581.723	194
1995Q3	7683.125	10671.738	195
1995Q4	7772.586	10744.203	196
1996Q1	7868.468	10824.674	197
1996Q2	8032.840	11005.217	198
1996Q3	8131.408	11103.935	199
1996Q4	8259.771	11219.238	200
1997Q1	8362.655	11291.665	201
1997Q2	8518.825	11479.330	202
1997Q3	8662.823	11622.911	203
1997Q4	8765.907	11722.722	204
1998Q1	8866.480	11839.876	205
1998Q2	8969.699	11949.492	206
1998Q3	9121.097	12099.191	207
1998Q4	9293.991	12294.737	208
1999Q1	9411.682	12410.778	209
1999Q2	9526.210	12514.408	210
1999Q3	9686.626	12679.977	211
1999Q4	9900.169	12888.281	212
2000Q1	10002.179	12935.252	213
2000Q2	10247.720	13170.749	214
2000Q3	10318.165	13183.890	215
2000Q4	10435.744	13262.250	216
2001Q1	10470.231	13219.251	217
2001Q2	10599.000	13301.394	218
2001Q3	10598.020	13248.142	219
2001Q4	10660.465	13284.881	220
2002Q1	10783.500	13394.910	221
2002Q2	10887.460	13477.356	222
2002Q3	10984.040	13531.741	223
2002Q4	11061.433	13549.421	224
2003Q1	11174.129	13619.434	225
2003Q2	11312.766	13741.107	226
2003Q3	11566.669	13970.157	227
2003Q4	11772.234	14131.379	228
2004Q1	11923.447	14212.340	229
2004Q2	12112.815	14323.017	230
2004Q3	12305.307	14457.832	231
2004Q4	12527.214	14605.595	232
2005Q1	12767.286	14767.846	233
2005Q2	12922.656	14839.707	234
2005Q3	13142.642	14956.291	235
2005Q4	13324.204	15041.232	236
2006Q1	13599.160	15244.088	237
2006Q2	13753.424	15281.525	238
2006Q3	13870.188	15304.517	239
2006Q4	14039.560	15433.643	240
2007Q1	14215.651	15478.956	241
2007Q2	14402.082	15577.779	242
2007Q3	14564.117	15671.605	243
2007Q4	14715.058	15767.146	244
2008Q1	14706.538	15702.906	245
2008Q2	14865.701	15792.773	246
2008Q3	14898.999	15709.562	247
2008Q4	14608.208	15366.607	248
2009Q1	14430.901	15187.475	249
2009Q2	14381.236	15161.772	250
2009Q3	14448.882	15216.647	251
2009Q4	14651.248	15379.155	252
2010Q1	14764.611	15456.059	253
2010Q2	14980.193	15605.628	254
2010Q3	15141.605	15726.282	255
2010Q4	15309.471	15807.995	256
2011Q1	15351.444	15769.911	257
2011Q2	15557.535	15876.839	258
2011Q3	15647.681	15870.684	259
2011Q4	15842.267	16048.702	260
2012Q1	16068.824	16179.968	261
2012Q2	16207.130	16253.726	262
2012Q3	16319.540	16282.151	263
2012Q4	16420.386	16300.035	264
2013Q1	16629.050	16441.485	265
2013Q2	16699.551	16464.402	266
2013Q3	16911.068	16594.743	267
2013Q4	17133.114	16712.760	268
2014Q1	17144.281	16654.247	269
2014Q2	17462.703	16868.109	270
2014Q3	17743.227	17064.616	271
2014Q4	17852.540	17141.235	272
2015Q1	17991.348	17280.647	273
2015Q2	18193.707	17380.875	274
2015Q3	18306.960	17437.080	275
2015Q4	18332.079	17462.579	276
2016Q1	18425.306	17565.465	277
2016Q2	18611.617	17618.581	278
2016Q3	18775.459	17724.489	279
2016Q4	18968.041	17812.560	280
2017Q1	19148.194	17889.094	281
2017Q2	19304.506	17979.218	282
2017Q3	19561.896	18127.994	283
2017Q4	19894.750	18310.300	284
2018Q1	20155.486	18437.127	285
2018Q2	20470.197	18565.697	286
2018Q3	20687.278	18699.748	287
2018Q4	20819.269	18733.741	288
2019Q1	21013.085	18835.411	289
2019Q2	21272.448	18962.175	290
2019Q3	21531.839	19130.932	291
2019Q4	21706.532	19215.691	292
2020Q1	21538.032	18989.877	293
2020Q2	19636.731	17378.712	294
2020Q3	21362.428	18743.720	295
2020Q4	21704.706	18924.262	296
2021Q1	22313.850	19216.224	297
2021Q2	23046.934	19544.248	298
2021Q3	23550.420	19672.594	299
2021Q4	24349.121	20006.181	300
2022Q1	24740.480	19924.088	301
2022Q2	25248.476	19895.271	302
2022Q3	25723.941	20054.663	303
2022Q4	26144.956	20187.495	304

152	**9.815**	
153	**9.822**	**2018**
154	**9.829**	
155	**9.836**	
156	**9.838**	
157	**9.843**	**2019**
158	**9.850**	
159	**9.859**	
160	**9.863**	
161	**9.852**	**2020**
162	**9.763**	
163	**9.839**	
164	**9.848**	
165	**9.864**	**2021**
166	**9.880**	
167	**9.887**	
168	**9.904**	
169	**9.900**	**2022**
170	**9.898**	
171	**9.906**	
172	**9.913**	

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 408

ROE: TIPS Implied Inflation

June 13, 2023

2023 through 2053 TIPs-Implied Average Annual Inflation Rate: **2.33%**

Implied Market-based Inflationary Expectations						
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	
2022-Q4	0.024	0.024	0.023	0.026	0.023	PGE UE 416

Source: Federal Reserve Statistical Release H.15

See H15 Qtrly Avg for data feed

Yr. End		Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied	
Mo.-Yr.	Years	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Price Level	Check
Dec-23	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-24	1	102.41	102.40	102.34	102.60	102.33	102.41					102.41	
Dec-25	2	104.88	104.86	104.73	105.27	104.71	104.88					104.88	
Dec-26	3	107.41	107.38	107.19	108.02	107.15	107.41					107.41	
Dec-27	4	109.99	109.97	109.69	110.83	109.65	109.99					109.99	
Dec-28	5	112.64	112.61	112.26	113.71	112.21	112.64					112.64	
Dec-29	6		115.31	114.89	116.67	114.82		115.33				115.33	
Dec-30	7		118.09	117.58	119.71	117.50		118.09				118.09	
Dec-31	8			120.33	122.83	120.23			120.67			120.67	
Dec-32	9			123.14	126.02	123.03			123.32			123.32	
Dec-33	10			126.02	129.30	125.90			126.02			126.02	
Dec-34	11				132.67	128.83				129.64		129.64	128.95
Dec-35	12				136.12	131.84				133.35		133.35	131.95
Dec-36	13				139.67	134.91				137.18		137.18	135.02
Dec-37	14				143.30	138.05				141.11		141.11	138.16
Dec-38	15				147.04	141.27				145.16		145.16	141.37
Dec-39	16				150.86	144.56				149.32		149.32	144.66
Dec-40	17				154.79	147.93				153.60		153.60	148.02
Dec-41	18				158.82	151.37				158.01		158.01	151.46
Dec-42	19				162.96	154.90				162.54		162.54	154.99
Dec-43	20				167.20	158.51				167.20		167.20	158.59
Dec-44	21					162.20					170.18	170.18	162.28
Dec-45	22					165.98					173.22	173.22	166.05
Dec-46	23					169.85					176.31	176.31	169.91
Dec-47	24					173.81					179.46	179.46	173.86
Dec-48	25					177.86					182.67	182.67	177.90
Dec-49	26					182.00					185.93	185.93	182.04
Dec-50	27					186.24					189.25	189.25	186.27
Dec-51	28					190.58					192.63	192.63	190.60
Dec-52	29					195.02					196.07	196.07	195.03
Dec-53	30					199.57					199.57	199.57	199.57

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**
2022-Q1	-1.21	-0.90	-0.64	-0.25	-0.05
2022-Q2	**-0.13**	**0.05**	**0.20**	**0.43**	**0.55**
2022-Q3	0.66	0.66	0.69	0.87	1.01
2022-Q4	**1.59**	**1.53**	**1.49**	**1.52**	**1.57**

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**	**2.66**
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**
2022-Q1	1.82	1.92	1.94	2.32	2.25
2022-Q2	**2.95**	**2.98**	**2.93**	**3.24**	**3.04**
2022-Q3	3.23	3.20	3.11	3.51	3.26
2022-Q4	**4.00**	**3.93**	**3.83**	**4.12**	**3.90**

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**	**1.52**
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**
2022-Q1	3.03	2.82	2.58	2.57	2.30
2022-Q2	**3.08**	**2.93**	**2.73**	**2.81**	**2.50**
2022-Q3	2.57	2.53	2.42	2.64	2.26
2022-Q4	**2.41**	**2.40**	**2.34**	**2.60**	**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

Staff Accessed , Feb. 13, 2023 at: http://federalreserve.gov/releases/h15/data.htm
https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

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**

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**

Staff Accessed, Feb. 13, 2023 at: http://federalreserve.gov/releases/h15/data.htm
https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

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

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

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**
2018-01	0.45	0.51	0.54	0.69	0.80
2018-02	0.63	0.73	0.76	0.89	0.99
2018-03	0.61	0.71	0.75	0.89	0.99
2018-04	**0.65**	**0.72**	**0.74**	**0.85**	**0.93**
2018-05	**0.72**	**0.82**	**0.84**	**0.92**	**0.98**
2018-06	**0.71**	**0.76**	**0.79**	**0.87**	**0.93**
2018-07	0.74	0.76	0.77	0.84	0.88
2018-08	0.79	0.79	0.79	0.86	0.92
2018-09	0.89	0.88	0.88	0.95	1.00
2018-10	**1.01**	**1.03**	**1.04**	**1.14**	**1.21**
2018-11	**1.10**	**1.11**	**1.11**	**1.21**	**1.30**
2018-12	**1.08**	**1.04**	**1.02**	**1.11**	**1.19**
2019-01	0.91	0.91	0.92	1.07	1.19
2019-02	0.73	0.76	0.80	0.96	1.10
2019-03	0.56	0.60	0.66	0.85	1.02
2019-04	**0.49**	**0.54**	**0.60**	**0.79**	**0.97**
2019-05	**0.48**	**0.52**	**0.57**	**0.75**	**0.92**
2019-06	**0.28**	**0.32**	**0.37**	**0.59**	**0.79**
2019-07	0.25	0.27	0.31	0.54	0.77
2019-08	0.11	0.07	0.04	0.25	0.49
2019-09	0.17	0.13	0.11	0.32	0.51
2019-10	**0.12**	**0.12**	**0.15**	**0.36**	**0.55**
2019-11	**0.09**	**0.12**	**0.17**	**0.37**	**0.54**
2019-12	**0.06**	**0.09**	**0.14**	**0.35**	**0.52**
2020-01	-0.09	-0.04	0.04	0.26	0.43
2020-02	-0.26	-0.20	-0.11	0.12	0.29
2020-03	-0.08	-0.13	-0.12	0.03	0.16
2020-04	**-0.37**	**-0.44**	**-0.45**	**-0.28**	**-0.12**
2020-05	**-0.43**	**-0.45**	**-0.44**	**-0.26**	**-0.08**
2020-06	**-0.67**	**-0.62**	**-0.54**	**-0.28**	**-0.06**
2020-07	-1.03	-0.95	-0.83	-0.53	-0.29
2020-08	-1.28	-1.17	-1.01	-0.62	-0.35
2020-09	-1.26	-1.14	-0.98	-0.59	-0.34
2020-10	**-1.23**	**-1.10**	**-0.92**	**-0.51**	**-0.29**
2020-11	**-1.24**	**-1.06**	**-0.84**	**-0.44**	**-0.26**
2020-12	**-1.48**	**-1.24**	**-0.98**	**-0.54**	**-0.33**
2021-01	-1.66	-1.31	-1.00	-0.53	-0.28
2021-02	-1.77	-1.35	-0.92	-0.35	-0.10
2021-03	-1.67	-1.14	-0.66	-0.14	0.11
2021-04	**-1.67**	**-1.11**	**-0.71**	**-0.20**	**0.05**
2021-05	**-1.83**	**-1.25**	**-0.85**	**-0.27**	**-0.01**
2021-06	**-1.63**	**-1.18**	**-0.82**	**-0.34**	**-0.13**
2021-07	-1.73	-1.32	-1.01	-0.52	-0.29
2021-08	-1.72	-1.34	-1.07	-0.56	-0.31
2021-09	-1.63	-1.28	-0.97	-0.51	-0.30
2021-10	**-1.64**	**-1.28**	**-0.95**	**-0.51**	**-0.29**
2021-11	**-1.78**	**-1.39**	**-1.06**	**-0.63**	**-0.44**
2021-12	**-1.52**	**-1.24**	**-0.99**	**-0.61**	**-0.42**
2022-01	-1.26	-0.94	-0.69	-0.31	-0.14
2022-02	-1.06	-0.78	-0.52	-0.13	0.07
2022-03	-1.30	-0.99	-0.72	-0.30	-0.08
2022-04	**-0.54**	**-0.32**	**-0.14**	**0.13**	**0.26**
2022-05	**-0.15**	**0.04**	**0.21**	**0.47**	**0.60**
2022-06	**0.30**	**0.42**	**0.53**	**0.70**	**0.78**
2022-07	0.38	0.45	0.53	0.75	0.89
2022-08	0.34	0.36	0.39	0.65	0.84
2022-09	1.25	1.18	1.14	1.21	1.29
2022-10	**1.71**	**1.64**	**1.59**	**1.64**	**1.71**
2022-11	**1.61**	**1.56**	**1.52**	**1.55**	**1.60**
2022-12	**1.45**	**1.39**	**1.36**	**1.37**	**1.40**

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**
2018-01	2.38	2.51	2.58	2.73	2.88
2018-02	2.60	2.78	2.86	3.02	3.13
2018-03	2.63	2.77	2.84	2.97	3.09
2018-04	**2.70**	**2.82**	**2.87**	**2.96**	**3.07**
2018-05	**2.82**	**2.93**	**2.98**	**3.05**	**3.13**
2018-06	**2.78**	**2.87**	**2.91**	**2.98**	**3.05**
2018-07	2.78	2.85	2.89	2.94	3.01
2018-08	2.77	2.84	2.89	2.97	3.04
2018-09	2.89	2.96	3.00	3.08	3.15
2018-10	**3.00**	**3.09**	**3.15**	**3.27**	**3.34**
2018-11	**2.95**	**3.04**	**3.12**	**3.27**	**3.36**
2018-12	**2.68**	**2.75**	**2.83**	**2.98**	**3.10**
2019-01	2.54	2.61	2.71	2.89	3.04
2019-02	2.49	2.57	2.68	2.87	3.02
2019-03	2.37	2.47	2.57	2.80	2.98
2019-04	**2.33**	**2.43**	**2.53**	**2.76**	**2.94**
2019-05	**2.19**	**2.29**	**2.40**	**2.63**	**2.82**
2019-06	**1.83**	**1.95**	**2.07**	**2.36**	**2.57**
2019-07	1.83	1.93	2.06	2.36	2.57
2019-08	1.49	1.55	1.63	1.91	2.12
2019-09	1.57	1.64	1.70	1.97	2.16
2019-10	**1.53**	**1.62**	**1.71**	**2.00**	**2.19**
2019-11	**1.64**	**1.74**	**1.81**	**2.13**	**2.28**
2019-12	**1.68**	**1.79**	**1.86**	**2.16**	**2.30**
2020-01	1.56	1.67	1.76	2.07	2.22
2020-02	1.32	1.42	1.50	1.81	1.97
2020-03	0.59	0.78	0.87	1.26	1.46
2020-04	**0.39**	**0.55**	**0.66**	**1.06**	**1.27**
2020-05	**0.34**	**0.53**	**0.67**	**1.12**	**1.38**
2020-06	**0.34**	**0.55**	**0.73**	**1.27**	**1.49**
2020-07	0.28	0.46	0.62	1.09	1.31
2020-08	0.27	0.46	0.65	1.14	1.36
2020-09	0.27	0.46	0.68	1.21	1.42
2020-10	**0.34**	**0.55**	**0.79**	**1.34**	**1.57**
2020-11	**0.39**	**0.63**	**0.87**	**1.40**	**1.62**
2020-12	**0.39**	**0.66**	**0.93**	**1.47**	**1.67**
2021-01	0.45	0.77	1.08	1.63	1.82
2021-02	0.54	0.91	1.26	1.88	2.04
2021-03	0.82	1.27	1.61	2.24	2.34
2021-04	**0.86**	**1.31**	**1.64**	**2.20**	**2.30**
2021-05	**0.82**	**1.28**	**1.62**	**2.22**	**2.32**
2021-06	**0.84**	**1.23**	**1.52**	**2.09**	**2.16**
2021-07	0.76	1.07	1.32	1.87	1.94
2021-08	0.77	1.06	1.28	1.83	1.92
2021-09	0.86	1.16	1.37	1.87	1.94
2021-10	**1.11**	**1.40**	**1.58**	**2.03**	**2.06**
2021-11	**1.20**	**1.45**	**1.56**	**1.97**	**1.94**
2021-12	**1.23**	**1.40**	**1.47**	**1.90**	**1.85**
2022-01	1.54	1.70	1.76	2.15	2.10
2022-02	1.81	1.91	1.93	2.31	2.25
2022-03	2.11	2.15	2.13	2.51	2.41
2022-04	**2.78**	**2.80**	**2.75**	**2.99**	**2.81**
2022-05	**2.87**	**2.92**	**2.90**	**3.26**	**3.07**
2022-06	**3.19**	**3.21**	**3.14**	**3.48**	**3.25**
2022-07	2.96	2.97	2.90	3.35	3.10
2022-08	3.03	2.98	2.90	3.35	3.13
2022-09	3.70	3.64	3.52	3.82	3.56
2022-10	**4.18**	**4.09**	**3.98**	**4.28**	**4.04**
2022-11	**4.06**	**3.99**	**3.89**	**4.22**	**4.00**
2022-12	**3.76**	**3.72**	**3.62**	**3.87**	**3.66**

NWN UG 344

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 409

ROE: Financial News that Investors in Electric Utilities Are Seeing

June 13, 2023

Financial News Investors Are Seeing

April Jobs Report Shows Hiring Remained Robust in a Slowing Economy

by Sarah Chaney Cambon – WSJ – May 5, 2023
Nick Timiraos contributed to this article.

Employers added 253,000 jobs, unemployment fell to 3.4% amid banking turmoil, rising interest rates and still-high inflation.

A historically low unemployment rate kept pressure on wages in April.

Hiring strengthened in April, showing the job market is resilient amid banking turmoil, rising interest rates and high inflation.

Employers added 253,000 jobs in April, the best gain since January, the Labor Department said Friday. The **jobless rate fell to 3.4% last month**, matching the **lowest reading since 1969**.

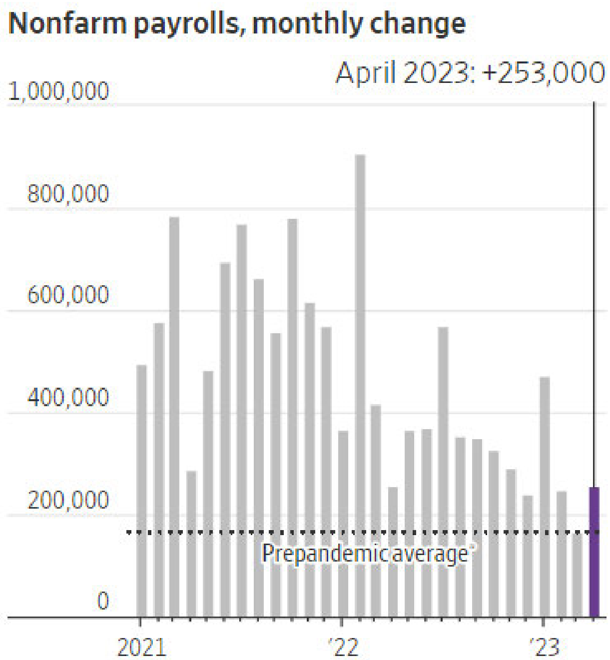
A historically low unemployment rate kept pressure on wages, which grew 4.4% in April from a year earlier. That was slightly higher than a 4.3% annual increase in March.

Last month's job growth suggests the labor market remains a pillar of strength in a cooling economy. The economy grew more slowly to start the year versus the end of 2022 as businesses cut back on investments, while the housing market remained weak. Many economists forecast the U.S. to slip into recession in the next 12 months.

The April jobs report provides the latest update on the health of U.S. consumers and how companies are responding to higher borrowing costs. It's also got key data about the pace of inflation.

The jobs report does little to clarify the outlook for Federal Reserve policy because officials will have one more employment report before their June 13-14 meeting and because they are paying closer attention to banking stress.

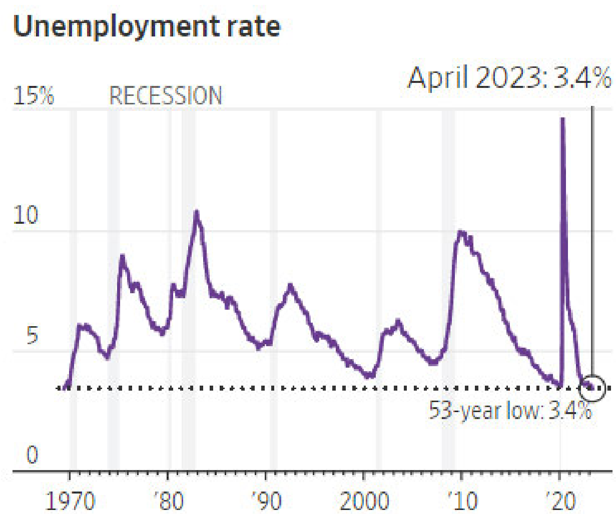
Officials raised their benchmark federal-funds rate this week to a range between 5% and 5.25%, the highest level in 16 years, to slow down the economy and combat inflation. Fed Chair Jerome Powell suggested that the central bank might pause rate rises after that to study the impact of its rapid increases over the past year and assess any fallout from the failures of three midsize banks since March.



Friday's report showed job gains in most industries. Businesses in professional and business services, healthcare, and leisure and hospitality bulked up with workers in April. Temporary-help agencies cut jobs.

After the pandemic spurred a rise in pet ownership, Goodheart Animal Health Center has hired front-desk staff as well as veterinarians and nurses in recent months to meet the demand from pet owners bringing their dogs and cats in for checkups and surgeries, said Alex Robb, medical director at one of the two Denver locations.

The center has increased wages to retain existing employees in an industry suffering from high levels of worker burnout,



Note: Seasonally adjusted
Source: Labor Department

Mr. Robb said. “You can’t underpay folks and expect them to stay,” he said.

The hospital has raised pay an average of about 10% in the past 16 months. Receptionists now make between $18 and $20 an hour and nursing staff between $21 and $25. Goodheart also raised prices last year including for lab work and surgical fees, helping offset the higher labor costs.

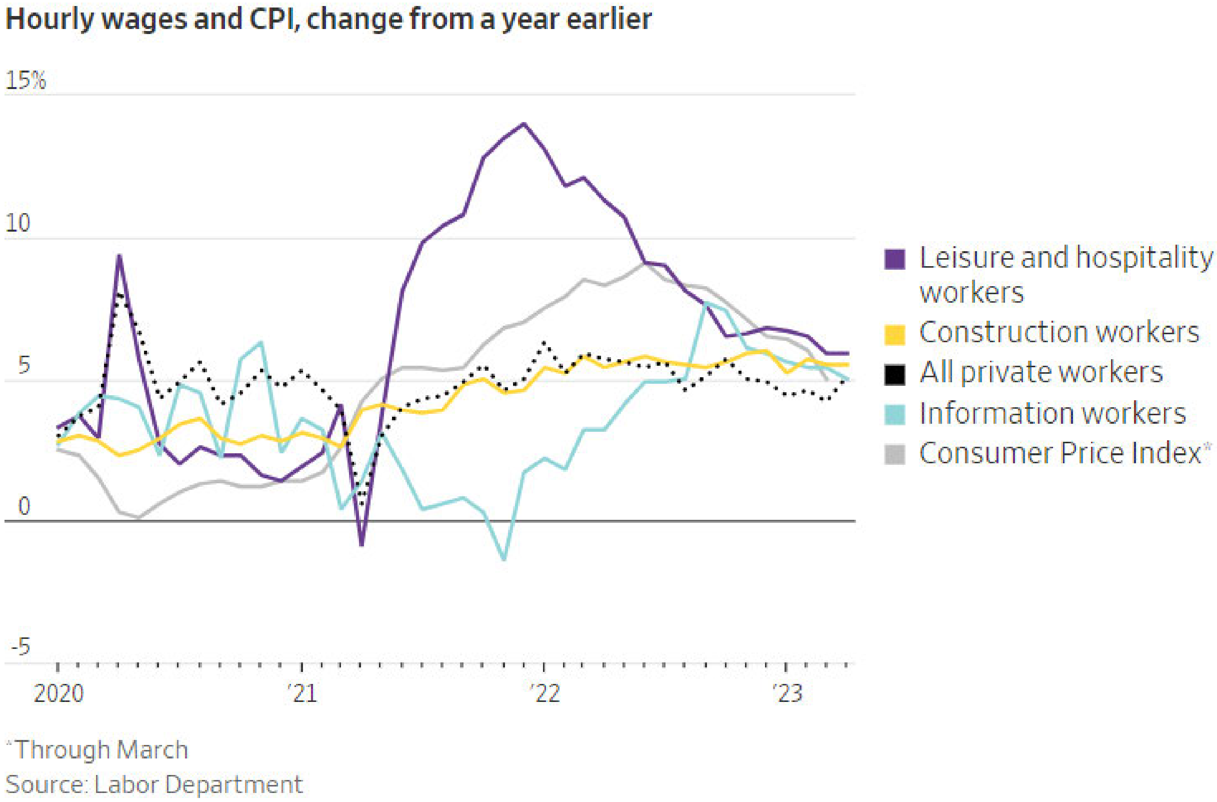
April’s monthly payrolls increase was slightly below the average monthly gain of 290,000 over the prior six months, but consistent with a healthy labor market. After mass layoffs in early 2020 during pandemic lockdowns, hiring surged in the middle of that year. Job gains have moderated since, but have trended above the pace in the year before the pandemic began.

Demand for metal parts has slowed over the past 18 months at Birmingham, Ala., manufacturer DSW Cutting, President Chris McIlvaine said. DSW makes parts used in tractors, lawn mowers and electrical hardware.

Weaker sales and production volumes mean less need for workers. The 75-person company is looking to hire four employees, fewer than it sought to hire in 2021 when business was booming.

“Things are not terrible, but they’re not nearly as active as they were,” Mr. McIlvaine said. “It’s been a very strange economy.”

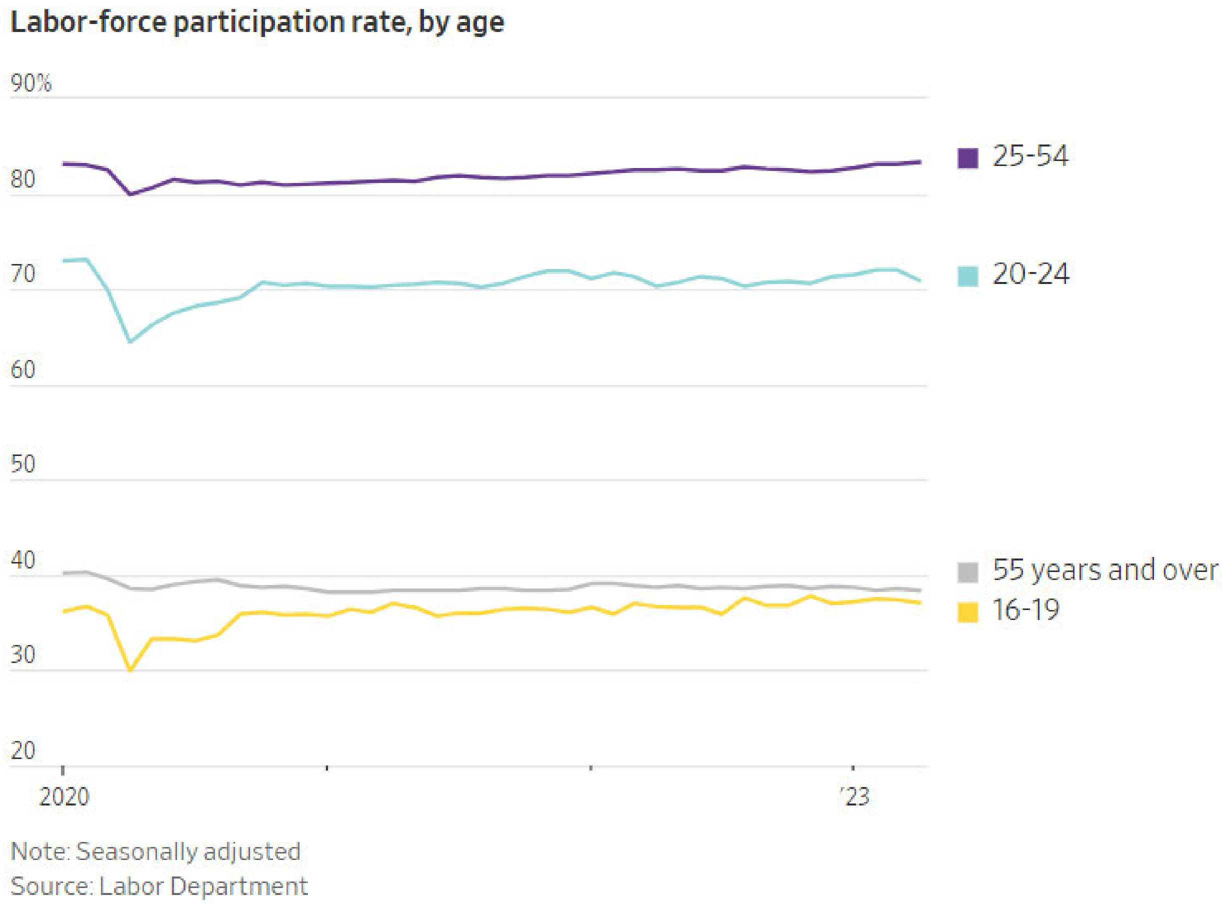
The company finds hiring becoming easier as more people enter the labor force. DSW’s recruitment agency can now fill factory-floor positions within two to three days of searching, compared with two to three weeks a year ago, Mr. McIlvaine said.



The **share of Americans** in their prime working years, **ages 25 to 54**, who are **employed or seeking jobs has climbed over** the **past year**. The influx of job seekers is helping restaurants, bars and hotels snap up workers, after they struggled with acute labor shortages for much of the pandemic. Healthcare providers are also staffing up, replacing workers who quit or retired early.

Job gains at providers of **in-person services**, **such as restaurants**, have **offset** recent **cuts** at **large companies** such as Facebook parent Meta Platforms, Google parent Alphabet and Walt Disney.

Wage growth is running above pre-pandemic levels but is cooling as more Americans seek work. Slowing wage growth could comfort Federal Reserve officials who have worried that strong earnings gains would fuel continued inflation above the central bank's 2% target.



The **Fed approved its 10th consecutive interest-rate increase this week** and signaled it could be done lifting rates. The latest move brings its **benchmark federal-funds rate** to a **range between 5% and 5.25%**, a **16-year high**.

Officials considered skipping a rate increase in March after the **failures** of two regional lenders, **Silicon Valley Bank** and **Signature Bank**, raised worries about a bank-funding crisis. But they concluded that the stresses had calmed enough on the eve of their March 22 decision to move ahead with an increase.

Federal regulators recently **seized** another regional lender, Fir**st Republic Bank**, **orchestrating** a **sale to JPMorgan Chase**. The banking stress could lead to tighter lending conditions for businesses and households that ultimately results in layoffs. Workers, meanwhile, could be more hesitant to search for new jobs.

–

Average Authorized ROE Rises for Electric, But Declines for Gas in 2022

by Lisa Fontanella – Regulatory Research Associates (RRA)
an Affiliate of S&P Global Market Intelligence – Jan. 11, 2023

Rate case activity remained elevated with about 136 decisions issued by state public utility commissions in 2022. This level of activity, however, is down from 2021, which was a record year with 151 decisions rendered in electric and gas rate cases in the U.S.

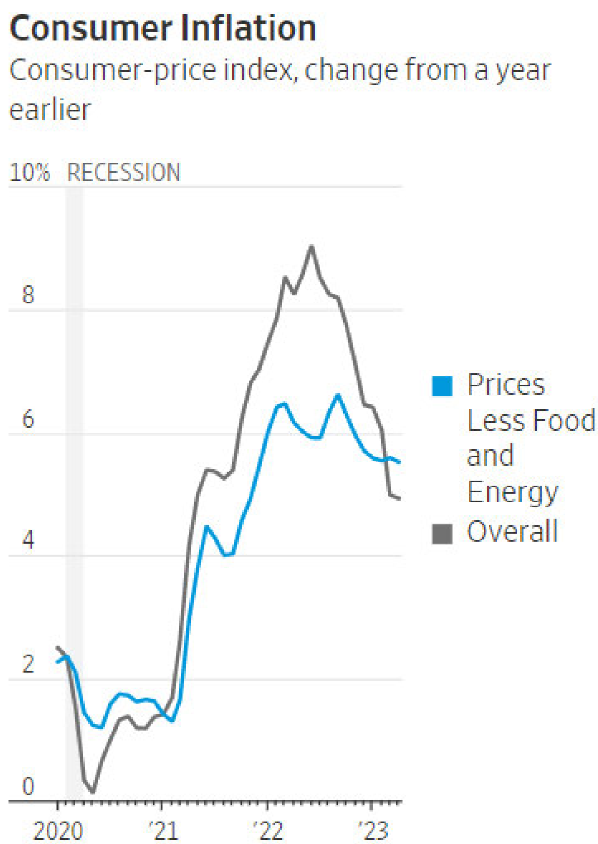
As per preliminary calculations from Regulatory Research Associates, a group within S&P Global Commodity Insights, the average authorized return on equity for electric utilities approved in cases decided during 2022 rebounded from 2021, which was the lowest annual average in RRA's rate case database comprised of all major rate cases decided since 1980. Despite the rise, however, the average authorized ROE for electric utilities in 2022 remains near historic lows and was the third-lowest annual average on record.

For gas utilities, the average authorized ROE in 2022 fell to the second-lowest annual average on record.

The average ROE authorized for electric utilities rose to **9.54%** for **rate cases decided** in **2022** from the 9.38% average for cases decided in 2021. The **average ROE** authorized **for gas utilities** was **9.53%** for cases decided during **2022**, slightly lower than the 9.56% average observed in 2021.

CPI Report Shows Inflation Eased in April But Remains Stubbornly High

by Gabriel T. Rubin – WSJ – May 10, 2023
Nick Timiraos contributed to this article



Source: Labor Department via St. Louis Fed

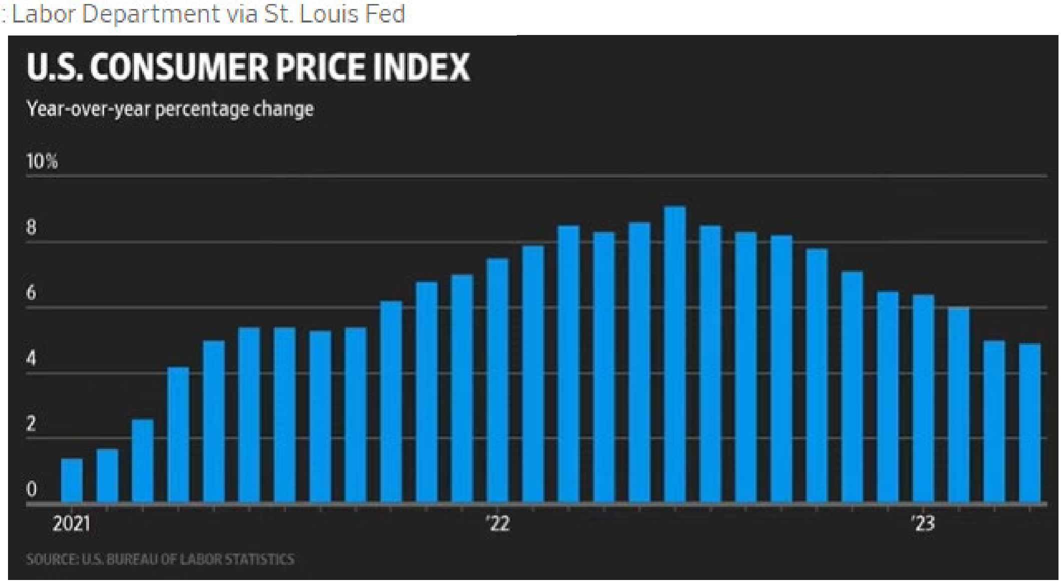
Consumer-price index rose 4.9% from year earlier, 10th straight month of easing.

Inflation is still much higher than the Fed's target and economists are warning it may be stickier than markets are expecting.

Inflation eased slightly in April, the 10th straight month of cooling, but price gains remain historically high as the broader economy cools.

The Consumer-Price **Index rose 4.9%** in **April from** a **year earlier**, the **Labor Department** said Wednesday, down slightly from March's 5% increase. The inflation reading has **eased from** a recent **peak** of **9.1%** in **June 2022**.

The Federal Reserve aggressively raised rates for more than a year to try to tame inflation by slowing economic activity. The Fed is looking to see signs of inflation declining toward its 2% target.

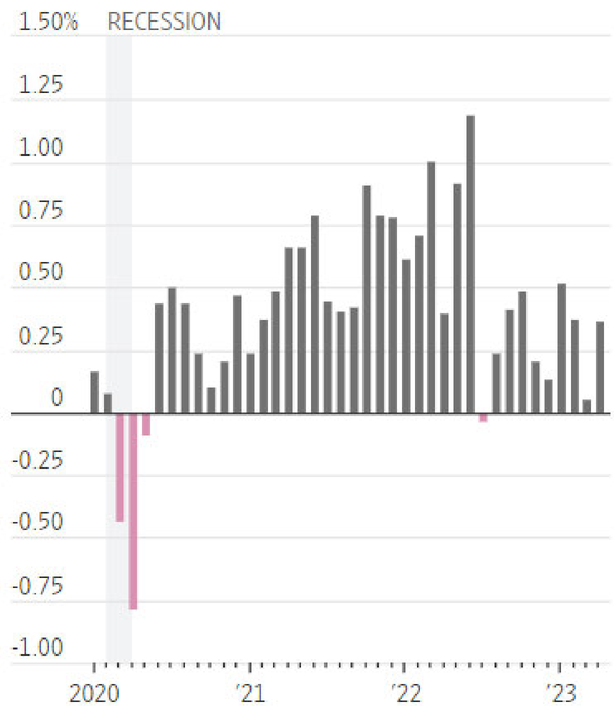


Consumer prices rose a seasonally adjusted 0.4% in April from the prior month, versus a 0.1% gain in March. April's increase was driven by housing costs and an uptick in gasoline prices. **Used vehicle prices surged** by **4.4% over** the **month** due to lack of inventory, **while new car prices declined modestly**.

Wednesday's report could keep Fed officials on course to pause rate increases at their next meeting because they have shifted their focus away from lagging indicators of economic activity to assess the impact of recent bank failures on lending conditions and economic activity, which won't immediately show up in broad measures of hiring and inflation.

Fed officials **raised** their benchmark **federal-funds rate** last week to a **range between 5% and 5.25%**, the highest level in 16 years, to slow down the economy and combat inflation. At that meeting, some officials had discussed whether to pause rate rises after the most recent increase, said Fed Chair Jerome Powell at a news conference on May 3. "We feel like we're getting closer or maybe even there," he said.

Consumer-price index, change from prior month



Note: Seasonally adjusted.
Source: Labor Department via St. Louis Fed

Until now, officials have been looking for clear signs of a slowdown to justify ending rate increases. But Mr. Powell indicated that calculation could shift now, and officials would need to see signs of stronger-than-expected growth, hiring and inflation to continue raising rates. The Fed slows the economy through lifting rates, which causes tighter financial conditions such as higher borrowing costs, lower stock prices and a stronger dollar.

While the report contains some positive signs for a continued slowdown in price gains, "it does suggest a risk that rates will need to remain high for a little longer than we have assumed," said Andrew Hunter, an economist at Capital Economics.

On Wednesday, investors saw a 14% chance that the Fed would raise rates at its next meeting, according to CME Group.

Wednesday's report showed that when removing volatile food and energy costs, prices rose 5.5% from a year earlier, a slightly slower increase than in March. Those so-called core prices remain elevated due to persistently strong shelter costs that economists expect to cool in the coming months. **Housing** price changes can take time to show up in inflation data due to the lag in mortgage and rental contracts.

Economists see core prices as a better predictor of future inflation.

Left: Ryan Flick, a tech sales professional in Denver.

Some Americans are making adjustments as prices rise.

Ryan Flick, 39, said he used to eat fast food a couple of times a week. "It never really felt like it was making a dent whatsoever in my budget," he said.

But as prices for meals he favored rose to over $10 from $5 to $8 he was paying a few years ago, he made a choice to cut back. He said he would rather forgo a few forgettable weekday lunches and save money by making a sandwich at home, especially since he works remotely more often than in the past.

"If you're going to eat out, you might as well take three times where you might have gotten fast food and go out for something nicer," said Mr. Flick, a Denver resident who works in tech sales. Food prices have remained flat over the past two months, though a decline in grocery prices in April was offset by a rise in prices for dining out.

That divergence could provide relief to household budgets by giving them "an option to avoid inflation by cutting out at least one discretionary spending indulgence from their routines," said PNC Senior Economist Kurt Rankin.

Inflation started to rise sharply in late 2020, as pandemic restrictions eased, and the rate remains well above 2019 levels. Price pressures initially grew because of supply-chain bottlenecks and high commodity prices, but those factors have significantly improved.

More recently, one factor supporting inflation is sustained demand for workers among service providers. **Average hourly wages rose 4.4%** in **April from** a **year earlier**, slightly faster than the prior month, while the **unemployment fell to match** the **lowest level since 1969**. Some companies are passing along higher labor costs to consumers.

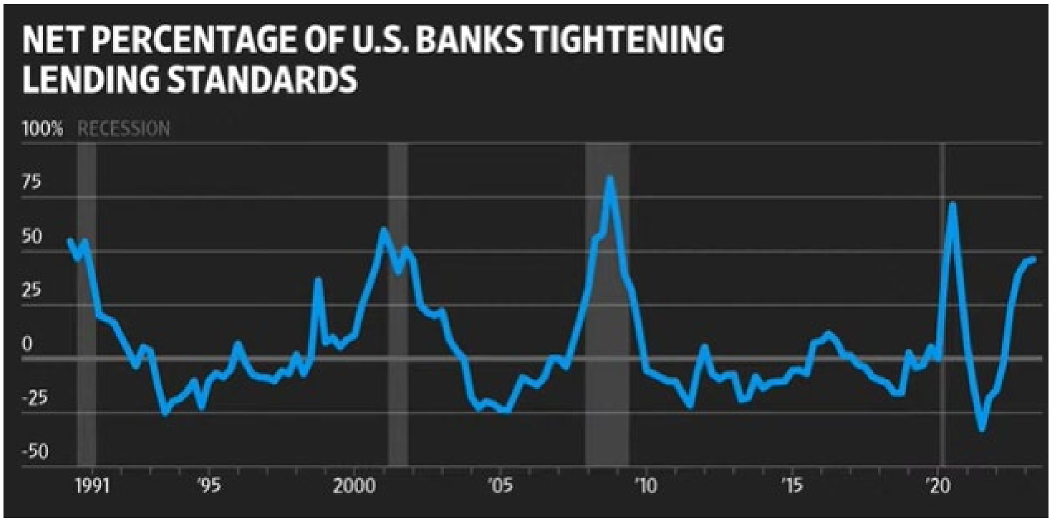
Another factor is that companies have been able to raise prices, and boost profits, without prompting a backlash.

However, some companies say the significant pricing power they enjoyed in recent years has begun to fade amid early signs of a consumer pullback. Consumer spending, the primary driver of economic growth, has stagnated recently after jumping at the start of the year.

Higher gasoline prices are one of the factors keeping upward pressure on inflation.

Businesses struggling with high input costs are trying new strategies. Becky Nelson, co-owner of Nelson's Greenhouse in Clinton, Ind., recently decided that they would add a surcharge for customers who paid with credit cards, rather than raising prices. Encouraging shoppers to pay with cash will save the greenhouse on interchange fees.

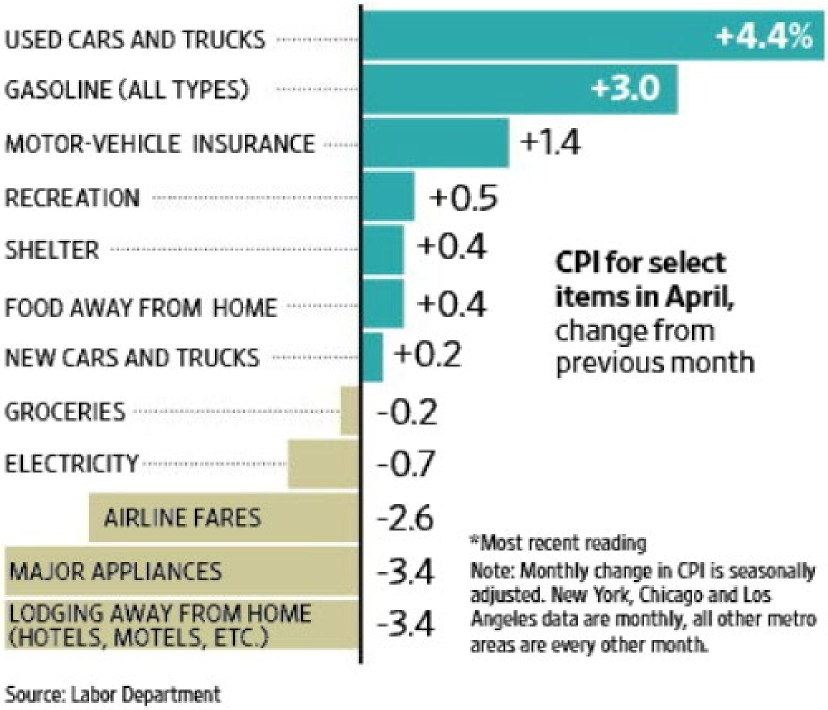
They have also cut back on their offerings, opting to shut down the greenhouse over the winter to save money on propane, which they use to heat the 35,000 square foot facility.



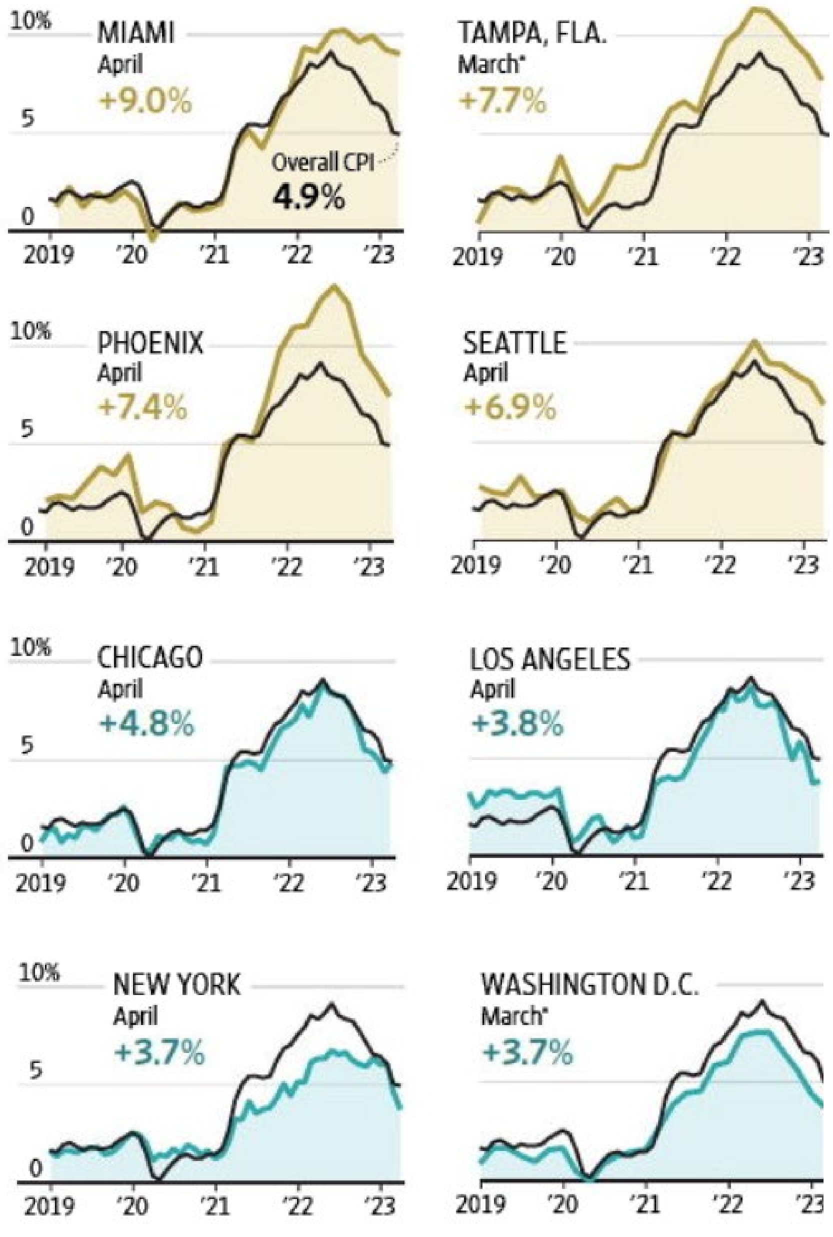
Banks are making it harder for individuals and small businesses to get loans.

"We had to quit growing poinsettias," Mrs. Nelson said. "It's not that we don't like growing year-round, it's that we couldn't keep up with the prices."

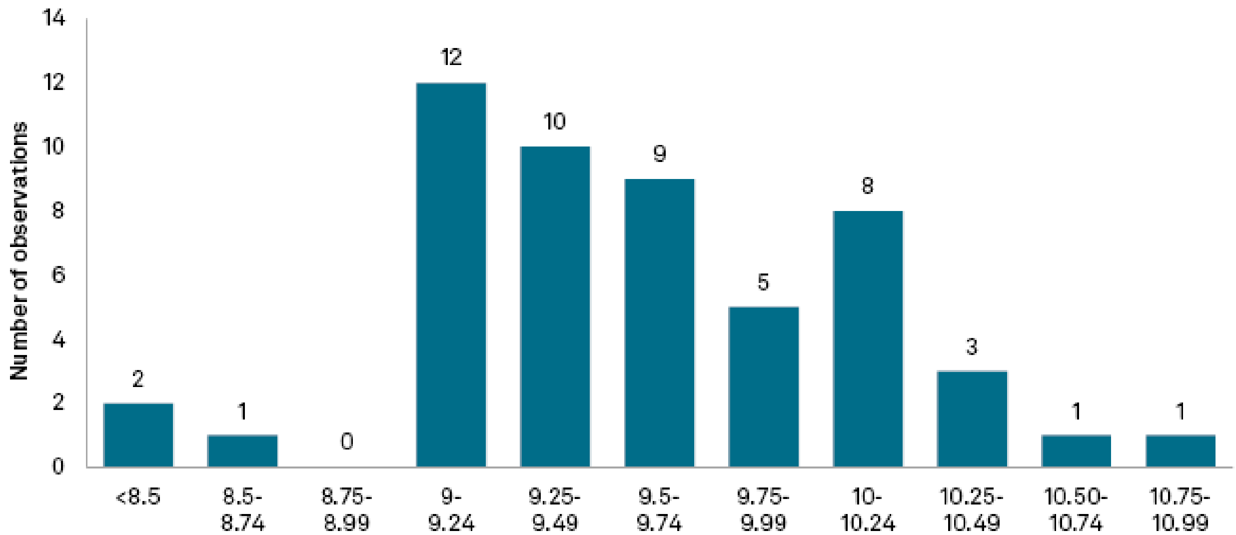
The **P**roducer **P**rice **I**ndex will be out on Thursday. PPI **usually leads CPI**.



Consumer-price index for select metropolitan areas,
change from a year earlier



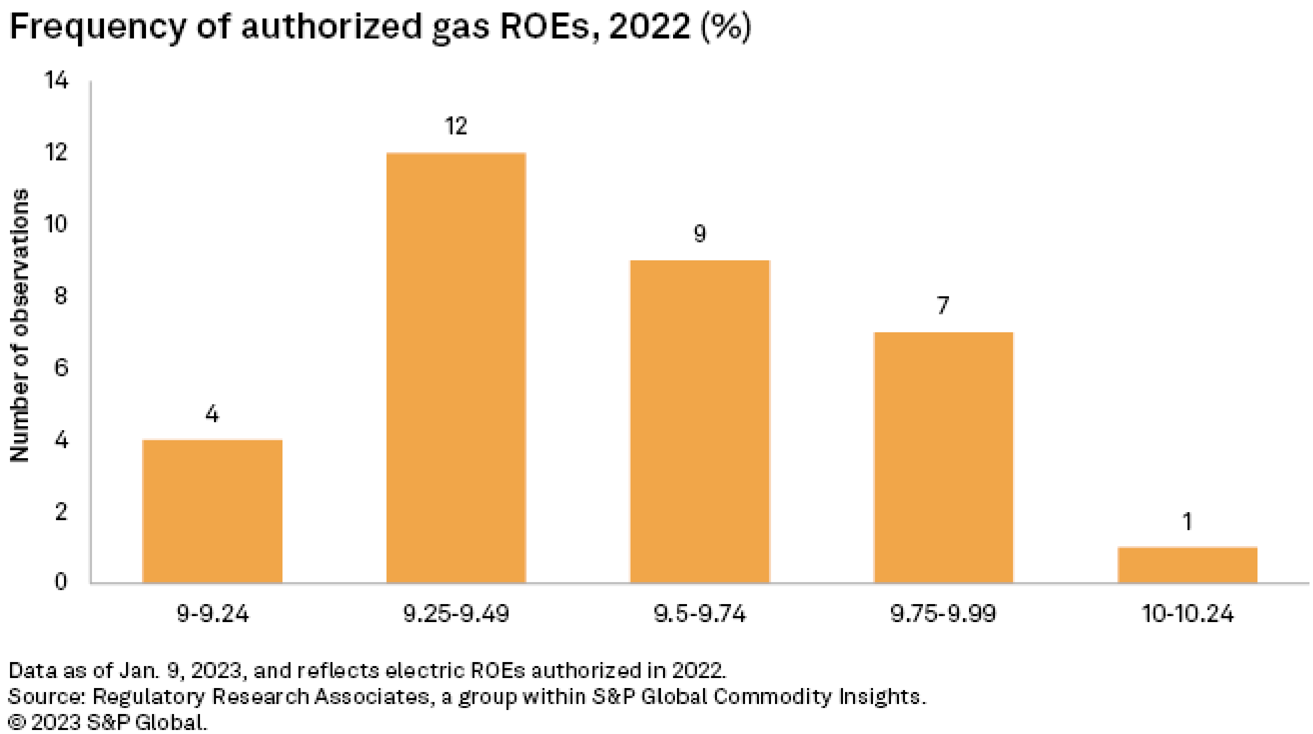
Frequency of authorized electric ROEs, 2022 (%)



Data as of Jan. 9, 2023, and reflects electric ROEs authorized in 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

There were 52 electric ROE determinations reflected in the calculations for 2022 versus 55 in 2021. The accompanying chart and table show the distribution of the 52 new electric ROE determinations in 2022, awarded across 23 regulatory jurisdictions. These authorized equity returns ranged from 7.85% to 10.80%, with an average of 9.54% and a median of 9.50%.

RRA's calculations reveal 33 gas rate case decisions that included an ROE determination during 2022 versus 43 in 2021. The accompanying chart and table show the distribution of the 33 ROE determinations in 2022, awarded across 22 regulatory jurisdictions. These authorized equity returns ranged from 9.0% to 10.2%, with an average of 9.53% and a median of 9.60%.

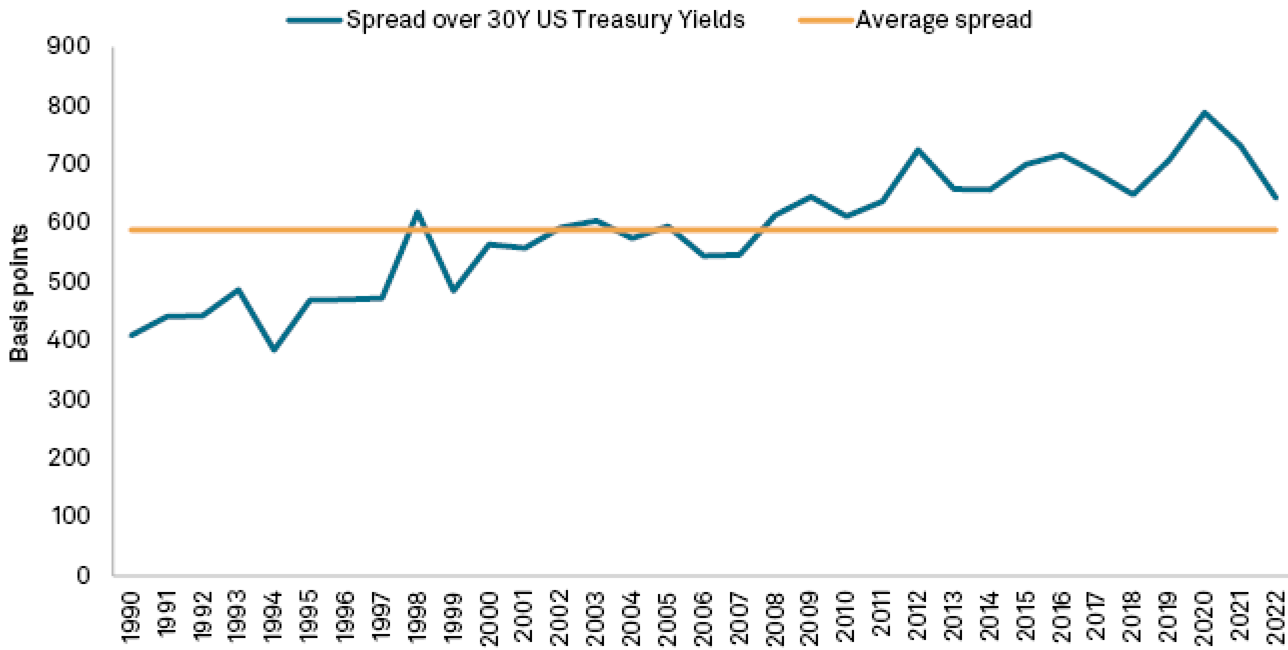


For many years, interest rates, **including long-term U.S. Treasury bond yields** that are **used** to **represent** the **risk-free rate** in **utility ratemaking**, have **remained historically low, exerting downward pressure** on **authorized ROEs** over the past several years. With **inflation** running at multi-decade highs, however, the U.S. **Fed**eral Reserve **hiked** its benchmark policy **interest rate** during 2022 as part of an aggressive effort to combat high and persistent inflationary pressures.

While both interest rates and **authorized ROEs** have generally been **declining since 1990**, the **gap** between authorized ROEs and interest rates **widened** somewhat over this period, largely as a result of the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, **regulators did not** necessarily **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.

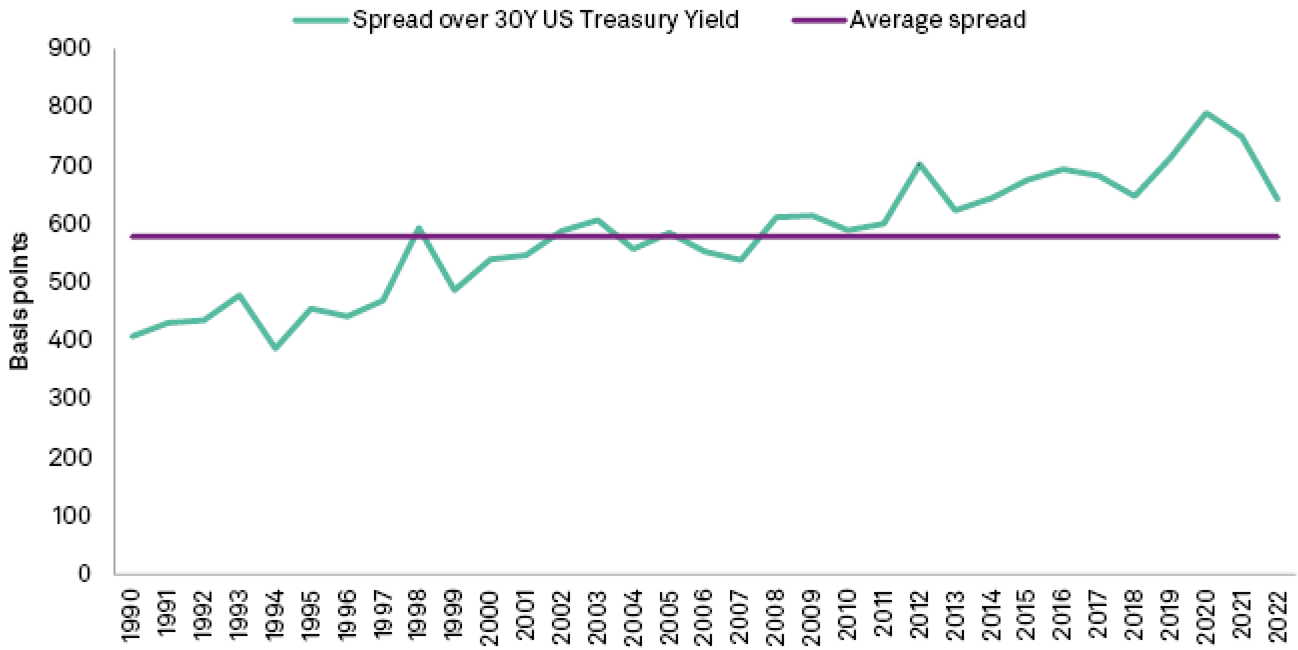
With interest rates on the rise, the average authorized return for 2022 edged higher for the electric group. For the gas group, the average authorized return declined slightly. The spread between authorized ROEs and U.S. Treasury yields, however, narrowed considerably in 2022.

Spread between US authorized electric ROEs and Treasury yields*



Data as of Jan. 9, 2023.
* Average of the daily Treasury yields.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury.

Spread between US authorized gas ROEs and Treasury yields*



Data as of Jan. 9, 2023.
* Average of the daily Treasury yields.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; U.S. Department of the Treasury.

A detailed report regarding major rate case decisions rendered in 2022, as well as historical ROE authorizations, is expected to be issued later this month.

Authorized electric ROEs, 2022

ROE interval (%)	Rate case completed date	Co. Name	State	Authorized return on equity (%)	Decision type	Case type
<8.5	11/17/22	Commonwealth Edison Co.	IL	7.85	Fully litigated	Distribution
	12/01/22	Ameren Illinois Co.	IL	7.85	Fully litigated	Distribution
8.5-8.74	08/31/22	Green Mountain Power Corp.	VT	8.57	Fully litigated	Vertically integrated
8.75-8.99						
9-9.24	01/20/22	Niagara Mohawk Power Corp.	NY	9.00	Settled	Distribution
	01/28/22	Appalachian Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	02/10/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	03/15/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	03/18/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	03/24/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	04/14/22	Orange and Rockland Utilities Inc.	NY	9.20	Settled	Distribution
	05/12/22	Unitil Energy Systems Inc.	NH	9.20	Settled	Distribution
	05/13/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	06/09/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	07/15/22	Appalachian Power Co.	VA	9.20	Fully litigated	Limited-issue rider
	08/05/22	Virginia Electric and Power Co.	VA	9.20	Fully litigated	Limited-issue rider
9.25-9.49	03/16/22	Public Service Co. of Colorado	CO	9.30	Settled	Vertically integrated
	02/16/22	Southwestern Public Service Co.	NM	9.35	Settled	Vertically integrated
	03/09/22	Virginia Electric and Power Co.	VA	9.35	Fully litigated	Limited-issue rider
	03/11/22	Virginia Electric and Power Co.	VA	9.35	Fully litigated	Limited-issue rider
	07/01/22	Virginia Electric and Power Co.	VA	9.35	Settled	Limited-issue rider
	09/15/22	El Paso Electric Co.	TX	9.35	Settled	Vertically integrated
	09/21/22	Virginia Electric and Power Co.	VA	9.35	Fully litigated	Limited-issue rider
	10/20/22	Virginia Electric and Power Co.	VA	9.35	Fully litigated	Limited-issue rider
	10/31/22	Virginia Electric and Power Co.	VA	9.35	Fully litigated	Limited-issue rider
	12/22/22	Puget Sound Energy Inc.	WA	9.40	Settled	Vertically integrated
9.5-9.74	04/25/22	Portland General Electric Co.	OR	9.50	Settled	Vertically integrated
	05/23/22	Southwestern Electric Power Co.	AR	9.50	Fully litigated	Vertically integrated
	09/08/22	Oklahoma Gas and Electric Co.	OK	9.50	Settled	Vertically integrated
	10/25/22	Kingsport Power Co.	TN	9.50	Settled	Vertically integrated
	12/14/22	Duke Energy Ohio Inc.	OH	9.50	Settled	Distribution
	12/16/22	PacifiCorp	OR	9.50	Settled	Vertically integrated
	12/27/22	Sierra Pacific Power Co.	NV	9.56	Fully litigated	Vertically integrated
	12/14/22	Delmarva Power & Light Co.	MD	9.60	Settled	Distribution
	02/23/22	Indiana Michigan Power Co.	IN	9.70	Settled	Vertically integrated
9.75-9.99	11/30/22	NSTAR Electric Co.	MA	9.80	Fully litigated	Distribution
	12/22/22	Wisconsin Public Service Corp.	WI	9.80	Fully litigated	Vertically integrated
	12/29/22	Wisconsin Electric Power Co.	WI	9.80	Fully litigated	Vertically integrated
	11/18/22	DTE Electric Co.	MI	9.90	Fully litigated	Vertically integrated
	12/15/22	San Diego Gas & Electric Co.	CA	9.95	Fully litigated	Vertically integrated
10-10.24	12/14/22	The Dayton Power and Light Co.	OH	10.00	Fully litigated	Distribution
	12/15/22	Pacific Gas and Electric Co.	CA	10.00	Fully litigated	Vertically integrated
	12/15/22	Southern California Edison Co.	CA	10.05	Fully litigated	Vertically integrated
	10/04/22	Duke Energy Florida, LLC	FL	10.10	Settled	Limited-issue rider
	02/08/22	Virginia Electric and Power Co.	VA	10.20	Fully litigated	Limited-issue rider
	08/16/22	Tampa Electric Co.	FL	10.20	Settled	Limited-issue rider
	11/03/22	San Diego Gas & Electric Co.	CA	10.20	Fully litigated	Vertically integrated
	12/06/22	Tampa Electric Co.	FL	10.20	Settled	Limited-issue rider
10.25-10.49	11/03/22	Pacific Gas and Electric Co.	CA	10.25	Fully litigated	Vertically integrated
	11/03/22	Southern California Edison Co.	CA	10.30	Fully litigated	Vertically integrated
	05/26/22	Virginia Electric and Power Co.	VA	10.35	Fully litigated	Limited-issue rider
10.50-10.74	12/20/22	Georgia Power Co.	GA	10.50	Settled	Vertically integrated
10.75-10.99	10/04/22	Florida Power & Light Co.	FL	10.80	Settled	Limited-issue rider
Average ROE				9.54		
Median ROE				9.50		

Data as of Jan. 9, 2023, and reflects electric ROEs authorized in 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Authorized gas ROEs, 2022

ROE interval (%)	Rate case completed date	Co. Name	State	Authorized return on equity (%)	Decision type
9.00-9.24	01/20/22	Niagara Mohawk Power Corp.	NY	9.00	Settled
	04/14/22	Orange and Rockland Utilities Inc.	NY	9.20	Settled
	10/25/22	Public Service Co. of Colorado	CO	9.20	Fully litigated
	05/19/22	Atmos Energy Corp.	KY	9.23	Fully litigated
9.25-9.49	01/03/22	Delta Natural Gas Co. Inc.	KY	9.25	Settled
	06/16/22	Corning Natural Gas Corp.	NY	9.25	Settled
	07/20/22	Northern Utilities Inc.	NH	9.30	Settled
	09/15/22	Piedmont Natural Gas Co. Inc.	SC	9.30	Settled
	11/30/22	New Mexico Gas Co. Inc.	NM	9.38	Settled
	08/18/22	CenterPoint Energy Resources Corp.	MN	9.39	Settled
	03/22/22	Southwest Gas Corp.	NV	9.40	Settled
	03/22/22	Southwest Gas Corp.	NV	9.40	Settled
	08/02/22	Avista Corp.	OR	9.40	Settled
	08/23/22	Cascade Natural Gas Corp.	WA	9.40	Settled
	10/24/22	Northwest Natural Gas Co.	OR	9.40	Settled
	12/22/22	Puget Sound Energy Inc.	WA	9.40	Settled
9.50-9.74	01/06/22	Piedmont Natural Gas Co. Inc.	NC	9.60	Settled
	01/21/22	Public Service Co. of North Carolina Inc.	NC	9.60	Settled
	08/17/22	Elizabethtown Gas Co.	NJ	9.60	Settled
	10/10/22	Black Hills Energy Arkansas Inc.	AR	9.60	Fully litigated
	10/12/22	Delmarva Power & Light Co.	DE	9.60	Settled
	12/21/22	South Jersey Gas Co.	NJ	9.60	Settled
	12/23/22	Dominion Energy Inc.	UT	9.60	Fully litigated
	11/17/22	Columbia Gas of Maryland Inc.	MD	9.65	Settled
	10/27/22	The Berkshire Gas Co.	MA	9.70	Settled
9.75-9.99	10/27/22	Northern States Power Co.	ND	9.80	Settled
	12/15/22	Southern California Gas Co.	CA	9.80	Fully litigated
	12/22/22	Wisconsin Public Service Corp.	WI	9.80	Fully litigated
	12/29/22	Wisconsin Gas LLC	WI	9.80	Fully litigated
	12/29/22	Wisconsin Electric Power Co.	WI	9.80	Fully litigated
	07/27/22	Northern Indiana Public Service Co.	IN	9.85	Settled
	07/07/22	Consumers Energy Co.	MI	9.90	Settled
10.00-10.24	11/03/22	San Diego Gas & Electric Co.	CA	10.20	Fully litigated
Average ROE				**9.53**	
Median ROE				**9.60**	

Data as of Jan. 9, 2023, and reflects gas ROEs authorized in 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Commodities Prices Signal Slump

by Yusuf Khan and Joe Wallace – WSJ – Jun. 5, 2023

Industrial malaise, particularly in China, is draining demand for energy and metals.

Grain prices have fallen along with those for many other commodities.

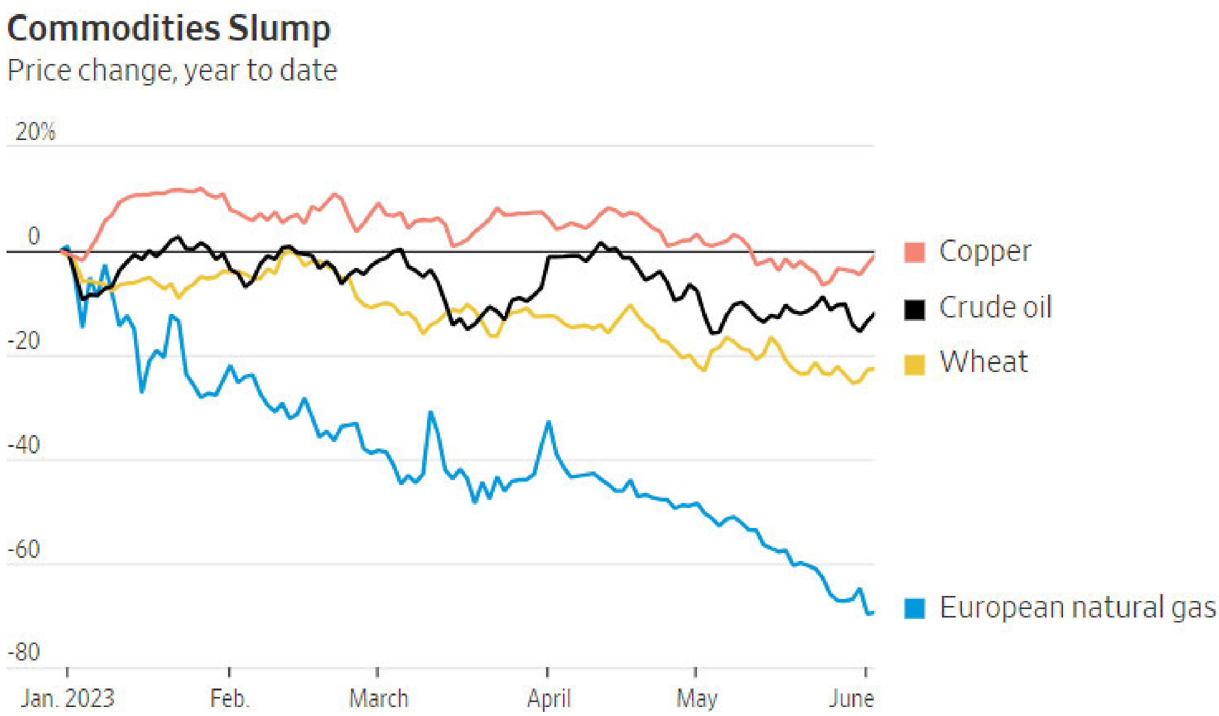
Commodity prices are in retreat, signaling a slowdown in the world economy but lending central banks a hand in their fight against inflation.

The S&P GSCI commodities index has **fallen** about **11% so far this year** through Friday, as prices for energy, metals, grains and other raw materials have retreated. Crude oil is close to its lowest levels since just before Russia's invasion of Ukraine – even after Saudi Arabia's weekend decision to cut output boosted prices early Monday.

Wheat hasn't been this cheap since 2020 and **natural gas** has **taken** a **tumble in Europe**. **Almost every commodity besides weather-affected sugar, cocoa and coffee has pulled back**. Niche materials such as glass have fallen. **Copper**, a bellwether for the global economy because of its use in everything from buildings to cars, has **slipped 1.3% this year**.

A **big driver** is **sluggish** activity in **manufacturing**, particularly **in China**, the **world's biggest consumer** of **metals** and **second-biggest user** of **oil**.

A pre-markets primer packed with news, trends and ideas. Plus, up-to-the-minute market data.



Note: Shows most-active futures contracts.
Source: FactSet

Traders' hopes for a post-pandemic surge in Chinese demand for industrial materials and energy proved wide of the mark. That is partly because China's recovery has been led by services, rather than the resource-intensive manufacturing and construction sectors that powered previous upswings.

"Industrial activity is subdued," said Caroline Bain, chief commodities economist at Capital Economics. Chinese imports of semirefined copper dropped 13% year-over-year in the first four months of 2023, she said.

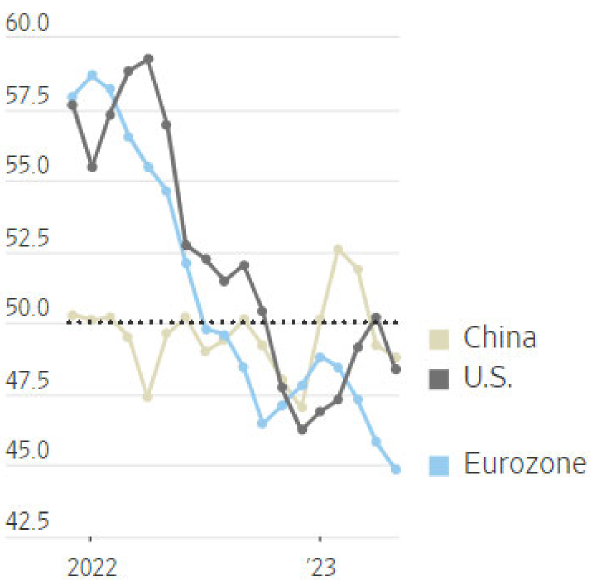
In the U.S. and Europe, too, manufacturers are in a funk, even as economies grow overall thanks to a stronger services sector. The rise of hybrid working has made economies less oil-dependent, some economists say.

The **commodity declines** mark a **reversal from** a year ago, when **Russia's invasion** of **Ukraine** sent prices for energy and grains soaring. **That surge stoked inflation in** the **West**, encouraging the Federal Reserve and its peers to jack up interest rates, and led to fuel and food shortages in parts of Africa and Asia.

The **selloffs largely take prices back down to more typical levels**, rather than depressed ones indicative of serious oversupply or an economic shock. For instance, early on Monday, Brent crude oil was trading at close to $78 a barrel, which would be near the high end of the range in which the benchmark traded between 2015 and early 2022.

The drops **nonetheless point to slowing growt**h, if not an outright recession in which economic activity contracts.

Manufacturing activity by region



Note: Purchasing managers indexes; readings below 50 suggest contraction.
Sources: S&P Global (U.S., eurozone); National Bureau of Statistics (China)

"In a recession, demand for commodities lowers," said Arlan Suderman, chief commodities economist at StoneX Group, a brokerage. "We're finally getting to data showing decreased demand for commodities."

A silver lining for consumers and financial markets is that cheaper energy has started to feed into slower inflation. That could eventually help the Fed, and other monetary authorities such as the European Central Bank and the Bank of England, to lower rates. For now, though, other drivers of inflation are sufficiently strong that investors expect further rate rises.

Higher rates are **likely** to **curb demand for commodities even more**, said Darwei Kung, who runs commodities investments at DWS Group – one reason why he is betting on lower energy and industrial-metal prices.

Losers from the decline include commodity companies such as Exxon Mobil and Chevron. The energy sector is the worst performer in the S&P 500 so far this year, having been the best in 2022.

Some states that depend on oil-and-gas sales to sustain their budgets, notably Russia and Gulf oil producers, have experienced difficulties. **Saudi Arabia** said Sunday that it would **cut** a million barrels from its daily oil **output** in an effort **to raise prices**, **after** a contentious **meeting** at which other members of the Organization of the Petroleum Exporting Countries cartel and its allies, known as **OPEC+**, agreed to extend existing curbs.

Consumers will enjoy the benefits of lower wholesale prices at varying speeds. In the U.S., for instance, lower crude prices quickly feed through to the pump. Average gas prices stand at $3.55 a gallon, according to AAA, down from about $4.82 a year ago.

In Europe, households and businesses won't feel the drop in wholesale gas and power prices so fast, in part because governments put in policies to ease the pain on the way up.

And **food prices** are **still** galloping **higher**, **even though wholesale wheat** is **down 22% this year**, aided by bumper harvests in Russia and Australia, and exports from Ukraine under the Black Sea grain deal.

Many food producers locked in prices near the peak of the market because they feared losing access to ingredients. "It's a long supply chain for a lot of these supermarkets," said Dave Whitcomb, founder of Peak Trading Research.

Some analysts see commodity prices leveling off rather than falling further. They expect OPEC+ cuts to drain oil supplies in the second half of the year. Metals could get a boost from a splurge in spending on the electricity grid in China, and in the longer term from demand for materials needed for the energy transition.

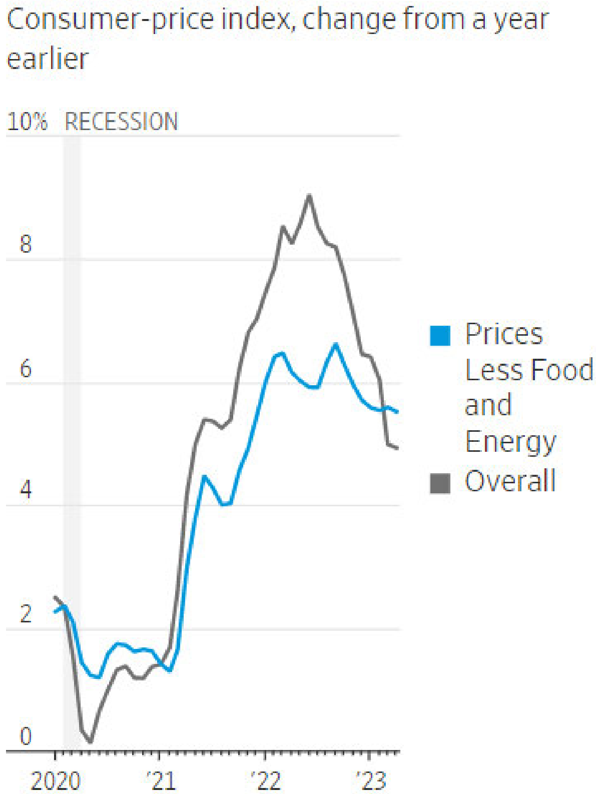
For now, though, many say high interest rates and industrial malaise could bring more pressure. "**Central banks in developed nations** are **pushing on** the **brakes** pretty **hard**," said Nitesh Shah, head of commodities research at exchange-traded-fund provider WisdomTree.

The **prices investors pay** in the **open market for commodities** like coffee, copper or corn **can have little to do with** the **price customers pay at** the **store**.

–

CPI Report Shows Inflation Eased in April But Remains Stubbornly High

by Gabriel T. Rubin – WSJ – May 10, 2023
Nick Timiraos contributed to this article



Source: Labor Department via St. Louis Fed

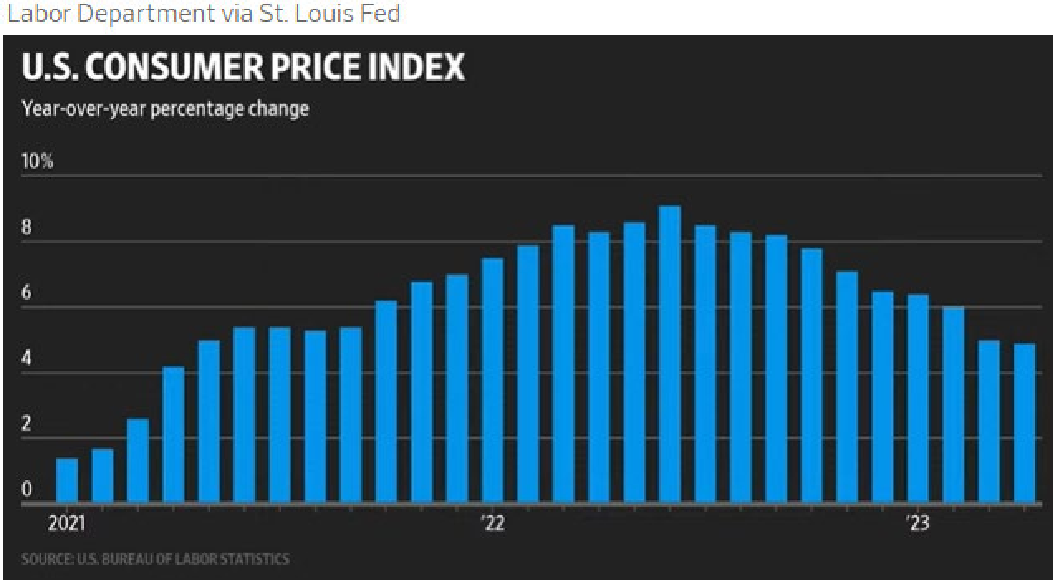
Consumer-price index rose 4.9% from year earlier, 10th straight month of easing.

Inflation is still much higher than the Fed's target and economists are warning it may be stickier than markets are expecting.

Inflation eased slightly in April, the 10th straight month of cooling, but price gains remain historically high as the broader economy cools.

The **Consumer-Price Index rose 4.9%** in **April from** a **year earlier**, the **Labor Department** said Wednesday, down slightly from March's 5% increase. The inflation reading has **eased from** a recent **peak** of **9.1%** in **June 2022**.

The Federal Reserve aggressively raised rates for more than a year to try to tame inflation by slowing economic activity. The Fed is looking to see signs of inflation declining toward its 2% target.



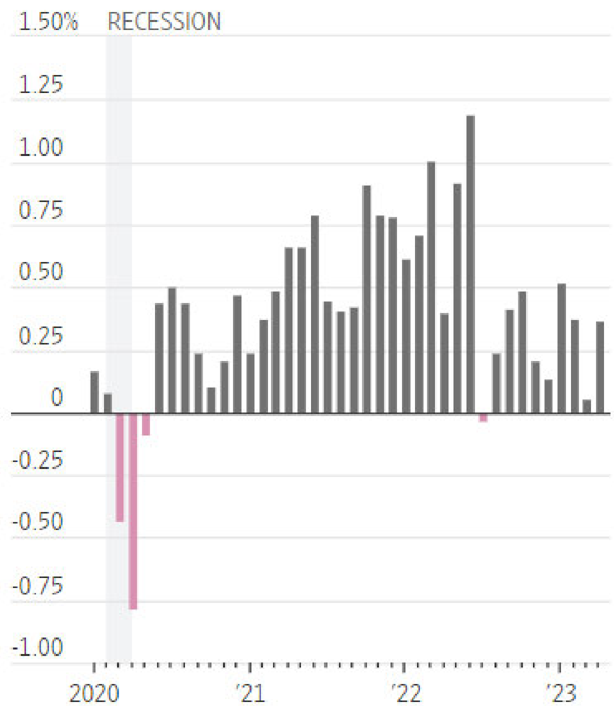
Consumer prices rose a seasonally adjusted 0.4% in April from the prior month, versus a 0.1% gain in March. April's increase was driven by housing costs and an uptick in gasoline prices. **Used vehicle prices surged** by **4.4% over** the **month** due to lack of inventory, **while new car prices declined modestly**.

Wednesday's report could keep Fed officials on course to pause rate increases at their next meeting because they have shifted their focus away from lagging indicators of economic activity to assess the impact of recent bank failures on lending conditions and economic activity, which won't immediately show up in broad measures of hiring and inflation.

Fed officials **raised** their benchmark **federal-funds rate** last week to a **range between 5% and 5.25%**, the highest level in 16 years, to slow down the economy and combat inflation. At that meeting, some officials had discussed whether to pause rate rises after the most recent increase, said Fed Chair Jerome Powell at a news conference on May 3. "We feel like we're getting closer or maybe even there," he said.

Until now, officials have been looking for clear signs of a slowdown to justify ending rate increases. But Mr. Powell indicated that calculation could shift now, and officials would need to see signs of stronger-than-expected growth, hiring and inflation to continue raising rates. The Fed slows the economy through lifting rates, which causes tighter financial conditions such as higher borrowing costs, lower stock prices and a stronger dollar.

Consumer-price index, change from prior month



Note: Seasonally adjusted.
Source: Labor Department via St. Louis Fed

While the report contains some positive signs for a continued slowdown in price gains, "it does suggest a risk that rates will need to remain high for a little longer than we have assumed," said Andrew Hunter, an economist at Capital Economics.

On Wednesday, investors saw a 14% chance that the Fed would raise rates at its next meeting, according to CME Group.

Wednesday's report showed that when removing volatile food and energy costs, prices rose 5.5% from a year earlier, a slightly slower increase than in March. Those so-called core prices remain elevated due to persistently strong shelter costs that economists expect to cool in the coming months. **Housing** price changes can take time to show up in inflation data due to the lag in mortgage and rental contracts.

Economists see core prices as a better predictor of future inflation.

Left: Ryan Flick, a tech sales professional in Denver.

Some Americans are making adjustments as prices rise.

Ryan Flick, 39, said he used to eat fast food a couple of times a week. “It never really felt like it was making a dent whatsoever in my budget,” he said.

But as prices for meals he favored rose to over $10 from $5 to $8 he was paying a few years ago, he made a choice to cut back. He said he would rather forgo a few forgettable weekday lunches and save money by making a sandwich at home, especially since he works remotely more often than in the past.

“If you’re going to eat out, you might as well take three times where you might have gotten fast food and go out for something nicer,” said Mr. Flick, a Denver resident who works in tech sales. Food prices have remained flat over the past two months, though a decline in grocery prices in April was offset by a rise in prices for dining out.

That divergence could provide relief to household budgets by giving them “an option to avoid inflation by cutting out at least one discretionary spending indulgence from their routines,” said PNC Senior Economist Kurt Rankin.

Inflation started to rise sharply in late 2020, as pandemic restrictions eased, and the rate remains well above 2019 levels. Price pressures initially grew because of supply-chain bottlenecks and high commodity prices, but those factors have significantly improved.

More recently, one factor supporting inflation is sustained demand for workers among service providers. **Average hourly wages rose 4.4%** in **April from** a **year earlier**, slightly faster than the prior month, while the **unemployment fell to match** the **lowest level since 1969**. Some companies are passing along higher labor costs to consumers.

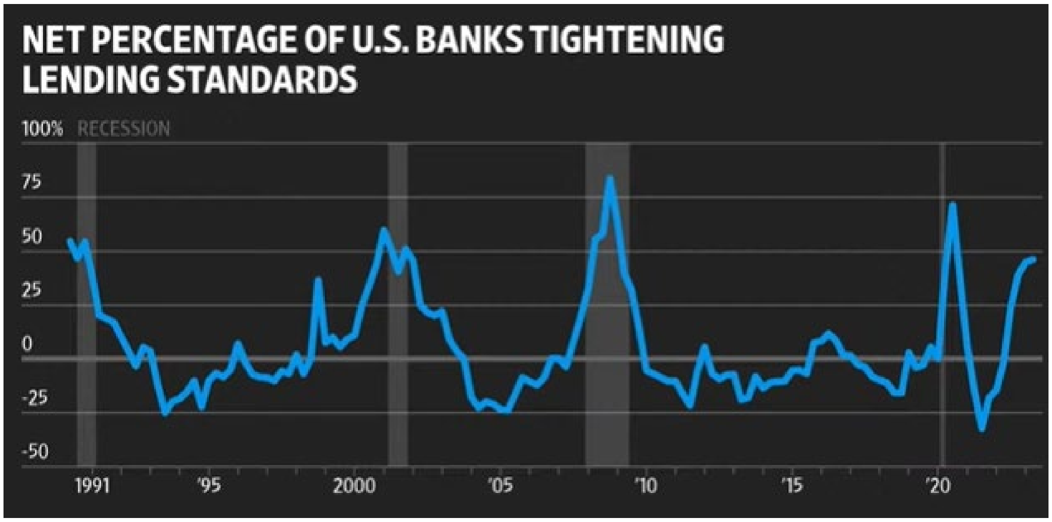
Another factor is that companies have been able to raise prices, and boost profits, without prompting a backlash.

However, some companies say the significant pricing power they enjoyed in recent years has begun to fade amid early signs of a consumer pullback. Consumer spending, the primary driver of economic growth, has stagnated recently after jumping at the start of the year.

Higher gasoline prices are one of the factors keeping upward pressure on inflation.

Businesses struggling with high input costs are trying new strategies. Becky Nelson, co-owner of Nelson's Greenhouse in Clinton, Ind., recently decided that they would add a surcharge for customers who paid with credit cards, rather than raising prices. Encouraging shoppers to pay with cash will save the greenhouse on interchange fees.

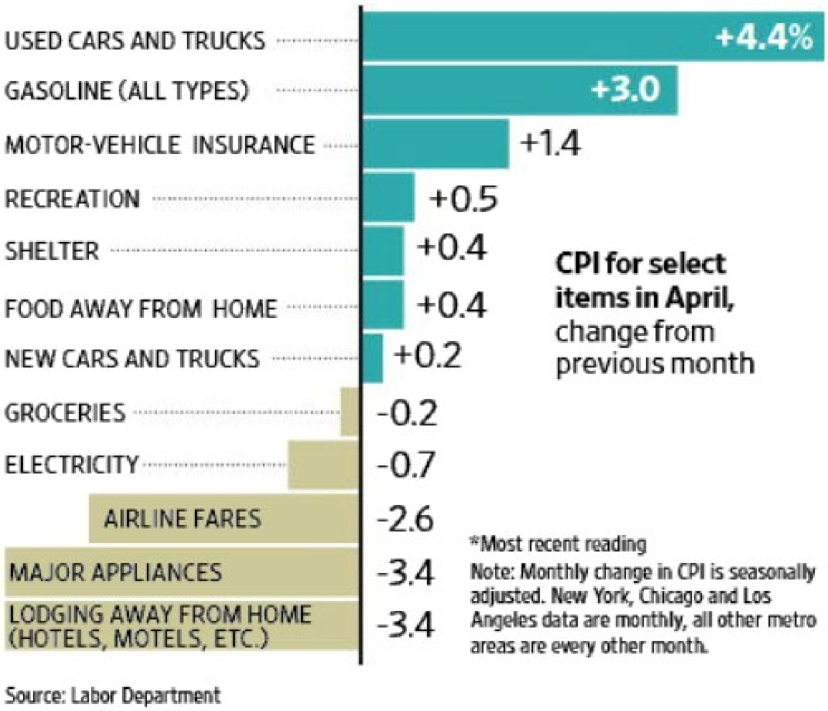
They have also cut back on their offerings, opting to shut down the greenhouse over the winter to save money on propane, which they use to heat the 35,000 square foot facility.

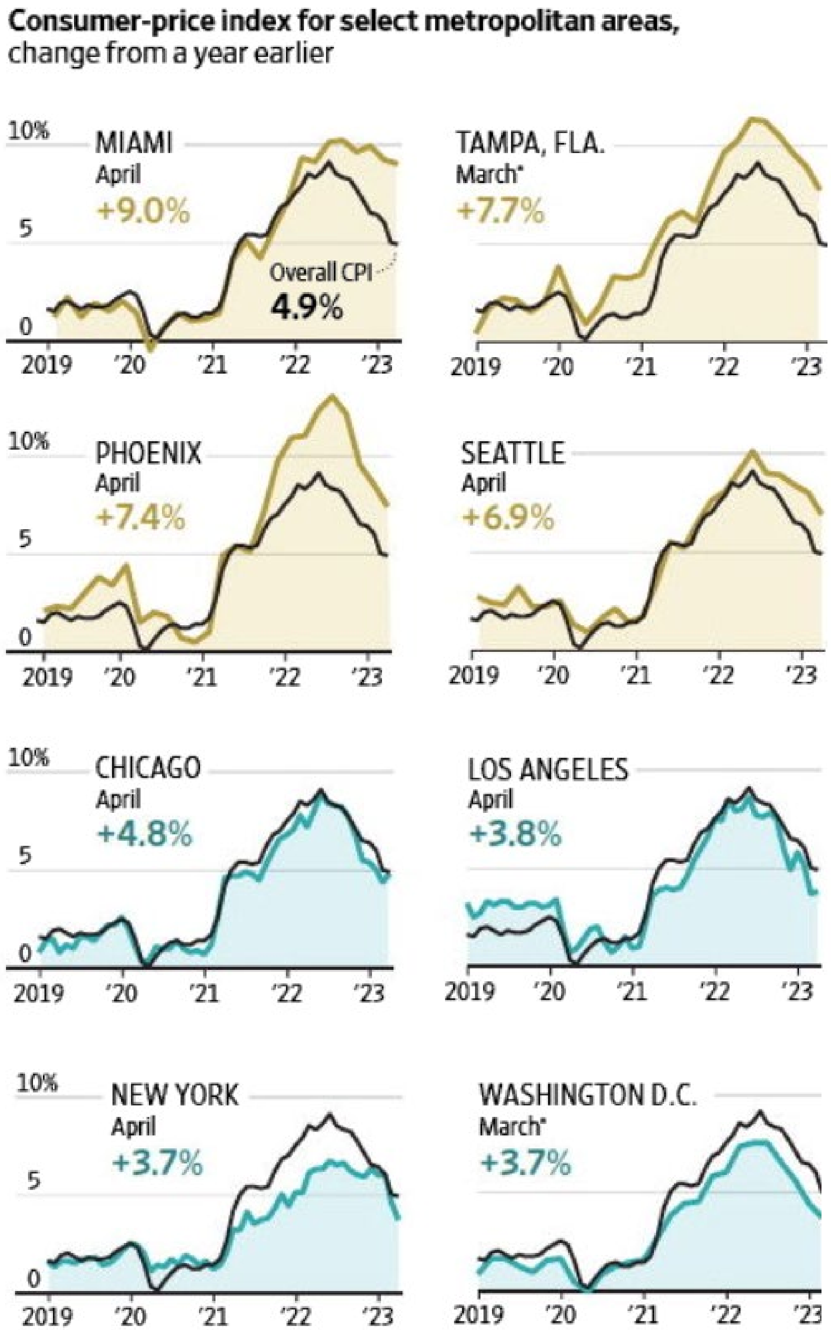


Banks are making it harder for individuals and small businesses to get loans.

"We had to quit growing poinsettias," Mrs. Nelson said. "It's not that we don't like growing year-round, it's that we couldn't keep up with the prices."

The **P**roducer **P**rice **I**ndex will be out on Thursday. PPI **usually leads CPI**.




Consumer-price index for select metropolitan areas,
change from a year earlier
10%
5
0
MIAMI
April
+9.0%
Overall CPI
4.9%
TAMPA, FLA.
March*
+7.7%
PHOENIX
April
+7.4%
SEATTLE
April
+6.9%
CHICAGO
April
+4.8%
LOS ANGELES
April
+3.8%
NEW YORK
April
+3.7%
WASHINGTON D.C.
March*
+3.7%
2019
'20
'21
'22
'23

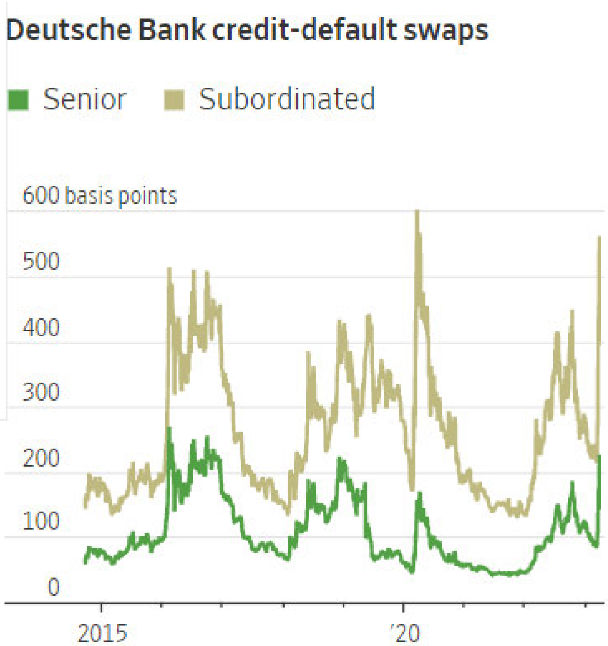
–

Deutsche Bank Stock Falls on Contagion Fears

by Patricia Kowsmann and Anna Hirtenstein – WSJ – Mar. 24, 2023
Caitlin McCabe contributed to this article.

Concern over Germany's leading lender emerges days after Credit Suisse was forced into a takeover.

Shares of Deutsche Bank, one of Europe's largest and most important lenders, tumbled to their lowest level since last fall.



Note: Shows five-year contracts denominated in euros. A price of 100 basis points means it costs €100 a year to insure €10,000 of debt against default.
Source: S&P Global Market Intelligence

Investors sparked a **selloff** in **Deutsche Bank** and thrust one of Europe's most important lenders into the center of concerns about the health of the global financial system.

Shares of **Germany's largest lender tumbled** as much as **15%**, their **third consecutive day of losses**, though they later regained some ground and **closed down 8.5%**. The cost **to insure against its default using credit-default swaps soared** to the highest levels since 2020.

The **concern over Deutsche Bank** emerged **days after Credit Suisse** Group AG was **forced into** a **takeover by** its larger and more stable rival **UBS** Group AG. Since the **collapse** of **Silicon Valley Bank in** the **U.S. earlier this month**, investors have scoured the globe for institutions perceived as vulnerable.

"People want to avoid anything that could come under focus," said Jon Jonsson, credit portfolio manager at Neuberger Berman.

Deutsche Bank sits at the heart of the German economy. Despite years of retrenchment to make the bank smaller and safer, it remains a globally vital bank, with a major footprint on Wall Street trading bonds, derivatives and currencies. It serves multinational companies with bread-and-butter basics of lending, managing money and corporate accounts.

"Deutsche Bank has thoroughly modernized and reorganized its business model and it is a very profitable bank," German Chancellor Olaf Scholz told reporters at an European Union summit in Brussels on Friday. "There is no reason whatsoever to be concerned."

Some analysts and investors appeared perplexed that Deutsche Bank was taking the brunt of the market's ire. Though it has long been considered one of Europe's most problematic banks, an overhaul launched in 2019 stabilized its operations. Unlike Credit Suisse, Deutsche Bank's deposit base has remained steady in recent quarters. Last year was the Frankfurt-based bank's most profitable since 2007.

Left: Credit Suisse struck a deal to be bought by UBS, its larger and more stable rival.

"The market is on edge. It seems to just be looking for targets," said Tatjana Greil Castro, portfolio manager at Muzinich & Co.

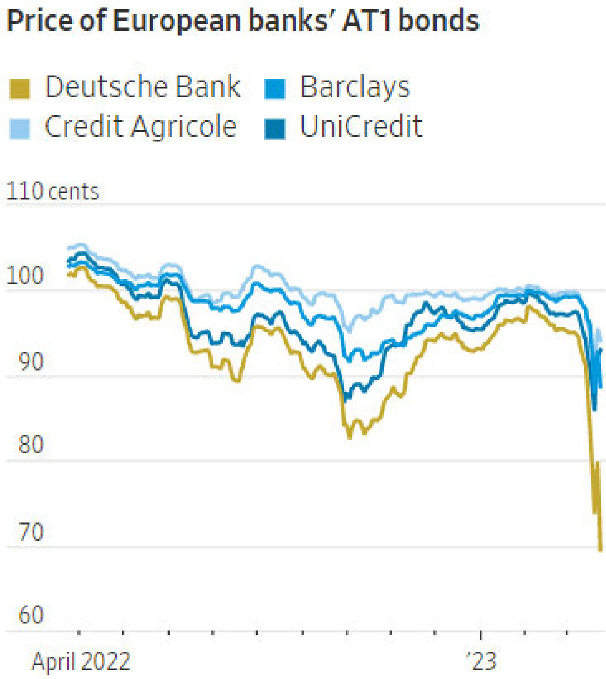
Shares of **other European banks also fell Friday**, **but** by **less than Deutsche Bank**. Shares of crosstown rival **Commerzbank** AG **dropped 6.5%**. **Barclays** PLC was **down 5.8%**, **as was France's most valuable bank**, **BNP Paribas** SA.

One factor hammering Deutsche Bank: Mentions of the German bank have exploded on social media in recent days, a bout of activity reminiscent of the social-media frenzy that surrounded Credit Suisse last fall and which that bank's executives said was partly to blame for its eventual demise.

Markets have reeled since the sudden collapse of **Silicon Valley Bank**, reminding investors how quickly confidence can erode in banks. SVB was an institution few had on their radar screens. It **failed** in a matter of days **despite** an **investment**-**grade credit rating** and a seemingly devoted base of customers and investors.

Signature Bank followed within days, and then a **week later Credit Suisse** was **pushed into** a **deal** after more than a century and a half of independence.

The terms of the UBS takeover of Credit Suisse engineered by Swiss regulators shook European banking markets this week, especially a provision to write down $17 billion of Credit Suisse bonds. Known as additional tier one bonds or **AT1s**, these instruments are an important part of European bank capital, money regulators require them to raise to protect themselves from losses.



Note: Bonds are denominated in U.S. dollars and have yields between 7.5% and 8%
Source: Tradeweb

The price of AT1 bonds fell hard this week. The fewer investors are willing to pay for AT1 bonds and bank bonds in general, the higher the borrowing costs banks have to pay, squeezing their ability to turn a profit.

A Deutsche Bank AT1 bond issued in 2014 declined to 70 cents on the dollar on Friday from 95 cents at the start of the month, according to Tradeweb. Other bank AT1s also fell despite assurances from U.K. and European regulators about the importance of the capital instruments.

Deutsche Bank tried to ameliorate investor concerns over its debt on Friday by offering to redeem a separate type of subordinated bond, due in 2028. The offer promised to buy back the bonds at 100% of the principal, plus accrued interest, showing the bank has money to spare.

The price of those specific bonds jumped after the redemption offer. While that helped individual bondholders, it did little to assuage wider concerns.

Friday's fall adds to the reversal in the shares from a huge upswing they and other European bank shares enjoyed to start the year. Rising interest rates in Europe and the U.S. promised fatter profits.

Deutsche Bank, like other European banks, suffered for years from Europe's negative interest rates. When interest rates are near zero or negative, banks struggle to charge much more to lend than they pay on deposits, squeezing what is known in the industry as the net-interest margin.

Worries over the banks prompted investors Friday to dive into government bonds for safety, lowering yields, further suppressing the ability for banks to profit.

Deutsche Bank's checkered past has long drawn skeptics. It paid regulatory fines for facilitating money laundering in Russia, for holding accounts for convicted sex offender Jeffrey Epstein and for weak internal controls.

Its asset-management arm, DWS is under investigation in the U.S. for allegedly overstating sustainability claims over its investments. Last year, it agreed to extend the term of an outside compliance monitor after Justice Department prosecutors found the bank violated a criminal settlement by not disclosing a complaint about how DWS managed its ESG, or environmental, social and governance investments.

Deutsche Bank was also a key lender to former President Donald Trump, and became ensnared in a long-running fight between the president and Congress over access to his tax returns.

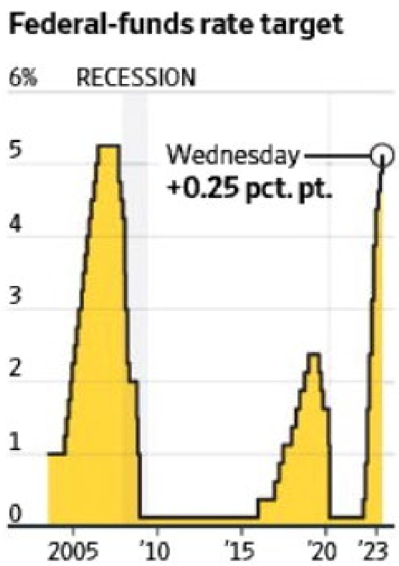
But investors and regulators have by and large lauded Deutsche Bank's turnaround under Chief Executive Officer Christian Sewing, who took over in 2018. He shrank Deutsche Bank's investment-banking business in the U.S., cut costs and focused on serving Germany's mighty companies.

Unlike Credit Suisse, Deutsche Bank is profitable and its big litigation woes are mostly behind it, analysts said. The German lender avoided losses on the meltdown of Archegos Capital Management in 2021, which spread $10 billion of losses across Wall Street, with Credit Suisse taking about half of the pain.

"Deutsche is NOT the next Credit Suisse," said analysts at Autonomous Research, a unit of AllianceBernstein. They added that interest-rate risk in Deutsche Bank's books, which sparked troubles in U.S. banks, is in line with European peers and well below the levels of some U.S. regional banks.

Fed Boosts Rates to 16-Year High

by Nick Timiraos – WSJ – May 4, 2023



Note: Chart shows midpoint of range since 2008.
Source: Federal Reserve

Central-bank officials signal they could be done tightening after 10th straight increase.

Federal Reserve officials signaled they might be done raising interest rates for now after approving another increase at their meeting that concluded Wednesday.

"People did talk about pausing, but not so much at this meeting," Fed Chair Jerome Powell said at a news conference. "We feel like we're getting closer or maybe even there."

Wednesday's unanimous decision to **lift rates by** a **quarter percentage point** marked the Fed's 10th consecutive rate increase aimed at battling inflation. It will **bring** its **benchmark federal-funds rate** to a **range between 5% and 5.25%**, a **16-year high**.

Stocks retreated after the decision after rising earlier in the day. The Dow Jones Industrial Average fell about 270 points, or 0.8%, while the S&P 500 and Nasdaq Composite indexed closed down 0.7% and 0.5%, respectively. U.S. government bonds rallied slightly, pushing the benchmark 10-year Treasury yield down to 3.401%, from 3.438% Tuesday.

The **Fed** has now **raised** its **benchmark federal-funds rate by** a **cumulative 5 percentage points from near zero in March 2022**, the most rapid series of increases since the 1980s. The rate influences other rates throughout the economy, such as on mortgages, credit cards and business loans.

"I think that policy is tight," Mr. Powell said. But he said, "we are prepared to do more if greater monetary policy restraint is warranted."

Until now, officials have been looking for clear signs of a slowdown to justify ending rate rises. But Mr. Powell indicated that calculation could shift now and that officials would need to see signs of stronger-than-expected growth, hiring and inflation to continue raising rates. The Fed's next meeting is June 13-14.

Banking stresses are expected to further tighten financial conditions, but the magnitude of any credit crunch might not be apparent for months.

"We have a broad understanding of monetary policy. Credit tightening is a different thing," Mr. Powell said.

Analysts said Mr. Powell's comments suggested an important shift in what the Fed would monitor as it determines any further moves.

“For the last 12 months, it has been all about inflation and the pace of employment growth,” said Blerina Uruci, chief U.S. economist at T. Rowe Price. “Now, perhaps, that is broadening. Banking-sector stress and credit conditions are going to be part of that calculation much more now.”

Some said the Fed would have been better off holding rates steady Wednesday to see how those strains slow the economy. “It’s not clear this move was necessary,” said Brian Sack, an economist and former senior executive at the New York Fed. “The arguments for the hike were very backward- looking, and that’s just not the right approach when you have such important developments affecting the path of the economy going forward.”

Mr. Sack said he thought the Fed wouldn’t raise rates again this year.

Others said the increase was a reasonable way to balance the risks of sustained inflation pressures in a resilient economy. “It’s not an indefensible position, I don’t think. Is it one made a lot more difficult by the current backdrop? Yes,” said Michael de Pass, global head of linear rates trading at Citadel Securities.

Officials dropped a key phrase from their previous policy statement, in March, that said they anticipated some additional increases might be appropriate, and they replaced it with new language saying they would carefully monitor the economy and the effects of their rapid increases over the past year.

“That’s a meaningful change, that we’re no longer saying that we ‘anticipate’ ” additional increases, Mr. Powell said.

Officials considered skipping a rate hike in March after the failures of two regional lenders, Silicon Valley Bank and Signature Bank, raised worries about a bank-funding crisis. But they concluded that the stresses had calmed enough on the eve of their March 22 decision.

The sale of First Republic Bank to JPMorgan Chase, announced Monday, showed how those strains are still clouding the economic outlook.

Mr. Powell said conditions in the banking sector had broadly improved since March. “There were three large banks, really, from the very beginning that were at the heart of the stress that we saw,” he said. “Those have now all been resolved, and all the depositors have been protected.”

Officials have signaled growing divergence over the policy outlook recently, with some urging greater caution about raising rates given the lagged effects of the banking stress and the Fed’s earlier increases. Others are more worried about stopping prematurely only to see economic activity and inflation remain strong.

In projections released after their March meeting, most Fed officials thought they would need one more quarter-point rate rise before moving to the sidelines. But many thought they might need at least two more increases.

At the March meeting, the Fed staff forecast a recession would start later this year due to the banking-sector turmoil. The staff hasn't usually projected a recession before a downturn begins. Previously, the staff had judged a recession this year was about as likely to occur as not.

Mr. Powell said he didn't share the staff's view, but he didn't dismiss the prospect of a recession. "It's possible that we will have – what I hope would be – a mild recession," he said.

Since officials' March meeting, the economy has shown only modest signs of cooling, including more muted consumer spending and factory activity. Job openings declined in February and March, and the share of private-sector workers voluntarily leaving their jobs has returned closer to pre-pandemic levels. **Hiring remains robust**.

Steady job growth and brisk wage gains could sustain higher inflation. The Fed's preferred inflation gauge, the personal- consumption expenditures price index, rose 4.2% in March from a year earlier. That was down from the previous month's 5.1% increase. Core prices, which exclude volatile food and energy prices, rose 4.6% in March, down from 5.1% in October. The Fed targets 2% inflation over time.

The Fed and many investors have sometimes been at odds during the past nine months over how high rates might rise and how long rates will stay at those higher levels to ensure inflation declines. Investors have often anticipated a speedier decline in inflation and rates, in part because they expect rate increases to tip the economy into recession.

Mr. Powell pushed back against expectations of rate cuts this year, but he acknowledged that investors expecting inflation to fall quickly could take that view.

"We on the committee have a view that inflation is going to come down not so quickly. In that world, if that forecast is broadly right, it would not be appropriate to cut rates, and we won't cut rates," he said.

–

Frantic Weekend Led Officials to One Conclusion

by Andrew Ackerman, Andrew Duehren, and Rebecca Ballhaus
WSJ – Mar. 17, 2023
Tarini Parti and Nick Timiraos contributed to this article.

$200B – Silicon Valley Bank's assets as of Dec. 31.

For more than a decade **after** the **collapse** of **Lehman Brothers** in **2008, Washington's regulatory watchdogs sought to ensure** that they would **never again face** fraught weekend deliberations about **propping up** the **financial system from** a **bank failure**.

Last weekend, they did.

For the nation's top economic officials – Federal Reserve Chair Jerome Powell, Treasury Secretary Janet Yellen, Federal Deposit Insurance Corp. Chairman Martin Gruenberg and White House National Economic Council director Lael Brainard – the challenge boiled down to a single decision: whether to employ a federal law allowing a "**systemic risk exception**" **permitting** the **FDIC** to **guarantee deposits beyond** the **$250,000 limit per customer**.

The government rescued banks, shareholders, auto makers and others in 2008. This time they were considering a rescue of bank depositors. The **regulators triggered** the **rule to guarantee all deposits** at on **Sunday**, **regardless of account size**. It was the most powerful tool at their disposal **to stop panicked households and businesses from pulling deposits from** those and other **banks**.

Silicon Valley Bank and Signature Bank

This account of the internal deliberations over deposit coverage, based on interviews with people involved, many of whom declined to be identified, shows how the supervisors came to a decision they had hoped to avoid. The continued financial-market turmoil also raises questions over whether their measures are working.

Reluctance at FDIC

Mr. Gruenberg was initially reluctant to use the exception that would let his agency expand deposit insurance. The FDIC chairman, whose agency is constrained by legal requirements, wanted more evidence that the collapse of the roughly $200 billion SVB would risk the stability of the financial system.

By the time Ms. Yellen briefed President Biden on Sunday, the White House and the regulators had concluded that they didn't have another realistic option. At the same time, the Fed launched a special lending program to ensure banks had wide access to central bank credit as needed.

"Americans can have confidence that the banking system is safe," Mr. Biden said the next morning.

Many of the questions the supervisors faced over the weekend about the broadened use of deposit guarantees remain unanswered: Was backstopping two banks' depositors enough to stop an exodus from other small- and medium-size banks? Would the public expect the backstop to be extended to others – and would that require taxpayer money?

"You now really have this issue of the government being the ultimate protector of all deposits," said Thomas Hoenig, former FDIC vice chairman. "What you've done with very good intentions is you've removed market discipline as a preventative to unsafe and unsound practices."

SVB had been on the radar of the Fed, its primary federal regulator, and of the FDIC before last week, according to people familiar with its oversight. Examiners had raised concern about its portfolio of securities, which had lost significant value as the central bank raised interest rates. The bank was also seen as an unusual case for the FDIC because its customers were so concentrated in venture-capital and tech startups, officials said.

Officials were coordinating their efforts by Thursday evening, as SVB faced a run. Depositors had become spooked about signs of instability at the bank, including its hasty effort to raise funds from stock investors.

The Fed is the first line of defense for a bank in a panic. Banks can turn to the **Fed** for **emergency funds through** a mechanism called a **discount window**, as long as these banks have collateral to pledge against temporary Fed loans. **SVB sought and received emergency loans** at the discount window on Thursday. But the scale of borrower demands for withdrawals ultimately exceeded the amount of unpledged assets it could offer as collateral for more loans.

By Thursday evening of that week, regulators began to worry that SVB wouldn't make it to the weekend.

Ms. Brainard and White House chief of staff Jeff Zients briefed Mr. Biden in the Oval Office on Friday before he left Washington for Delaware for the weekend. They told the president that the crisis at SVB threatened to engulf banks across the country – which could endanger the ability of small businesses to make payroll, a White House official said.

Mr. Powell scrapped plans to travel to Basel, Switzerland, for a routine international bank meeting. Michael Barr, the Fed's point-man on regulation, had left for a vacation on Thursday morning but was deluged by phone calls as soon as he got on the plane. After two days of nonstop work, he flew back to Washington early.

Ms. Yellen later Friday met with Mr. Powell, Mr. Gruenberg and other top regulators. She told them she was worried that the crisis would spread, kicking off a marathon of Zoom calls over the weekend.

They hoped they could prepare SVB for a sale during the weekend that would reassure depositors that their money was safe. But they also realized that they needed to develop backup plans if panic spread.

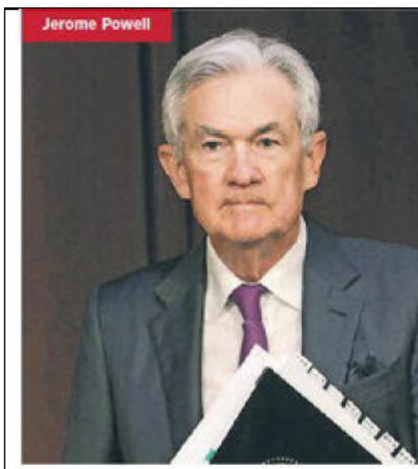
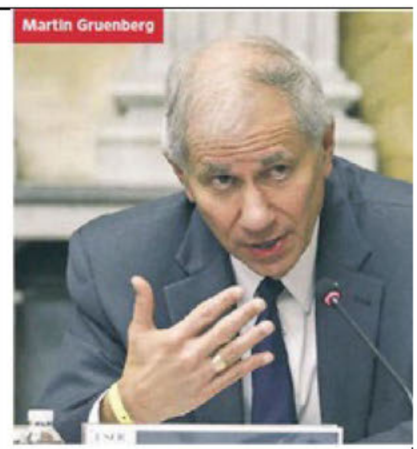
Big Banks Shunned the Auction of SVB

In **2008**, regulators' **go-to tactic** for a bank in danger was to **have big private banks** such as JPMorgan Chase & Co. and Bank of America Corp. **purchase troubled rivals**, including Countrywide Financial, Bear Stearns and Washington Mutual.

This time around, leaders of the big banks such as JPMorgan Chief Executive Jamie Dimon were in contact with regulators. But when the Federal Deposit Insurance Corp. held its auction of SVB, the **big banks didn't bid**. PNC Financial Services Group Inc. considered making an offer on SVB, but its interest depended on government support that regulators couldn't offer at the time, according to people familiar with the discussions. No other serious parties emerged.

The search for buyers was difficult for other reasons. The FDIC didn't have time to run through its normal processes for a bank closure. Last weekend, the agency was still scrambling to set up data rooms where bidders could examine SVB's financial statements, people familiar with the matter said.

Eventually, regulatory officials realized that, even if bidders emerged, they wouldn't have time to close an auction for SVB before markets in Asia opened on Monday.

		
Jerome Powell	Lael Brainard	Martin Gruenberg

Payroll concerns

Ms. Brainard and others made the case that depositors at other midsize banks like SVB could pull out their deposits on Monday, precipitating a bank run across the country that could endanger billions in deposits. They also feared that the loss of deposits at SVB could leave startups that banked with SVB and even other regionals without the cash to meet payroll this week.

Ms. Yellen and other Treasury officials faced a crush of warnings and lobbying from California lawmakers, bank chief executives and small-business associations about the risk of runs at other banks. Ms. Yellen was interrupted during a Zoom meeting on Sunday by a call from House Speaker Kevin McCarthy (R., Calif.) to discuss the banking crisis.

Officials at the Fed monitored real-time data showing a growing pile of withdrawal requests.

By Friday evening, another crisis was brewing. After SVB was closed, Signature began to see significant outflows of uninsured depositors. The FDIC and New York state's banking regulator worried the bank wouldn't be able to open Monday, and doubted the firm's management when it assured them it would.

Signature's problems were critical to regulators who were worried that panic was spreading. By Saturday, the regulators were seeing signs of large deposit outflows from fewer than 20 midsize banks, whose share prices had also been tumbling, a person familiar with the matter said. That convinced the group that the crisis was systemic and required urgent intervention.

Regulators had considered telling uninsured depositors that they could access at least 50% of their deposits as early as Monday, but after Signature's failure and other stresses became clear, they decided that would be insufficient. By Saturday morning, Ms. Yellen had concluded that a blanket guarantee of SVB bank deposits would be needed. Ms. Brainard shared Ms. Yellen's assessment of the developments over the weekend.

By Sunday afternoon, the four top overseers concluded that they had no choice but to invoke the systemic-risk exception, backstopping all SVB and Signature depositors.

Jobs Market Proves Resilient

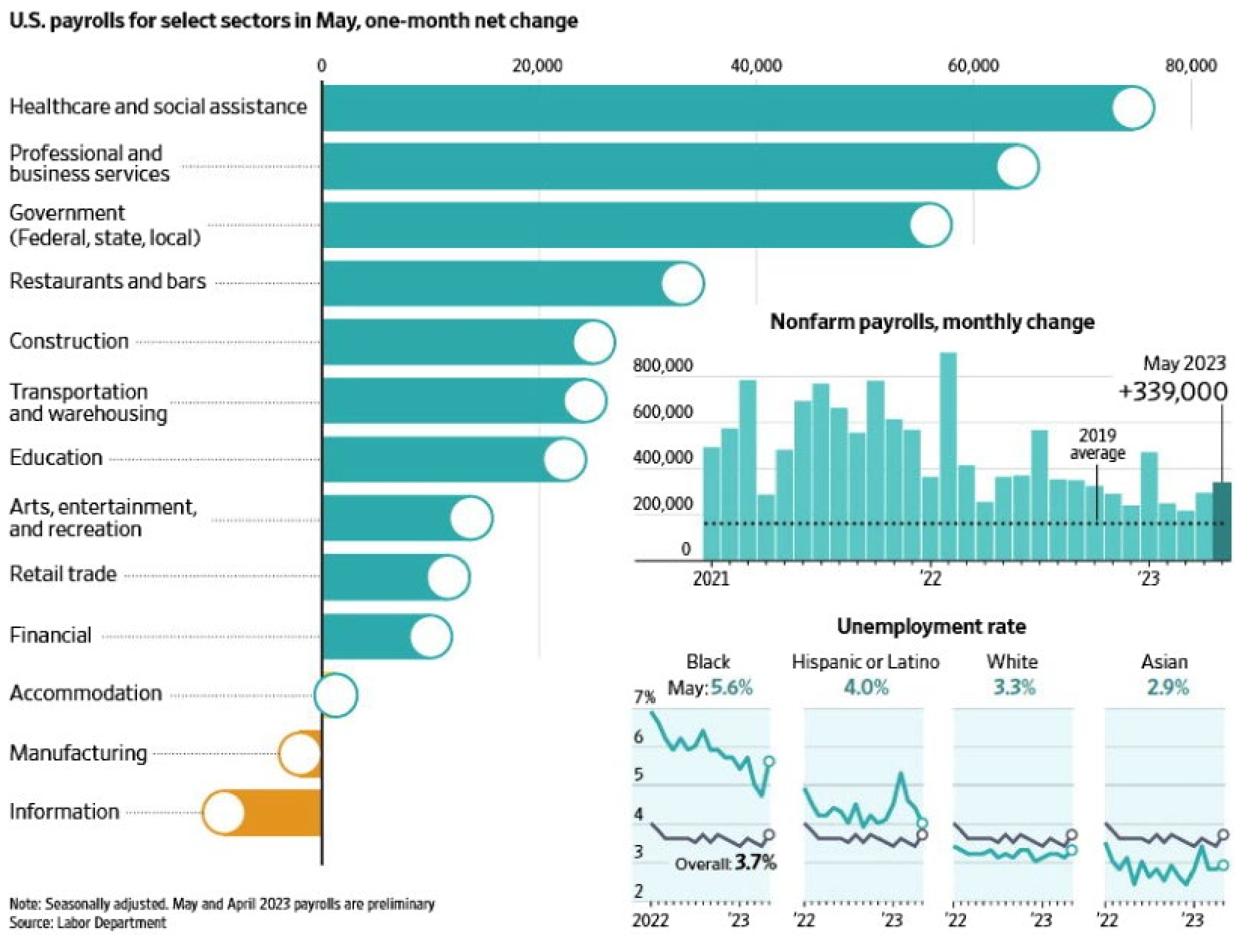
by Gabriel R. Rubin – WSJ – Jun. 3, 2023
Nick Timiraos contributed to this article

Stocks rally on strong hiring, **modest gain in wages**, **complicating picture for Fed.**

Hiring surged this spring, the latest sign the U.S. economy maintains momentum in the face of rising interest rates, complicating the Federal Reserve’s decision over whether to pause rate in-creases this month.

Employers added a **seasonally adjusted 339,000 jobs** in **May**, and the prior two months’ payrolls were revised up by nearly 100,000, the Labor Department said Friday. Workers gained more than 1.5 million jobs in 2023, more evidence of economic vitality, including robust consumer spending and a stabilizing housing market.

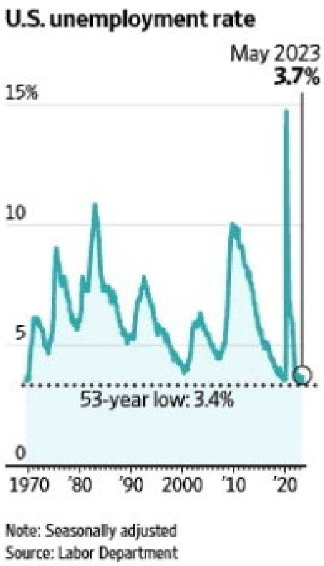
U.S. employers added 339,000 jobs in May with strong gains across much of the economic spectrum. Unemployment notched up to 3.7%, but remains near its historic lows.



Note: Seasonally adjusted. May and April 2023 payrolls are preliminary
Source: Labor Department

The latest data does little to settle the Fed's debate over whether to hold rates steady at a meeting this month, but does suggest that if officials do so, they could favor raising rates later this summer.

Stocks leapt on Friday, with the blue-chip Dow industrials advancing 701.19 points. The largest one-day point gain since November came after the strong jobs report and the Senate passing legislation that suspends the debt ceiling. A measure of financial-market volatility fell to the lowest level in nearly two years.



The U.S. unemployment rate rose to 3.7% in May, still near historic lows but an uptick from April's 3.4%, the Labor Department said. Average hourly earnings grew a solid 4.3% in May over the prior year, similar to annual gains in March and April.

Fed officials in May lifted the benchmark federal-funds rate by a quarter percentage point to a range between 5% and 5.25%, their 10th consecutive increase aimed at taming stubbornly high inflation.

Fed Chair Jerome Powell and some colleagues have raised the idea of skipping a rate increase in June to study the effects of past moves. But other officials have said the Fed may need to continue to lift rates, and the May jobs data likely reinforces that view. The central bank had hoped to see higher borrowing costs cause the economy to slow more by now, curbing wage and price increases.

"The labor market and the economy it supports will just not go gently into that good night despite policy efforts to cool both," said Joe Brusuelas, chief economist at RSM US.

Even with the spring hiring jump, there were some underlying signs of weakness in the report. Unemployment rates rose for women and Black Americans, both groups that had seen joblessness fall over the past few years.

The average workweek fell to 34.3 hours, the lowest since April 2020, near the start of the pandemic. As a result of fewer hours worked, average weekly earnings advanced at a slower rate than hourly earnings, and gains have cooled since the start of the year.

The labor-force participation rate, the share of Americans who are working or actively seeking jobs, remained flat in May at 62.6% and below the February 2020 pre-pandemic level of 63.3%. That partly reflects the aging U.S. population. Among workers age 25 to 54, the participation rate rose to 83.4%, a level last touched in 2007.

May's job gains were broad-based. Professional and business services, including accounting and engineering firms, added 64,000 jobs. Healthcare, including hospitals and nursing homes, added 52,000 jobs. Government employment increased by 56,000, construction firms added 25,000 jobs, and transportation and warehousing payrolls increased by 24,000.

Young workers prepare for summer camp at a Boys & Girls Club in Scottsdale, Ariz. May's job gains were broad-based, although service industries fared better than technology and manufacturing.

Service providers, including restaurants, have been a driver of job gains this year. Restaurants and bars added 33,000 jobs in May.

At Red Robin Gourmet Burg-ers, a 500-location chain, executives have added more positions to keep up with customer demand and to refocus their restaurants on better service. Wages have gone up, but so have productivity and revenue, said G.J. Hart, Red Robin's chief executive.

Hart said the moves are intended to reverse decisions from previous years when the company used a more barebones approach to staffing that led to declining sales and frustrated customers. Understaffed locations would shut down whole sections of the restaurant and make customers wait for the remaining tables, and additional staffing means that is no longer happening, according to Hart.

"It's getting a little bit better on the labor front," Hart said. "But you still have to make people feel wanted, make people feel special."

Some sectors such as tech, finance and manufacturing have shown signs of stress. The **tech-heavy information sector cut 9,000 jobs in May**.

High-profile companies such as Facebook parent Meta Platforms, Goldman Sachs Group and Grant Thornton recently moved to cut jobs. **Overall layoffs have remained low,** and **job openings ticked up in April**, the Labor Department said. Workers, especially in tech, have largely been able to find new jobs quickly, although a new position might be less lucrative or at a company with less cachet.

Manufacturers slightly reduced employment in May. Retail payrolls have been little changed since February, even as job gains have been widespread throughout the economy.

Home Depot warned last month that its annual sales will decline for the first time since 2009. Power tools manufacturer Makita said it would lay off 213 workers at the end of June and close two of its five U.S. distribution centers.

Sales of power tools took off during the height of the pandemic. But increased material and energy costs, as well as tariffs and inflation, have eroded Makita's pricing advantage. The layoffs are the Japanese company's first in the U.S. in nearly 20 years.

"It speaks to the confluence of these challenging conditions," said Wayne Hart, a Makita spokesman.

–

PGE CFO to Retire

by Selene Balasta – S&P Global Market Intelligence – Apr. 28, 2023

Jim Ajello is planning **to retire as CFO**, senior vice president of finance, treasurer and corporate compliance officer of Portland General Electric Co. (**PGE**), the company said in an April 28 news release.

Ajello joined PGE in 2020. He will transition from his current roles on **June 30** and serve as a **senior adviser** to the company **through Aug. 31**.

PGE has launched a search to identify its next CFO and **will consider both internal and external candidates**, the release said.

–

Portland General Electric to Purchase 75-MW Ore. Battery Storage System

by Nephele Kirong – S&P Global Market Intelligence – May 31, 2023

Portland General Electric Co. (**PGE**) will **invest $150 million** to **purchase** a **planned 75-MW battery energy storage system** in **Hillsboro**, Ore., the company said in a May 31 filing.

The Evergreen battery energy storage system is the last project to be procured under PGE's 2021 all-source RFP and will be constructed by an unspecified third party. The project is expected to come online on Dec. 31, 2024, and to qualify for the federal investment tax credit.

PGE plans incremental capital spending on the project of roughly $40 million in 2023, with the balance invested in 2024. This will **bring** the **company's total expected capital spending** to **$1.37 billion** in **2023 and $1.02 billion** in **2024**, the filing said.

The agreement for the Evergreen facility is **subject** to a **prudency review by** the **O**regon **P**ublic **U**tility **C**ommission.

–

Productivity Drop Blurs Economic Picture

by Gwynn Guilford – WSJ – Jun. 5, 2023

You would think from May's blowout jobs report the economy was booming.

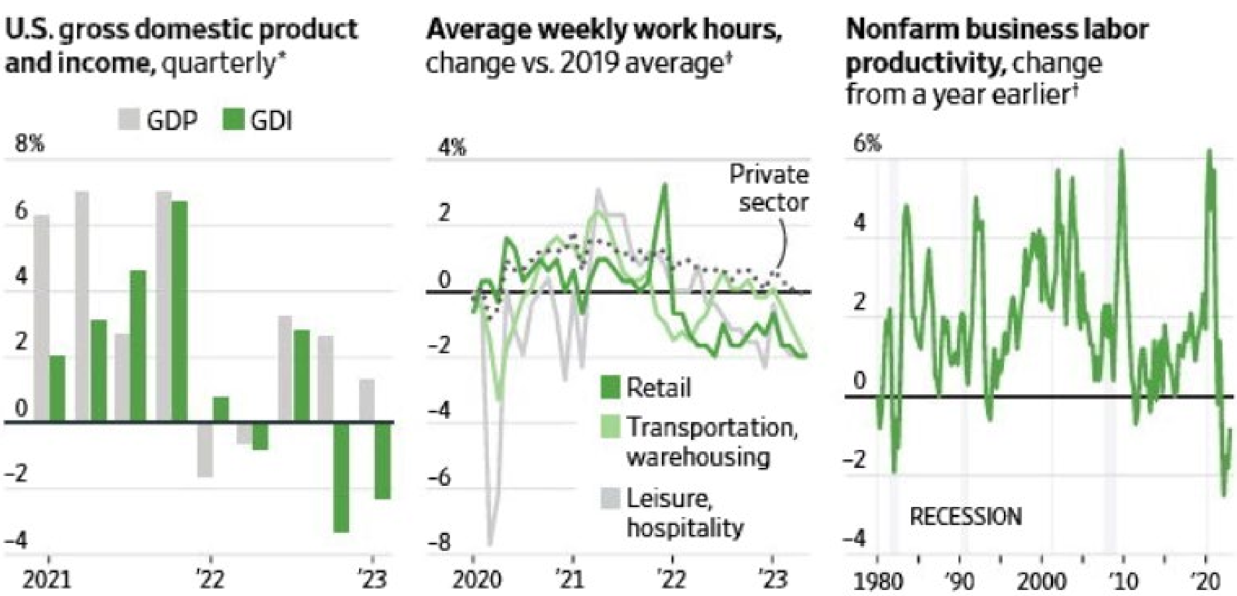
Here's the puzzle: Other recent data suggest it is in recession.

The dichotomy emerges from the **divergent behavior** of **employment and output**, two key indicators of economic activity. **In May**, **employers added 339,000 jobs**, bringing the **total number of jobs added this year** to **nearly 1.6 million**, a **gain** of **2.5% annualized**.

But real gross domestic income, a measure of **total economic activity**, **shrank** in both the **fourth quarter and** the **first quarter**. **Two negative quarters** of **output growth** are **one indicator** of a **recession**.

The economy has gone through periods where output has expanded faster than employment, but seldom the other way around, said Ryan Sweet, chief U.S. economist at Oxford Economics.

What explains these dissonant signals is **productivity, or output per hour worked**: It **is cratering**. That raises questions about whether the much-hyped technology adoption during the pandemic and, more recently, artificial intelligence are making a difference. It also raises the risk that the Federal Reserve will have to raise interest rates more to tame inflation.



*Inflation and seasonally adjusted annual rate †Seasonally adjusted
Sources: Commerce Department (GDP and GDI); Labor Department (weekly hours, nonfarm business labor productivity)

Labor productivity fell 2.1% in the **first quarter from** the **fourth at** an **annual rate**, and was **down 0.8%** in the **first quarter from** a **year earlier**, the Labor

Department said Thursday. That is the **fifth-straight quarter** of **negative year-over-year productivity growth**—the **longest** such run **since records began** in **1948**.

Those calculations are derived from **gross domestic product**, which shows output rising at a 1.3% annualized rate in the first quarter. But another key measure – **gross domestic income** – declined, implying an even bigger productivity collapse.

GDI is the yin to **GDP**'s yang, measuring incomes earned in wages and profits, while GDP tallies up purchases of goods and services produced. In theory, the two should be equal, since someone's spending is another's income.

They never exactly match because of statistical challenges. Lately, though, the divergence is dramatic. "Over the past two quarters, real GDP shows the economy expanding by 1.0%, not far off potential growth, whereas GDI shows it contracting by 1.4%, which amounts to a deportant cent-sized recession," said Paul Ashworth, chief U.S. economist at Capital Economics. The divergence is ominous: GDI previously undershot GDP dramatically during the 2007-09 financial crisis and in the early 1990s recession, Ashworth said.

The second quarter is also shaping up to be weak. **S&P Global Market Intelligence sees second-quarter real GDP expanding** at a **0.8% annual rate**; **Morgan Stanley projects 0.3%**. The **Atlanta Fed's GDP-Now model estimates 2%**. Most economists don't forecast GDI.

Usually, employment plummets during recessions because as factories, offices and restaurants produce less, they need fewer workers. That clearly isn't happening. "If you look at the early 2000s, that was what was called a 'jobless recovery,' because employment took a long time to come back even though the economy was growing," said Sweet. "This time around it could be the opposite – the economy could be contracting, but you're not seeing job losses."

One reason could be **labor hoarding**. After struggling to hire and train workers during the pandemic-induced labor crunch, employers are now balking at letting them go, even as sales slip, given the labor market's unusual tightness. There were **10.1 million vacant jobs in April**, well above the 5.7 million people looking for work that month. Some firms – particularly services such as restaurants and travel-related businesses – ran short-staffed for the past couple of years and are still catching up.

It's "not that technology got worse in the last year, but that businesses were selling less stuff and they're nervous about their ability to attract employees, so they're holding on to their employees," said Jason Furman, an economist at Harvard University who served in the Obama administration. It is also plausible, he said, that the shift to working from home generated a hit to productivity, whose impact grows with the cumulative loss of creative exchange and mentoring.

Productivity growth is im- in the long run because it is one of two engines of economic growth, the other being an expanding workforce. Sweet, the Oxford Economics economist, notes businesses have been spending on equipment, software and intellectual property, investments that should eventually raise productivity. Though it may take many years, so should recent advances in artificial intelligence.

Amore imminent concern is that when workers produce more, companies can raise wages without increasing prices. **When productivity falls**, it is **harder to keep inflation in check**.

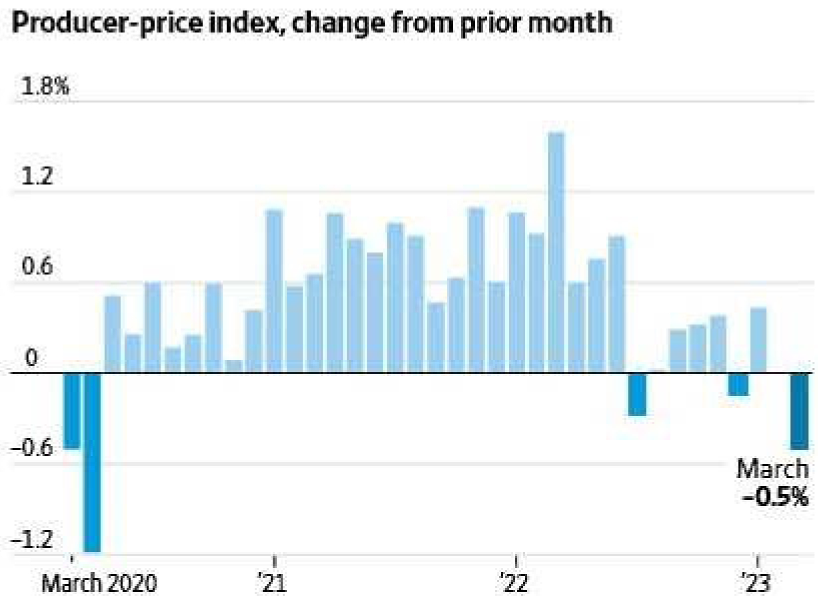
This could make things even more **challenging for** the **Fed**. "Companies probably have the ability to pass on higher prices to consumers if they want to," said Neil Dutta, head of economic research at Renaissance Macro Research. "That would be problematic for the Fed."

Moreover, if GDI is a better indicator of output than GDP, "it would mean that the economy has slowed more than we had thought, without bringing down inflation that much," Furman said. That might mean it will ultimately take an even bigger economic pullback "to bring inflation down."

–

Supplier Data Point to Easing Inflation

by Gabriel T. Rubin – WSJ – Apr. 14, 2023
Austen Hufford contributed to this article.



Note: Seasonally adjusted
Sources: Labor Department via St. Louis Fed (PPI); U.S. Employment and Training Administration via St. Louis Fed (claims)

U.S. supplier prices fell in March by the most in nearly three years, the latest evidence that inflation is moderating.

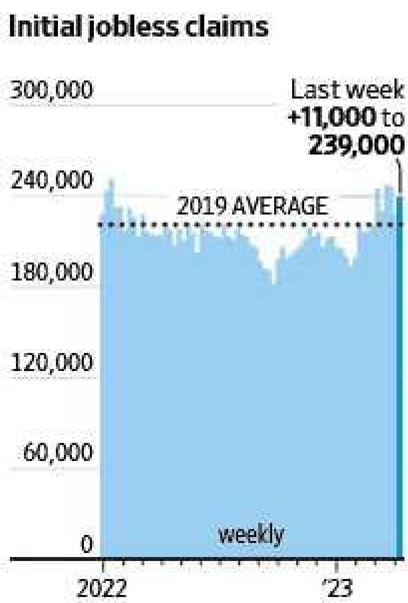
The **Producer-Price Index**, which generally reflects supply conditions across the economy, **fell 0.5% in March from** the **prior month**, the **largest monthly decrease since April 2020**, the Labor Department said Thursday.

From a **year earlier**, **supplier prices rose by 2.7% in March**, a **significant slowdown** from highs reached last year, **but above pre-pandemic levels**. **PPI increased 4.9% in February**, **from** a **year earlier**.

Cooling supplier prices can signal future fading of consumer inflation, if firms pass on easing costs. The **Consumer- Price Index rose 5% in March from** a **year earlier**, extending a **cooling** trend **but well above** the **Federal Reserve's 2% inflation target**. Consumer inflation, especially excluding volatile food and energy costs, remains elevated enough for the Fed to contemplate another interest-rate increase next month.

"We expect the bite from the Fed's previous rate hikes will further reduce business and consumer demand, pushing producer-price inflation lower throughout the rest of the year," said Matthew Martin, U.S. economist at Oxford Economics.

Excluding often volatile food and energy costs, the PPI decreased 0.1% from the prior month and was up 3.4% from a year earlier. The year-over-year figure was a slowdown from the February reading. A decline in goods prices was a major factor in the cooling of supplier prices in March, particularly for gasoline, diesel and residential natural gas. A drop in warehousing costs as well as in machinery and vehicle wholesaling drove a more modest decline of the services supply index.



Separate Labor Department data Thursday showed that worker filings for unemployment benefits rose last week but were still near 2019 levels, a sign the labor market remains solid despite large companies announcing layoffs and stresses in the banking sector.

Initial jobless claims, a **proxy for layoffs**, **increased** by **11,000 to** a **seasonally adjusted 239,000 last week**. The latest reading was down from the highest level of the year, touched last month.

The **red-hot labor market cooled some in March**, with hiring moderating and wage growth easing as more Americans sought work. Sectors that boomed earlier in the pandemic, such as construction, manufacturing and retail, lost jobs last month. Recent turmoil in the banking sector raised concerns about a pullback in lending slowing the economy this year.

–

UBS Agrees to Buy Rival Credit Suisse

Margot Patrick, Ben Dummett, Dana Cimilluca and Patricia Kowsmann
WSJ – Mar. 20, 2023
Summer Said and Julie Steinberg contributed to this article.

Deal for over $3 billion forged by regulators is the first big merger of global banks since 2008.

UBS Group AG agreed **to take over** its **longtime rival Credit Suisse** Group AG **for** more than **$3 billion**, pushed into the biggest banking deal in years by regulators eager to halt a dangerous decline in confidence in the global banking system.

The deal between the twin pillars of Swiss finance is the first megamerger of systemically important global banks since the 2008 financial crisis, when banks across the landscape were carved up and matched with rivals, often at the behest of regulators.

The **Swiss government** said it would **provide** more than **$9 billion** to **backstop** some **losses that UBS might incur by taking over Credit Suisse**. The **Swiss National Bank also provided** more than **$100 billion** of **liquidity to UBS** to help facilitate the deal.

Swiss authorities were under pressure to make the deal happen before Asian markets opened for the week. They had to walk a fine line, needing to get the two banks' boards to agree to the deal and avoiding the alternative, a regulator-led winddown of Credit Suisse, which could have proved more protracted and painful for the financial system.

The urgency on the part of regulators was prompted by an increasingly dire outlook at **Credit Suisse**. The bank **faced** as much as **$10 billion** in **customer outflows a day last week**, according to a person familiar with the matter.

Regulators also worried that Credit Suisse's failure could make Switzerland a new source of contagion for global stress. Hours after the UBS deal, a group of central banks, including the U.S. Federal Reserve and the Swiss National Bank, announced an expanded dollar swap line, a type of international lending operation. They called the expansion "an important liquidity backstop to ease strains in global funding markets."

Credit Suisse Chairman Axel Lehmann said the recent bank troubles that started in the U.S. were too much to withstand. "The acceleration of the loss of trust and the worsening of the last few days made it clear that Credit Suisse cannot continue to operate in its current form," he said.

Left: UBS Chairman Colm Kelleher said UBS would shrink Credit Suisse's investment-banking business and align it with UBS's "conservative risk culture." He said the deal "supports financial stability in Switzerland and creates significant sustainable value for UBS shareholders." To help absorb the deal, however, UBS said it would pause its stock buyback program.

The **sudden collapse** of **Silicon Valley Bank** earlier this month prompted investors globally to scour for weak spots in the financial system. **Credit Suiss**e was already first on many lists of troubled institutions, **weakened** by years of self-inflicted **scandals** and **trading losses**, most notably the **failure** of **two key clients** in **2021**, **Greensill Capital and Archegos Capital Management**.

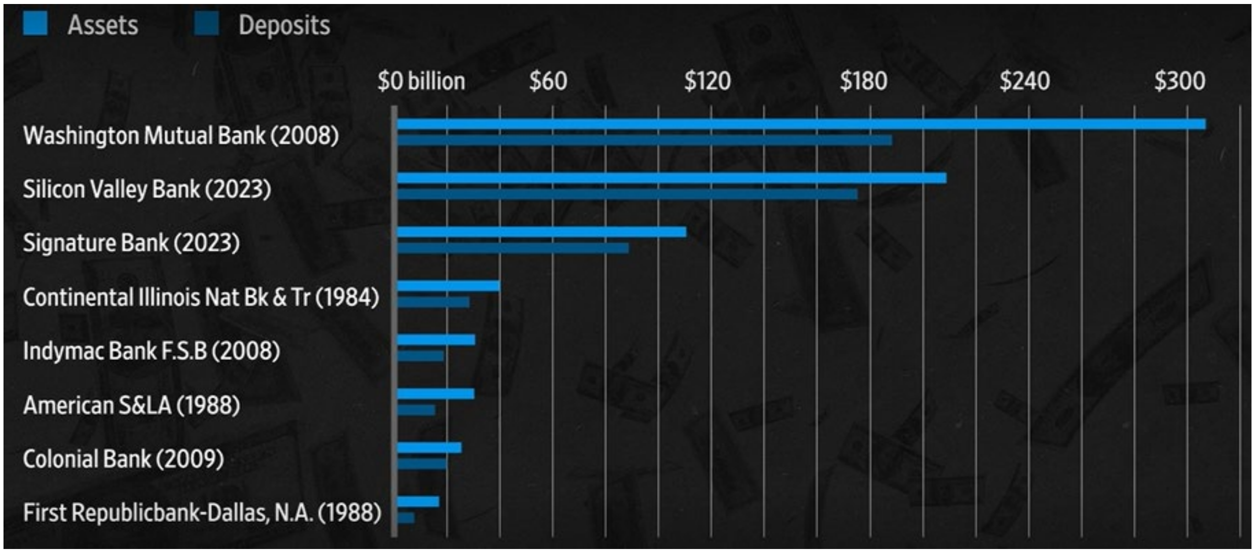
Despite repeated executive changes and pledges to reform, there was what felt to investors like a never-ending series of stumbles.

The bank's new management, which took over last year, many of them hailing from UBS, tried a campaign of reassurance among customers and promised a restructuring that would turn the bank around.

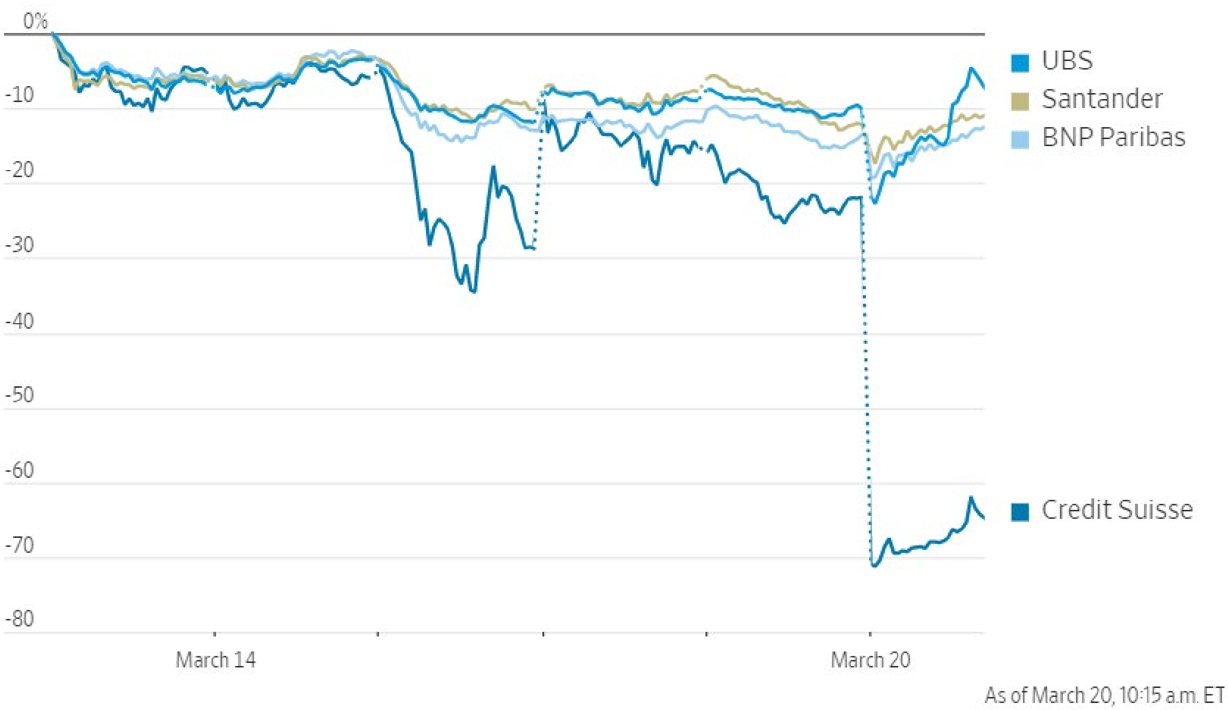
The **bank had just raised $4 billion** in **fresh equity from Saudi National Bank** and other investors last fall to finance a sweeping overhaul. **But customers were fleeing in droves and taking with them $120 billion** in assets under management in the last months of 2022.

Friday, Silicon Valley Bank's parent company filed for bankruptcy, the largest bank failure since Washington Mutual Bank in 2008. That is for the parts of the parent that are not SVB. SVB is already under federal control.

Bank Failures



Its stock price and bonds in free fall, **Credit Suisse took** a **$54 billion lifeline from** the **Swiss National Bank last Thursday**. Switzerland's finance minister said on Sunday that the **liquidity line was doubled later that day** to ensure the bank could survive until the weekend.



Source: FactSet

But Swiss officials, along with regulators in the U.S., U.K. and European Union, who all oversee parts of the bank, feared it would become insolvent this week if not dealt with, and they were concerned crumbling confidence could spread to other banks.

Finma, Switzerland's financial regulator, said Credit Suisse experienced a "crisis of confidence." It added that there was "a risk of the bank becoming illiquid, even if it remained solvent, and it was necessary for the authorities to take action in order to prevent serious damage to the Swiss and international financial markets."

Finma said the banks would open normally on Monday.

The talks among the regulators and the two banks began last Wednesday.

Regulators laid out two choices: A takeover or a bankruptcy. Bankruptcy would be a protracted mess, and UBS executives worried that it would taint the whole brand of Swiss banking, according to a person familiar with the matter.

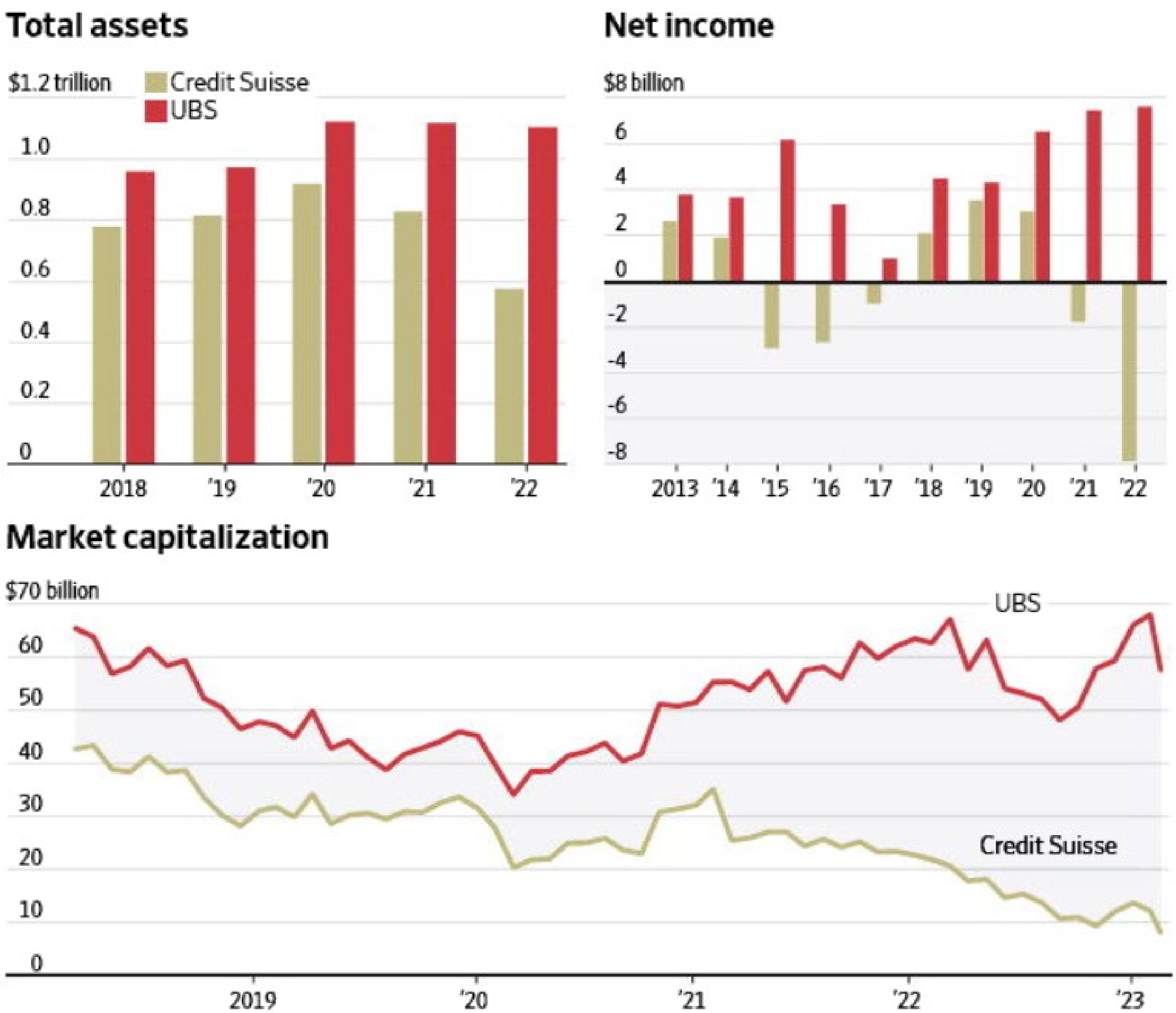
A forced marriage of the two titans was something UBS had never wanted. Credit Suisse had its scandals, and its big investment bank was the opposite of UBS's model built around managing the finances of rich clients. But other parts of the deal were attractive, as Credit Suisse is UBS's chief rival in the Swiss banking system.

On Sunday, there was a last-ditch effort by a group including Credit Suisse's largest shareholder, Saudi National Bank, to keep the lender alive, according to people familiar with the offer. The group made a rival proposal to inject around $5 billion into Credit Suisse. Under the plan, Credit Suisse bondholders would have been fully protected.

Swiss ministers rejected the offer outright, according to the people. The shareholders wanted the same government backstops being offered to UBS, such as the liquidity line, but were turned down.

Agitation by the shareholders did have an effect. An earlier **UBS** proposal to pay around 1 billion Swiss francs, or around $1.1 billion, was eventually lifted to **3 billion** francs, **paid in UBS shares**. Still, that is **less than half of Credit Suisse's last traded market value** on **Friday**. An **end to Credit Suisse's nearly 167-year run** represents a **new global dimension** of damage from a **banking storm that started with SVB's collapse**.

Credit Suisse had a **half-trillion- dollar balance sheet** and around **50,000 employees** at the **end of 2022**, including more than 16,000 in Switzerland.



Sources: S&P Global Market Intelligence (assets, arket capitalization); S&P Capital IQ (income)

UBS has around **74,000 employees globally**. It has a **balance sheet** about twice as large, at **$1.1 trillion** in **total assets**.

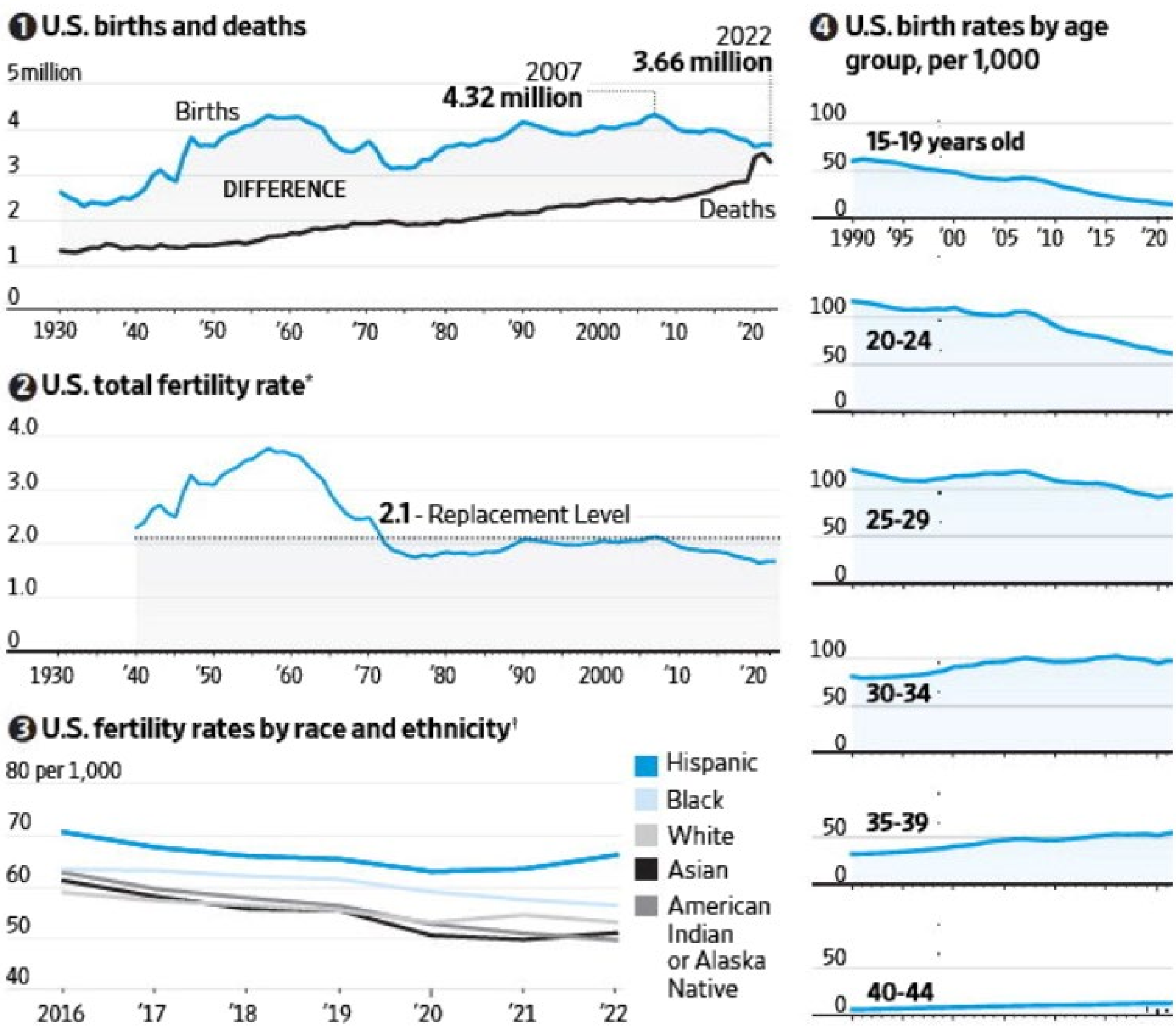
–

U.S. Births Held Flat in 2022

by Anthony Debarros – WSJ – Jun. 1, 2023

About 3.66 million babies were **born** in the **U.S. in 2022**, essentially **unchanged from 2021** and **15% below** the **peak** hit in **2007**, according to new federal figures released Thursday.

The provisional total – 3,661,220 births – is about 3,000 under 2021's final count, according to the Centers for Disease Control and Prevention's National Center for Health Statistics. Final government data expected this year could turn that small deficit positive.



Note: 2022 data are provisional. *An estimate of the average number of babies a woman would have in her lifetime
†Births for women aged 15–44 in specified group
Source: Centers for Disease Control and Prevention

Experts have pointed to a confluence of factors behind the nation's recent relative dearth of births, including economic and social obstacles ranging from child-care to housing affordability.

Absent increases in immigration, fewer births combined with continuing baby-boomer **retirements will likely weigh on** the **labor** force **supply within** the next **10 years**, said Kathy Bostjancic, chief economist at Nationwide, an insurance and financial-services company.

"You're going to have a real shortage of workers unless we have technology somehow to fill the gap," Bostjancic said.

A look at the trends:

1. **The government tallied –** about 655,000 fewer births in 2022 than at the 2007 high of 4.32 million, reflecting continuing decreases. Coupled with **still-elevated deaths** partly because of the latter part of the **Covid-19 pandemic**, the U.S. in 2022 saw only about 385,000 more births than deaths. The 2022 total may tick higher when final data is tallied this year. Final 2021 births were about 5,000 above the provisional number; for 2020.

2. **The total fertility rate –** closely watched because a level of **2.1 children per woman** is the "**replacement rate**" needed for a population to maintain current levels—was **1.665 in 2022**, essentially unchanged from **1.664 in 2021** and only a slight recovery from a record low in 2020.

   The U.S. has generally been below replacement level since the early 1970s.

3. **The general fertility rate for Hispanic mothers increased 4% in 2022**, second only to people of Native Hawaiian or other **Pacific Islander** origin. Fertility rates among **Asian** women **rose** 3%; rates for **all other groups fell**.

   Hispanic mothers accounted for 25.5% of U.S. births in 2022, a record, while the shares of births from non-Hispanic white and Black women declined. White women accounted for 50.1% of births in 2022, Black women for 13.9%, and Asian women for 6%.

4. **The trend of decreasing birthrates among younger women continued in 2022.** For teens **ages 15 to 19**, the birthrate **fell 3%**, and for ages **20 to 24** it was **down 2%**. The rate for the next oldest group, **25 to 29**, edged **up** only **slightly**. **Increases** were **mainly** seen **among women 35 to 44**. If trends continue, the birthrate for women ages 35 to 39 may soon eclipse the rate for ages 20 to 24.

–

US Utility-Earned Returns on Equity Trail Authorized ROEs for 3rd Year

by Dan Lowrey – Regulatory Research Associates (RRA)
an Affiliate of S&P Global Market Intelligence – Apr. 19, 2023

The **average annual earned return on equity** for the Financial Focus energy coverage universe of utility operating companies **trailed** the **average authorized** return on equity (**ROE**) **for electric and gas utilities again** in **2022 for** the **third year** since the beginning of the COVID-19 pandemic.

Energy utilities' average annual earned ROE climbed steadily from 2014 to 2018 and **exceeded** the **average authorized ROE from 2016 to 2019**. However, the average earned ROE declined in 2019, fell sharply in 2020 and declined again in 2021 before slipping slightly further in 2022 as utility disconnection moratoriums expired and states of emergency were lifted.

Utility-earned ROEs, on average, have trailed ROEs authorized for those utilities by state regulatory commissions over the past three years, reflecting the difficult operating environment for utilities during a period of tremendous volatility brought about by the pandemic.

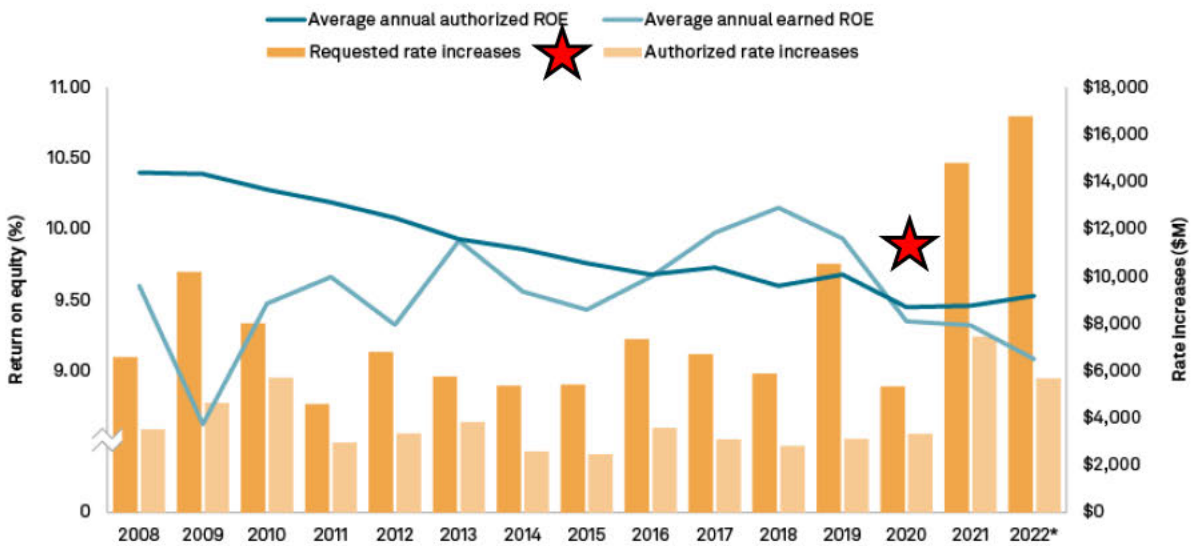
A hotter-than-normal summer and a record number of rate cases that address growing capital spending plans by utilities could pave the way for a return to higher earned returns.

While there is new evidence of rising authorized ROEs in data collected by Regulatory Research Associates, history cautions about the **stickiness of authorized returns**. Commissions may be less inclined to boost approved returns in an environment of high inflation and interest rates.

The pandemic forced states to institute service disconnection moratoriums for customers unable to pay their utility bills as businesses shuttered or curtailed operations. In turn, earned ROEs for US investor-owned utility operating subsidiaries have fallen below authorized levels since the pandemic began, and some utilities delayed rate case filings or postponed capital investments to alleviate financial impacts on ratepayers.

Disconnection moratoriums have largely expired, and states of emergency imposed by state governors and the federal government have also been lifted. In the past two years, utilities have filed some of the largest rate cases ever witnessed by RRA, and underearning has been frequently cited as a factor by utilities in testimony. Rate requests by utilities totaled a combined $16.78 billion in 2022, up about 13% from a record-setting 2021, as tracked by RRA. Coinciding with record-breaking capital investment plans by utilities, this should bode well for utilities and could point toward a rebound in earned ROEs.

Energy utility operating companies' average annual earned versus authorized ROEs, 2008–2022



Data as of April 14, 2023.
ROE = return on equity.
Includes a sample of US investor-owned utility operating subsidiaries tracked by Regulatory Research Associates.
* Average annual earned ROE excludes four utilities with data unavailable.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Utilities have noted several capital market factors that could increase their cost of equity, including changes in monetary policy, exceptionally high inflation, increasing interest rates and volatile market conditions. Inflation and rising interest rates, in particular, pose challenges to the recovery of capital investment and authorized ROEs. Examining the period from 2008 to 2018, a range of outcomes with respect to utilities' earned ROEs becomes clear.

From 2008 to 2015, utilities' average annual earned ROEs were, at best, modestly below authorized equity returns. The largest variance was in 2009 when earned ROEs fell short of authorized ROEs by 177 basis points. At that time, the economy was in the depths of a sharp recession, and US GDP declined by 2.5%. The largest calendar-year positive variance occurred in 2018, when utilities' earned ROE was 56 basis points higher than the authorized equity return. GDP grew by 2.9% in 2018, matching the period's highest growth rate, which occurred in 2015.

Earned ROEs peaked in 2018 but dropped in 2022 to the lowest levels in the review period. Interestingly, in 2022, the utilities experienced favorable weather. The US experienced a higher-than-average number of cooling degree days during the summer and a higher-than-average number of heating degree days during the waning months of the year.

Authorized ROEs have also drifted lower through the review period. More recently, there is some evidence of rising authorized ROEs. The latest authorized ROE data collected by RRA for the first quarter of 2023 point to an increase in returns for both gas and electric utilities from that observed in the previous three years.

In RRA's view, macroeconomic factors could reduce customer and regulatory tolerance for rate increases, which could put downward pressure on authorized ROEs. If history is any guide, the contraction in spreads between US Treasurys and average authorized returns may continue, causing authorized ROEs to remain relatively flat, or perhaps even fall in some instances, as interest rates continue to rise. For more information, refer to Macro challenges give utility regulators a chance to differentiate themselves.

Energy utility operating companies' average annual earned versus authorized ROEs, 2008–2022

Year	Average annual earned ROE (%)	Average annual authorized ROE (%)	Number of ROE authorizations	Difference, earned versus authorized ROE
2008	9.60	10.40	69	-0.80
2009	8.62	10.39	70	-1.77
2010	9.47	10.28	100	-0.81
2011	9.66	10.19	58	-0.52
2012	9.32	10.09	93	-0.76
2013	9.92	9.92	70	0.00
2014	9.56	9.86	64	-0.30
2015	9.43	9.76	46	-0.33
2016	9.66	9.68	68	-0.02
2017	9.97	9.73	77	0.24
2018	10.15	9.59	88	0.56
2019	9.93	9.68	80	0.25
2020	9.35	9.45	90	-0.10
2021	9.32	9.46	98	-0.13
2022*	9.08	9.53	86	-0.45
Averages	**9.61**	**9.87**	**77**	**-0.25**

Data as of April 14, 2023.
ROE = return on equity.
Includes a sample of US investor-owned utility operating subsidiaries tracked by Regulatory Research Associates.
* Average annual earned ROE excludes four utilities with data unavailable.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Another interesting issue is whether the authorized equity return accurately represents the utility's cost of equity capital. Unlike the cost of debt, which can be observed, the **cost of equity cannot be directly observed/measured**, as it is an investor expectation, and expectations, as a psychological concept, do not always lend themselves well to measurement. **Regulators utilize various models** to **estimate** the **required ROE**. Because the required ROE is not directly observable, it cannot be conclusively demonstrated that the authorized ROE, as estimated by regulators, is the **company's actual cost of equity capital**, which **may be higher or lower**.

Comments on methodology

The earned ROE data represents the simple average of the returns for the electric and gas utility operating companies in the Financial Focus coverage universe, and the authorized ROE is the simple average of the equity returns adopted by regulators in the specified 12-month period. As noted, **RRA uses the average annual authorized ROE as** a **proxy for** the **average required equity return in each annual period**.

RRA emphasizes that this analysis is an **overall industry study** and **not** one of **individual companies**. For some companies, determining the authorized ROE is difficult, if not impossible, since rate cases can be resolved through "**black box settlements**" that do not specify an authorized ROE. In addition, some utilities operate in multiple regulatory jurisdictions, and the authorized ROE can differ across jurisdictions. Also, for multijurisdictional companies, ROE determinations in various jurisdictions may have occurred in different years.

–

Why Americans Are Having Fewer Babies

by Janet Adamy – WSJ – May 27, 2023
Anthony DeBarros and Paul Overberg contributed to this article.

The U. S. birthrate is down sharply since 2007, as women say economic and social obstacles prevent them from having as many children as they want.

The number of babies born in the U. S. **started plummeting 15 years ago** and **hasn't recovered since**. What looked at first like a temporary lull triggered by the 2008 financial crisis has stretched into a prolonged fertility downturn. Provisional monthly figures show that there were about **3.66 million babies born** in the **U.S. last year**, a **decline** of **15% since 2007**, even though there are 9% more women in their prime childbearing years.

The decline has demographers puzzled and economists worried. America's longstanding geopolitical advantages, they say, are underpinned by a robust pool of young people. Without them, the U.S. economy will be weighed down by a worsening shortage of workers who can fill jobs and pay into programs like Social Security that care for the elderly. At the heart of the falling birthrate is a central question: Do American women simply want fewer children? Or are life circumstances impeding them from having the children that they desire?

The **gap between women's intended number of children** and their **actual family size** has **widened**.

New evidence points to the latter explanation. In a **study** published in January in the journal Population and Development Review, sociologists Karen Benjamin Guzzo and Sarah R. Hayford found that when **millennials** (born 1981 to 1996) and the oldest members of Generation Z (starting in 1997) were surveyed in their late teens and early 20s, they said, **on average**, that they **wanted** to have **at least two children** – just a fraction less than members of Generation X and the youngest baby boomers when they were surveyed at the same age.

But the gap between women's intended number of children and their actual family size has widened considerably. The researchers found that by the time women born in the late 1980s were in their early 30s, they had given birth, on average, to about one child less than they planned. That is roughly double the size of the shortfall for women born two decades earlier, and it is likely too large to be erased by a spurt of childbearing in their late 30s.

These findings reflect a growing consensus among demographers that for many Americans, **economic and social obstacles** have become intractable deterrents to having children. Young adults can't afford to buy a house as nice as the one their parents raised them in or to pay for childcare while they are still repaying student loans. Many men lack the earning power to be providers, because blue-collar jobs don't pay as well and fewer men are employed. More women can't find a suitable partner because, with their own greater education and economic status, it's harder for them to find a man who measures up.

"People aren't able to have the kids that they want," said Guzzo. "There's a growing feeling that if you were to have kids, you really need to provide something for them. You have to do all these things to give your kids advantages because the world is really tough right now. In a world where social mobility is limited and there's a weak social safety net, I think a lot of people look around and say, 'Well, maybe not.'" Leticia Quiles, a 36-year-old unemployed administrative assistant who lives in West Haven, Conn., said that she and her husband, an ATM coordinator, talked about having two children before they got married a decade ago. "We had definitely planned on having children at some point, but because of the economy and the time that you need to put aside for children, it's not something we can do," she said. "We can barely take care of ourselves let alone take care of a child." Instead, Quiles helps to care for her nieces and nephews, babysitting them and taking them for outings like wall climbing. "I get my fill," she said.

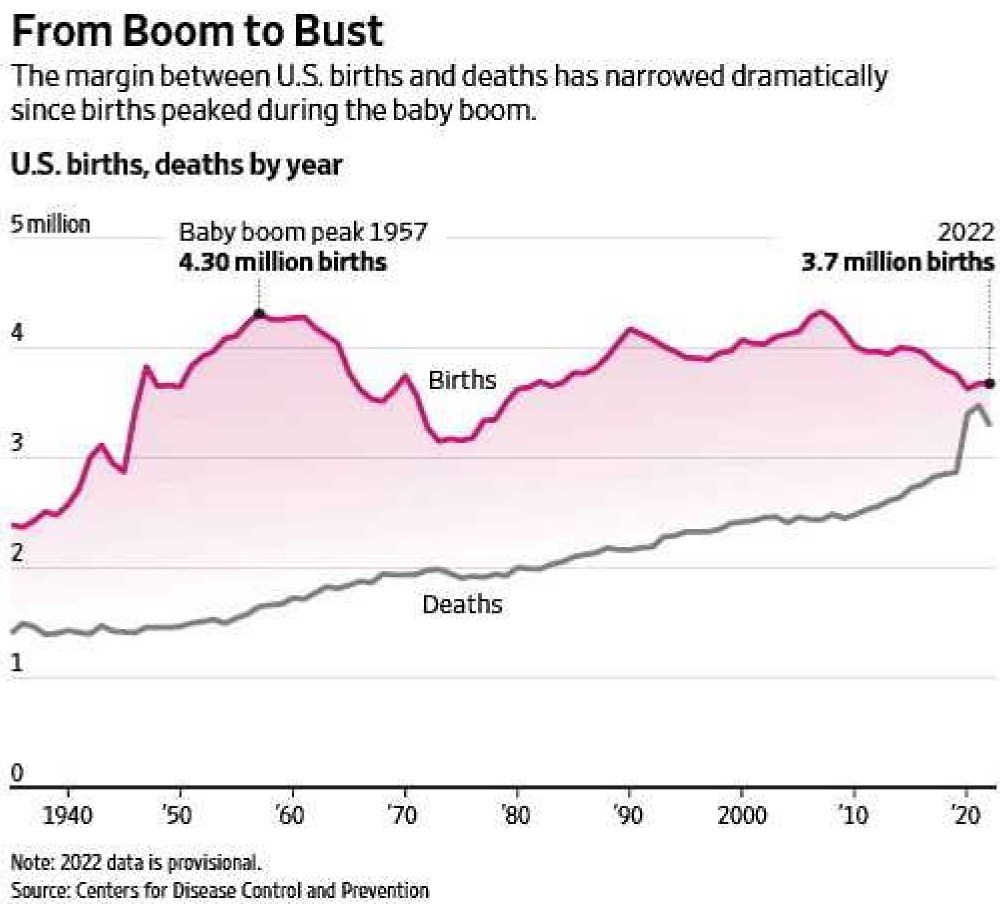
Some young people say that by not having children, they're helping to solve other global problems. "To me it feels borderline unethical to even be having kids with the way the future is looking in terms of climate change and resource shortages and all of that," said Cara Pattullo, a 31-year-old urban and environmental planner who lives with her boyfriend in Chicago. Instead, she thinks that she might adopt or foster children when she gets older, or forego childrearing altogether.

To maintain current population levels, the total fertility rate—a snapshot of the average number of babies women have over their lifetime – must stay at a "replacement rate" of **2.1 children per woman**. In **2021**, the **U.S. rate was 1.66**. Had fertility rates stayed at their 2007 peak, the U.S. would now have 9.6 million more kids, according to Kenneth Johnson, senior demographer at the University of New Hampshire.

Federal agencies are treating the slump like a temporary downturn. The **Social Security Administration**'s board of trustees **projects** that the **total fertility rate** will **slowly climb to 2 by 2056** and **hold there** until the end of the century. **Yet** it's been **over a decade since** fertility rates reached **that level**.

Last year there **were 2.8 workers for every Social Security recipient**. That ratio is **projected** to **shrink to 2.2 by 2045**, roughly **two-thirds** what it was in **2000**. Some other developed countries are in a far deeper childbearing trough than the U.S. In South Korea, the total fertility rate hit a world record low of 0.84 in 2020 and has since sagged to 0.78. Italy's rate slid to 1.24 last year. China's population fell in 2022 for the first time in decades because its fertility rate as been far below the replacement rate for years. Its two-century reign as the world's **most populous country** is expected to end this year when **India** overtakes it, if it hasn't already. In a recent note to clients, Neil Howe, a demographer at Hedgeye Risk Management, pointed to a World Bank report showing that the 2020s could be a second consecutive " lost-decade" for global economic growth, in large part because of worsening demographics.

By 2026 or 2027, he wrote, the growth rate of the working-age population in the entire high-income and emerging-market world will turn from slightly positive to slightly negative, reversing a durable driver of economic growth since the Industrial Revolution. This shift will make the U.S. more dependent on immigration to supply enough workers to keep the economy humming. **Immigrants** accounted for **80% of U.S. population growth last year**, census figures show, **up from 35%** just over a **decade ago**. Yet the **number of young immigrant women coming to** the **U.S. has diminished**, Johnson said, and the decline in fertility has been greatest among Hispanics. Having fewer children has already changed the social fabric of the country's schools, neighborhoods and churches. J.P. De Gance, president and founder of Communio, a nonprofit that helps churches encourage marriage, said that lower marriage and birth rates are one of the largest drivers of the decline in religious affiliation that's left pews empty across the country. That matters for the whole community, De Gance said, because churches give lonely people a place to form friendships, as well as feeding hungry people and running schools that fill gaps in public education. "When that's diminished, the entire culture's diminished," he said.



One reason the U.S. has fewer children is that the **teen birth rate** has **plunged 78% since** its **peak in 1991**. Greater access to contraception, including long-acting methods such as intrauterine devices, has helped curb unplanned pregnancies that prompt the youngest women to halt their education and become mothers before they're ready.

Whether the Supreme Court's 2022 Dobbs decision allowing states to prohibit abortion will materially lift the number of births is an open question. In 2017, the national abortion rate reached its lowest level since Roe v. Wade legalized the procedure in 1973, before drifting up over the next three years, according to data from the Guttmacher Institute, a policy group that supports abortion rights. There were about 930,000 abortions performed in the U.S. in 2020, the most recent year for which figures are available.

Kathryn Kost, Guttmacher's director of domestic research, said that new state-level restrictions on the procedure will make it harder to track abortions. "These laws push it underground," she said. In a recent paper, Kost and co-authors found that between 2009 and 2015, there was a drop in the rates of women who said they got pregnant too soon. At the same time, older women saw an uptick in pregnancies they described as happening later than they desired.

The median age at which women give birth is 30, three years older than it was in 1990. Despite advances in fertility treatments, women who delay having kids until their final childbearing years reduce their chances of doing so – not just because it narrows their biological window but because other priorities and roadblocks can more easily derail their plans.

“Right now I think we’re one and done,” said Hester Graves, a 42-year-old math researcher at a think tank who lives outside Washington, D.C. After giving birth to her daughter four years ago, she hemorrhaged and had to undergo surgeries and blood transfusions: “I would love to have a second. I don’t know that I can risk my life to have a second.”

U.S. policymakers are looking for solutions to the falling birth rate. President Joe Biden has proposed a series of measures aimed at aiding parents, including paid family leave, subsidized child care and federally funded preschool, though they’ve stalled amid opposition from lawmakers who say they’re too expensive. Former president Donald Trump, who is trying to return to the White House in 2024, recently said that he supports paying out “ baby bonuses” to fuel a reproductive boom.

Demographers say that it takes years of large-scale programs to spur childbearing. France, which has one of the highest fertility rates in the developed world, has long invested in pro-natalist policies including subsidized child care. Other countries are catching up. Hungary recently exempted women under the age of 30 who have a child from paying personal income tax.

Pilar Muner, a 34-year-old married human resources executive at a tech company, said that her desire to have children has run up against a series of deterrents, including long Covid. She doesn’t want to waltz into parenthood like her mother and father’s generation did: “You had more kids than you could afford. You smoked cigarettes when you were pregnant. Not a lot of thought went into it,” said Muner, who lives outside Boston. “I think I’m just not ready.”

For now, she is exploring freezing her eggs. “I have a lot of things I enjoy that have made me really happy,” she said. “I don’t want to feel like parts of my life are being compromised.”

–

Why Did Inflation Take Off? Two Top Economists Answer

by Greg Ip – WSJ – May 24, 2023

For two years, debate has raged over **what caused** the **highest inflation since** the **1980s**: government stimulus or pandemic-related disruptions.

Now two top economists have an answer: It's both. **Pandemic-related supply shocks** explain **why inflation shot up in 2021**. An **economy overheated by fiscal stimulus and low interest rates** explain **why** it has **stayed high** ever **since**. The conclusion: For inflation to fade, the economy has to cool off, which means a weaker labor market.

The **study**, released Tuesday, is **by Ben Bernanke**, **former chair** of the **Fed**eral Reserve, **and Olivier Blanchard**, **former chief economist** of the **International Monetary Fund**. **Bernanke** is **now at** the **Brookings Institution** and **Blanchard** is at the **Peterson Institute for International Economics**.

When Congress passed President Biden's $1.9 trillion American Rescue Plan in 2021, which included checks to households, enhanced jobless benefits and aid to state and local governments, inflation was around 2% and unemployment still above 6%.

At the time many forecasters thought stimulus could push demand above the economy's potential to supply goods and services and unemployment below its long-run natural rate of around 4%. Yet few thought this would meaningfully raise inflation.

A few disagreed, notably former Treasury Secretary Lawrence Summers and Blanchard. Both warned the stimulus was so large it would push the economy into overheating territory.

Inflation did shoot up, hitting 7% that December, 5.5% excluding food and energy. "The critics' forecasts of higher inflation would prove to be correct – indeed, even too optimistic – but, in substantial part, the sources of the inflation would prove to be different from those they warned about," Blanchard and Bernanke write.

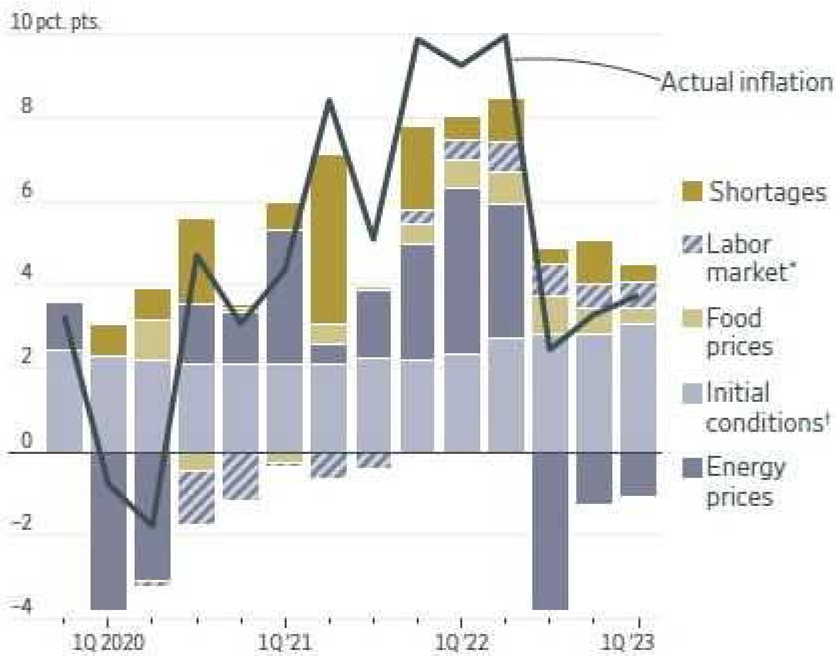
To tease out sources of inflation, **Bernanke and Blanchard** build a relatively conventional **model** in which **inflation** is a **function of**, among other things, the **gap between** the **supply and demand for labor**, **public expectations of inflation**, and **commodity prices**.

Usually economists judge labor market tightness from how far unemployment is above or below its natural rate. But this time the labor market heated up before unemployment got that low. So Bernanke and Blanchard use the **ratio of job vacancies to unemployed workers**. Finally, their **model lets** these **factors interact**, with varying lags.

If stimulus had overheated the economy, it should have shown up in the labor market. In fact, labor conditions put downward pressure on inflation through 2021's third quarter, the authors concluded. Instead, inflation that year was driven almost entirely by shortages and energy prices. (To be sure, many shortages reflected restricted supply interacting with demand boosted by stimulus.)

Demand shifted abruptly from services to goods early in the **pandemic**. The effect should have been a wash as prices rose for goods and fell for services. It wasn't, because **goods producers faced supply constraints**, while costs to service producers didn't decline much. "These **sectoral mismatches between demand** and **supply proved** more **intractable** and **longer-lasting** than many had expected," the authors note.

Contributions to inflation by source



*Ratio of job vacancies to unemployed †Effect of pre-2020 data and productivity.
Note: Contributions are model estimates and don't add exactly to actual inflation.
Quarterly data, annualized.
Source: Ben Bernanke and Olivier Blanchard

Pandemic disruptions eventually subsided. Why didn't inflation then fall? The reason, the authors conclude, is that by this point demand was so strong, and the labor market was significantly overheated. Moreover, the initial surge of inflation lifted workers' expectations of short-term inflation, which then partly found its way into their wages.

If anything, the study might understate the effect of pandemic disruptions. The labor market didn't just overheat because of excess demand, but reduced supply, as well. The rising ratio of vacancies to unemployed, which the model equates with a tighter labor market, reflects employers' struggling to fill vacancies. The authors note much of that struggle was because of the pandemic: Firms that had laid off employees had to find new ones, while some workers left the labor force because of family obligations, illness or work-life priorities.

This decline in supply-side potential hasn't gotten much attention, but its role could be significant. New York Fed President John Williams has estimated that potential was 4.2% lower at the end of 2022 than its pre-pandemic trend.

That stimulus wasn't the inflation culprit it's often made out to be doesn't entirely absolve the Fed and Biden. Arguably, they should have anticipated supply disruptions would amplify the risks of stoking demand. In 2020, under new Fed framework and guidance, interest rates would stay near zero until maximum employment was restored, even if inflation topped 2%. That "contributed to delayed action and the inflation overshoot," former Fed Vice Chair Donald Kohn and Brown University economist Gauti B. Eggertsson say in a new paper.

Bernanke and Blanchard conclude that because inflation today reflects a too-hot labor market, the solution is to cool it off. They estimate unemployment would have to rise above 4.3% assuming vacancies remain difficult to fill. But, they say, inflation could drop without a significant increase in unemployment if the ease of hiring returns to pre-pandemic norms. The good news: There are tentative signs that is happening.

–

Why Did Inflation Take Off? Two Top Economists Answer

by Greg Ip – WSJ – May 24, 2023

For two years, debate has raged over **what caused** the **highest inflation since** the **1980s**: government stimulus or pandemic-related disruptions.

Now two top economists have an answer: It's both. **Pandemic-related supply shocks** explain **why inflation shot up in 2021**. An **economy overheated by fiscal stimulus and low interest rates** explain **why** it has **stayed high** ever **since**. The conclusion: For inflation to fade, the economy has to cool off, which means a weaker labor market.

The **study**, released Tuesday, is **by Ben Bernanke**, **former chair** of the **Fed**eral Reserve, **and Olivier Blanchard**, **former chief economist** of the **International Monetary Fund**. **Bernanke** is **now at** the **Brookings Institution** and **Blanchard** is at the **Peterson Institute for International Economics**.

When Congress passed President Biden's $1.9 trillion American Rescue Plan in 2021, which included checks to households, enhanced jobless benefits and aid to state and local governments, inflation was around 2% and unemployment still above 6%.

At the time many forecasters thought stimulus could push demand above the economy's potential to supply goods and services and unemployment below its long-run natural rate of around 4%. Yet few thought this would meaningfully raise inflation.

A few disagreed, notably former Treasury Secretary Lawrence Summers and Blanchard. Both warned the stimulus was so large it would push the economy into overheating territory.

Inflation did shoot up, hitting 7% that December, 5.5% excluding food and energy. "The critics' forecasts of higher inflation would prove to be correct – indeed, even too optimistic – but, in substantial part, the sources of the inflation would prove to be different from those they warned about," Blanchard and Bernanke write.

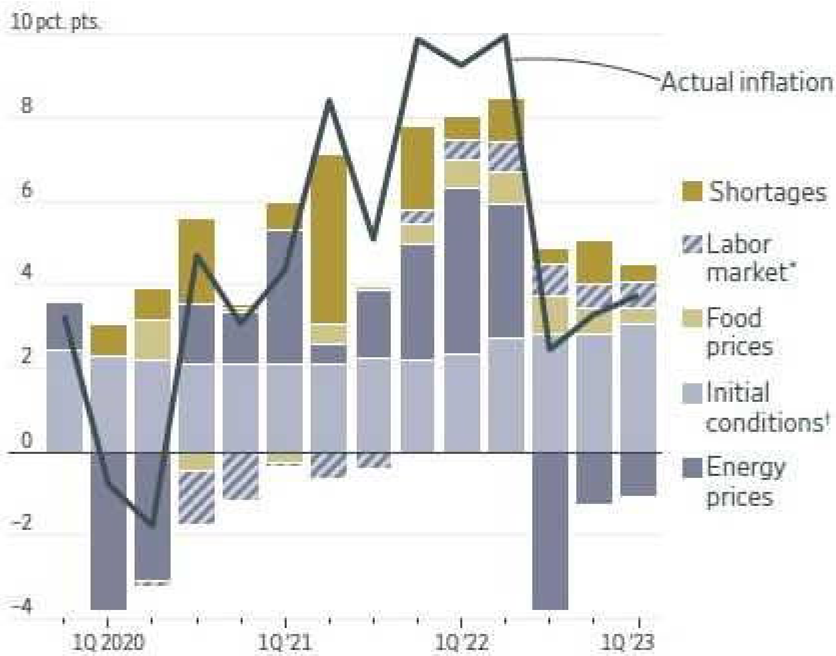
To tease out sources of inflation, **Bernanke and Blanchard** build a relatively conventional **model** in which **inflation** is a **function of**, among other things, the **gap between** the **supply and demand for labor**, **public expectations of inflation**, and **commodity prices**.

Usually economists judge labor market tightness from how far unemployment is above or below its natural rate. But this time the labor market heated up before unemployment got that low. So Bernanke and Blanchard use the **ratio of job vacancies to unemployed workers**. Finally, their **model lets** these **factors interact**, with varying lags.

If stimulus had overheated the economy, it should have shown up in the labor market. In fact, labor conditions put downward pressure on inflation through 2021's third quarter, the authors concluded. Instead, inflation that year was driven almost entirely by shortages and energy prices. (To be sure, many shortages reflected restricted supply interacting with demand boosted by stimulus.)

Demand shifted abruptly from services to goods early in the **pandemic**. The effect should have been a wash as prices rose for goods and fell for services. It wasn't, because **goods producers faced supply constraints**, while costs to service producers didn't decline much. "These **sectoral mismatches between demand** and **supply proved** more **intractable** and **long**er-**lasting** than many had expected," the authors note.

Contributions to inflation by source



*Ratio of job vacancies to unemployed †Effect of pre-2020 data and productivity.
Note: Contributions are model estimates and don't add exactly to actual inflation.
Quarterly data, annualized.
Source: Ben Bernanke and Olivier Blanchard

Pandemic disruptions eventually subsided. Why didn't inflation then fall? The reason, the authors conclude, is that by this point demand was so strong, and the labor market was significantly overheated. Moreover, the initial surge of inflation lifted workers' expectations of short-term inflation, which then partly found its way into their wages.

If anything, the study might understate the effect of pandemic disruptions. The labor market didn't just overheat because of excess demand, but reduced supply, as well. The rising ratio of vacancies to unemployed, which the model equates with a tighter labor market, reflects employers' struggling to fill vacancies. The authors note much of that struggle was because of the pandemic: Firms that had laid off employees had to find new ones, while some workers left the labor force because of family obligations, illness or work-life priorities.

This decline in supply-side potential hasn't gotten much attention, but its role could be significant. New York Fed President John Williams has estimated that potential was 4.2% lower at the end of 2022 than its pre-pandemic trend.

That stimulus wasn't the inflation culprit it's often made out to be doesn't entirely absolve the Fed and Biden. Arguably, they should have anticipated supply disruptions would amplify the risks of stoking demand. In 2020, under new Fed framework and guidance, interest rates would stay near zero until maximum employment was restored, even if inflation topped 2%. That "contributed to delayed action and the inflation overshoot," former Fed Vice Chair Donald Kohn and Brown University economist Gauti B. Eggertsson say in a new paper.

Bernanke and Blanchard conclude that because inflation today reflects a too-hot labor market, the solution is to cool it off. They estimate unemployment would have to rise above 4.3% assuming vacancies remain difficult to fill. But, they say, inflation could drop without a significant increase in unemployment if the ease of hiring returns to pre-pandemic norms. The good news: There are tentative signs that is happening.

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 410

Edison Electric Institute (EEI)
2022 Annual Financial Review Report

June 13, 2023

Edison Electric INSTITUTE

2021 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry

Thank you to the following EEI Power Member for sponsoring the 2021 Financial Review.

For more than 25 years, PowerPlan has helped North American energy companies make the right financial decisions. Between market dynamics, regulators, technology, green energy, and investor and public sentiment, the electric industry is always changing. Having access to the right data enables you to respond to trends, challenges and change to make the most of your organization's assets. Through our industry-leading expertise, innovative technology and vast experience listening to and working in tandem with our customers, PowerPlan software sets the standard that CFOs can count on for financial clarity to prepare today for tomorrow's challenges.

Edison Electric INSTITUTE

2021 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 2021 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 80 for a list of these companies.

Contents

Highlights of 2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2021	2020r	% Change
Total Operating Revenues	385,500	347,934	10.8%
Utility Plant (Net)	1,362,155	1,309,480	4.0%
Total Capitalization	1,299,776	1,232,301	5.5%
Earnings Excluding Non-Recurring and Extraordinary Items	53,480	54,217	(1.4%)
Dividends Paid, Common Stock	30,075	29,503	1.9%

r = revised   Note: 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

2021 Financial Review

EEI's member companies—America's investor-owned electric companies—are woven tightly into the fabric of our nation. For nearly 140 years, we have provided the energy that has sustained our customers and our communities, while powering our economy.

In 2021, we made substantial progress on our commitment to provide America's resilient clean energy. At the same time, we saw the continuation—and the emergence—of many unprecedented challenges. Our nation's economy faces headwinds from rising inflation and interest rates, as well as ongoing pressure within key supply chains. And, around the world, we are seeing the impacts of extreme weather and other natural disasters. Russia's war in Ukraine and its human toll on civilians have compounded these challenges, even as geopolitical tensions rise in other flashpoints.

Against this backdrop, EEI's member companies are maintaining the powerful momentum we have built over many years. Electricity truly is the energy that powers our lives. Now more than ever, our customers depend on the supply of resilient clean energy that EEI's member companies provide. As always, our customers are the focus of everything we do.

For us, the path forward is clear—and the path forward is clean. Thanks largely to the leadership of EEI's member companies, carbon emissions from the U.S. electric power sector today are nearly 40 percent below 2005 levels. At the same time, 40 percent of our nation's electricity now comes from clean, carbon-free sources, including nuclear energy, hydropower, wind, and solar energy. Dozens of EEI's member companies have announced ambitious long-term carbon-reduction targets, including net-zero targets, showing the path forward.

In 2020, nearly 28 gigawatts (GW) of renewable technologies went online in the United States—a record deployment by a wide margin. Early data show that renewables also had a banner year in 2021, making up 20 percent of the energy mix for the second year in a row. EEI's member companies are well-positioned to be a major part of the climate solution—and we want to be part of the solution. With new technologies and the right policies—including congressional passage of a robust clean energy tax package that will deliver significant long-term benefits to electricity customers—a 100-percent clean energy future can be more than a goal. It can be a reality.

To create a cleaner economy, we will need a cleaner transportation sector. Today, the biggest barrier to electric vehicle (EV) adoption is not a lack of EVs. It is a lack of access to charging infrastructure that is convenient, affordable, equitable, and reliable. EEI projects that there will be nearly 22 million EVs on U.S. roads in 2030. Given this growth in EVs, we estimate that more than 100,000 EV fast charging ports will be needed. That is more than a ten-fold increase over what we have today.

EEI's member companies already are investing more than $3.4 billion to help build and to deploy this charging infrastructure and to accelerate electric transportation programs, with more than $1 billion of additional investment pending. In December 2021, we proudly launched the National Electric Highway Coalition, which is a collaboration among electric companies that are committed to providing EV fast charging stations that will allow the public to drive EVs with confidence along major U.S. travel corridors by the end of 2023.

We also are working every day to improve energy grid security, reliability, and resiliency, and we continue to strengthen cyber and physical defenses and to enhance preparedness. Our strong industry-government partnership, coordinated through the CEO-led Electricity Subsector Coordinating Council, continues to be critical to accomplishing our shared goal of protecting the energy grid against all threats.

Increasingly, EEI's member companies are investing in adaptation, hardening, and resilience (AHR) initiatives to make the grid stronger and more secure for all customers. In October 2021, EEI published industry-level information on AHR capital expenditures based on a member company survey, which indicated that more than one-third of transmission and distribution investment is being driven specifically by AHR initiatives, rather than the traditional drivers of growth or maintenance.

We know that our stakeholders need a clear and consistent way to measure our progress on delivering a sustainable energy future. That is why EEI, working with our member companies and the investment community, created the first-of-its-kind, industry-wide environmental, social, governance, and sustainability (ESG/sustainability) reporting template. Launched in 2018, the template helps member companies provide investors, Wall Street analysts, and other key stakeholders with more consistent and uniform ESG/sustainability data and information. We continue to expand and to refine our original template, adding a qualitative disclosure on cybersecurity governance and formally integrating the American Gas Association's members, among other improvements.

As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the eighth straight year in 2021, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set a tenth consecutive record high of $134.1 billion in 2021. We continue to be America's most capital-intensive industry.

The EEI Index returned a strong 17.1 percent for 2021, yet the major averages were stronger. The S&P 500 Index returned 28.7 percent, while the Dow Jones Industrial Average and Nasdaq Composite each gained more than 21 percent. Nonetheless, the EEI Index has produced a positive total return in 16 of the last 19 years, with returns of greater than 10 percent in 13 of the 16 positive years, and greater than 20 percent in 5 of the 16 positive years. Notably, the combined market capitalization for the 39 companies included in the EEI Index exceeded $1 trillion for the first time in 2021, landing at $1.03 trillion at year-end.

Our industry extended its long-term trend of widespread and consistent dividend increases last year, with a total of 32 companies increasing their dividend in 2021. The percentage of companies that raised or reinstated their dividend in 2021 was 82 percent, slightly lower than the range of 87 percent to 93 percent in each of the prior five years. Our industry's dividend payout ratio was 66.2 percent for the 12 months ended December 31, 2021, leading among the other major U.S. business sectors. As of December 31, 2021, 38 of the 39 companies in the EEI Index were paying a common stock dividend.

In 2022 and beyond, EEI and our member companies will remain focused on our commitment to delivering America's resilient clean energy. Fulfilling this commitment—and reaching a clean energy, net-zero carbon future—is not just a goal. It is the opportunity of our lifetimes—as well as a great challenge.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn

Thomas R. Kuhn

President
Edison Electric Institute

Capital Markets

Stock Performance

The EEI Index returned a strong 17.1% in 2021, yet the major averages were even stronger. The S&P 500 Index returned 28.7% while the Dow and Nasdaq each gained more than 21%. Yet utilities' relative weakness occurred in 2021's first half, as the post-pandemic bull market lifted major averages up 12% to 15% while the EEI Index returned only 2.3%. The year's second half was a different story. Utilities outperformed the major averages in both Q3 and Q4. The EEI Index gained a notably strong 12.9% in Q4 even as rising monthly inflation data made news headlines. In fact, 2021's second half marked a trend change in relative return as utilities had sharply trailed the market's surge from the pandemic-induced low in Q1 2020 through Q2 2021. The industry's robust Q4 gain also helped it outperform the other primarily defensive sector, telecommunications, for 2021, which returned –8.7% for the year.

Economy Watch

Economic data throughout 2021 showed a relatively steady economic recovery from the impact of 2020's lockdowns and restrictions. In late February, the Bureau of Economic

2021 Index Comparison

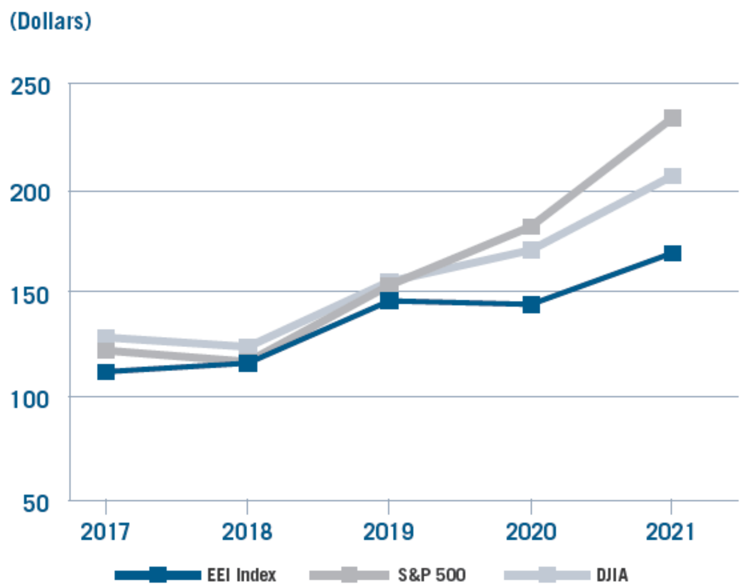
EEI Index	**17.1**
Dow Jones Industrials	21.0
S&P 500	28.7
Nasdaq Composite Index*	21.4

* 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 1/1/17–12/31/21

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2016.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Top 10 Performers

Twelve-month period ending 12/31/2021

Company	Total Return %	Category
Otter Tail Corp.	72.5	R
FirstEnergy Corp.	41.7	R
Exelon Corp.	41.2	MR
CenterPoint Energy, Inc.	32.4	R
Portland General Electric Co.	28.1	R
Evergy, Inc.	28.0	R
OGE Energy Corp.	26.3	R
NiSource Inc.	24.6	R
NextEra Energy, Inc.	23.4	MR
Consolidated Edison, Inc.	23.0	R

Note: Return figures include capital gains and dividends.
Source: EEI Finance Department.

Sector Comparison 2021 Total Shareholder Return

Sector	Total Return %
Oil & Gas	54.4%
Technology	37.2%
Financials	32.3%
Basic Materials	27.8%
Healthcare	23.6%
Consumer Goods	21.8%
Industrials	18.4%
Utilities	17.4%
EEI Index	**17.1%**
Consumer Services	12.0%
Telecommunications	-8.7%

Source: EEI Finance Dept., Dow Jones & Company, Y Charts.

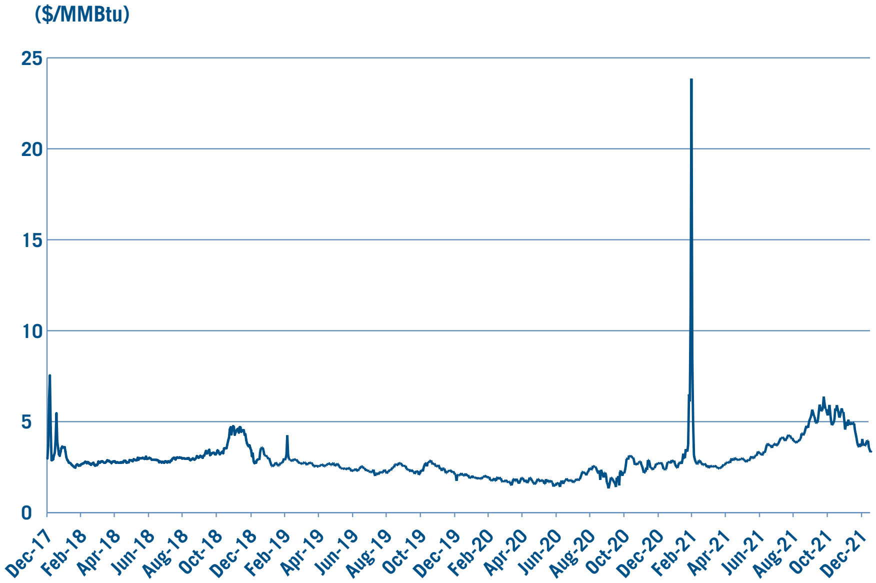
Analysis (BEA) reported Q4 2020 real gross domestic product (GDP) rose 4.1% from its level in Q3 2020, which in turn jumped 33.8% from Q2, when pandemic stress was at its worst. In late June 2021, the BEA said real GDP rose at an annual rate of 6.1% in Q1. In late July, the agency said Q2 GDP gained an even stronger 6.5%, which was revised higher to 6.7% in late September. Real GDP growth slowed to 2.3% in Q3 before surging to 6.9% in Q4 (announced in January 2022), marking its fastest quarterly pace of the year.

The corporate earnings outlook also became increasingly bullish as 2021 evolved. By late December, Wall Street analysts surveyed by Zacks Investment Research collectively pegged S&P 500 2022 revenue and profit growth at 7.4% and 8.5%, respectively, with further gains of 5.3% and 9.8% expected for 2023. The year's economic data and optimistic corporate profit outlook lifted stocks across the board in 2021.

Inflation Fireworks

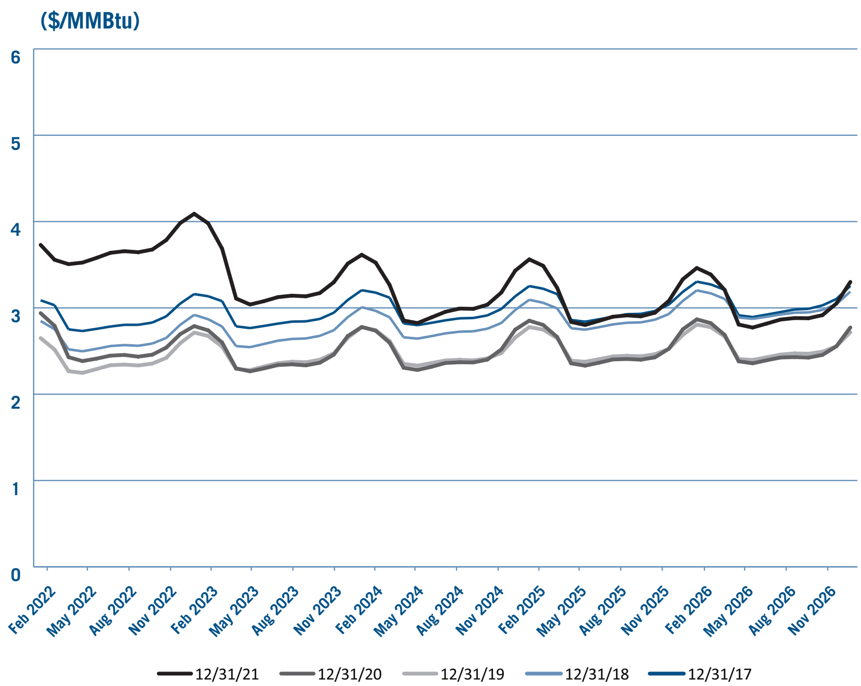
While investors in early 2021 focused on strong growth readings, economic headlines later in the year centered on inflation. Monthly inflation measured by the consumer price index (CPI) rose above 4% in April, held over 5% through Q3, breached 6% in October and November, and reached 7.1% in December. In fact, 2021's final quarter produced the highest inflation numbers since the early 1980s. Economists framed the inflation surge as a consequence of post-pandemic economic strength along with related supply chain disruptions, not as a new secular trend. That was the Federal Reserve's position too, as it held short-term interest rates at zero in Q4 and continued monthly purchases of Treasury and agency mortgage-backed securities. Natural gas spot prices seemed to confirm inflation skepticism; spot prices surged early in the year, reaching their highest levels since 2014, but fell back sharply in Q4 and longer-dated futures remained unchanged at lower levels.

Natural Gas Spot Prices - Henry Hub
12/31/17 through 12/31/21



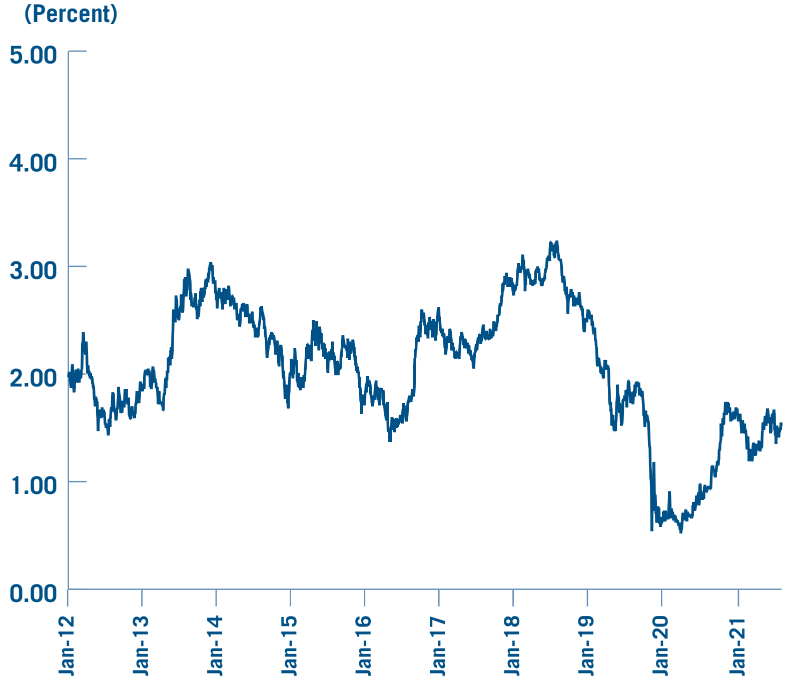
Source: S&P Global Market Intelligence.

NYMEX Natural Gas Futures
February 2022 through December 2026



Source: S&P Global Market Intelligence.

10-Year Treasury Yield
1/1/12 through 12/31/21



Source: U.S. Federal Reserve.

Interest rates during 2021 seemed to confirm the belief that inflation pressures are temporary. The 10-year U.S. Treasury yield jumped from 0.9% to 1.7% in Q1, but despite the headline, inflation numbers fell back to 1.2% in July and spent 2021's second half drifting between 1.3% to 1.7%, closing the year at 1.5%.

Electric Output Up 2.8% in 2021

Electricity demand rose a strong 2.8% for the year, powered in part by the economic rebound. Demand jumped 4.1% in the year's first half (rising a notable 5.1% in Q2) mirroring the buoyant economic data. Analysts cited a hot June across much of the nation combined with an economic recovery-induced boost in commercial and industrial load as likely drivers of Q2's strength. Weather had a smaller impact on Q3, as demand gained 1.7% year-to-year. U.S. electric output rose 1.5% nationwide in Q4 with the fast-growing West Central region up more than 3%. Heating degree days in October and December were well below last year's level and historical averages, which may have suppressed electric demand for heating.

Simplification Trend Continues

The industry's dominant strategic trend continued in 2021. Utility industry business strategies had already coalesced in 2020 around ambitious environmental, social and governance (ESG) agendas centered on improving carbon profiles and ESG metrics, in many cases tied to a focus on regulated rate base. Numerous companies in 2020 announced moves to restructure and focus on developing state-regulated, clean energy infrastructure as their primary path to shareholder value creation. These moves continued in 2021 with an extensive list of announcements and transactions that included sales of fossil generation assets, natural gas midstream operations, international operations, and non-utility subsidiaries, along with the spin-off of competitive generation (see Business Segmentation for additional discussion).

Other Industry Themes

Wall Street's analytical attention in early 2021 was focused on tracking and interpreting the new Biden Administration's many moves to advance a clean energy agenda. While a stronger federal focus on climate change was expected after Biden's 2020 election victory, the details that emerged as administration plans came into focus left industry analysts more bullish on prospects for long-term utility industry capex and rate base growth. Analytical attention shifted later in the year to tracking day-to-day news from Capitol Hill concerning legislative prospects for spending and tax proposals that support clean energy and decarbonization.

Utilities' perspectives on inflation were another key point of interest, particularly in the year's second half. Wall Street research suggested analysts and companies did not see meaningful pressure on near-term operating costs, which are mostly labor related and controlled through long-term contracts or stable workforce pay schedules. But longer-term impacts are impossible to predict and if inflation becomes a secular trend the outlook is far less clear.

The EEI Financial Conference held in November is always a key industry event. Analysts noted discussions there with utility managements as well as upbeat Q3 earnings calls affirmed the industry's growth outlook. With broad public, state, regulatory and federal support, along with rising corporate demand for clean power, opportunities for renewable capex seemed to grow during 2021. Some utilities raised growth guidance for clean energy capex and analysts ratcheted up related earnings outlooks.

While not a new theme, utility bill headroom for funding aggressive capex arose as a focal point of analyst discussions; this was spurred in part by headline inflation data. Customer rates in aggregate nationwide have been almost flat for a decade, benefitting from low fuel commodity costs, falling interest rates, lower corporate taxes, and utilities' efforts to hold operations and maintenance (O&M) costs down. While analysts viewed state regulation as generally constructive, a few noted that funding capex plans may require rate increases that risk pushback from state commissions. That becomes especially hard to predict if inflation evolves into a durable source of consumer discontent, so it's a topic the industry watches carefully.

2021 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	3.0	(0.7)	1.4	12.9
Dow Jones Industrial Average	8.3	5.1	(1.5)	7.9
S&P 500	6.2	8.6	0.6	11.0
Nasdaq Composite*	2.8	9.5	(0.4)	8.3

Category	Q1	Q2	Q3	Q4
All EEI Index Companies	6.0	0.3	(0.7)	11.5
Regulated	4.8	0.3	(0.7)	11.9
Mostly Regulated	10.6	0.3	(0.8)	10.1

* 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.

2021 Category Comparison

Category	Return (%)
EEI Index	**17.6**
Regulated	16.7
Mostly Regulated	21.1

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2021 Index Comparison table is cap-weighted.

Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

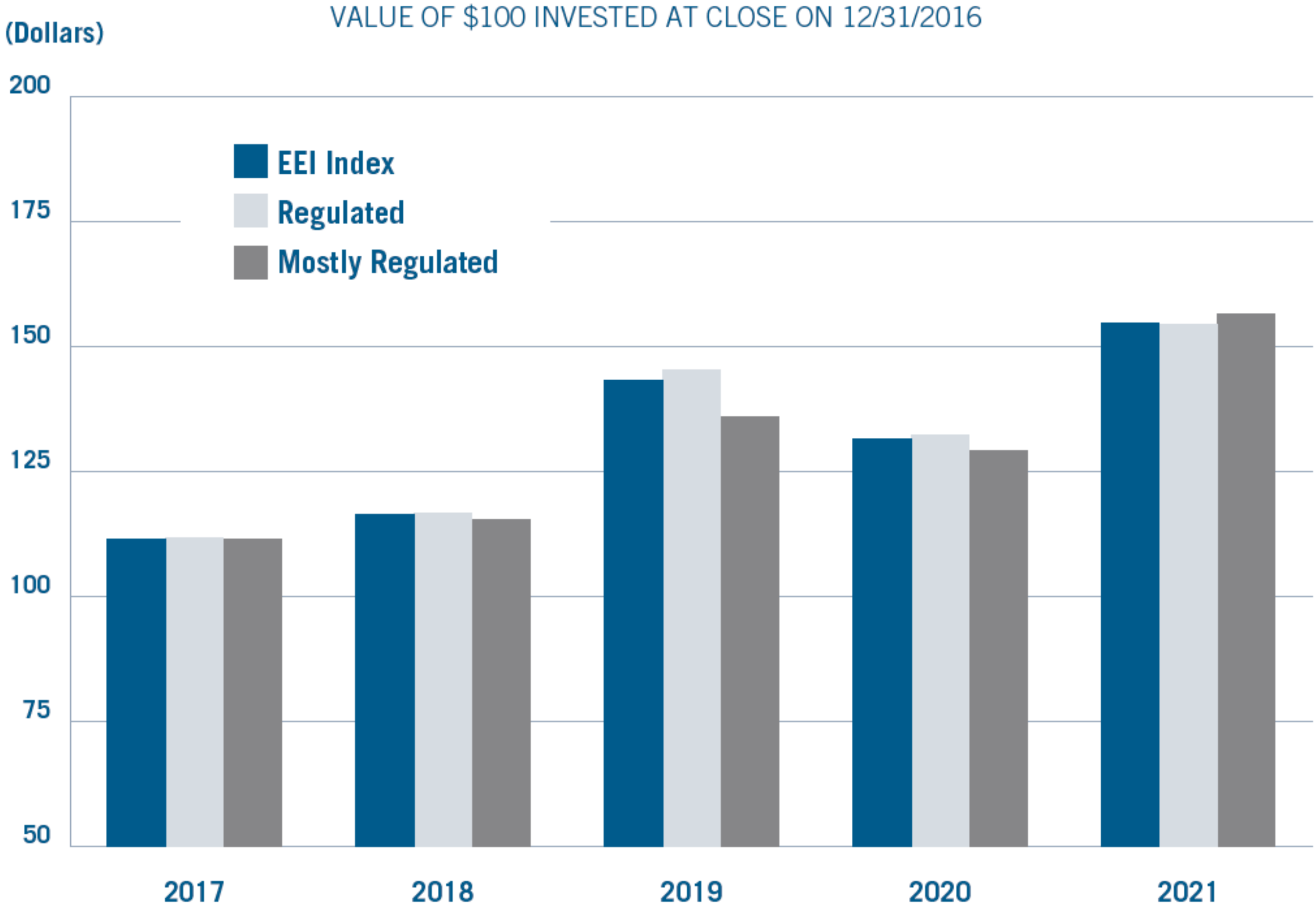
Infrastructure Bill Implementation

EEI was instrumental in advocating for many key provisions within the Infrastructure Investment and Jobs Act, particularly with respect to electric transportation, grid modernization, cybersecurity, energy resilience, broadband, and research, development, and deployment of new clean energy technologies. In early January 2022, the White House outlined its strategy for helping to accelerate the deployment of clean energy using new authorities and the substantial funding that was included in this legislation.

EEI is focused now on coordinating and leading industry efforts related to funding programs and im-

Comparative Category Total Annual Returns 2017–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2016



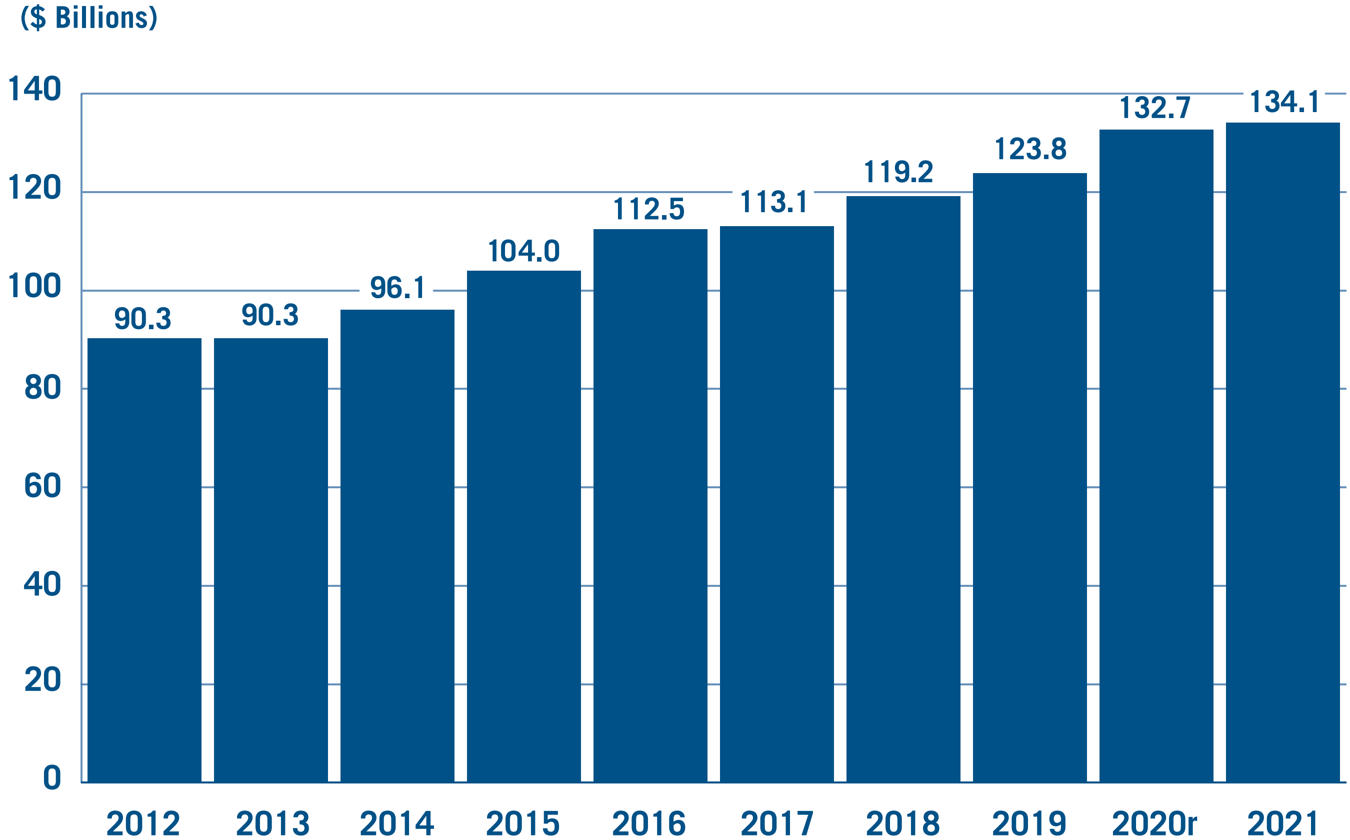
	2017	2018	2019	2020	2021
EEI Index Annual Return (%)	11.56	4.28	23.06	(8.07)	17.62
EEI Index Cumulative Return ($)	111.56	116.34	143.16	131.60	154.78
Regulated EEI Index Annual Return	11.66	4.55	24.56	(9.01)	16.72
Regulated EEI Index Cumulative Return	111.66	116.74	145.41	132.30	154.43
Mostly Regulated EEI Index Annual Return	11.32	3.62	17.87	(4.95)	21.09
Mostly Regulated EEI Index Cumulative Return	111.32	115.35	135.97	129.24	156.50

- 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, 2016.

Source: EEI Finance Dept., S&P Global Market Intelligence.

Capital Expenditures 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

plementation of this law, working to ensure that member companies and their state and local governments are ready and able to access and to use new federal infrastructure funds and programs. Through careful planning and partnerships, everyone can benefit from the clean energy transition.

Relative Performance Drought

The 2019 through 2021 period produced the worst stretch of relative return for utilities since the late 1990s tech bubble. The group generally lags a sharply rising bull market, so perhaps that three-year trend should not be a surprise. Yet investors may wonder if utilities have gotten the respect they deserve. As 2021 ended, analysts noted the industry offers good prospects for mid-single-digit steady earnings gains along with a 3% dividend yield. The S&P 500's 40%+ profit gain in 2021 overshadowed that but looking forward utilities may offer a comparable growth outlook with more than double the S&P 500's 1.4% dividend yield and with less business risk.

As inflation numbers rose, analysts' reports late in the year tried to gauge utilities' sensitivity to rising interest rates, noting utilities typically suffer when long-term rates rise but are less sensitive to short-term yields. Of course, it is difficult to be certain about any rate sensitivity analysis. Interest rates have tracked a steady secular downtrend since the early 1980s, rising rate environments have

Market Capitalization at December 31, 2021 (in $MM)

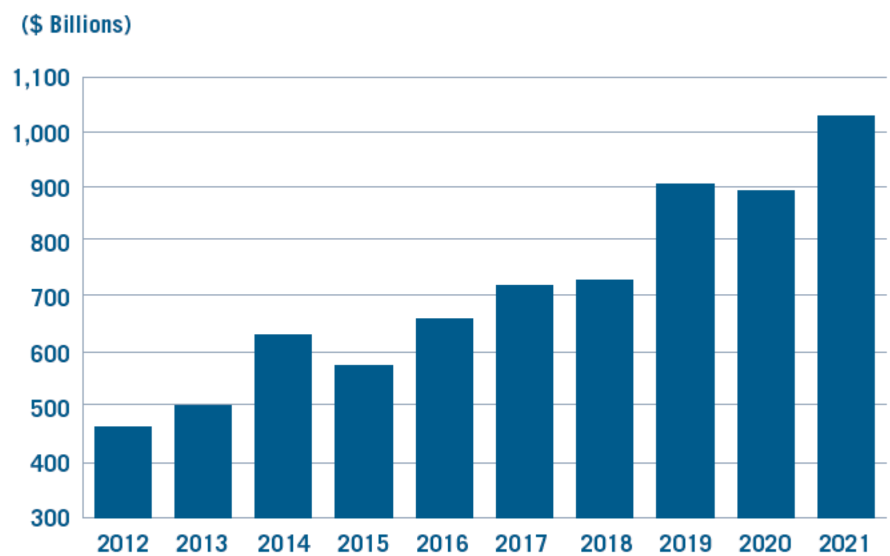
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Ticker	Market Cap.	% of Total	Company Name	Ticker	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	183,238	17.82%	CMS Energy Corporation	CMS	18,806	1.83%
Duke Energy Corporation	DUK	80,668	7.84%	CenterPoint Energy, Inc.	CNP	16,875	1.64%
Southern Company	SO	72,763	7.07%	Evergy, Inc.	EVRG	15,760	1.53%
Dominion Energy, Inc.	D	63,531	6.18%	Alliant Energy Corporation	LNT	15,386	1.50%
Exelon Corporation	EXC	56,547	5.50%	NiSource Inc.	NI	10,856	1.06%
American Electric Power Company, Inc.	AEP	44,595	4.34%	Pinnacle West Capital Corporation	PNW	7,971	0.78%
Sempra Energy	SRE	42,216	4.10%	OGE Energy Corp.	OGE	7,684	0.75%
Xcel Energy Inc.	XEL	36,490	3.55%	MDU Resources Group, Inc.	MDU	6,256	0.61%
Public Service Enterprise Group Inc.	PEG	33,632	3.27%	IDACORP, Inc.	IDA	5,735	0.56%
Eversource Energy	ES	31,299	3.04%	Portland General Electric Company	POR	4,731	0.46%
WEC Energy Group, Inc.	WEC	30,616	2.98%	Hawaiian Electric Industries, Inc.	HE	4,536	0.44%
Consolidated Edison, Inc.	ED	30,152	2.93%	Black Hills Corporation	BKH	4,470	0.43%
Edison International	EIX	25,935	2.52%	PNM Resources, Inc.	PNM	3,926	0.38%
PG&E Corporation	PCG	24,098	2.34%	ALLETE, Inc.	ALE	3,477	0.34%
PPL Corporation	PPL	23,078	2.24%	Avista Corporation	AVA	2,977	0.29%
DTE Energy Company	DTE	23,071	2.24%	MGE Energy, Inc.	MGEE	2,974	0.29%
Ameren Corporation	AEE	22,902	2.23%	NorthWestern Corporation	NWE	2,966	0.29%
Entergy Corporation	ETR	22,638	2.20%	Otter Tail Corporation	OTTR	2,964	0.29%
FirstEnergy Corp.	FE	22,625	2.20%	Unitil Corporation	UTL	715	0.07%
AVANGRID, Inc.	AGR	19,320	1.88%				
				Total Industry		**1,028,480**	**100%**

Source: EEI Finance Department and S&P Global Market Intelligence.

been few and short-lived, and Federal Reserve policy has dominated bond markets since the Financial Crisis of 2008 and 2009. That history may not offer much to go on looking forward. And rising rates will probably impact high-growth, high-P/E companies more sharply than utilities, as early 2022's market volatility seemed to portend. It may take a bear market for utilities to really shine on a relative basis, if not in absolute terms. And investors have not seen a real bear for a long, long time.

EEI Index Market Capitalization 2012–2021

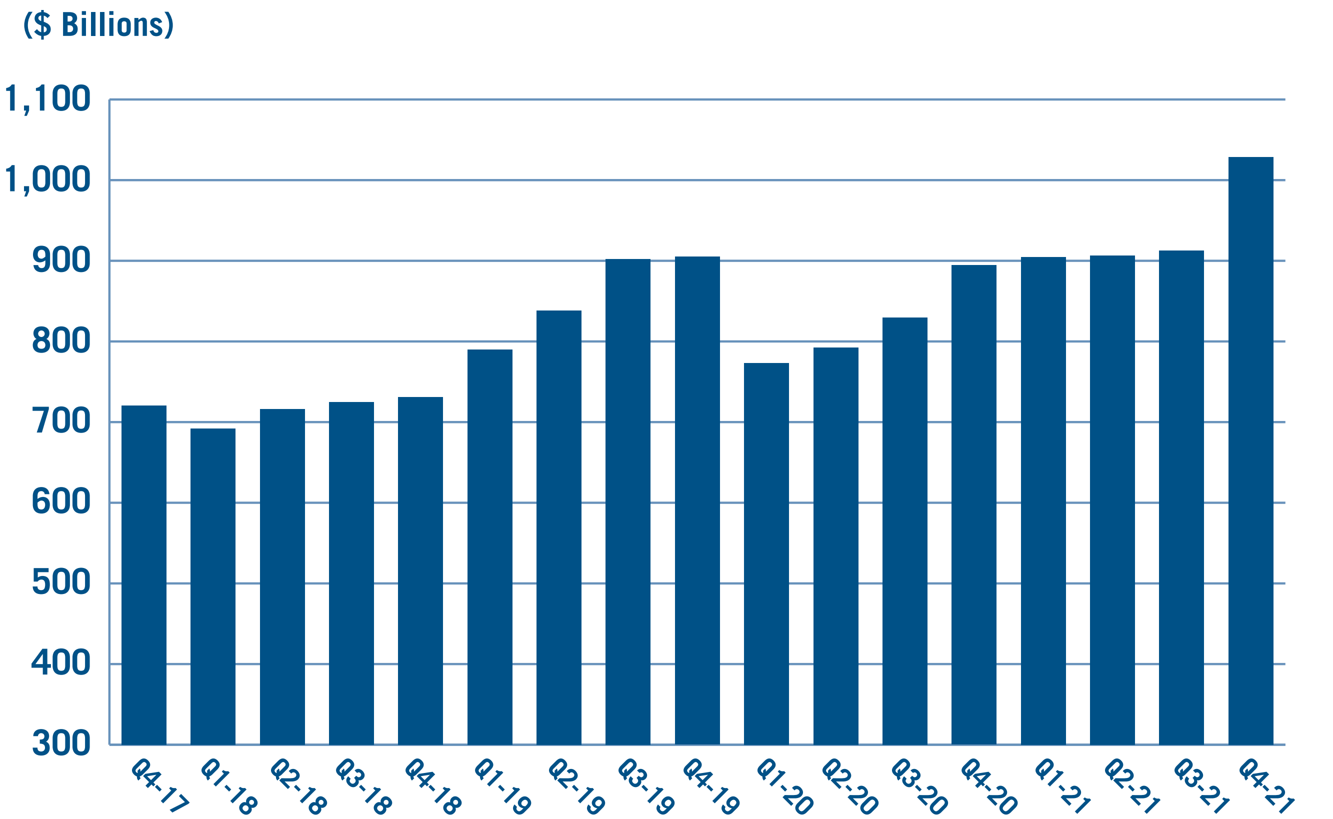


Note: Results are as of December 31 of each year.

Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization

December 31, 2017–December 31, 2021



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 2021. A total of 32 companies increased or reinstated their dividend compared to 34 in 2020, 37 in 2019, 39 in 2018 and 36 to 40 companies annually from 2012 through 2017.

The percentage of companies that raised or reinstated their dividend in 2021 was 82%, just below the 85% to 93% range seen 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 based on data beginning 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 2021.

Dividend Patterns 1996–2021

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%

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Average of the Increased Dividend Actions ***	7.2%	5.3%	5.7%	5.8%	5.6%	5.6%	5.7%	5.1%	5.1%	4.8%
Average of the Declining Dividend Actions ***	NA	(41.0%)	(34.5%)	NA	NA	NA	(79.8%)	NA	(40.6%)	NA

* 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.

2021 current year figures reflect dividend changes (raised, lowered, etc.) through 12/31/2021 and earnings and dividends through 12/31/2021 (payout ratio).

Source: S&P Global Market Intelligence and EEI Finance Department

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, 2021. 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. Companies generally use the same quarter each year for dividend changes, with Q1 the most common for electric utilities.

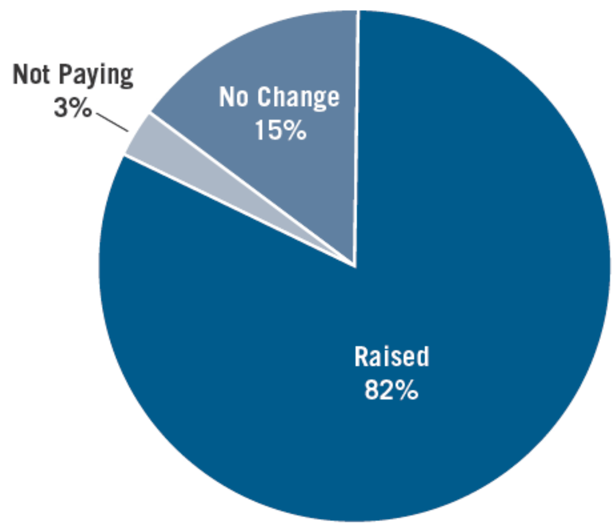
2021 Increases Average 4.8%

The average dividend increase in 2021 was 4.8%, with a range of 1.3% to 10.0% and a median increase of 5.4%. NextEra Energy (+10.0% in Q1), DTE Energy (+7.3% in Q4), WEC Energy (+7.1% in Q1) and Evergy (+7.0% in Q4) posted the largest percentage increases.

NextEra Energy, headquartered in Juno Beach, Florida, increased its quarterly dividend from $0.35 to $0.385 per share during the first quarter. The increase is consistent with its plan, announced in 2020, to target roughly 10% per year annual growth in dividends per share through at least 2022, off a 2020 base. NextEra recorded the industry's highest percentage increases in 2020 (+12.0%) and 2019 (+12.6%), 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). DTE Energy, based in Detroit, Michigan, increased its quarterly dividend from $0.825 to $0.885 per share in Q4. DTE has issued a cash dividend for more than 100 years. WEC Energy Group,

2021 Dividend Patterns

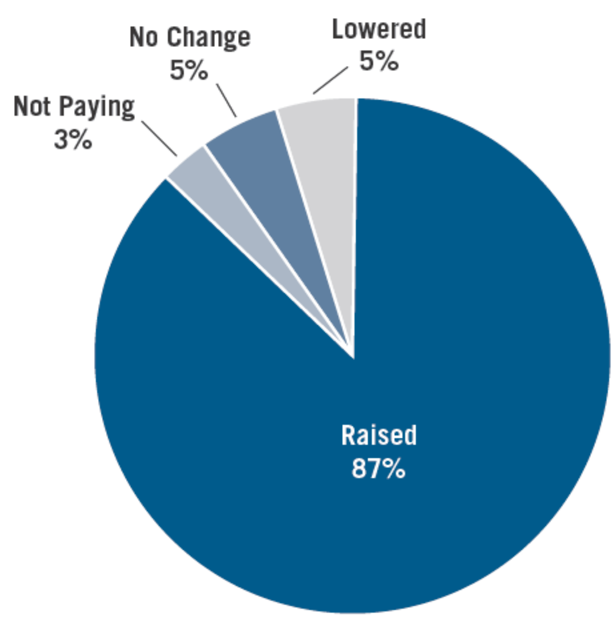
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2020 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

headquartered in Milwaukee, Wisconsin, raised its quarterly dividend from $0.6325 to $0.6775 in the first quarter. This marked its 310th consecutive quarterly dividend dating back to 1942 and its 17th straight annual increase. WEC Energy continues to target a dividend payout ratio of 65% to 70% of earnings. Evergy, based in Kansas City, Missouri, increased its quarterly dividend from $0.535 to $0.5725 in the fourth quarter.

The industry's average and median increases have been relatively consistent in recent years. The average increase was 5.1% in 2020 and 2019, 5.7% in 2018, and 5.6% in 2017 and 2016. The median increase was 5.3% in 2020, 4.9% in 2019, 5.5% in 2018 and 2017, and 5.1% in 2016.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 66.2% for the twelve months ended December 31, 2021, exceeding all other U.S. business sectors. The industry's payout ratio was 62.7% when measured as an un-weighted average of individual company ratios. From 2000 through 2020, the industry's annual payout ratio ranged from 60.4% to 69.6%.

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.

The industry's average dividend yield was 3.3% on December 31, trailing only the Energy sector's 4.2%. The year-end yield was 3.6% in 2020, 3.0% in 2019 and 3.4% in each of the three previous years. In 2021, the industry's strong dividend activity was more than offset by higher stock prices, resulting in the lower average yield. The market cap-weighted EEI Index had a total return of 17.1% in 2021.

We calculate the industry's aggregate dividend yield using an un-weighted average of the yields of EEI Index companies paying a dividend. The strong yields prevalent among

Sector Comparison
Dividend Payout Ratio
For 12-month period ending 12/31/21

Sector	Payout Ratio (%)
EEI Index Companies*	**66.2%**
Utilities	63.9%
Energy	60.8%
Consumer Staples	54.5%
Industrial	38.1%
Materials	29.2%
Health Care	26.4%
Financial	22.9%
Technology	22.7%
Consumer Discretionary	20.5%

* 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 2021E dividends and earnings per share (estimates as of 12/31/2021).

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, 2021

Sector	Dividend Yield (%)
EEI Index Companies	**3.3%**
Energy	4.2%
Utilities	2.9%
Consumer Staples	2.5%
Financial	1.7%
Materials	1.7%
Health Care	1.4%
Industrial	1.4%
Technology	0.8%
Consumer Discretionary	0.6%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2021); S&P sector yields based on 2021E cash dividends (estimates as of 12/31/2021).

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.

most electric utilities have benefitted their stock prices over the past decade, particularly given the period's historically low interest rates.

Business Category Comparison

The Regulated category's dividend payout ratio was 60.5% for the 12 months ended December 31, 2021 compared to 70.3% for the Mostly Regulated category. The Regulated group produced the highest annual payout ratio in 2020, 2017, 2015, 2011, 2010 and from 2003 through 2008.

The Regulated and Mostly Regulated average dividend yields were 3.3% and 3.0% on December 31, 2021, compared to 3.6% and 3.4% at year-end 2020 and 3.0% and 3.1% at year-end 2019. The dividend yield for both categories at year-ends 2018 and 2017 was 3.4%.

Electric Utilities' History of Strong Dividends

For more than a century, the investor-owned electric utility industry has stood out among U.S. business sectors for its steady and rising dividends. This reputation is founded on:

- A steady stream of income from a product that is universally needed with low elasticity of demand.
- A highly regulated industry that provides reasonable returns on investment with associated low business risk.
- A mature industry comprised of companies with very long track records of maintaining and/or steadily increasing their dividends over time.

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 4-5% annual earnings growth and a 3-4% dividend yield, producing highly visible and relatively stable 7-9% annualized long-term total return potential. The market's valuation of that return stream, of course, will shift with investor sentiment.

Legislative Proposals

During much of 2021, increases in capital gains and dividend tax rates for the top individual tax bracket were on the table as potential revenue sources for the Administration's "Build Back Better" plan. The House version of the bill, called the Build Back Better Act, was passed in November and did not include changes to capital gains or dividend tax rates. As 2022 started, passing a "slimmed down" version of the Build Back Better Act in the Senate remained a possibility.

The top tax rate for dividends and capital gains is currently 20%, with 2021 income thresholds of $501,600 for couples and $445,850 for individuals. For taxpayers below these

Category Comparison, Dividend Payout Ratio

Category	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
EEI Index	**64.2**	**61.5**	**60.4**	**67.0**	**62.9**	**64.0**	**63.9**	**62.6**	**65.3**	**62.7**
Regulated	62.1	60.5	59.4	68.7	61.1	68.7	60.1	62.1	65.3	60.5
Mostly Regulated	69.7	64.7	63.8	62.6	68.0	53.3	72.8	64.1	65.2	70.3
Diversified	53.4	44.7	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

*2021 figures reflect earnings and dividends through 12/31/2021.

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department

thresholds, dividends and capital gains are taxed at rates of either 15% or 0%, depending on a 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).

Low dividend tax rates support the electric utility industry's ability to attract capital for investment. Maintaining parity between dividend and capital gains tax rates is crucial to avoid a disadvantage for companies that rely on strong dividends to attract investors.

Category Comparison, Dividend Yield
As of December 31, 2021

Category	Dividend Yield
EEI Index	**3.3%**
Regulated	3.3%
Mostly Regulated	3.0%

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

Dividend Summary
As of December 31, 2021

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	$2.52	95.7%	3.8%	Raised	$2.52	$2.47	2021 Q1
Alliant Energy Corporation	LNT	R	$1.61	59.8%	2.6%	Raised	$1.61	$1.52	2021 Q1
Ameren Corporation	AEE	R	$2.20	56.8%	2.5%	Raised	$2.20	$2.06	2021 Q1
American Electric Power Company, Inc.	AEP	R	$3.12	60.8%	3.5%	Raised	$3.12	$2.96	2021 Q4
AVANGRID, Inc.	AGR	MR	$1.76	88.8%	3.5%	Raised	$1.76	$1.73	2018 Q3
Avista Corporation	AVA	R	$1.69	80.2%	4.0%	Raised	$1.69	$1.62	2021 Q1
Black Hills Corporation	BKH	R	$2.38	57.7%	3.4%	Raised	$2.38	$2.26	2021 Q4
CenterPoint Energy, Inc.	CNP	R	$0.68	NM	2.4%	Raised	$0.68	$0.64	2021 Q3
CMS Energy Corporation	CMS	R	$1.74	66.3%	2.7%	Raised	$1.74	$1.63	2021 Q1
Consolidated Edison, Inc.	ED	R	$3.10	63.0%	3.6%	Raised	$3.10	$3.06	2021 Q1
Dominion Resources, Inc.	D	R	$2.52	65.7%	3.2%	Lowered	$2.52	$3.76	2020 Q4
DTE Energy Company	DTE	MR	$3.54	57.7%	3.0%	Raised	$3.54	$3.30	2021 Q4
Duke Energy Corporation	DUK	R	$3.94	78.2%	3.8%	Raised	$3.94	$3.86	2021 Q3
Edison International	EIX	R	$2.80	41.1%	4.1%	Raised	$2.80	$2.65	2021 Q4
Entergy Corporation	ETR	R	$4.04	56.1%	3.6%	Raised	$4.04	$3.80	2021 Q4
Evergy, Inc.	EVRG	R	$2.29	55.0%	3.3%	Raised	$2.29	$2.14	2021 Q4
Eversource Energy	ES	R	$2.41	64.4%	2.6%	Raised	$2.41	$2.27	2021 Q1
Exelon Corporation	EXC	MR	$1.53	47.3%	2.6%	Raised	$1.53	$1.45	2020 Q1
FirstEnergy Corp.	FE	R	$1.56	62.4%	3.8%	Raised	$1.56	$1.52	2019 Q4
Hawaiian Electric Industries, Inc.	HE	MR	$1.36	60.1%	3.3%	Raised	$1.36	$1.32	2021 Q1
IDACORP, Inc.	IDA	R	$3.00	59.4%	2.6%	Raised	$3.00	$2.84	2021 Q4
MDU Resources Group, Inc.	MDU	MR	$0.87	45.4%	2.8%	Raised	$0.87	$0.85	2021 Q4
MGE Energy, Inc.	MGEE	R	$1.55	51.8%	1.9%	Raised	$1.55	$1.48	2021 Q3
NextEra Energy, Inc.	NEE	MR	$1.54	122.6%	1.6%	Raised	$1.54	$1.40	2021 Q1
NiSource Inc.	NI	R	$0.88	57.9%	3.2%	Raised	$0.88	$0.84	2021 Q1
NorthWestern Corporation	NWE	R	$2.48	68.8%	4.3%	Raised	$2.48	$2.40	2021 Q1
OGE Energy Corp.	OGE	R	$1.64	80.9%	4.3%	Raised	$1.64	$1.61	2021 Q3
Otter Tail Corporation	OTTR	R	$1.56	36.7%	2.2%	Raised	$1.56	$1.48	2021 Q1
PG&E Corporation	PCG	R	$-	0.0%	0.0%	Lowered	$-	$2.12	2017 Q4
Pinnacle West Capital Corporation	PNW	R	$3.40	58.1%	4.8%	Raised	$3.40	$3.32	2021 Q4
PNM Resources, Inc.	PNM	R	$1.31	49.7%	2.9%	Raised	$1.31	$1.23	2020 Q4
Portland General Electric Company	POR	R	$1.72	61.5%	3.3%	Raised	$1.72	$1.63	2021 Q2
PPL Corporation	PPL	R	$1.66	NM	5.5%	Raised	$1.66	$1.65	2020 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$2.04	45.1%	3.1%	Raised	$2.04	$1.96	2021 Q1
Sempra Energy	SRE	R	$4.40	44.0%	3.3%	Raised	$4.40	$4.18	2021 Q1
Southern Company	SO	R	$2.64	71.1%	3.8%	Raised	$2.64	$2.56	2021 Q2
Unitil Corporation	UTL	R	$1.52	65.4%	3.3%	Raised	$1.52	$1.50	2021 Q1
WEC Energy Group, Inc.	WEC	R	$2.71	64.3%	2.8%	Raised	$2.71	$2.53	2021 Q1
Xcel Energy Inc.	XEL	R	$1.83	58.5%	2.7%	Raised	$1.83	$1.72	2021 Q1
Industry Average				**62.7%**	**3.3%**				

NOTES

Business Segmentation: Based on assets as of 12/31/2020.

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 12/31/2021.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2021 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2021. 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 12/31/2021 divided by stock price at market close on 12/31/2021.

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.

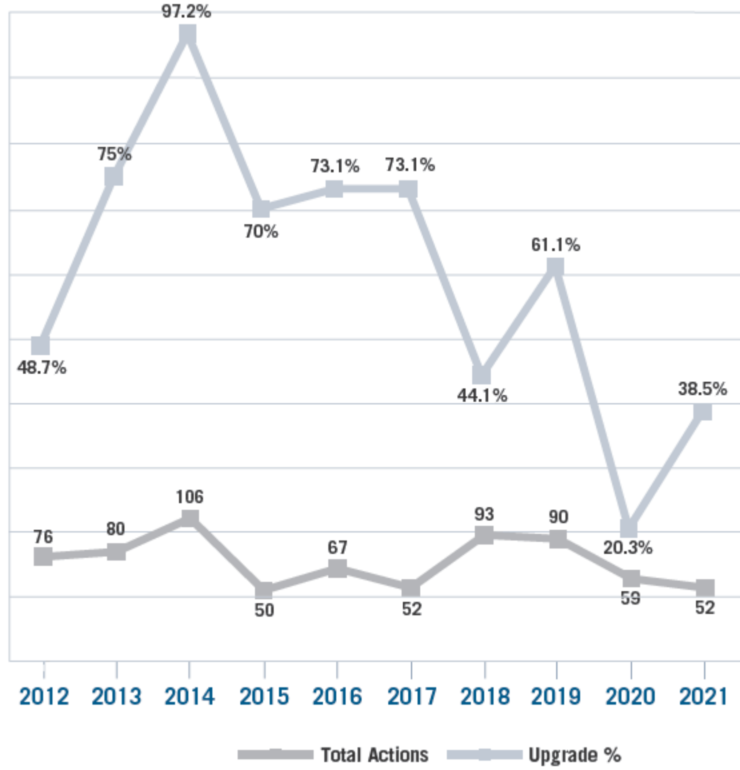
Credit Ratings

The industry's average parent company credit rating in 2021 remained at BBB+ for an eighth straight year, although three parent-level downgrades versus one upgrade caused a slight weakening in aggregate holding company credit quality. There were only 52 total actions — 20 upgrades and 32 downgrades — affecting both parents and subsidiaries. This pace was below the 73-action annual average of the previous ten calendar years and is the third-lowest annual total in our historical dataset (back to 2000).

On December 31, 2021, 68.2% of parent company ratings outlooks were "stable" and 9.1% were "positive" or "watch-positive". The 22.7% share that was "negative" or "watch negative", down from 31.8% at year-end 2020, was in line with

Direction of Rating Actions

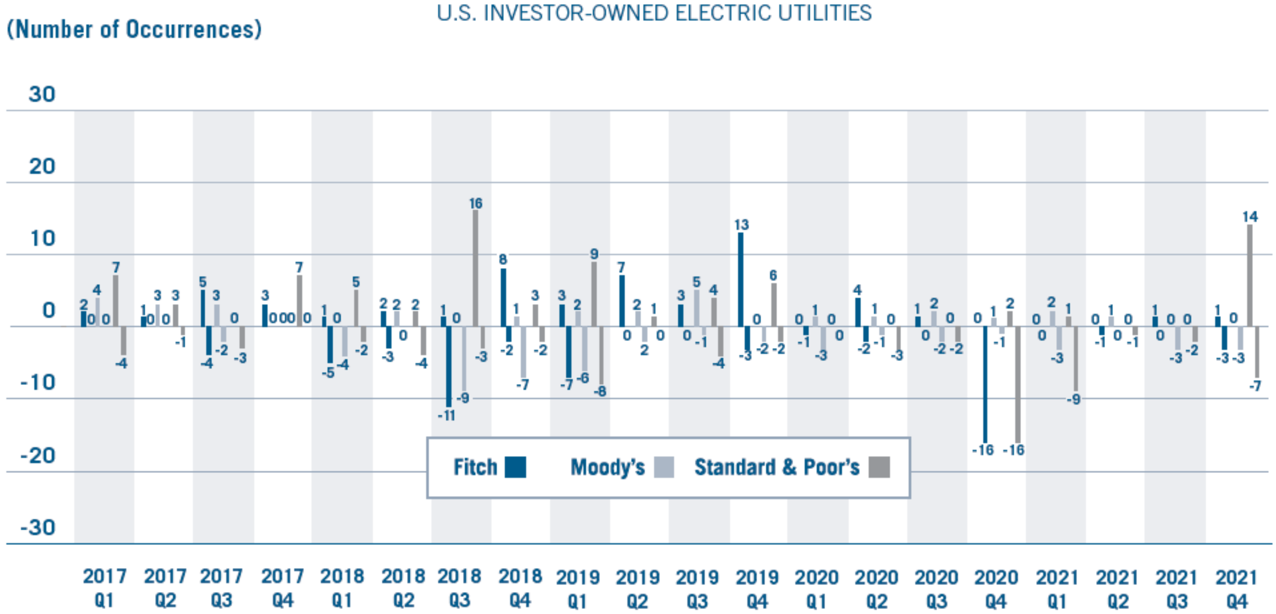
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2017 Q1–2021 Q4

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 2017 Q1–2021 Q4

	2017		2018		2019		2020		2021	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch										
Q1	2	0	1	(5)	3	(7)	0	(1)	0	0
Q2	1	0	2	(3)	7	0	4	(2)	0	(1)
Q3	5	(4)	1	(11)	3	0	1	0	1	0
Q4	3	0	8	(2)	13	(3)	0	(16)	1	(3)
Total	**11**	**(4)**	**12**	**(21)**	**26**	**(10)**	**5**	**(19)**	**2**	**(4)**
Moody's										
Q1	4	0	0	(4)	2	(6)	1	(3)	2	(3)
Q2	3	0	2	0	2	(2)	1	(1)	1	0
Q3	3	(2)	0	(9)	5	(1)	2	(2)	0	(3)
Q4	0	0	1	(7)	0	(2)	1	(1)	0	(3)
Total	**10**	**(2)**	**3**	**(20)**	**9**	**(11)**	**5**	**(7)**	**3**	**(9)**
S&P										
Q1	7	(4)	5	(2)	9	(8)	0	0	1	(9)
Q2	3	(1)	2	(4)	1	0	0	(3)	0	(1)
Q3	0	(3)	16	(3)	4	(4)	0	(2)	0	(2)
Q4	0	(1)	7	0	3	(2)	2	(16)	14	(7)
Total	**31**	**(7)**	**17**	**(8)**	**26**	**(11)**	**2**	**(21)**	**15**	**(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.

the 18.2% and 23.4% shares at year-end 2019 and 2018, respectively.

Electric utility industry credit quality generally improved over the past decade, although it experienced a slight decline, in aggregate, in each of the last three years. Aggregate parent-level credit had steadily strengthened from 2013 through 2018. Across the numerically larger universe that includes both parents and subsidiaries, the five-year period 2013 through 2017 produced the five highest upgrade percentages in our 22 years of historical data. Moreover, upgrades outnumbered downgrades in six of the past ten calendar years with an annual average upgrade percentage of 60.1% 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 S&P parent holding company ratings and outlooks. However, our upgrade/downgrade totals reflect all actions by the three major ratings agencies directed at parent holding companies as well as individual subsidiaries. Our universe of 44 U.S. parent company electric utilities at December 31, 2021 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.

The three major rating agencies remain somewhat divergent in their outlooks for 2022. S&P maintained a negative outlook, Moody's outlook remained stable and Fitch held its neutral outlook. While the agencies noted regulatory relations are broadly constructive, managing regulatory risk and financial metrics in an era of high capex and potentially rising costs were cited as key concerns.

Credit Actions at Parent Level

Parent-level ratings actions in 2021 included three downgrades and one upgrade. By comparison, there were three downgrades, one upgrade and one reinstatement in 2020, five downgrades and one upgrade in 2019, and six upgrades and two downgrades in 2018.

Duke Energy

On January 26, S&P downgraded Duke Energy to BBB+ from A- after Duke's North Carolina utilities (Duke Energy Carolinas and Duke Energy Progress) reached a rate settlement agreement where they would forgo recovery of roughly $1.1 billion in coal ash management costs.

Southern Co.

On October 27, S&P lowered Southern Co.'s issuer credit rating to BBB+ from A-, observing that construction delays and higher costs at Vogtle Units 3 and 4 indicate heightened construction risk until these nuclear generating facilities are in service. S&P also lowered the ratings of subsidiaries Alabama Power (A- from A), Georgia Power (BBB+ from A-), Mississippi Power (BBB+ from A-), and Southern Power (BBB from BBB+).

FirstEnergy

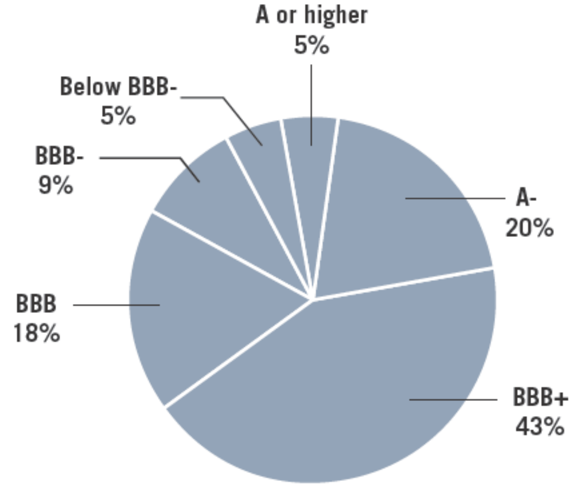
On November 8, S&P raised FirstEnergy's rating by two notches to BBB- from BB based on recent significant improvements to the company's business risk and financial measures. The higher rating incorporates the effects of FirstEnergy's proposed minority sale of FirstEnergy Transmission LLC, the issuance of common equity, and the settlement in multiple Ohio proceedings.

Pinnacle West Capital

On November 9, S&P downgraded Pinnacle West's rating to BBB+ from A due to a recent rate decision in Arizona. The downgrade reflects the Arizona Corporation Commission's final order, which included a reduced authorized ROE of 8.7% and a $119 million base rate reduction in the form of a $5 million rate decrease and denied recovery of $216 million of pollution control investments. S&P expects Pinnacle West's

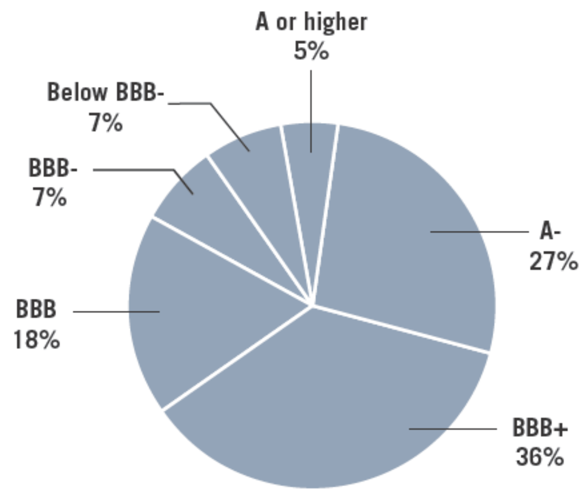
Bond Ratings December 31, 2021
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



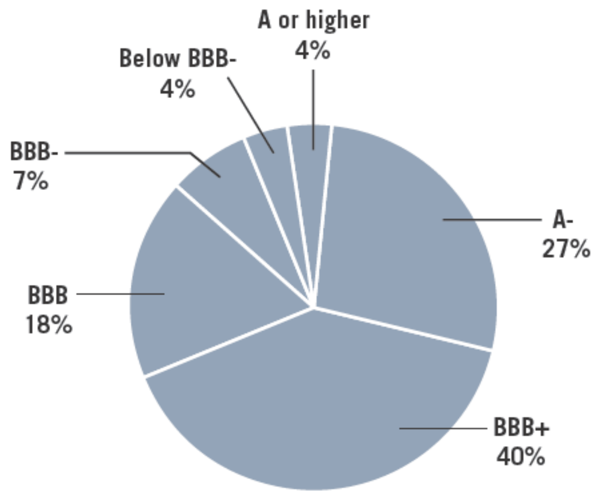
Bond Ratings December 31, 2020
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



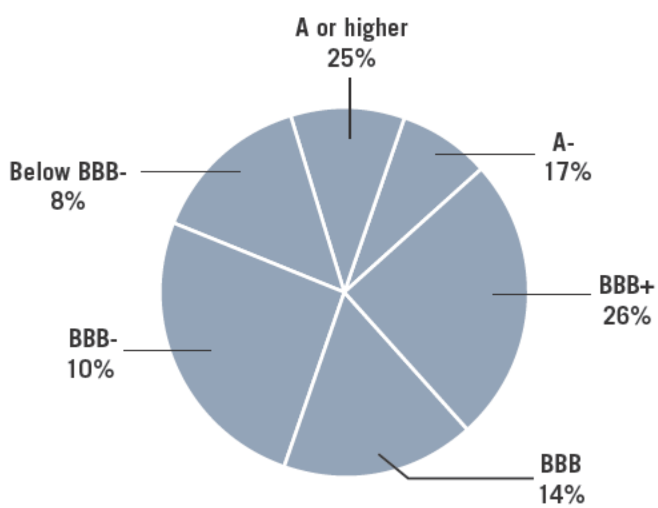
Bond Ratings December 31, 2019
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2001
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



credit metrics to suffer as a result of regulatory lag from the lower ROE and disallowance of investment and cost recovery. S&P also downgraded subsidiary Arizona Public Service to BBB+ from A-.

Ratings Activity Remained Slow in 2021

The 52 rating changes during 2021 (upgrades plus downgrades), seven fewer than in 2020, was the third-lowest total of any year back to our dataset's inception in 2000. By comparison, there were 90 actions in 2019, 93 in 2018, and an annual average of 73 over the last decade. Given the heightened activity in 2019 and 2018, a slowdown in 2020 and 2021 is not surprising.

The industry's 20 upgrades in 2021 versus 32 downgrades produced an upgrade percentage of 38.5%, up from 20.3% in 2020 but below the 61.1% result in 2019. The five-year period 2013 through 2017 produced the five-highest upgrade percentages in our historical data. Upgrades outnumbered downgrades in six of the past ten calendar years, with an annual average upgrade percentage of 60.1%.

The Credit Rating Agency Upgrades and Downgrades table on page 17 presents quarterly activity by all three ratings agencies. Following are full-year totals for 2021:

- Fitch (2 upgrades, 4 downgrades)
- Moody's (3 upgrades, 9 downgrades)
- Standard & Poor's (15 upgrades, 19 downgrades)

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Fitch	26	23	14	11	16	15	33	36	24	6
Moody's	20	17	85	12	13	12	23	20	12	12
Standard & Poor's	30	40	7	27	38	25	37	34	23	34
Total	**76**	**80**	**106**	**50**	**67**	**52**	**93**	**90**	**59**	**52**

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

Improved Metrics, Regulatory Outcomes Spur Upgrades

Most of the year's 20 upgrades were based on significant improvements to business risk and financial measures, while several were due to favorable regulatory outcomes.

Along with FirstEnergy, 13 of its subsidiaries were also upgraded on November 8 in recognition of the company's recent significant improvements to its business risk and financial measures. Twelve of those subsidiaries were increased two notches, to BBB from BB+, with Allegheny Generating Company rising one notch to BB+ from BB.

On March 17, S&P upgraded Hawaiian Electric Company (HECO), the utility operating company of Hawaiian Electric Industries (HEI), to BBB from BBB-. S&P cited the strength of HECO's financial measures and regulatory protections. On April 20, Moody's also upgraded HECO to Baa1 from Baa2, reflecting the company's considerable progress adding renewable resources to its energy supply mix and its improving regulatory relationship with the Hawaii Public Utilities Commission. Parent company HEI derives about 80% of its cash flow from operations and 75% of its operating income from HECO. HEI relies to a lesser extent on its banking subsidiary, American Savings Bank, which S&P also views as having an investment-grade credit profile.

On March 30, Moody's upgraded Sempra Energy subsidiary San Diego Gas & Electric (SDG&E) to A3 from Baa1, reflecting the agency's expectation that SDG&E will maintain robust credit metrics. The upgrade also considers SDG&E's track record of effective wildfire risk mitigation and the credit support provided by wildfire fund legislation enacted by the state of California in July 2019. Moody's said the combination of these factors has reduced SDG&E's exposure to wildfire risk, a key ESG risk consideration and an important driver of the organization's improved credit quality.

On July 26, Fitch upgraded Dominion Energy South Carolina to A- from BBB+. Fitch cited financial improvements that have occurred since Dominion Energy acquired the subsidiary in January 2019, including equity contributions, debt reductions and a recent favorable rate case outcome.

On December 23, Fitch upgraded AEP subsidiary Indiana Michigan Power Company to A- from BBB+ due to strong credit metrics and supportive regulation, including a resolution with the Indiana Utility Regulatory Commission regarding a lease termination for the utility subsidiary's Rockport power plant.

Merger activity resulted in a rating increase on January 4 when Moody's upgraded Gulf Power, a NextEra Energy subsidiary, to A1 from A2, reflecting Gulf Power's January 1, 2021 merger with affiliate Florida Power & Light Company (FPL). FPL, which has an A1 rating and stable outlook, assumed all of Gulf Power's outstanding debt obligations. Gulf Power was initially acquired by NextEra Energy in January 2019.

Weaker Metrics, Regulatory Outcomes Drive Downgrades

Weaker credit metrics were cited in the majority of 2021's downgrades. Among the underlying drivers, adverse regulatory outcomes were the most common followed by planned and/or potential divestitures of subsidiaries or business units.

On January 26, Moody's downgraded Orange & Rockland Utilities (O&R), a subsidiary of Consolidated Edison, to Baa2 from Baa1 due to a weakened financial profile and higher political and regulatory risk in New York, its primary service territory. Moody's said O&R's weakening financial profile comes at the same time that political and regulatory risks are rising. Given rising business risk and a projected cash flow to debt ratio expected to be around 15% for a sustained period, Moody's noted O&R's credit profile is better aligned with Baa2-rated peers.

On January 26, S&P lowered the rating for seven Duke Energy subsidiaries as a result of Duke's coal ash settlement, all falling to BBB+ from A-. S&P's outlook for Duke Energy and its subsidiaries is stable. On March 26, Moody's lowered its ratings for Duke Energy (to Baa2 from Baa1) and Duke Energy Carolinas (to A2 from A1), citing weaker financial metrics and the coal ash settlement agreement.

On February 25, Exelon Generation was downgraded by S&P to BBB- from BBB due to its planned spinoff by parent Exelon. The rating agency now considers Exelon Generation as nonstrategic to Exelon with resulting heightened business risk. S&P also noted that Exelon Generation's business risk profile has weakened due to declining costs for renewable power along with the advancement of energy storage technologies.

On April 8, Fitch lowered its rating for AEP Texas (AEPTX), a subsidiary of American Electric Power, to BBB from BBB+. The downgrade reflects weaker credit measures from a lower equity capitalization, lower than expected parent capital contributions, high capex, and regulatory lag associated with a fast-growing service territory.

On April 28, S&P downgraded Kentucky Power Co. (KPCo), a subsidiary of American Electric Power, to BBB+ from A-, following the parent company's announcement that it had launched a process to sell KPCo. AEP views this potential sale as a means to finance robust renewable energy investment over the next decade.

On July 20, Moody's downgraded AVANGRID's parent company rating to Baa2 from Baa1 and its subsidiaries New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RG&E) to Baa1 from A3. The downgrade of AVANGRID reflects weaker financial ratios, a higher-risk capital program through 2025, and heightened political influence and uncertainty in utility rate making in the company's two largest regulatory environments, New York and Connecticut. The downgrades of NYSEG and RG&E reflect the financial implications of their combined three-year rate plan in addition to heightened risk of political intervention in New York state's utility regulatory process.

In September, two Entergy subsidiaries were downgraded by S&P in the aftermath of Hurricane Ida. On September 2, Entergy Louisiana (ELL) was lowered to BBB+ from A- due to the severity of storm activity in its Gulf Coast service territory, which eroded its business risk profile relative to peers rated A-. After factoring in the impact of Hurricane Ida, S&P expects ELL's financial measures to weaken but remain largely credit supportive. On September 24, S&P downgraded Entergy New Orleans (ENO) to BB from BB+ based on parent company Entergy's announcement of a variety of options for ENO's future, including a sale, spinoff, or municipalization of the utility.

On October 8, Moody's downgraded Public Service Electric and Gas to A3 from A2, reflecting the agency's concern that cash flow metrics will weaken as the utility implements its robust capital investment program.

On October 12, Fitch downgraded Pinnacle West Capital (PNW) and subsidiary Arizona Public Service (APS) to BBB+ from A- in anticipation of an adverse final order in APS's pending general rate case, which Fitch said could degrade credit metrics and elevate business risk. On November 17, Moody's lowered PNW's rating to Baa1 from A3 and APS's rating to A3 from A2; both moves were based on the Arizona Corporate Commission's final order that included a lower authorized ROE.

Ratings by Company Category

The S&P Utility Credit Ratings Distribution by Company Category chart presents the distribution of credit ratings over time by company category (Regulated, Mostly

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2017 #	2017 %	2018 #	2018 %	2019 #	2019 %	2020 #	2020 %	2021 #	2021 %
Regulated										
A or higher	2	6%	1	3%	1	3%	1	3%	1	3%
A-	12	34%	11	32%	11	31%	11	32%	8	23%
BBB+	10	29%	11	32%	11	31%	10	29%	14	40%
BBB	7	20%	7	21%	8	23%	7	21%	7	20%
BBB-	4	11%	4	12%	2	6%	2	6%	3	9%
Below BBB-	0	0%	0	0%	2	6%	3	9%	2	6%
Total	35	100%	34	100%	35	100%	34	100%	35	100%
Mostly Regulated										
A or higher	1	7%	2	15%	1	10%	1	10%	1	11%
A-	2	14%	2	15%	1	10%	1	10%	1	11%
BBB+	7	50%	7	54%	7	70%	6	60%	5	56%
BBB	2	14%	1	8%	0	0%	1	10%	1	11%
BBB-	1	7%	1	8%	1	10%	1	10%	1	11%
Below BBB-0	1	7%	0	0%	0	0%	0	0%	0	0%
Total	14	100%	13	100%	10	100%	10	100%	9	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.

Regulated and Diversified) for the investor-owned electric utilities. The Diversified category was eliminated in 2017 due to its dwindling number of companies. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. At December 31, 2021, the average rating for both the Regulated and Mostly Regulated categories was BBB+.

Rating Agency Credit Outlooks

The three major ratings agencies held somewhat divergent utility industry credit outlooks as 2022 began. S&P maintained a negative outlook, Moody's outlook remained stable and Fitch retained its neutral outlook. The agencies cited the regulatory environment, rising costs and related customer bill impacts, elevated capital expenditures, success managing the clean energy transformation, and stability of financial metrics as key themes they are watching. It should be noted that the groups of underlying companies vary slightly across the three rating agency outlooks.

Standard & Poor's (S&P)

Published in late January 2022, S&P's report "Industry Top Trends 2022 – North America Regulated Utilities" maintained the agency's negative industry outlook. The report noted that downgrades outpaced upgrades in 2021 and in 2020, and many utilities continue to operate with minimal financial cushion above downgrade thresholds. Given that 20% of the industry has a negative outlook versus about 5% with a positive outlook, the agency said downgrades will likely outpace upgrades again in 2022.

The report cited the size of the clean energy transformation and management of regulatory risk as other key concerns. Acknowledging the industry's ongoing success at reducing greenhouse gas (GHG) emissions, the agency said pressure to accelerate that pace could lead to unintended con-

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.

sequences, such as operational issues from over-reliance on intermittent power, which might weaken financial measures and credit quality. The S&P report noted many utilities delayed rate case filings during the pandemic or received rate orders that were lower than expected. While the pace of rate case filings has subsequently increased, the agency said effective management of regulatory relations remains a risk. Moreover, rising interest rates, general price inflation, and higher commodity fuel prices could increase customer bills and contribute to a more challenging regulatory environment.

While limiting excess credit capacity and maintaining thin downgrade cushions works well under favorable conditions, the report said utilities risk a weakening of credit quality if unexpected risks materialize or base case assumptions deviate from expectations.

Moody's

In its "Outlook – Regulated Electric and Gas Utilities–US" (released November 2021), Moody's maintained its stable outlook. The report said the regulatory environment will likely remain supportive for rate base growth, infrastructure investment, and efforts to protect networks from extreme weather events, and that utilities will benefit from continuing U.S. economic growth. The report projects average aggregate rate base growth of about 6% in 2022. The sector's aggregate industry funds from operations (FFO) to debt ratio will range between 14% and 15% in 2022 according to the report; this is consistent with Moody's projections last year for 2021.

Moody's listed several factors that could change its outlook to positive: 1) if regulation turns more credit supportive, 2) if there is additional legislative support for certainty and visibility of cost recovery, and 3) if the sector's consolidated FFO-to-debt ratio rises to around 18% on a sustainable basis. Factors that could change its outlook to negative were: 1) a widespread and sustained decline in regulatory support for timely cost recovery, 2) a less favorable capital market environment, and 3) if availability of bank credit facilities becomes constrained. Moody's could also change its outlook to negative if aggregate FFO-to-debt appears likely to dip below 14% during 2022 and beyond, which could result from higher leverage, a slower-than-expected U.S. recovery, material load declines, high or unrecoverable bad debt expenses or the postponement of needed rate increases.

Fitch Ratings

In its "2022 Outlook: North American Utilities, Power & Gas" (released December 2021), Fitch Ratings maintained a neutral outlook for the North American utilities, power and gas sector.

Fitch believes state regulatory environments will remain broadly constructive and retail electricity sales will continue to gain strength as commercial and industrial sales reach and/or exceed pre-pandemic levels. Fitch expects overall retail electricity sales to increase between 0.5% and 1.0% in 2022, however it cited the late-2021 increase in natural gas prices as a near-term concern since fuel and purchased power costs are passed through to customers. The report said that, based on natural gas futures prices in December 2021, customer rates may experience a high-single to low-double digit percent increase over the next one to two years and current winter heating bills may rise 30% versus last year. In addition, elevated capex, recovery of storm restoration costs, and recovery of deferred coronavirus-related expenses may compound any pressure on customer bills.

Fitch noted weather-driven outages are on the increase and regulatory/political scrutiny is forcing utilities to explore further storm-hardening responses, such as undergrounding electric lines, that may require further grid-hardening investment. While broadly supported by regulators, higher capex is also resulting from rising investments in solar, onshore and offshore wind, and battery storage projects. The report noted declining O&M expenses from cost control initiatives as well as the ongoing transition to lower cost renewables should provide some offset to customer impacts.

With more than 80% of company ratings at a stable outlook, Fitch expects limited rating movement in 2022. The number of downgrades from Fitch declined in 2021 after elevated levels in the preceding three years.

Business Strategies

Business Segmentation

The industry's regulated business segments — regulated electric and natural gas distribution — grew their combined assets by $79.3 billion, or 5.1%, in 2021, extending a multi-year trend and driving a $73.4 billion, or 3.9%, increase in total industry assets. Regulated assets were 81.6% of the industry total at year-end, rising from 80.8% at year-end 2020. The Regulated Electric segment's share of total industry assets was nearly unchanged at 68.6% compared to 68.7% at year-end 2020, although the segment's total assets increased $50.6 billion, or 3.8%. The industry's other two significant business segments also grew assets in 2021. Natural Gas Distribution assets rose $28.7 billion, or 12.3%, and Competitive Generation assets rose $2.3 billion, or 1.1%. Assets for the smaller Natural Gas Pipeline segment fell by $2.6 billion, or 7.3%. A record-high $134.1 billion of capital expenditures and generally constructive regulatory relations supported the significant growth in Regulated assets.

Revenue for each primary business segment rose in 2021 as energy demand broadly rebounded from the impact of the COVID-19 pandemic. The Regulated Electric business segment's revenue increased by $20.0 billion, or 8.0%, as power demand was 2.8% higher in 2021 than in 2020. Revenue also experienced significant gains in each of the other primary business segments: Natural Gas Distribution revenue increased $8.1 billion, or 18.0%; Competitive Energy revenue increased $4.3 billion, or 10.2%; Natural Gas Pipeline revenue increased $1.3 billion, or 28.9%. As a result, total industry revenue increased $34.4 billion, or 9.8%, in 2021.

2021 Revenue by Segment

Regulated Electric revenue in 2021 increased by $20.0 billion, or 8.0%, to $271.5 billion from $251.4

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2021	2020	Difference	% Change
Regulated Electric	271,452	251,443	20,008	8.0%
Competitive Energy	46,800	42,463	4,338	10.2%
Natural Gas Distribution	53,149	45,054	8,096	18.0%
Natural Gas Pipeline	5,798	4,499	1,299	28.9%
Other	19,497	18,592	905	4.9%
Discontinued Operations	—	—	—	0.0%
Eliminations/Reconciling Items	(11,197)	(10,966)	(230)	2.1%
Total Revenues	**385,500**	**351,085**	**34,415**	**9.8%**

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)	12/31/2021	12/31/2020	Difference	% Change
Regulated Electric	1,377,457	1,326,815	50,642	3.8%
Competitive Energy	208,901	206,563	2,338	1.1%
Natural Gas Distribution	261,706	233,005	28,702	12.3%
Natural Gas Pipeline	32,691	35,283	(2,593)	-7.3%
Other	126,527	129,298	(2,772)	-2.1%
Discontinued Operations	1	1	(0)	-28.5%
Eliminations/Reconciling Items	(66,629)	(63,662)	(2,967)	4.7%
Total Assets	**1,940,653**	**1,867,303**	**73,350**	**3.9%**

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

billion in 2020. The segment's share of total industry revenue fell to 68.4% from 69.4% in 2020, but remained well above its level at the start of the industry's two-decade-long migration back to a regulated focus (Regulated Electric's share was only 51.9% in 2005).

Natural Gas Distribution revenue rose $8.1 billion, or 18.0%, to $53.1 billion from $45.1 billion in 2020. This followed 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; the sharp gains in 2016 and 2017 were due in part to the 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 — increased by $28.1 billion, or 9.5%, to $324.6 billion in 2021. The industry's focus on regulated operations has driven a steady growth in these business segments' share of industry revenue in recent years. Regulated revenue accounted for 81.8% of total industry revenue in 2021, matching its percentage in 2020 and 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 2021 and 2020.*

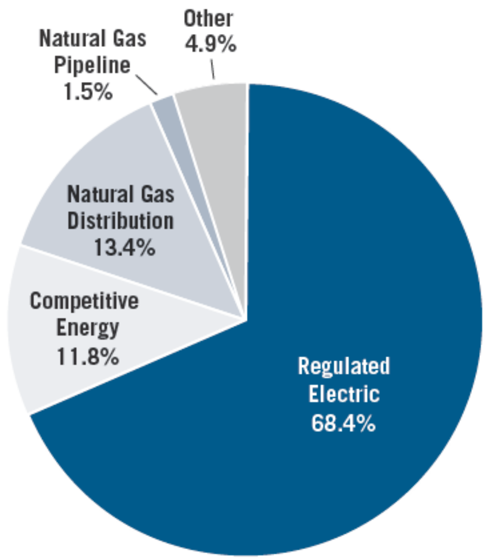
2021 Assets by Segment

Regulated Electric assets increased $50.6 billion, or 3.8%, during 2021. The segment's share of total industry assets was 68.6% at year-end, just below its 68.7% share at year-end 2020. Natural Gas Distribution assets increased by $28.7 billion, or 12.3%, while Competitive Energy assets edged up $2.3 billion, or 1.1%. The Natural Gas Pipeline segment's relatively small asset total got even smaller, declining $2.6 billion, or 7.3%, to $32.7 billion at year-end 2021 and representing just 1.6% of industry assets.

Total regulated assets (Regulated Electric and Natural Gas Distribution) grew $79.3 billion, or 5.1% in 2021, increasing its share of total industry assets to 81.6% at year-end 2021 from 80.8% at year-end 2020. This aggregate 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 19-year period. Thirty of the industry's 44 constituent companies (68.2%) either increased regulated assets as a percent of total assets or maintained a 100% regulated structure in 2021.

Revenue Breakdown 2021

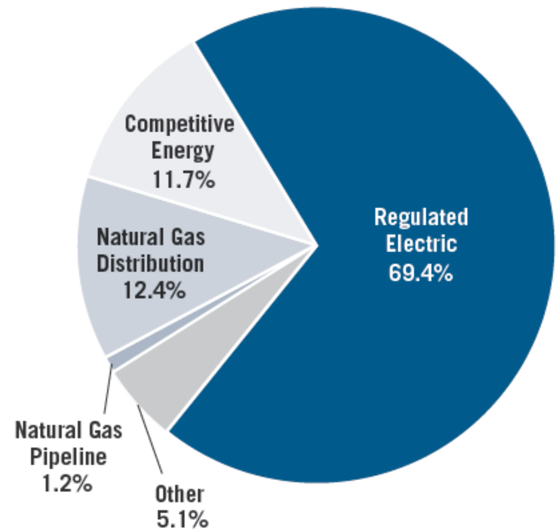
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2020

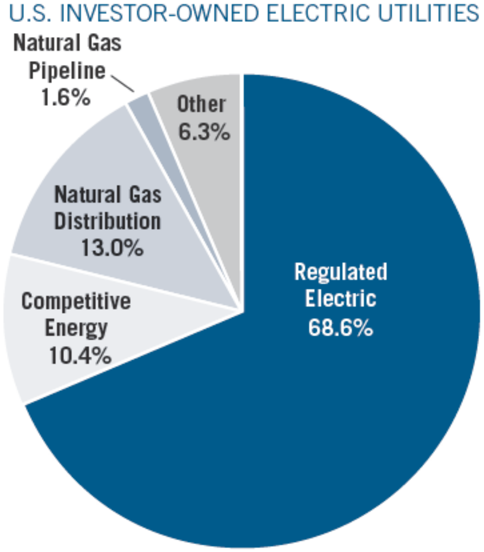
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2021

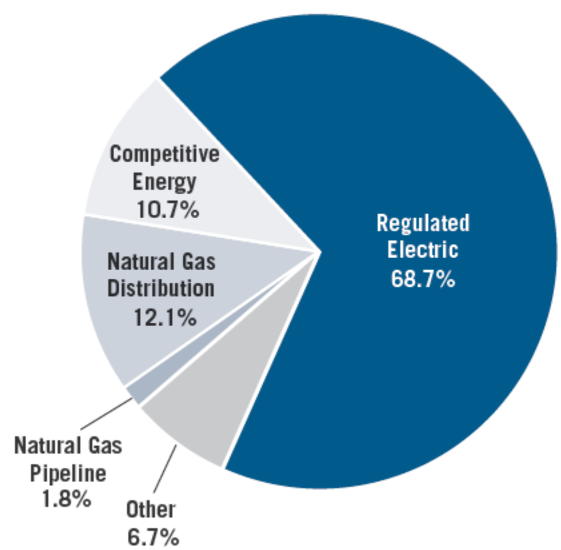
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2020

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and industrial customers. Regulated Electric revenue experienced a significant jump in 2021, rising $20.0 billion, or 8.0%. Forty-two companies, or 95% of the industry, had higher Regulated Electric revenue versus the prior year. Regulated Electric revenue fell by 0.8% in 2020 and by 0.5% in 2019, was unchanged in 2018, grew 0.8% in 2017 and declined in 2016 (-0.1%) and in 2015 (-2.6%).

Total nationwide electric output increased 2.8% in 2021, recovering from a 2.9% decline in 2020. On a weather-adjusted basis, electric output gained 2.4% in 2021. Electric output has risen in only seven of the past 14 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 $50.6 billion, or 3.8%, in 2021, marking the largest asset growth in dollar terms of all business segments. The industry's record-high $134.1 billion of capital expenditures in 2021 and generally constructive regulatory relations supported the increase in regulated assets. The 2021 capital expenditure total was the tenth consecutive annual record high, with the decade-long expansion well represented across the industry's Regulated Electric and Natural Gas Distribution segments. Asset growth is also evident in the industry's property, plant and equipment in service, which rose 4.0% from year-end 2020 and 38.5% over the level at year-end 2015. 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 $2.3 billion, or 1.1%, to $208.9 billion at year-end 2021 from $206.6 billion at year-end 2020. This followed a $9.7 billion, or 4.9%, increase in 2020. The recent growth has been driven largely by new renewable generation. Although the segment's assets are on the rise and its revenue rose $4.3 billion, or 10.2%, in 2021 to $46.8 billion from $42.5 billion in 2020, 2020's revenue was the lowest annual total in data back to 2000. The segment's recent asset growth has only returned total assets to their level a decade ago; the segment's year-end 2011 asset total was $209.4 billion, and its annual revenue peaked at $110.9 billion in 2008. 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 20 companies that maintain Competitive Energy operations, ten (50%) grew these assets during 2021 and 14 (70%) had revenue gains from this segment.

Natural Gas

Natural Gas Distribution assets rose $28.7 billion, or 12.3%, to $261.7 billion at year-end 2021 from $233.0 billion at year-end 2020. The segment's revenue rose $8.1 billion, or 18.0%, to $53.1 billion in 2021 from $45.1 in 2020, after declining 3.3% in 2020. This followed revenue growth of 4.4% in 2019, 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016, gains that were supported by four large gas acquisitions completed in 2016. All 26 companies that report gas distribution revenue showed a year-to-year increase in 2021 while only 26% did so in 2020. This followed increases at 70%, 86% and 93% of reporting companies in 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 $2.6 billion, or 7.3%, to $32.7 billion at year-end 2021 from $35.3 billion at year-end 2020. Five of the six companies that report this segment showed asset declines. Despite lower assets, higher natural gas prices enabled the segment's revenues to increase by $1.3 billion, or 28.9%, to $5.8 billion in 2021 from $4.5 billion in 2020. 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 increased assets by $26.1 billion, or 9.7%, in 2021 and produced revenue of $58.9 billion, up from $49.6 billion in 2020. In percentage terms, the contribution to total industry revenue from these two natural gas activities increased to 14.9% in 2021 from 13.6% in 2020.

Strategic Moves Completed in 2021

Several companies completed strategic transactions in 2021 that notably affected their business segmentation reporting.

- CenterPoint Energy closed the sale of its Arkansas and Oklahoma natural gas LDC assets to Summit Utilities for $2.15 billion in cash.
- CMS Energy completed the sale of its wholly owned subsidiary, EnerBank USA, to Regions Bank, a subsidiary of Regions Financial. CMS said the sale simplifies its investment thesis through a pure focus on energy, improves its risk profile, and helps finance its clean energy transformation. Estimated proceeds from the transaction were approximately $1 billion and will be used to fund key initiatives in CMS' core utility businesses.
- PPL completed the sale of its U.K. utility business, Western Power Distribution (WPD), to National Grid for £7.8 billion, concluding the first of two strategic transactions announced in March 2021. PPL's second transaction is its planned acquisition of Rhode Island's Narragansett Electric from National Grid for approximately $3.8 billion. PPL said the sale and purchase will simplify its business mix, strengthen credit metrics, and improve prospects for long-term earnings growth through investment in sustainable energy solutions.
- DTE Energy completed the spin-off of its non-utility natural gas pipeline, storage and gathering business, DT Midstream. DTE said the transaction transforms the company into a predominantly pure-play electric and natural gas utility, where approximately 90% of DTE Energy's operating earnings and investments focus on utility operations.

Strategic Announcements in 2021

In addition to 2021's completed transactions, several announcements were made that, if completed, will impact business segment reporting in 2022 and beyond.

- OGE Energy announced it would exit its midstream investment in Enable Midstream Partners and become a pure-play electric utility.
- Public Service Enterprise Group (PSE&G) announced it would sell its fossil fleet as it transitions to a 100% clean energy company.
- Duke Energy agreed to sell a 20% stake in subsidiary Duke Energy Indiana, which emphasizes coal and gas generation, to Singapore's sovereign wealth fund for $2 billion. Duke said the move would eliminate the need for an equity offering and help accelerate its regulated, clean energy rate base growth.
- Exelon announced plans for a tax-free separation of its regulated utilities and its competitive generating business into two independent companies. Exelon said the move would give each company better flexibility to focus on its core strategy and better address customer and shareholder goals.
- American Electric Power announced the sale of its Kentucky operations, which include Kentucky Power and AEP Kentucky Transco, to Liberty Utilities, a regulated utility subsidiary of parent company Algonquin Power & Utilities, for $2.846 billion enterprise value. The sale is expected to close in 2022, pending regulatory approvals.
- Con Edison announced it would divest Stagecoach Gas Services, a natural gas pipeline and storage subsidiary, to Kinder Morgan for $1.225 billion. Con Edison said the sale is consistent with its strategy to deliver the clean energy future customers expect.

2021 Year-End List of Companies by Category

Early each calendar year, we update 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 10-Ks. 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).

List of Companies by Category at December 31, 2021

Regulated (36)

- 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
- FirstEnergy Corp.
- IDACORP, Inc.
- _IPALCO Enterprises, Inc.*_
- NiSource Inc.
- NorthWestern Corporation
- MGE Energy, Inc.
- OGE Energy Corp.
- Otter Tail Corporation
- PG&E Corporation
- Pinnacle West Capital Corporation
- PNM Resources, Inc.
- Portland General Electric Company
- PPL Corporation
- _Puget Energy, Inc.*_
- Sempra Energy
- Southern Company
- Unitil Corporation
- WEC Energy Group, Inc.
- Xcel Energy Inc.

Mostly Regulated (8)

- ALLETE, Inc.
- AVANGRID, Inc.
- _Berkshire Hathaway Energy*_
- Exelon Corporation
- Hawaiian Electric Industries, Inc.
- MDU Resources Group, Inc.
- NextEra Energy, Inc.
- Public Service Enterprise Group Incorporated

Note:* Non-publicly traded companies.

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.

The only change in 2021 was DTE Energy's move from the Mostly Regulated to the Regulated category. DTE's regulated asset percentage rose above 80% due to the spin-off of its midstream natural gas pipeline, storage and gathering business. The transaction was completed on July 1, 2021. This lone migration increased the number of Regulated companies to 36 from 35 and reduced the Mostly Regulated group to eight companies from nine. The number of parent companies in the EEI universe remained at 44, the same as the year-end 2020 total. (*See List of Companies by Category on December 31, 2021*).

Mergers & Acquisitions

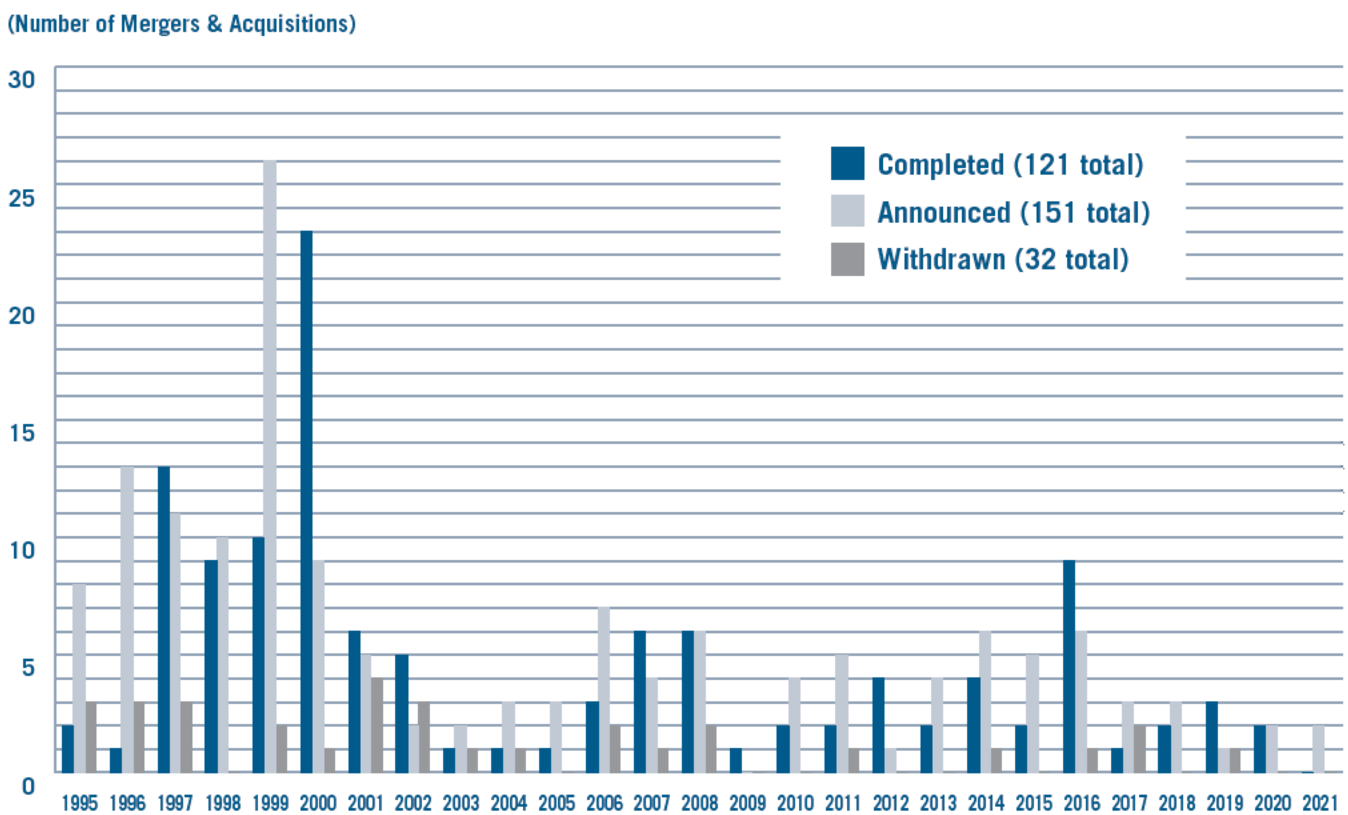
M&A activity involving whole U.S. utility operating companies with regulated service territories remained relatively low in 2021. There were two proposed whole company deals: 1) PPL's offer to buy Rhode Island regulated utility Narragansett Electric from National Grid USA (a subsidiary of the British utility holding company National Grid plc) and 2) Canadian utility Algonquin Power's move to buy regulated utility Kentucky Power from AEP. But 2021 was quite active if M&A activity is framed a bit more broadly.

The year produced several partial sales and restructurings that showcased key industry themes. Duke Energy sold a 19.9% stake in subsidiary Duke Indiana to Singapore's sovereign wealth fund. Exelon announced the split of its regulated and competitive operations into two separate companies. CenterPoint sold its Arkansas and Oklahoma LDC natural gas assets to Summit Utilities. Public Service Enterprise Group (PSEG) sold its fossil generation portfolio to private equity investor ArcLight Capital, which also bought a fossil portfolio from NRG Energy. And FirstEnergy sold a 19.9% stake in its transmission assets to private infrastructure investor Brookfield.

Duke, PPL, PSEG, AEP and FirstEnergy all cited the chance to finance their build-outs of regulated clean energy investment as a key rationale for their moves. The private buyers in turn noted strong and steady returns from regulated utility infrastructure or the ability to own productive fossil assets without the cash flow and ESG pressures associated with public ownership. Exelon's split reflected long-term challenges with low power prices in competitive markets and capital markets' preference for lower-risk regulated business strategies. All ac-

Status of Mergers & Acquisitions 1995–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

tions broadly illustrate the primary trend in the industry: the ongoing focus by most utilities on earnings growth through building and operating the state-regulated clean energy infrastructure needed for the nation's clean energy transition.

Finally, the December 2021 rejection by New Mexico state regulators of AVANGRID's proposed acquisition of PNM was a reminder that regulatory oversight of utility M&A can present a difficult path to success.

Status of Announced Mergers & Acquisitions 1995–2021

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	–
Totals	**121**	**151**	**32**

Source: EEI Finance Department.

Announced Transactions

Duke Energy sells Stake in Indiana Utility

On January 28, Duke Energy announced plans to sell a 19.9% stake in regulated subsidiary Duke Energy Indiana (DEI) to an affiliate of GIC Private Limited, Singapore's sovereign wealth fund and an experienced investor in U.S. infrastructure. Duke said the $2.05 billion purchase price represented a significant premium to its public equity valuation and said proceeds would allow it to forego plans to raise $1 billion of common equity as it accelerates its clean energy investments in its portfolio of regulated utilities. With the announcement, Duke raised its projected five-year capex from $58 billion to $60 billion and boosted long-term earnings growth guidance to a range of 5% to 7% from a previous range of 4% to 6%.

Duke, which called GIC a long-term investor in DEI, said it would continue to operate the Indiana utility as majority owner with work force intact. GIC said companies focused on meaningful sustainability practices deliver superior risk-adjusted long-term returns and cited Duke's proven management team and commitment to a clean energy transition as motivations for its investment, which it said supports Duke's ESG and decarbonization goals. In 2016, GIC acquired a 19.9% stake in independent electric transmission company ITC Holdings.

The first of the two-phase sale closed in September when Duke received $1.025 billion. The second phase was expected to close in early 2022.

Duke Energy provides regulated electric service to 7.8 million customers in North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky. It distributes natural gas to 1.6 million customers in North Carolina, South Carolina, Tennessee, Ohio and Kentucky. The Duke Energy Renewables unit operates wind and solar generation facilities across the U.S. as well as energy storage and microgrid projects.

Exelon Separates Regulated and Competitive Businesses

On February 24, Exelon announced a plan to separate its six regulated and gas utilities (RemainCo) from its competitive power generation and customer-facing energy businesses (SpinCo), creating two publicly traded companies. Exelon said the separation gives each company the financial and strategic independence to focus on its specific customer needs while executing its core business strategy.

RemainCo will continue as parent company for Exelon's fully regulated transmission and distribution utilities, which deliver electricity and natural gas to more than 10 million customers across five states and the District of Columbia. SpinCo will be the nation's largest supplier of clean energy with more than 31,000 megawatts of generating capacity consisting of nuclear, wind, solar, natural gas and hydro assets. SpinCo will produce about 12 percent of the nation's carbon-free energy.

Exelon shareholders retained their shares of Exelon stock and received a pro-rata dividend of shares of SpinCo. After the transaction closed on February 2, 2022, the regulated company retained the familiar EXC stock symbol while the competitive operations, named Constellation Energy Corp., began trading under the symbol CEG.

Exelon noted the regulatory business is a high-quality utility asset with strong earnings growth of 6% to 8% annually and a diversified rate base across seven jurisdictions with constructive regulation. Exelon said the combination of strong operations and attractive ESG attributes provides a platform that supports transition to a clean energy economy without owning generation. The competitive business operates 18.7 gigawatts of nuclear generation and 12.3 gigawatts of natural gas, hydro, solar and wind energy. Constellation Energy also includes a retail business with a strong share of commercial and industrial energy customers in the nation's competitive energy markets.

PPL Sells U.K. Business and Bids for Rhode Island Utility

Pennsylvania-based PPL Corporation announced in August 2020 it would seek to sell its U.K. utility distribution business, Western Power Distribution (WPD), and become a U.S. utility holding company focused on advancing the nation's clean energy goals with rate-regulated assets. That plan materialized on March 18, 2021, when PPL announced an agreement to sell its U.K. utility business, Western Power Distribution (WPD), to National Grid plc for £7.8 billion and, in a separate transaction, acquire National Grid's Rhode Island regulated utility business, The Narragansett Electric Company (NEC), for $3.8 billion. PPL said the strategic repositioning will refocus its strategy on strong, rate-regulated U.S. utilities, strengthen credit metrics and enhance long-term earnings growth and earnings predictability.

The agreement calls for PPL to sell WPD to National Grid in an all-cash transaction valued at £14.4 billion, including assumption of £6.6 billion of debt, for net cash proceeds of approximately $10.2 billion. Separately, PPL plans to acquire Narragansett Electric from National Grid in a transaction valued at $5.3 billion, including the assumption of approximately $1.5 billion of Narragansett Electric debt. PPL said it plans to use a portion of the proceeds from the sale of WPD to finance the acquisition. PPL also highlighted its plan to play a key role in advancing Rhode Island's decarbonization goals, noting its experience automating electricity networks can help the state achieve its target of 100% renewable energy by 2030.

PPL said net cash proceeds from the WPD sale will strengthen its balance sheet and enhance opportunities for strategic investment at its other utilities, in renewables or in share repurchases. On June 14, 2021, PPL announced it completed the sale of WPD to National Grid. It hopes to close the Narragansett purchase in the first half of 2022.

When both transactions are complete, PPL said it will serve approximately 3.5 million electricity and gas customers across diverse, constructive regulatory jurisdictions in the U.S. with rate base of approximately $22 billion, mostly in the form of electricity and gas T&D assets.

Merger Impacts 1995–2021

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	–

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.

CenterPoint Energy Sells Gas LDCs

In December 2020, CenterPoint Energy said it would seek to sell its Arkansas and Oklahoma natural gas distribution utilities to finance regulated electric system capex, including new solar and wind generation, without issuing new equity. It announced a sale on April 29, 2021 to Summit Utilities for $2.15 billion in cash, including recovery of approximately $425 million in unrecovered storm-related expenses. The assets include approximately 17,000 miles of main pipeline in Arkansas, Oklahoma, and Texarkana, TX serving more than half a million customers.

The proceeds represented a 2.5x multiple of 2020 rate base and a 38.0x multiple of 2020 earnings; industry observers noted the strong sale price was a vote of confidence in natural gas LDC assets, which had been shadowed by politicized anti-gas sentiments and concern about terminal values. CenterPoint, which retained other LDC assets, said the sale demonstrates its ability to efficiently recycle capital across its utility footprint — in this case selling assets at 2.5x rate base and building new rate base at the implied multiple of 1.0x. With the announcement, CenterPoint affirmed its goals of 6% to 8% annualized utility earnings per share growth and 10% annualized rate base growth. The transaction was completed on January 10, 2022.

The only investor-owned electric and gas utility based in Texas, CenterPoint Energy, Inc. (NYSE: CNP) is an energy delivery company with electric transmission and distribution, power generation and natural gas distribution operations that, after the closing of the Arkansas/Oklahoma transaction, serve nearly seven million metered customers in Indiana, Louisiana, Minnesota, Mississippi, Ohio and Texas.

PSEG Divests Fossil Portfolio

On July 31, 2020, Public Service Enterprise Group (PSEG) announced it would explore strategic alternatives for PSEG Power's non-nuclear generating fleet, which includes more than 6,750 megawatts of fossil generation and a 467-megawatt merchant solar portfolio. It said the move would accelerate its transformation into a primarily regulated electric and gas utility, reduce business risk and earnings volatility, improve its credit profile and enhance its ESG position through clean energy investments, methane reduction and zero-carbon generation.

On August 12, 2021, PSEG announced it would sell the fossil portfolio — which consists of 13 generating units in Maryland, New Jersey, New York and Connecticut — to ArcLight Energy Partners, a private equity fund controlled by Boston-based ArcLight Capital Partners, for approximately $1.92 billion. PSEG affirmed the move enhances its ESG profile and advances its strategy to prepare for a low-carbon future. With the sale, PSEG also said it accelerated its net-zero climate vision from 2050 to 2030.

PSEG completed the sale of its solar portfolio to Quattro Solar LLC, an affiliate of LS Power, in June 2021 and finalized the sale of its fossil portfolio in February 2022. PSEG said its business is now 90% regulated. The company noted it continues to advocate for the viability of its carbon-free 3,700-megawatt nuclear generation fleet, while also exploring investments in regional offshore wind.

PSEG is a diversified energy company whose operating businesses include Public Service Electric and Gas (PSE&G), New Jersey's largest provider of electric and natural gas service, and PSEG Long Island, which operates the electric transmission and distribution system of the Long Island Power Authority. PSEG Power owns and operates a diverse fleet of power plants located primarily in the Mid-Atlantic and Northeast regions and has solar energy facilities throughout the United States.

AEP to Sell Kentucky Power

AEP announced in April 2021 that it was conducting a strategic review of its Kentucky operations. On October 26, 2021 the company announced a sale, which included Kentucky Power and AEP Kentucky Transco, to Liberty Utilities, a regulated subsidiary of Canadian utility holding company Algonquin Power & Utilities. AEP said the sale is expected to close in the second quarter of 2022, pending regulatory approvals. It plans to use the expected $1.45 billion cash proceeds to eliminate equity needs in 2022 as it boosts investment in regulated renewable energy infrastructure. Kentucky Power owns 1,075 megawatts of generation including a 295-megawatt natural gas plant in Kentucky and 50% of the 1,560-megawatt coal-fired Mitchell Plant in Moundsville, West Virginia, which it operates.

Ontario-based Algonquin said acquisition of Kentucky Power and Kentucky TransCo adds to its regulated footprint in the United States and said it expects to replace Kentucky Power's fossil fuel generation with renewable generation. Algonquin noted it has experience "greening" fleets of regulated fossil fuel generation. In 2017, it completed the acquisition of The Empire District Electric Company and recently completed a $1.1 billion investment in 600 MW of wind generation to support Empire's service territory. AEP plans to grow its renewable generation portfolio to approximately 50% of total capacity by 2030. AEP noted it's on track to achieve an 80% reduction in carbon dioxide emissions from 2000 levels by 2030 and has committed to achieve net zero by 2050.

FirstEnergy Sells Stake in Transmission Business

News reports in the summer of 2021 said FirstEnergy was looking to sell a stake in its FirstEnergy Transmission subsidiary. On November 7, the company said it reached agreement with private equity investor Brookfield Super-Core Infrastructure Partners to sell a 19.9% stake in FET, the holding company for FirstEnergy's three regulated transmission subsidiaries, for $2.4 billion. FirstEnergy said the price represented an attractive electric utility valuation of 40 times trailing twelve-month earnings. On the same day, FirstEnergy announced that Blackstone Infrastructure

Mergers & Acquisitions Announcements Updated through December 31, 2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Complet-ed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
10/26/21	Algonquin Power & Utilities Corp	Kentucky Power Company & AEP Kentucky Transmission Company Inc	Pending				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	Pending				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	Pending				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		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)	12,337.0
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	43,882.0
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)	272.5
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

Partners would make a $1 billion equity investment at $39.08 per share to support FirstEnergy's smart grid and clean energy transition initiatives. With these simultaneous announcements, FE also announced a $2.2 billion increase to its capital investment plan through 2025, which now totals $17 billion from 2021 to 2025 including $10 billion in sustainable energy investments.

FirstEnergy said the two transactions will enhance its credit profile, fund strategic capital expenditures and address its equity capital needs. FirstEnergy said the initiatives will also support a more resilient grid and drive its transition to a low-carbon future; the company hopes to achieve carbon neutrality by 2050, with an interim 30% reduction in greenhouse gas emissions under the company's direct control by 2030, from a 2019 base. Brookfield said FET is well-positioned to capture significant capital investment opportunities driven by grid modernization, decarbonization and general electrification of the economy. FET owns and operates one of the largest transmission systems in PJM.

With the deal announcements, FE affirmed a 6-8% long-term growth rate along with the expanded investment plan. FirstEnergy's 10 regulated distribution companies form one of the nation's largest investor-owned electric systems, serving six million customers in the Midwest and Mid-Atlantic regions from the Ohio-Indiana border to the New Jersey shore,

New Mexico Regulators Block AVANGRID/PNM Merger

One of the 2020 announcements on EEI's list of whole company deals was AVANGRID's offer to acquire PNM Resources. AVANGRID said the transaction would support its U.S. growth strategy focused on regulated businesses and renewables in states with legal and regulatory stability and predictability. PNM, which operates regulated utilities in Texas and New Mexico, called the move a strategic fit that will 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. News reports cited concern about reliability, potential rate increases and slower development of renewable resources by PNM as reasons for the decision. Reports also noted nearly all intervening customers and clean energy advocates supported the merger, and that the PRC staff had said they would not oppose it. AVANGRID expressed disappointment with the decision but said it will evaluate next steps and hoped the merger could eventually succeed.

As 2022 began, most utilities seemed focused on organic growth opportunities and M&A was not high on most lists of shareholder value strategies. Yet industry analysts noted potential drivers that may prompt future deals. Load growth is uneven across the nation and smaller utilities operating in slow-growth territories may use M&A for potential cost savings and synergies with stronger parents; that may be particularly true for those facing heavy capex needs to fund clean energy development. Acquirers may seek utilities with fossil generation and constructive state regulators who would support greening the portfolio with regulated rate base. Vast global pools of private capital, whether infrastructure funds or sovereign wealth funds, will continue to view steady returns from utility infrastructure as attractive in a world with pervasive low bond yields. Productive fossil generation assets, whether coal or gas, do not present to private buyers the same strategic ESG and volatile cash flow concerns that public companies face. It is not possible to predict specifics, but it seems likely sporadic M&A deal flow will continue.

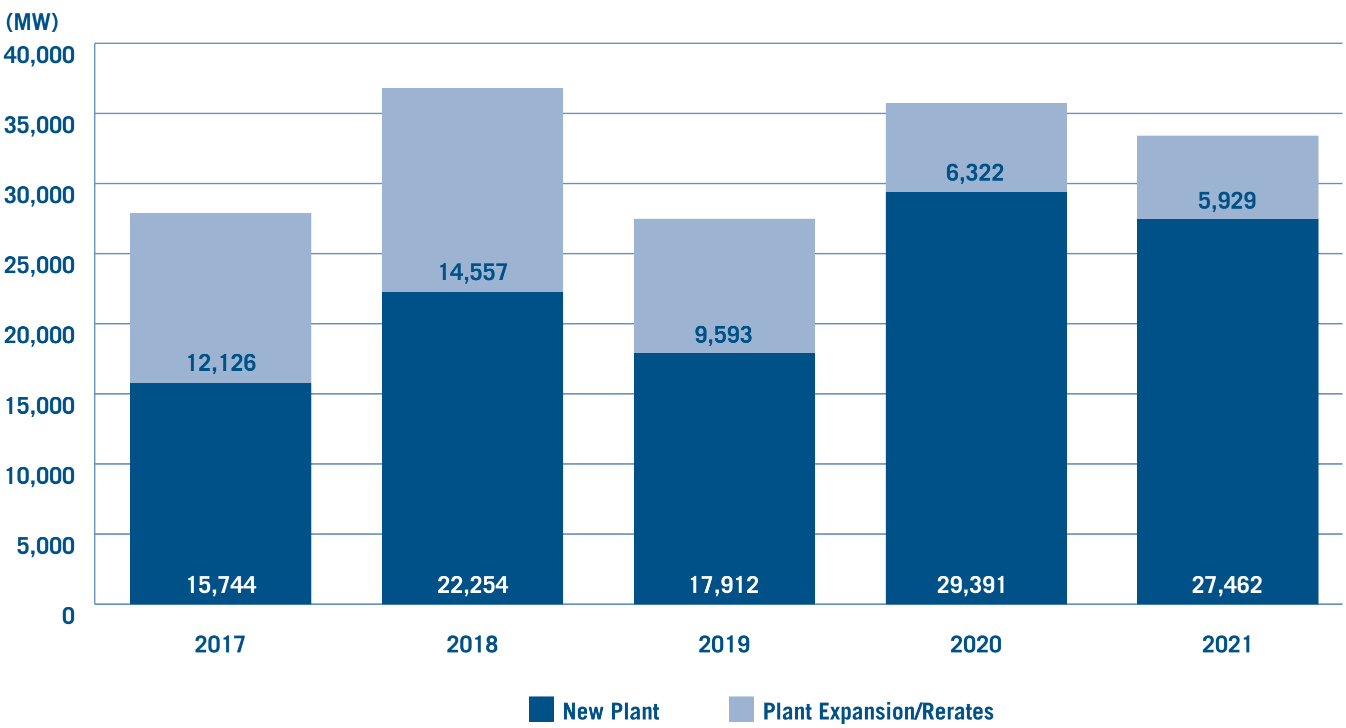
Construction

The electric utility industry brought 33,391 MW of new capacity online in 2021, 7% less than 2020's 35,714 MW but 21% more than the 27,505 MW of 2019. The decline from 2020 to 2021 was due to reductions in both new natural gas and wind capacity. New natural gas capacity declined from 7,892 MW in 2020 to 6,448 MW in 2021, extending a trend of annual declines that began with 2018. Supply chain issues plagued wind and solar projects in 2021, causing many to be delayed. As a result, new wind capacity brought online decreased from 16,359 MW in 2020 to 11,957 MW in 2021, marking wind's first annual decline since 2017. Despite supply chain challenges, solar capacity installation increased 35%, from 10,984 MW in 2020 to 14,845 MW in 2021.

New plants comprised 82% of 2021's total new capacity. Expansions and rerates accounted for the remaining 18%. The ratio of new plants to expansions was essentially unchanged from 2020.

Renewables continued to lead capacity additions, accounting for 80% of new capacity in 2021 versus 77% in 2020 even though supply chain challenges pushed some of 2021's scheduled projects into 2022. Supported by continually declining costs, wind and solar have powered more than half of new capacity each year since 2019. Solar led new capacity additions in 2021, accounting for 14,845 MW or 44% of the total across all fuels. Wind was second, with 11,957 MW or 36%. Investor-owned utilities that brought the most new renewable capacity online were NextEra Energy (2,126 MW of wind, 1,606 MW of solar), Duke Energy (534 MW of wind, 483 MW of solar), American Electric Power (488 MW of wind, 127 MW of solar), Southern Company (418

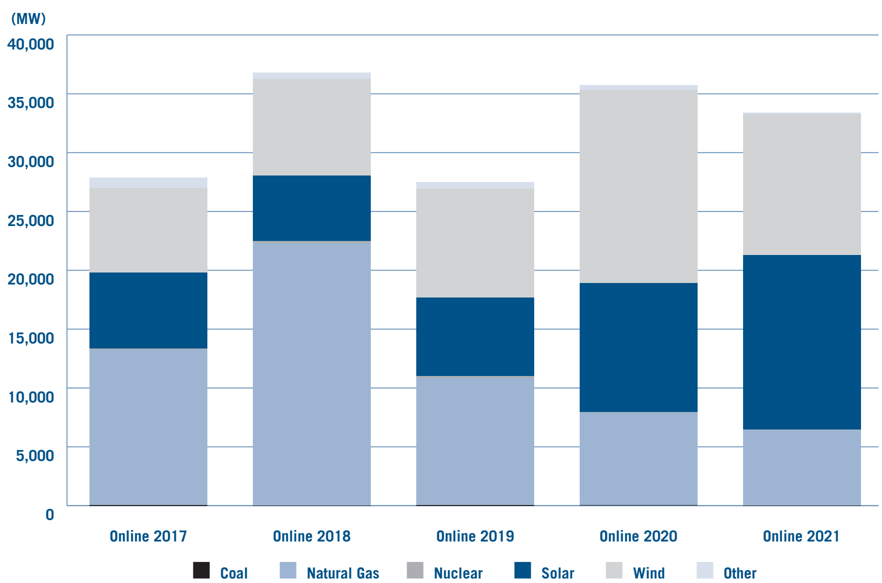
New Capacity Online 2017–2021



Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Totals may reflect rounding.

Source: Velocity Suite, Hitachi Energy, March 2022

New Capacity Online by Fuel Type 2017–2021



Fuel Type	2017	2018	2019	2020	2021
Coal	45	10	62	30	11
Natural Gas	13,194	22,282	10,773	7,892	6,448
Nuclear	102	192	175	20	0
Solar	6,467	5,570	6,683	10,984	14,845
Wind	7,190	8,187	9,240	16,359	11,957
Other	872	569	572	428	130
Total	**27,871**	**36,811**	**27,505**	**35,714**	**33,391**

Note: Includes all new capacity placed on the grid by 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, wood, and energy storage. Totals may reflect rounding.

Source: Velocity Suite, Hitachi Energy, March 2022

MW of wind, 139 MW of solar), Ameren (496 MW of wind), DTE Energy (459 MW of wind), ConEd (437 MW of solar), AES (376 MW of solar), NiSource (302 MW of wind), and Xcel Energy (200 MW of wind).

Natural gas accounted for nearly all the remaining new capacity added in 2021, totaling 6,448 MW or 19% of the total. Combined cycle accounted for 44% compared with 76% in 2020. Combustion turbine technology powered 56%. New plants represented 62% of total new gas capacity, expansions accounted for 34% and the remaining 4% were rerates. NextEra Energy led natural gas additions with 950 MW in gas plant expansions (940 MW gas turbine, 10 MW combined cycle), followed by TECO Energy, whose gas turbine expansions totaled 796 MW. Third was Otter Tail Power with 349 MW of new build gas turbine capacity.

New Capacity Online by Region

The Reliability First Corporation (RFC) region had the largest year-to-year percentage increase in new capacity, 120% higher than in 2020. Increases in natural gas (1,008 MW to 2,775 MW), solar (645 MW to 1,139 MW), and wind capacity (990 MW to 1,885 MW) all contributed to the gain. The Electric Reliability Council of Texas (ERCOT) had the second-largest year-to-year percentage growth, at 43%, with capacity gains for both gas (290 MW to 1,208 MW) and solar (2,102 MW to 4,130 MW); wind decreased from 3,481 MW in 2020 to 3,054 MW in 2021. The Alaska Systems Coordinating Council (ASCC) was the only other region with an increase in new capacity compared to 2020, up 21% from 6.7 MW to 8.1 MW. The Hawaiian Coordinating Council (HCC) saw the largest percentage decrease in new capacity added, down 71% due to a decline in new solar additions (17 MW compared to 32 MW in 2020) and no new wind additions. The Midwest Reliability Organization (MRO) had the largest absolute decrease in new capacity added, from 5,039 MW in 2020 to 2,693 MW in 2021, producing a drop of 47%. The decline resulted from reduced additions of gas (700 MW to 505 MW) and wind (3,995 MW to 1,761 MW); these were partly offset by an increase in solar installations (298 MW to 408 MW). New capacity additions in the Western Electricity Coordinating Council (WECC) region also declined more than 2,000 MW, dropping 28% from 8,111 MW in 2020 to 5,831 in 2021. That decline was led by lower gas (1,592 MW to 63 MW) and wind (3,643 MW to 1,917 MW) and was partially offset by an increase in solar capacity (2,680 MW to 3,799 MW).

New Capacity Online by Region (MW) 2017–2021

Region	Online 2017	Online 2018	Online 2019	Online 2020	Online 2021
ASCC	116	1	33	7	8
HCC	61	135	187	60	17
MRO	1,976	3,298	3,297	5,039	2,693
NPCC	682	3,294	2,156	1,647	1,096
RFC	5,484	12,023	4,026	2,656	5,843
SERC	6,507	9,582	7,282	8,938	7,146
SPP	3,233	1,906	1,118	3,370	2,354
TRE	6,537	2,950	5,277	5,888	8,402
WECC	3,274	3,622	4,130	8,111	5,831
Total	**27,871**	**36,811**	**27,505**	**35,714**	**33,391**

Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: Velocity Suite, Hitachi Energy, March 2022

Announced New Capacity by Region and Fuel Type in 2021 (MW)

Fuel Type	Electric Reliability Council of Texas	Hawaiian Coordinating Council	Midwest Reliability Organization	Northeast Power Coordinating Council	Reliability First	SERC Reliability Corp	Southeast Power Pool Inc.	Western Electricity Coordinating Council	Total
Coal	—	—	—	—	—	—	—	—	—
Natural Gas	8	—	635	17	913	1,296	—	190	3,060
Nuclear	—	—	—	22	—	—	—	—	22
Wind	665	—	1,652	1,230	2,100	994	870	1,158	8,668
Solar	1,013	13	1,041	7,516	8,367	8,109	19	9,029	35,107
Hydro	—	—	—	—	—	216	34	3,379	3,629
Other	—	—	2	9	—	27	—	509	546
Total	**1,686**	**13**	**3,330**	**8,793**	**11,381**	**10,642**	**923**	**14,265**	**51,032**

Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates. Other includes biomass, diesel/fuel oil, energy storage, fuel cells, geothermal, landfill gas, pet coke, waste heat, and wood. Totals may reflect rounding.

Source: Velocity Suite, Hitachi Energy, EEI Finance Department, March 2022

Announcements by Region and Fuel Type

New capacity announced in 2021 totaled 51,032 MW, a decrease of 23% from 66,386 MW in 2020. Renewable capacity accounts for 93% of 2021's total, with solar at 69%, wind at 17%, and hydro at 7%. The remaining 7% is almost all natural gas. As in 2020, no new coal capacity was announced in 2021.

Lower wind and solar announcements led the overall decline in new capacity announcements. New wind capacity announcements declined 34%, from 13,073 MW in 2020 to 8,668 MW in 2021. New solar capacity announcements also decreased, falling 28% from 48,449 MW in 2020 to 35,107 MW in 2021. The supply chain challenges that impacted renewable buildouts may also have contributed to lower renewable capacity announcements in 2021 compared to 2020.

Wind, solar, and hydro accounted for nearly 100% of new capacity

Stage of Announced Capacity Additions (MW) 2022–2026

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	95	—	—	—	—	—	—	95
Natural Gas	15,993	876	5,245	11,917	—	11,828	2,410	48,269
Nuclear	4,753	1,600	—	219	—	—	2,200	8,772
Wind	58,915	2,412	13,146	9,051	352	12,026	1,101	97,003
Solar	102,063	200	31,106	34,825	545	20,081	2,049	190,869
Other	2,321	8,777	719	1,851	6,511	—	5	20,183
Total	**184,140**	**13,865**	**50,215**	**57,863**	**7,408**	**43,935**	**7,765**	**365,191**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. 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 2026.

Source: Velocity Suite, Hitachi Energy, March 2022

announcements in the Electricity Reliability Council of Texas (ERCOT), Hawaiian Coordinating Council (HCC), Northeast Power Coordinating Council (NPCC), Southwest Power Pool (SPP), and Western Electricity Coordinating Council (WECC) regions. New natural gas capacity announcements decreased for the second year in a row, falling 26% from 4,144 MW in 2020 to 3,060 MW in 2021.

The Western Electricity Coordinating Council (WECC) region saw the most announced new capacity for the second year in a row, at 14,265 MW; 95% of that is renewable, with 63% solar, 24% hydro, and 8% wind. The Reliability First Corp (RFC) region had the second-largest amount of new capacity announced in 2021, at 11,381 MW; 92% is renewable, with 74% solar and 18% wind.

Projected Capacity Additions

As of March 2022, the new capacity expected to come online from 2022 through 2026 was 365,191 MW, a 10% increase over the projection one year ago for the 2021 through 2025 five-year period. Renewable capacity accounted for most of the projected new capacity, with solar representing 52%, wind accounting for 27%, natural gas at 13% and nuclear at 2%. Of the 365,191 MW total, 50% was in the proposal stage as of March 2022, including 53% of the projected solar and 61% of the projected wind. Only 12% of the total was under construction.

Retirements

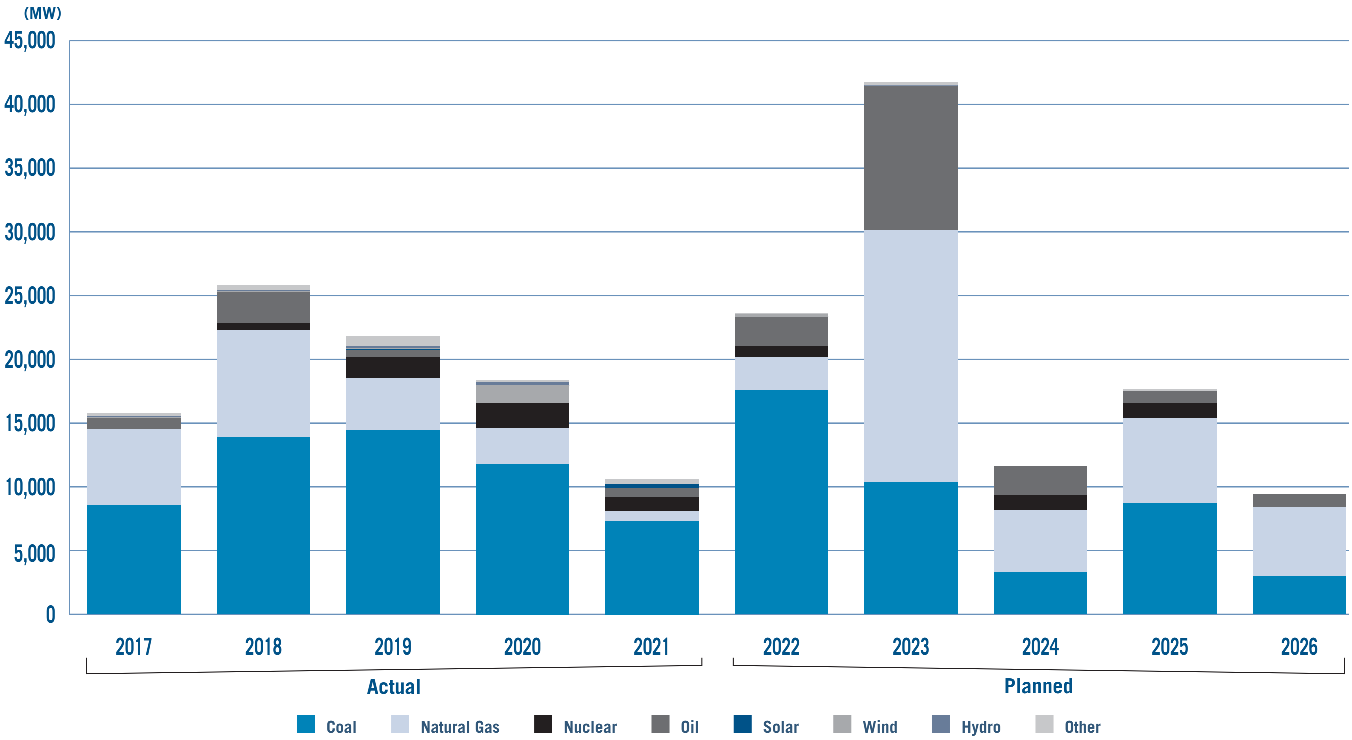
As of March 2022, 104,044 MW of capacity was scheduled to be retired from 2022 through 2026. Coal continues to lead retirements, accounting for 41% of the projected total. Coal retirements are expected to reach a new peak in 2022, with 17,597 MW expected to shut down. Natural gas ranked second and fuel oil third in terms of projected retirements, at 38% and 17%, respectively.

Natural gas retirements are expected to peak in 2023 at 19,761 MW; this would be the highest actual or projected annual retirement total of any fuel from 2017 through 2026. Wind and solar retirements remain minimal, together accounting for only a combined 0.3% of total retirements from 2022 through 2026. 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). Indian Point Unit 3 (1,074 MW) was the only nuclear facility to retire in 2021 and accounted for all nuclear capacity retired that year. An additional 3,146 MW of nuclear capacity is expected to retire over the next four years due to two anticipated shutdowns: the 823 MW Palisades Power Plant in Michigan in 2022 followed by the 2,323 MW Diablo Canyon Power Plant (CA) in stages between 2024 and 2025.

Energy Storage

Energy storage continues to be a fast-growing area for the industry. At year-end 2021, electric companies owned 19,135 MW of storage

Actual and Planned Retirements 2017–2026



	Actual					Planned					
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Coal	8,529	13,877	14,460	11,813	7,342	17,597	10,385	3,311	8,740	3,018	43,051
Natural Gas	6,012	8,390	4,108	2,760	747	2,617	19,761	4,852	6,673	5,384	39,288
Nuclear	—	550	1,641	2,031	1,074	823	—	1,159	1,164	—	3,146
Oil	848	2,482	543	1,336	765	2,306	11,333	2,292	947	1,004	17,882
Solar	—	3	8	—	265	—	—	—	—	1	1
Wind	60	63	135	224	—	203	—	—	1	—	205
Hydro	126	55	161	9	5	6	48	6	14	—	74
Other	207	384	733	180	367	106	200	—	91	—	397
Total	**15,781**	**25,803**	**21,789**	**18,353**	**10,565**	**23,658**	**41,727**	**11,620**	**17,631**	**9,408**	**104,044**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, wood, and energy storage. Totals may reflect rounding. 2017-2021 is actual plants retired. 2022-2026 is projected based on announced or expected retirements.
Source: Velocity Suite, Hitachi Energy; EEI Finance Department, March 2022

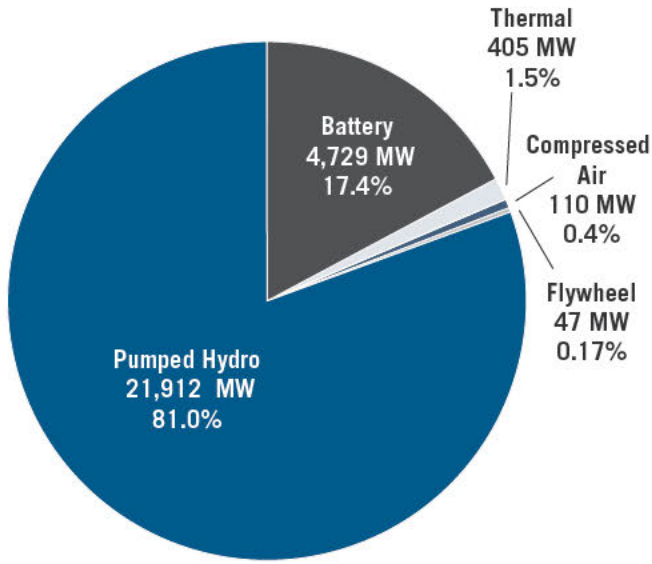
capacity, or about 70% of all energy storage in the United States. Since 2015, total installed energy storage capacity nationwide has increased 19%, from about 23 GW to just over 27 GW in 2021. Pumped hydro accounts for 81% of the total, at 21.9 GW of capacity. Battery storage is the fastest-growing storage technology in terms of capacity, with total deployed capacity up approximately 1,400% from 2015 to 2021. Between 2017 and 2021, battery energy storage grew from 2.75% of total energy storage capacity to 17.4%.

The fast-paced growth is likely to continue; 58,756 MW of storage capacity is expected to come online from 2022 through 2026, increasing total energy storage capacity by 200% by year-end 2026. Front-of-the-meter, grid-scale energy storage will continue to dominate energy storage deployments, accounting for 82% of projected deployment from 2022 through 2026. Battery storage is expected to continue to account for most new energy storage deployments, representing 55,881 MW, or 95%, of the projected new energy storage from 2022 through 2026 and becoming the dominant energy storage technology by 2024. Pumped hydro is expected to account for the remainder, with 1,520

MW provided by four new pumped hydro facilities — the Gordon Butte Pumped Storage Project in Montana (400 MW), the Old Forge Bore Hole Reclamation Pumped Storage Project in Pennsylvania (184 MW), the Cat Creek Energy & Water Project in Idaho (720 MW), and the Lewis Ridge Pumped Storage Project in Kentucky (216 MW). While data sources indicate these projects may become operational by 2026, they are in early stages of development and only Gordon Butte has been permitted. Rerates and expansions at existing facilities accounted for 1,355 MW of the projected new pumped storage capacity.

Total Installed Energy Storage Capacity by Technology - 27,203 MW

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



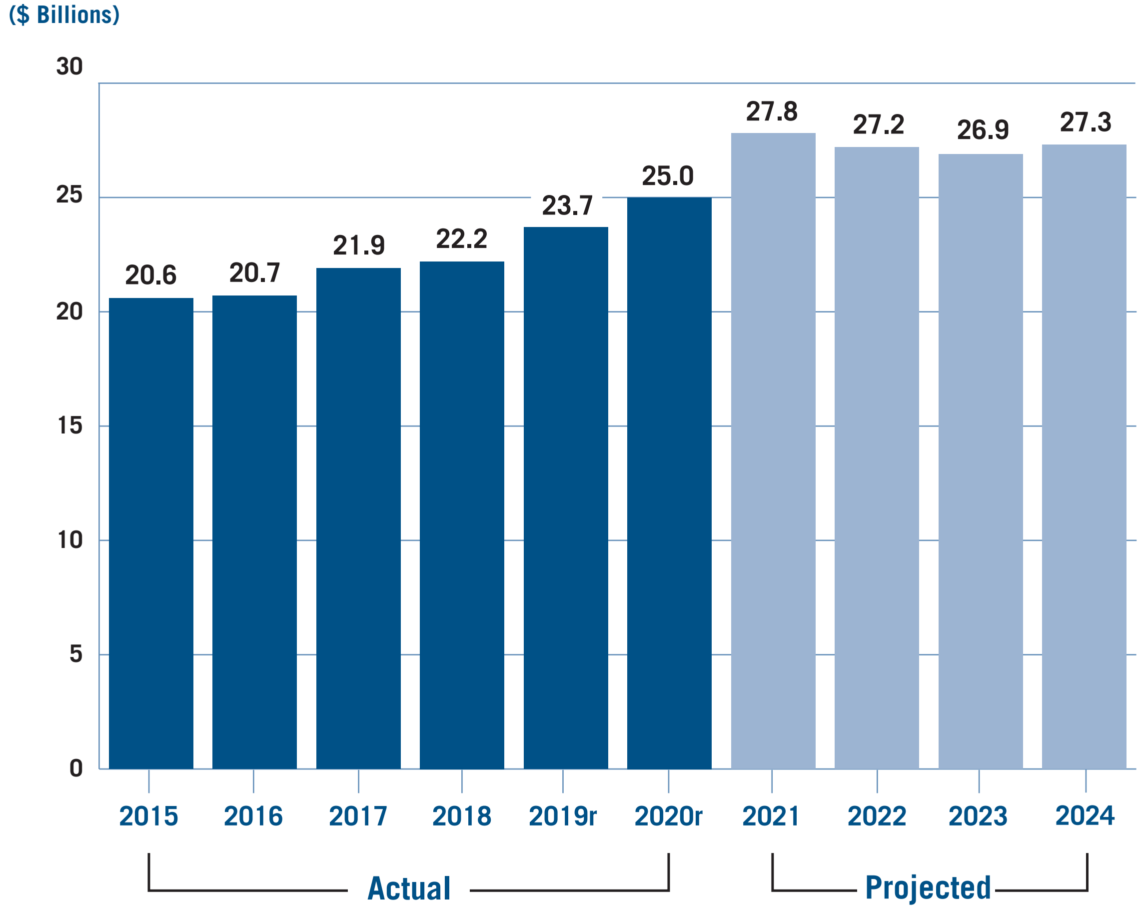
Source: Energy Information Administration Form 860.

Transmission and Distribution

According to EEI's Property & Plant Capital Investment Survey, investor-owned electric utilities and stand-alone transmission companies invested $25.0 billion in transmission assets in 2021, a 5.5% increase over the $23.7 billion invested in 2020.

EEI member companies are spending a significant and growing amount of resources on adaptation, hardening, and resilience (AHR) initiatives. In recent years, it is estimated that EEI's member companies have invested around $25 billion per year in AHR for transmission and distribution infrastructure. Specific examples of AHR investments in the electric grid include undergrounding power lines, installing cement poles, and elevating or relocating transformers. AHR is increasingly becoming an important way that electric companies fulfill their mission of supplying customers with reliable, affordable and increasingly sustainable energy. Electric companies also are developing weather predictive services, risk modeling, fire spread modeling, deployment of sensors and high-definition cameras, communication networks, satellite data damage assessment, and other real or near real time situational awareness instruments that can help them better predict and prepare for extreme weather events and wildfires.

Actual & Projected Transmission Investment* 2015–2024



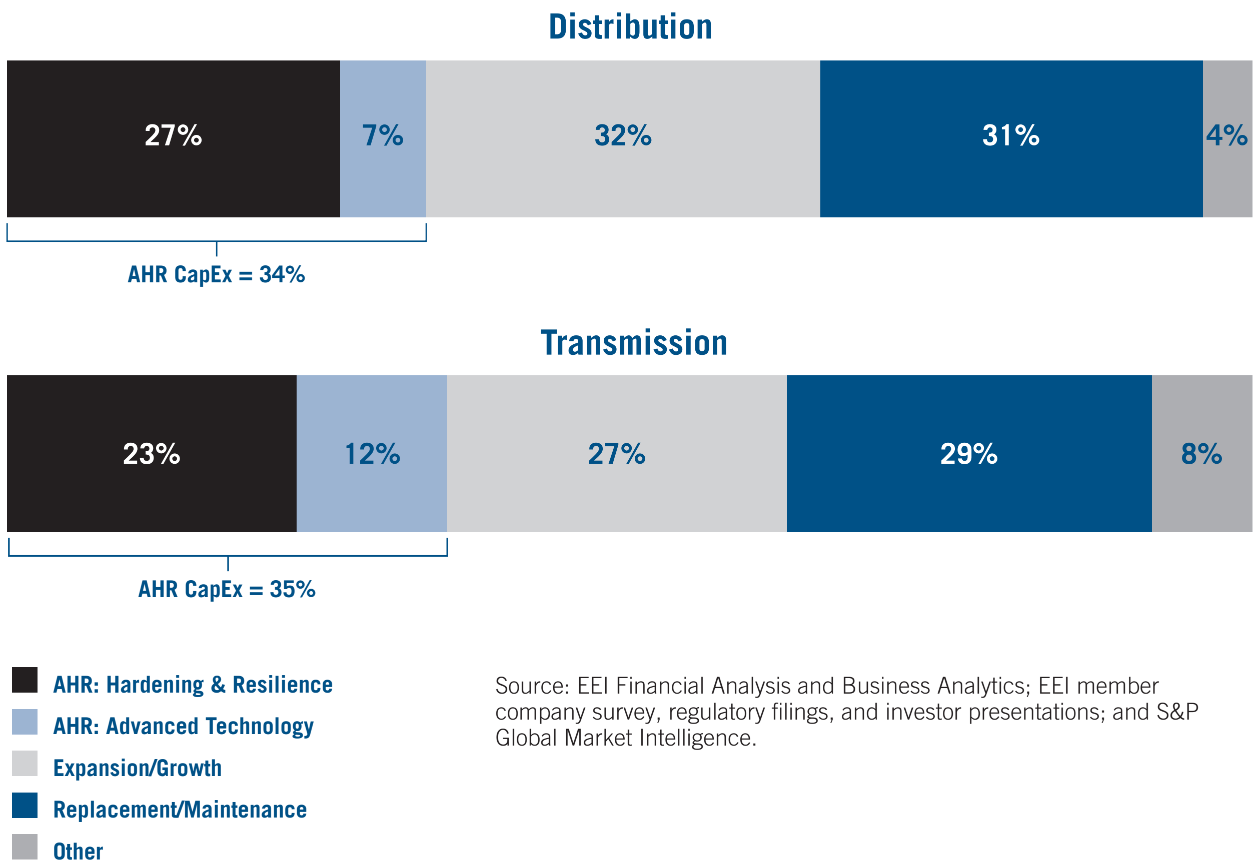
r = revised

*Investment of investor-owned electric companies and stand-alone transmission companies. Actual Investment figures were obtained from the EEI Property & Plant Capital Investment Survey supplemented with FERC Form 1 data. Projected investment figures were obtained from the EEI Transmission Capital Budget & Forecast Survey supplemented with data obtained from company 10-K reports and investor presentations.

Source: EEI Business Analytics.

Updated December 2021.

Adaptation, Hardening, and Resilience (AHR) as Drivers of T&D Investment
Based on 2021 Survey Results



Source: EEI Financial Analysis and Business Analytics; EEI member company survey, regulatory filings, and investor presentations; and S&P Global Market Intelligence.

Fuels Analysis

Net Generation and Electricity Sales

Electric power industry net generation in 2021 amounted to 4,164,566 gigawatt hours (GWh), an increase of 2.9% versus 2020. Nationwide retail electricity sales increased 2.1% in 2021, showing gains across 46 states and the District of Columbia, after declining 3.9% in 2020 due to the impact of the COVID-19 pandemic. The states with the largest year-to-year percentage increases in retail electricity sales in 2021 were Arkansas (+6.2%), Virginia (+5.7%), Tennessee (+5.5%), and North Dakota (+5.3%). California (-1.7%), Arizona (-1.1%), Florida (-0.6%), and Texas (-0.1%) were the few states with sales declines.

Total sales to commercial customers increased 2.9%, substantially above the 2.1% overall nationwide sales gain, indicating that businesses were reopening and resuming business-as-usual following 2020's pandemic-related shutdowns. Every state experienced an increase in commercial sales in 2021, with Rhode Island (+0.5%) showing the smallest percentage increase and Virginia (+10.1%) producing the largest.

Total electricity sales to industrial customers also increased 2.9% compared to 2020, showing year-to-year gains in 40 states and the District of Columbia. As with commercial sales, this was likely due to the resumption and expansion of industrial activity after states relaxed their COVID-19 protocols. The District of Columbia had the highest percentage increase, at 29%, followed by North Dakota (+10.7%) and Arkansas (+9.6%). Ohio showed the highest increase in absolute terms, at 3,298 GWh, representing a 7% increase from 2020. The states experiencing industrial sales declines were Arizona, California, Connecticut, Maine, Montana, New Jersey, Oregon, Texas, Utah, and Washington, where decreases ranged from 0.3% (Montana) to 5.7% (Maine).

Electricity sales to residential customers increased 0.8%, with Tennessee (+5.1%) and Arkansas (+5%) experiencing the highest percentage growth in 2021. Tennessee also experienced the highest growth in absolute terms, at 2,102 GWh, followed by North Carolina, at 2,079 GWh. 40 states and the District of Columbia saw residential electricity sales increase in 2021. Whereas California (-4.6%) and Arizona (-3.9%) had the largest declines in residential electricity sales.

The variations in year-to-year residential sales trend across states may be due, in part, to the impact of differing COVID-19 protocols and mandates. States with residential electricity sales growth may have seen an increase in the number of people working from home in 2021 compared to 2020. Conversely, resi-

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2020	2021
Coal	19.1%	21.6%
Gas	40.1%	37.8%
Nuclear	19.5%	18.7%
Hydro	7.0%	6.2%
Renewables	13.3%	14.8%
Biomass	1.4%	1.3%
Geothermal	0.4%	0.4%
Solar	3.2%	3.9%
Wind	8.3%	9.1%
Other fuels	0.9%	0.9%
Total	100%	100%

Note: Totals may not equal 100% due to rounding.

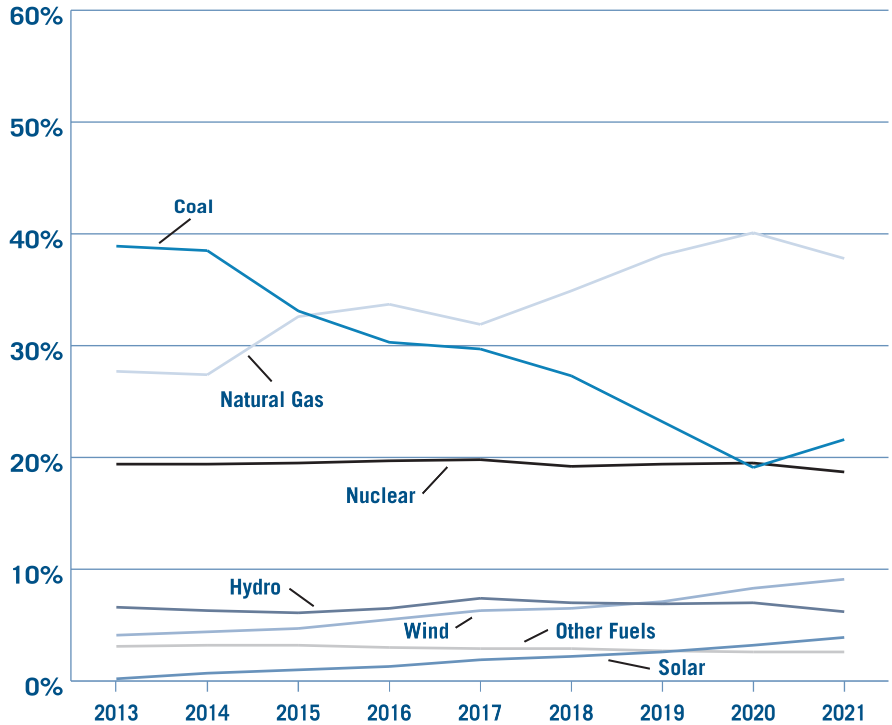
U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

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: U.S. Department of Energy, Energy Information Administration (EIA). March 2022.

Fuel Sources for Net Electric Generation (in Percent of total electric generation) 2013–2021

U.S. ELECTRIC UTILITY AND NON-UTILITY



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: U.S. Department of Energy, Energy Information Administration (EIA), March 2022.

dential sales declines may indicate that fewer people worked from home in those states in 2021 than in 2020.

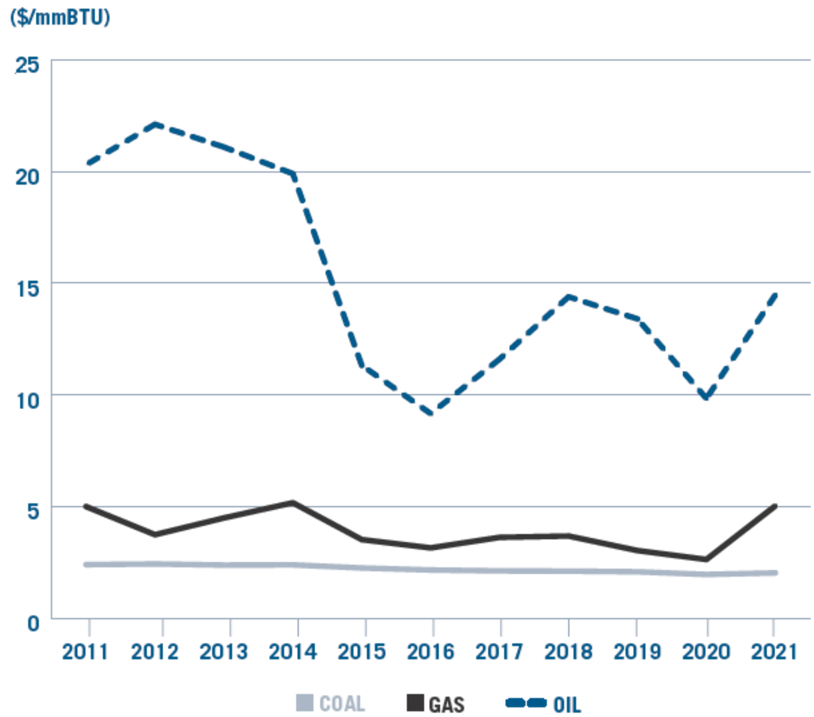
Coal

Generation from coal-fired plants increased for the first time since 2014, rising 16.2% above its 2020 total due to stable coal fuel prices and higher natural gas fuel prices. Coal accounted for 21.6% of total electricity generation nationwide in 2021. Coal's 898,679 GWh of generation placed it second, behind natural gas, among the fuels that contributed to total nationwide generation. The coal fleet's capacity factor increased for the first time since 2018, from 41% in 2020 to 49% in 2021.

The price of coal combined with operations and maintenance costs for coal plants decreased 1.4%, from $32.26/MWh in 2020 to $31.81/MWh in 2021. A 3.6% increase in the average price of coal, from $1.96 per million British Thermal Units (MMBtu) in 2020 to $2.03 MMBtu in 2021, was offset by a 14.4% decline in average operations and maintenance expenses, which dropped from $10.73/MWh in 2020 to $9.19/MWh in 2021. The largely unchanged overall generation cost for coal made it the second-most expensive fuel for electricity generation in 2021 as higher natural gas fuel prices made natural gas generation more costly.

Average Cost of Fossil Fuels 2011–2021 in $/MMBtu

U.S. ELECTRIC UTILITIES



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.

Source: U.S. Department of Energy, Energy Information Administration (EIA), March 2022.

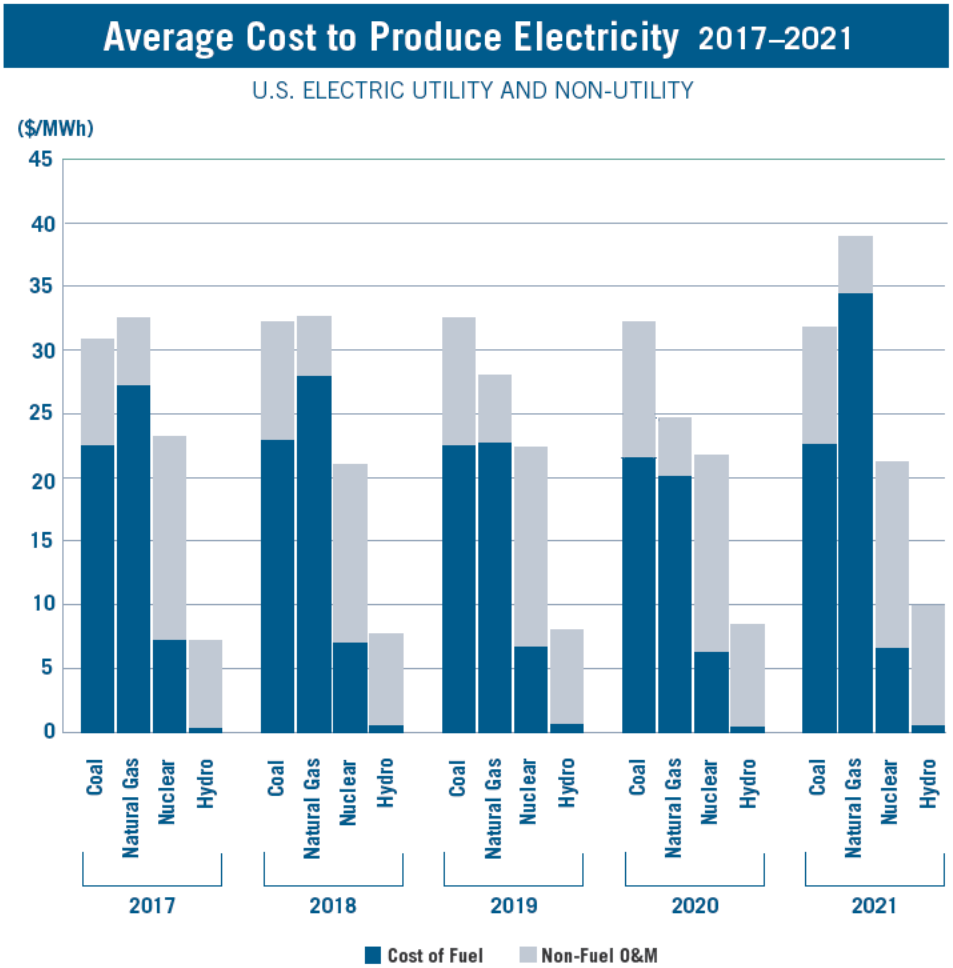
The rise in coal generation in 2021 was mainly due to an increased average capacity factor, instead of new coal capacity or lower-than-expected coal capacity retirements. From 2017 through 2021, only 158 MW of new coal capacity came on-line compared to 56,021 MW of coal retirements during the same period. Another 43,051 MW of coal capacity is projected to retire from 2022 through 2026.

Natural Gas

Natural gas accounted for 38% of 2021's total generation from utility-scale facilities, more than any other single fuel type. That share, however, was down two percentage points from its 2020 level due to higher natural gas fuel prices in 2021. The average cost of natural gas for electricity generation rose dramatically, increasing 91% from $2.63/MMBtu in 2020 to $5.03/MMBtu in 2021, its highest level since 2014. As a result, the average cost to produce electricity from natural gas rose 58% in 2021 versus 2020 and was 22% higher than the average cost to produce electricity from coal.

Renewables

The electric industry continues to add record amounts of renewable capacity. Electric generation from carbon-free sources increased to 1,653,563 MWh in 2021, representing 39.7% of the electric power in-



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.

*2021 results are preliminary. All years based on modeled data from Velocity Suite, Hitachi Energy; March 2022.

dustry's total generation. Generation from all renewable sources was 875,411 MWh, or 21% of the total in 2021 compared with 824,526 MWh, or 20.4%, in 2020.

Conventional hydroelectric generation fell to 260,225 MWh, an 8.8% decline from 2020's 285,274 MWh. It accounted for 6.2% of electricity generation in 2021, down from 7% in 2020, due to a historic drought in California and reduced hydroelectric output in the Pacific Northwest. Generation from wind power increased 12.4%, from 337,938 MWh in 2020 to 379,767 MWh in 2021 and accounted for 9.1% of 2021's total electricity generation. Solar generation increased 25.2%, from 130,721 MWh in 2020 to 163,793 MWh in 2021, reaching 3.9% of total electricity generation. Utility-scale solar accounted for 114,678 MWh, or 70%, of solar generation, an increase from 68% in 2020.

Nuclear

Nuclear generation decreased 1.5% in 2021 and accounted for 18.7% of total electric power generation, down from 19.5% in 2020. The decline was due to reduced capacity resulting from nuclear plant retirements – 5,298 MW of nuclear capacity was retired from 2017 through 2021. Another 3,146 MW is projected to retire over the next five years through closure of the Diablo Canyon power plant in California and the Palisades power plant in Michigan. Nuclear power plants had an average capacity factor of 92.7% in 2021, compared to average capacity factors of 49% for coal and 36% for natural gas.

Nuclear fuel costs increased 6%, from $6.26/MWh in 2020 to $6.64/MWh in 2021. However, non-fuel operations and maintenance costs decreased 6.2%, from $15.56/MWh in 2020 to $14.60/MWh in 2021. As a result, the total cost to produce electricity from nuclear power declined 2.6%.

A total of 15,962 MW of nuclear capacity is expected to come online from 2022 through 2026. Including reductions due to planned retirements, nuclear capacity is projected to increase 12,816 MW during this period. Five existing plants have planned expansions — 2,200 MW each at Vogtle (GA) and Harris (NC), 1,700 MW at Comanche Peak (TX), 1,520 MW at North Anna (VA), and 1,213 MW at Bellefonte (AL). An additional five new or restarted plants, including the proposed 3,000 MW Blue Castle Nuclear (UT), 1,650 MW Southern Ohio Clean Energy Park, and 1,600 MW Colorado Energy Park, are also expected to contribute to new nuclear capacity additions.

Small modular nuclear reactors (SMR) will also begin to contribute to nuclear capacity increases. The Idaho National Laboratory 300 MW Next Generation Nuclear plant is expected to restart in 2022 and the 540 MW NuScale Small Nuclear Modular Project (ID) is expected to come online in 2024. In addition, the Tennessee Valley Authority has proposed to build an 800 MW SMR project at its Clinch River site with an operational date of 2032.

States with Renewable Energy, Clean Energy and Greenhouse Gas Reduction Goals and Targets

State	State- and Economy-wide Greenhouse Gas Reduction Targets	Clean Energy Target	RPS Target
Arizona			15% by 2025, 4.5% distributed generation
California	40% below 1990 levels by 2030. Carbon neutrality by 2045. 80% below 1990 levels by 2050.	100% of electric retail sales from renewable energy and zero-carbon resources by 2045	44% by 2024, 52% by 2027, 60% by 2030
Colorado	26% below 1990 levels by 2025, 50% by 2030, 90% by 2050	By 2030, reduce emissions from electricity generation 80% from 2005 levels. 100% carbon-free electricity generation by 2050.	30% by 2020, 3% of electric retail sales from distributed generation, including 1.5% customer sited, by 2020. 100% by 2050. Energy storage charged solely by renewable resources is a qualified renewable energy source.
Connecticut	45% below 2001 levels by 2030,80% by 2050		28% by 2022, increasing 2% annually to 44% by 2030, plus 4% energy efficiency
Delaware	30% below 2008 levels by 2030		40% by 2035, 10% solar
District of Columbia	50% below 2006 levels by 2032, 80% reduction and net-zero emissions by 2050	100% of electric retail sales from renewable energy by 2032	32.5% by 2022 plus 2.175% local solar, 51.25% by 2025 plus 2.85% local solar, 82.5% by 2030 plus 4.5% local solar, 95% by 2032 plus 5% local solar
Hawaii	Net-zero emissions by 2050	100% of electric retail sales from renewable energy by 2045	40% by 2030, 70% by 2040, 100% by 2045
Illinois		By 2050, procure 100% of energy from clean energy sources, which are defined as sources that are at least 90% carbon-free. Coal-fired power plants must reduce emissions by 45% by 2035 and by 100% by 2045.	25% by 2025, 40% by 2030, 50% by 2040
Indiana			10% by 2025 (voluntary goal). Underground pumped hydro storage projects may be used to meet this goal.
Iowa			105 MW; 1 GW wind goal by 2010
Kansas			20% by 2020 (voluntary goal)
Louisiana	26-28% below 2005 level, 40-50% by 2030, Net-zero emissions by 2050		
Maine	45% below 1990 levels by 2030, 80% reduction and net-zero emissions by 2050	By 2050, 100% of electricity sold in the state must be supplied by renewable resources	50% by 2030, 80% by 2030, 100% by 2050
Maryland	60% below 2006 levels by 2031		50% by 2030, including 14.5% solar
Massachusetts	50% below 1990 levels by 2030, 75% by 2040, 85% reduction and carbon neutrality by 2050		35% by 2030, +1% annually, 80% of electricity sales from clean energy sources by 2050
Michigan	26-28% below 2005 levels by 2025. Carbon neutrality by 2050 and net negative emissions thereafter.		15% by 2021
Minnesota	30% below 2005 levels by 2025, 80% by 2050		31.5% by 2020 (Xcel Energy), 26.5% by 2025 (all other IOUs), 1.5% solar
Missouri			15% by 2021, 2% solar
Montana	GHG neutrality between 2045 and 2050		

Notes: The table depicts finalized and proposed state actions. Goal indicates there is no explicit compliance requirement.

Updated March 2022.

States with Renewable Energy, Clean Energy and Greenhouse Gas Reduction Goals and Targets (continued)

State	State- and Economy-wide Greenhouse Gas Reduction Targets	Clean Energy Target	RPS Target
Nebraska			No state goal but Nebraska's two largest public power districts have renewable goals
Nevada	28% below 2005 levels by 2025, 45% by 2030, Zero or near-zero emissions by 2050	State economy must have zero or near-zero carbon emissions by 2050	29% by 2022, 34% by 2024, 42% by 2027, 50% by 2030, 100% by 2030 (voluntary goal)
New Hampshire	20% below 1990 levels by 2025, 80% by 2050		22.5% by 2022 (0.7% solar), 25.2% by 2025
New Jersey	80% below 2006 levels by 2050	100% carbon-free electricity by 2050 (voluntary goal)	35% by 2025, 50% by 2030, 5.1% from solar by 2021 then declines to 1.1% by 2033
New Mexico	45% below 2005 levels by 2030	By 2045, zero-carbon resources must provide 100% of electric retail sales	50% by 2030, 80% by 2040, 100% by 2045 (IOUs)
New York	40% below 1990 levels by 2030, 85% reduction and net-zero emissions by 2050	By 2040, 100% of electricity sold in the state must come from carbon-free sources	70% by 2030, 100% by 2040
North Carolina	Per Executive Order, the state will strive to achieve 50% reduction below 2005 levels by 2030, 100% reduction by 2050, and 70% reduction in the electric power sector by 2030		12.5% by 2021 for investor owned utilities, 0.2% solar by 2018.
Ohio			8.5% by 2026
Oklahoma			15% by 2015 (voluntary goal)
Oregon	80% below baseline (average emissions level for period of 2010 through 2012) by 2030, 90% below baseline by 2035, 100% below baseline by 2040		25% by 2025, 50% by 2040
Pennsylvania	26% below 2005 levels by 2025, 80% by 2050		18% by 2021, 0.5% solar by 2021
Rhode Island	45% below 1990 levels by 2035, 80% by 2050		38.5% by 2035
South Carolina			2% by 2021, 0.25% from distributed generation (goal)
South Dakota			10% by 2015 (voluntary goal)
Tennessee			Tennessee Valley Authority's goal is 60% clean energy by 2030
Texas			5,880 MW by 2015, 10,000 MW by 2025. 500 MW non-wind (voluntary goal)
Vermont	40% below 1990 levels by 2030, 80% by 2050		55% by 2017, 75% by 2032. Additional 12% energy efficiency by 2032.
Virginia	Net-zero emissions by 2045	100% carbon-free electricity by 2050	Dominion Energy Inc.: 17% by 2022, 100% by 2045. Appalachian Power Co. and all retail providers: 7% by 2022, 100% by 2050.
Washington	45% below 1990 levels by 2030, 70% by 2040, 95% reduction and net-zero by 2050	Electricity generation must be carbon-neutral by 2030 and fossil fuel-free by 2045	15% renewables by 2020. Carbon-neutral electricity supply by 2030. Fossil fuel-free electricity supply by 2045.
Wisconsin		100% carbon-free electricity by 2050	Varies by electric company. Total of 10% by 2015.

Notes: The table depicts finalized and proposed state actions. Goal indicates there is no explicit compliance requirement.

Updated March 2022.

Industry Financial Performance

Income Statement

- Energy Operating Revenues rose 10.8% versus last year. The historically strong gain was mostly a result of sharply higher fuel commodity prices, which are directly passed through to customers under rate regulation. Nationwide electricity generation rose 2.8% due to a recovery in commercial and industrial sales from 2020's pandemic-related weakness. Residential sales rose only marginally in 2021. The average retail price of electricity nationwide increased 5.6%, according to EIA data, as recent rate reviews allowed for recovery of rising capex; the average retail price nationwide was nearly unchanged over the four previous years. Almost all of the utilities included in EEI's industry consolidated data reported higher revenue in 2021.

- The inflation pressures that made news headlines in 2021 impacted generation costs. The cost of natural gas for electric generation more than doubled from 2020's level while the cost of coal rose about 4%, based on EIA data. As a result, the industry's consolidated Total Electric Generation Cost climbed 21.7% year-to-year while Gas Cost jumped 41.1%. These two line items combined to drive the industry's Total Energy Operating Expenses up 24.2%. Many utilities separately disclose Electric Fuel Expense and Cost of Purchased Power. Based on that data, the industry's aggregate Electric Fuel Expense rose 28.8% while Cost of Purchased Power increased 15.3%.

- Operations and Maintenance (O&M) costs rose 4.6% after gaining only 1.0% to 1.5% in the three previous years. Utilities are benefitting from smart-grid investment productivity and they worked hard to constrain O&M-related expenses during the pandemic as a means of addressing revenue declines. But O&M costs are also driven by essential reliability needs. Most utilities showed a year-to-year increase in O&M for 2021.

- Depreciation & Amortization (D&A) expenses rose 6.9%. This metric increased for 39 of the 44 constituent companies, reflecting the industry's ongoing widespread and diverse investments in new clean generation, transmission, distribution and grid modernization.

- Most of the $5.8 billion year-to-year jump in Other Operating Expenses reflects accounting for energy trading at one utility and cost allocation for non-utility operations at another large diversified company with energy holdings. Neither reflect industry-wide trends.

- Operating Income was unchanged versus 2020. Higher Energy Operating Revenues were partially offset by higher generation and gas costs while Operations and Maintenance expenses and Depreciation and Amortization expenses also increased. Operating Income rose for 30 companies and declined for 14.

- Beneath the Operating Income line, 2021's negative $3.2 billion Gain on Sale of Assets resulted primarily from the sale of impaired fossil generation assets at one utility. The $4.7 billion reduction in Asset Write-downs, from $6.7 billion in 2020 to $2.0 billion in 2021, likewise sourced to three utilities with large write-downs in 2020 but not 2021.

- Interest Expense declined by 0.6%. However, this line item rose markedly for some utilities and declined for others in relation to each company's approach to balance sheet management. Exactly half the underlying utilities showed higher interest expense and half lower.
- Net Income Before Taxes increased 7.7%. Net Income rose 9.4%. These figures are driven by the industry's largest companies and mask a wide variation in company-specific results. Pre-Tax Income rose at 29 companies and declined at 15. Net Income likewise rose at 28 and fell at 16. The year-to-year change in both metrics showed considerable variation across companies.
- The industry's aggregate Common Dividend payments rose 1.9% versus 2020, although the average percentage dividend increase was 4.8%. The lower aggregate figure from 2020 reflects dividend cuts at two large utilities. Most utilities increased their dividend rates in 2021. The industry's reliable stock dividends offer a welcome source of income for savings-oriented investors, especially given the near-zero short-term rates and meager bond yields available during 2021.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

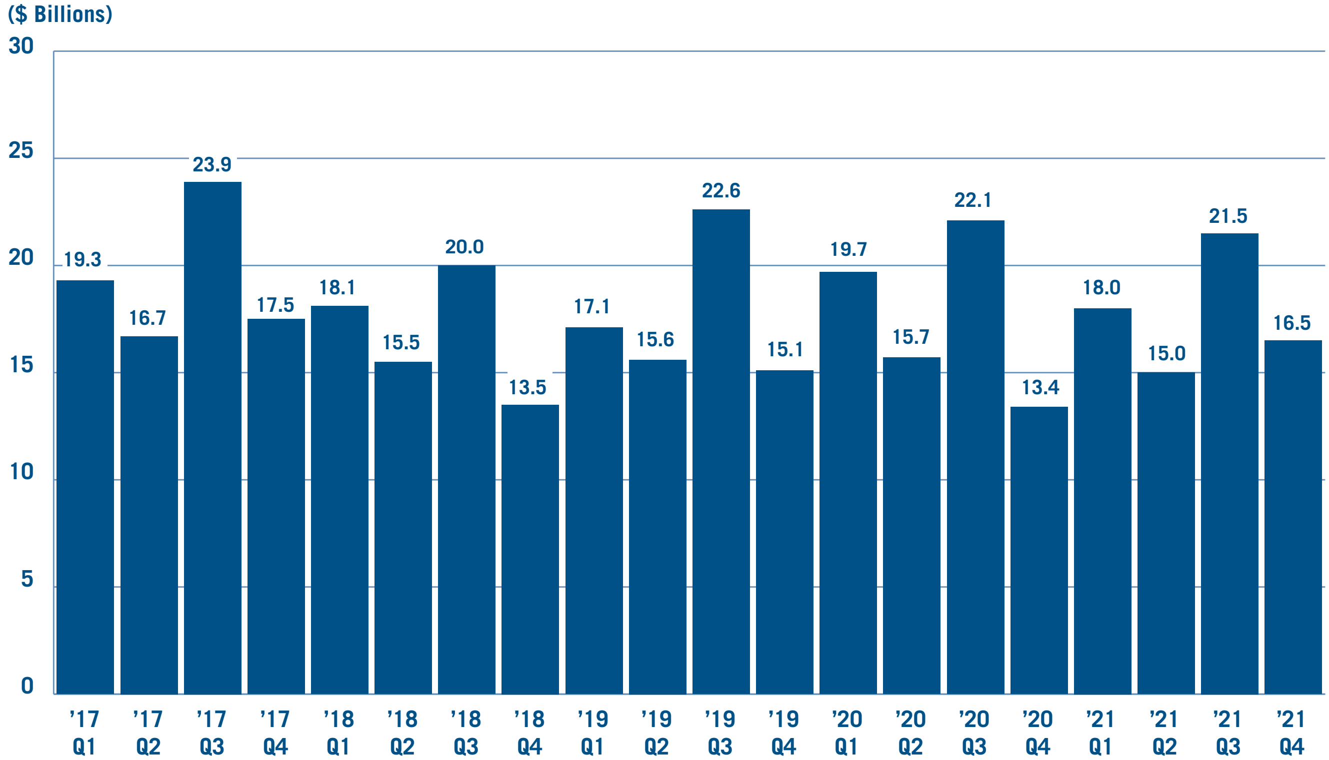
	12 Months Ended		
($ Millions)	**12/31/2021**	**12/31/2020r**	**% Change**
Energy Operating Revenues	$385,500	$347,934	10.8%
Energy Operating Expenses			
Total Electrical Generation Cost	98,104	80,606	21.7%
Gas Cost	16,910	11,984	41.1%
Total Energy Operating Expenses	**115,014**	**92,589**	**24.2%**
Revenues less energy operating expenses	**270,486**	**255,344**	**5.9%**
Other Operating Expenses			
Operations & maintenance	95,741	91,549	4.6%
Depreciation & Amortization	60,424	56,547	6.9%
Taxes (not income) - Total	22,156	20,895	6.0%
Other Operating Expenses	21,126	15,320	37.9%
Total Operating Expenses	**314,460**	**276,902**	**13.6%**
Operating Income	**71,040**	**71,032**	**0.0%**
Other Recurring Revenue			
Partnership Income	2,566	3,337	(23.1%)
Allowance for Equity Funds Used for Construction	2,085	2,032	2.6%
Other Revenue	8,290	8,291	(0.0%)
Total Other Recurring Revenue	**12,941**	**13,660**	**(5.3%)**
Non-Recurring Revenue			
Gain on Sale of Assets	(3,207)	(398)	705.2%
Other Non-Recurring Revenue	1,161	-	NM
Total Non-Recurring Revenue	**(2,046)**	**(398)**	**413.7%**
Interest expense	26,469	26,636	(0.6%)
Other expenses	385	486	(20.7%)
Asset Writedowns	2,012	6,704	(70.0%)
Other Non-Recurring Expenses	7,875	8,504	(7.4%)
Total Non-Recurring Expenses	9,888	15,208	(35.0%)
Net Income Before Taxes	**45,192**	**41,964**	**7.7%**
Provision for Taxes	3,646	3,354	8.7%
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	**41,547**	**38,610**	**7.6%**
Discontinued Operations	731	17	NM
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	731	17	NM
Net Income	**42,277**	**38,627**	**9.4%**
Preferred Dividends Declared	573	597	(4.0%)
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(2)	(3)	(33.3%)
Net Income Attributable to Noncontrolling Interests	(527)	(533)	NA
Net Income Available to Common	**42,227**	**38,558**	**9.5%**
Common Dividends	**30,075**	**29,503**	**1.9%**

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Net Operating Income

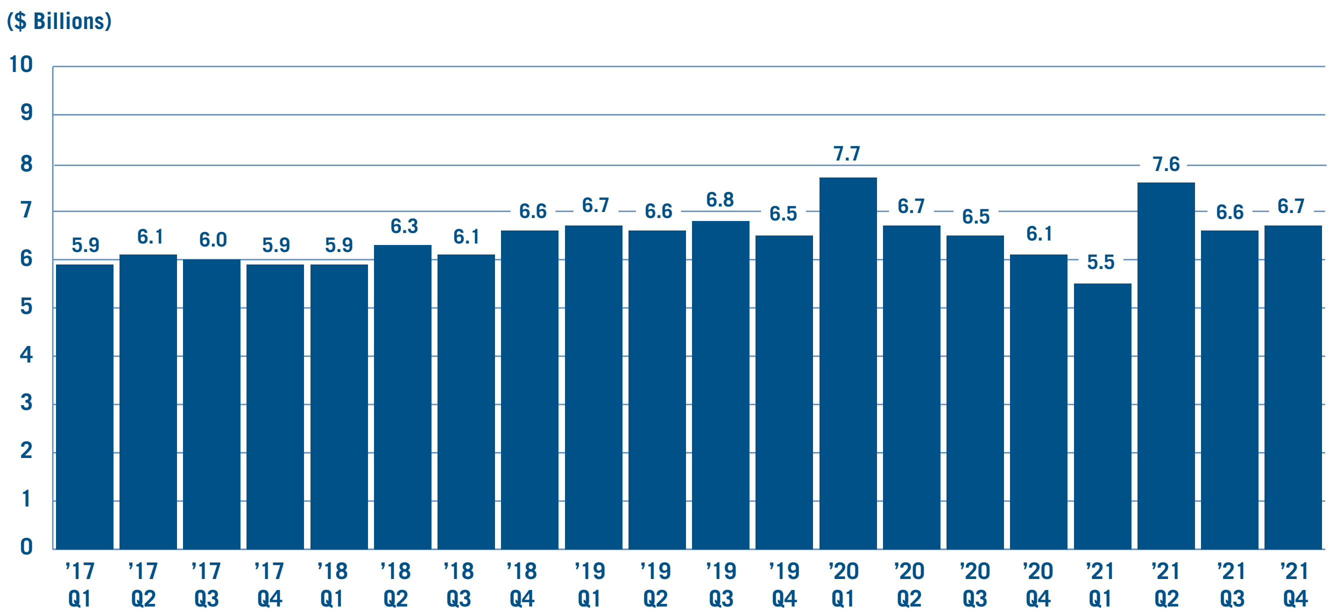
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



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 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2012	2013	2014	2015	2016	2017	2018	2019	2020r	2021
Net Gain (Loss) on Sale of Assets	311	414	996	789	767	1,012	5,272	3,049	(398)	(3,207)
Other Non-Recurring Revenue	264	78	296	(4)	888	493	131	117	–	1,161
Total Non-Recurring Revenue	**576**	**492**	**1,292**	**785**	**1,655**	**1,505**	**5,403**	**3,167**	**(398)**	**(2,046)**
Asset Writedowns	(5,646)	(4,276)	(8,762)	(5,189)	(17,487)	(4,166)	(4,121)	(3,470)	6,704	2,012
Other Non-Recurring Charges	(3,136)	(3,510)	(2,675)	(1,764)	(3,109)	(5,630)	(17,841)	(13,034)	8,504	7,875
Total Non-Recurring Charges	**(8,783)**	**(7,786)**	**(11,437)**	**(6,953)**	**(20,596)**	**(9,796)**	**(21,962)**	**(16,504)**	**15,208**	**9,888**
Discontinued Operations	(4,317)	(88)	295	(1,148)	(732)	(1,554)	602	1,243	17	731
Change in Accounting Principles	–	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	–	–	–	–	–	–	–	–	–	–
Total Extraordinary Items	**(4,317)**	**(88)**	**295**	**(1,148)**	**(732)**	**(1,554)**	**602**	**1,243**	**17**	**731**
Total Non-Recurring and Extraordinary Items	**(12,524)**	**(7,381)**	**(9,850)**	**(7,316)**	**(19,674)**	**(9,844)**	**(15,957)**	**(12,094)**	**(15,589)**	**(11,203)**

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) 2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

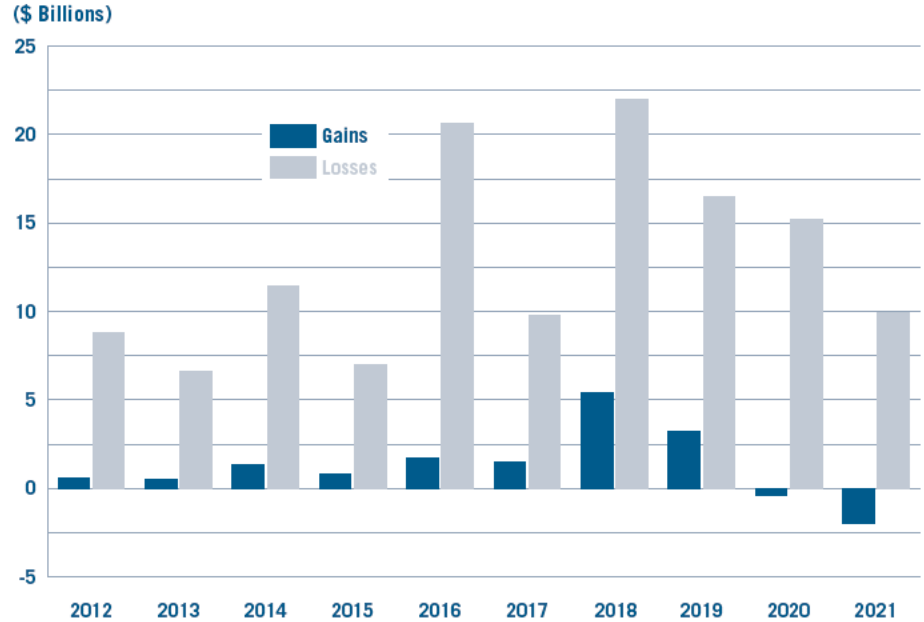
($ Millions)

Company	Gains	Losses	Net Total
Public Service Enterprise Group	(2,637)	298	2,935
Exelon Corp	(954)	1,305	2,259
Southern Company	186	1,785	1,599
Sempra Energy	36	1,596	1,560
Edison International	10	1,491	1,481
PG&E Corp	-	786	786
CenterPoint Energy	689	-	689
Duke Energy	13	484	471
Consolidated Edison	-	443	443
PPL Corp	-	432	432

Source: S&P Global Market Intelligence and EEI Finance Department.

Aggregate Non-Recurring and Extraordinary Items 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



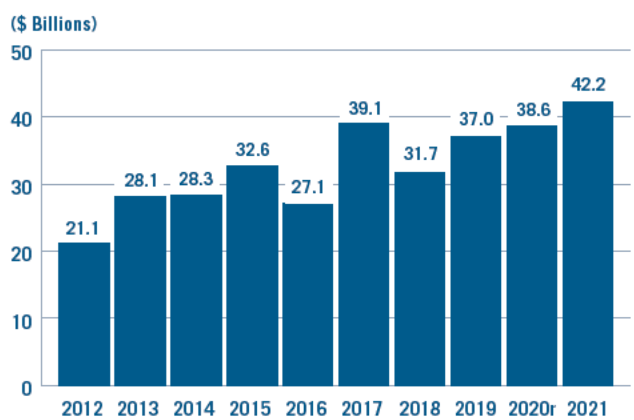
	2012	2013	2014	2015	2016	2017	2018	2019	2020r	2021	Total
Gains	0.6	0.5	1.3	0.8	1.7	1.5	5.4	3.2	(0.4)	(2.0)	12.6
Losses	8.8	6.6	11.4	7.0	20.6	9.8	22.0	16.5	15.2	9.9	127.8
Total	(8.2)	(6.2)	(10.1)	(6.2)	(18.9)	(8.3)	(16.6)	(13.3)	(15.6)	(11.9)	(115.2)

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

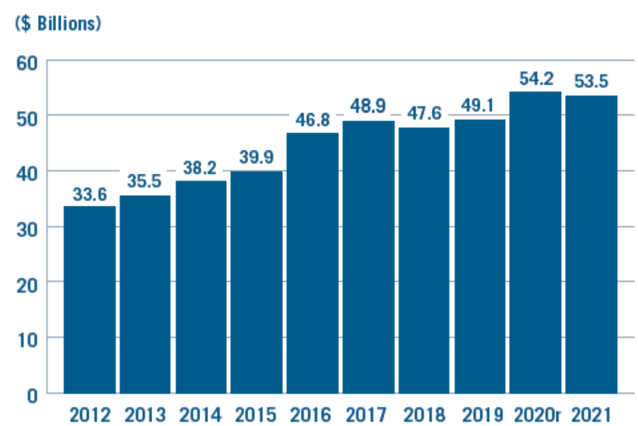


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items 2012-2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

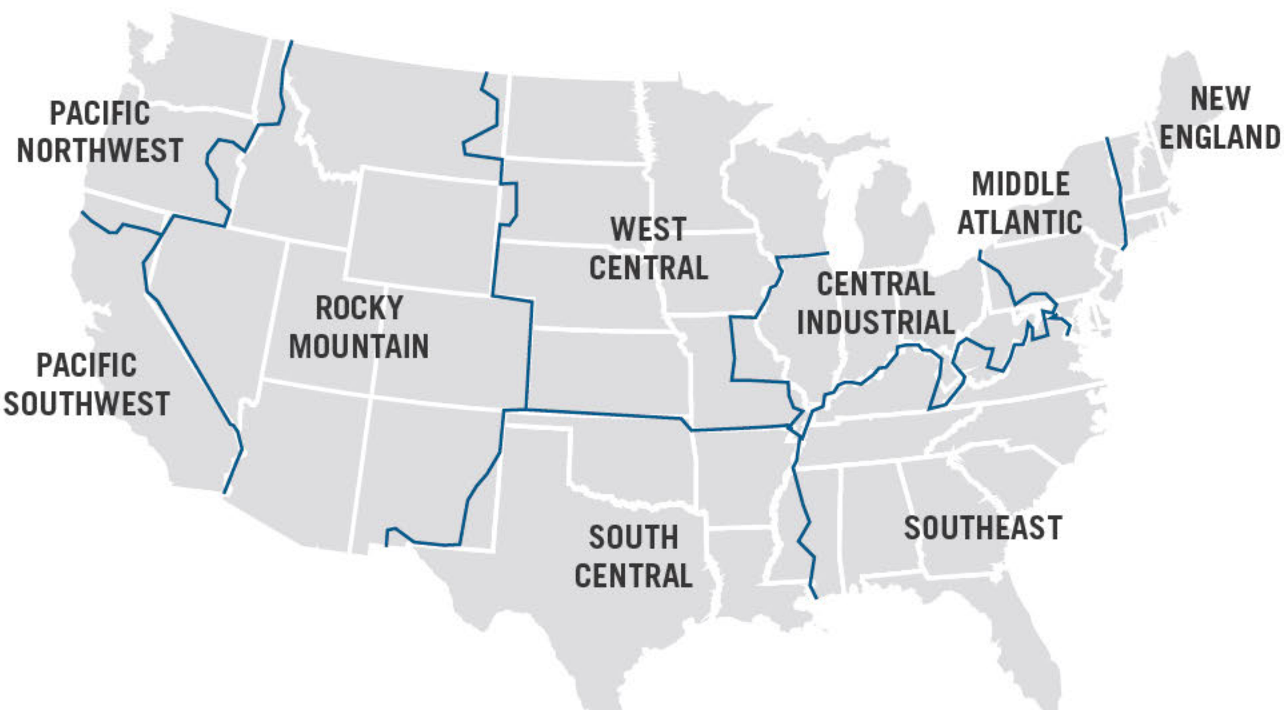
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2021	2020	% Change
New England	115,930	114,308	1.4%
Mid-Atlantic	418,296	408,677	2.4%
Central Industrial	651,041	630,703	3.2%
West Central	335,136	321,004	4.4%
Southeast	1,014,838	984,921	3.0%
South Central	778,018	756,856	2.8%
Rocky Mountain	292,947	287,084	2.0%
Pacific Northwest	158,170	153,806	2.8%
Pacific Southwest	268,259	266,450	0.7%
Total United States	**4,032,635**	**3,923,809**	**2.8%**

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 2021

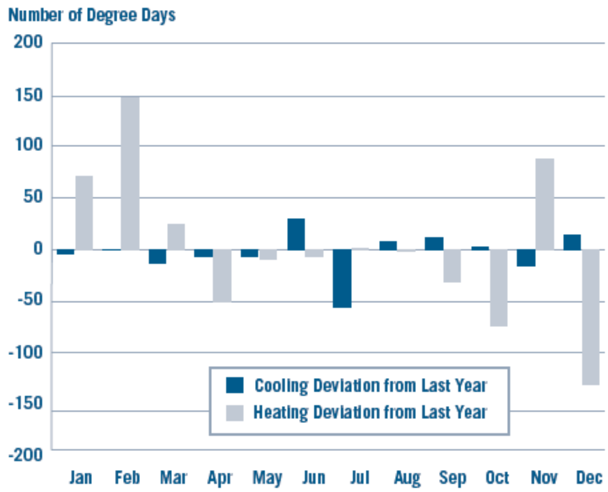
	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	656	239	57%	(81)	(11%)
Mid-Atlantic	912	256	39%	(33)	(3%)
East North Central	968	260	37%	101	12%
West North Central	1,117	189	20%	114	11%
South Atlantic	2,226	262	13%	(121)	(5%)
East South Central	1,684	136	9%	(10)	(1%)
West South Central	2,649	200	8%	(80)	(3%)
Mountain	1,400	157	13%	(103)	(7%)
Pacific	906	202	29%	(77)	(8%)
United States	**1,439**	**223**	**18%**	**(36)**	**(2%)**
Heating Degree Days					
New England	5,831	(780)	(12%)	17	0%
Mid-Atlantic	5,101	(810)	(14%)	31	1%
East North Central	5,745	(752)	(12%)	(75)	(1%)
West North Central	6,051	(699)	(10%)	(236)	(4%)
South Atlantic	2,454	(399)	(14%)	124	5%
East South Central	3,154	(450)	(12%)	127	4%
West South Central	1,964	(323)	(14%)	101	5%
Mountain	4,700	(509)	(10%)	(116)	(2%)
Pacific	3,105	(123)	(4%)	116	4%
United States	**4,012**	**(512)**	**(11%)**	**28**	**1%**

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.

2021 Weather Compared to 2020

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	(4)	71
Feb	0	147
Mar	(13)	24
Apr	(7)	(51)
May	(7)	(9)
Jun	29	(7)
Jul	(55)	1
Aug	8	(2)
Sep	11	(31)
Oct	3	(73)
Nov	(15)	88
Dec	14	(130)
Total	**(36)**	**28**

Heating and Cooling Degree Days and Percent Changes

January—December 2021

	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	5	(4)	(4)	812	(105)	71	(44.4%)	(44.4%)	(11.5%)	9.6%
Feb	10	2	0	811	79	147	25.0%	0.0%	10.8%	22.1%
Mar	21	3	(13)	518	(75)	24	16.7%	(38.2%)	(12.6%)	4.9%
First Quarter	**36**	**1**	**(17)**	**2,141**	**(101)**	**242**	**2.9%**	**(32.1%)**	**(4.5%)**	**12.7%**
Apr	33	3	(7)	321	(24)	(51)	10.0%	(17.5%)	(7.0%)	(13.7%)
May	102	5	(7)	161	2	(9)	5.2%	(6.4%)	1.3%	(5.3%)
Jun	275	62	29	19	(20)	(7)	29.1%	11.8%	(51.3%)	(26.9%)
Second Quarter	**410**	**70**	**15**	**501**	**(42)**	**(67)**	**20.6%**	**3.8%**	**(7.7%)**	**(11.8%)**
Jul	341	20	(55)	4	(5)	1	6.2%	(13.9%)	(55.6%)	33.3%
Aug	354	64	8	6	(9)	(2)	22.1%	2.3%	(60.0%)	(25.0%)
Sep	189	34	11	39	(38)	(31)	21.9%	6.2%	(49.4%)	(44.3%)
Third Quarter	**884**	**118**	**(36)**	**49**	**(52)**	**(32)**	**15.4%**	**(3.9%)**	**(51.5%)**	**(39.5%)**
Oct	78	25	3	186	(96)	(73)	47.2%	4.0%	(34.0%)	(28.2%)
Nov	12	(3)	(15)	511	(28)	88	(20.0%)	(55.6%)	(5.2%)	20.8%
Dec	19	12	14	624	(193)	(130)	171.4%	280.0%	(23.6%)	(17.2%)
Fourth Quarter	**109**	**34**	**2**	**1,321**	**(317)**	**(115)**	**45.3%**	**1.9%**	**(19.4%)**	**(8.0%)**
Full Year	**1,439**	**223**	**(36)**	**4,012**	**(512)**	**28**	**18.3%**	**(2.4%)**	**(11.3%)**	**0.7%**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Heating Degree Days Percentage Change from Historical Norm	(16.6)	(0.6)	1.1	(9.1)	(14.8)	(14.2)	(4.2)	(4.4)	(11.9)	(11.3)
Cooling Degree Days Percentage Change from Historical Norm	22.4	10.9	5.8	19.2	29.4	16.0	26.4	20.3)	21.1	18.3

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 economic turmoil of 2020 caused by the COVID-19 pandemic gave way to steady growth in 2021. U.S. real gross domestic product (GDP) gained 6.3% in Q1, 6.7% in Q2, slowed to 2.3% in Q3, then jumped to its strongest gain of the year, at 7.0%, in Q4. Full-year real GDP rose 5.7%, according to annualized data from the Bureau of Economic Analysis.

- An unwelcome consequence of the post-pandemic rebound was the worst inflation since the early 1980s. Monthly inflation measured by the Consumer Price Index jumped above 4% in April, above 5% in June and climbed steadily through the second half of 2021, reaching 7.9% in December.

- Surprisingly, interest rates barely responded to the inflation fireworks. The Federal Reserve held money market rates near zero all year to support the economic recovery and framed inflation pressures as only temporary. The 10-year Treasury yield drifted below 1.75% all year and ended the year at 1.5%. Investment-grade corporates could borrow long-term for less than 3% throughout 2021's second half, even with inflation above 6%.

- The industry's financial condition remained strong in 2021. The multi-decade trend toward a regulated focus continued along with leverage appropriate for a lower risk profile. Balance sheet leverage, in aggregate, was largely unchanged. Four large utilities – Sempra, CenterPoint, Dominion and Berkshire Hathaway Energy – each reduced preferred equity and drove the small reduction in this metric. However, aggregate figures convey only broad, long-term trends and emphasize large utility holding companies. Balance sheet structures widely vary across the industry. Leverage increased at 27 of the 44 utilities included in EEI's industry consolidated data, but rose more than one percentage point at only 21. Leverage was reduced by more than one percentage point at 14 companies.

- The industry's consolidated total debt rose in 2021, a natural consequence of strong asset growth. Utilities took advantage of another year of very low interest rates and strong demand from fixed-income investors with most companies managing balance sheet ratios and cash flows to maintain investment-grade credit ratings. Long-term debt increased at 35 utilities. The nine instances where debt declined included large debt reductions at AVANGRID and Sempra tied to equity financings, at PPL funded through the sale of its U.K. subsidiary, and at DTE financed through the spin-off of its midstream business. Balance sheet management also produced five much smaller debt reductions.

- Common equity issuance was sharply lower after three active years. Four companies accounted for almost 70% of 2021's $9.4 billion total. AVANGRID raised $4 billion in a private placement with parent Iberdrola and the Qatar Investment authority. FirstEnergy likewise raised $1 billion from private investor Blackstone Infrastructure Partners. Consolidated Edison raised $775 million through a public offering. AEP also issued $600.5 million in new equity. Thirty utilities reported equity issuance in 2021, but generally in small amounts. 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 4.0% from year-end 2020 and 10.1% over the level at year-end 2019. This metric grew at nearly all utilities included in EEI's consolidated data. Such broad growth indicates the size and scope of the industry's build-out of new renewable generation, new transmission, reliability-related infrastructure and other capital projects related to the nation's clean energy transition.

- Debt-to-capitalization ratios by category show the dominance of regulated operations in the industry. The tendency in the Mostly Regulated category toward slightly lower leverage in 2021 resulted from AVANGRID'S balance sheet restructuring and, to a lesser extent, reduction in leverage at MidAmerican Energy.

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2021	12/31/2020r	% Change	$ Change
PP&E in service, gross	1,746,509	1,677,413	4.1%	69,096
Accumulated depreciation	502,863	481,097	4.5%	21,765
PP&E in service, net	1,243,646	1,196,315	4.0%	47,331
Construction work in progress	86,365	81,559	5.9%	4,806
Net nuclear fuel	15,358	15,252	0.7%	107
Other property	16,786	16,354	2.6%	432
PP&E, net	1,362,155	1,309,480	4.0%	52,676
Cash & cash equivalents	17,842	16,404	8.8%	1,438
Accounts receivable	47,728	41,962	13.7%	5,766
Inventories	25,220	24,300	3.8%	919
Other current assets	67,067	70,954	(5.5%)	(3,886)
Total current assets	157,857	153,620	2.8%	4,237
Total investments	136,761	129,344	5.7%	7,417
Other assets	283,880	274,860	3.3%	9,020
Total Assets	**1,940,654**	**1,867,303**	**3.9%**	**73,350**
Common equity	526,146	494,872	6.3%	31,274
Preferred equity	10,870	14,566	(25.4%)	(3,697)
Noncontrolling interests	25,939	27,502	(5.7%)	(1,563)
Total equity	562,954	536,940	4.8%	26,014
Short-term debt	41,836	35,951	16.4%	5,885
Current portion of long-term debt	37,380	39,208	(4.7%)	(1,828)
Short-term and current long-term debt	79,217	75,160	5.4%	4,057
Accounts payable	79,979	72,654	10.1%	7,326
Other current liabilities	54,400	63,311	(14.1%)	(8,911)
Current liabilities	213,596	211,125	1.2%	2,471
Deferred taxes	112,686	106,328	6.0%	6,358
Non-current portion of long-term debt	699,441	656,153	6.6%	43,288
Other liabilities	349,363	356,000	(1.9%)	(6,638)
Total liabilities	1,375,086	1,329,606	3.4%	45,480
Subsidiary preferred	712	712	0.0%	0
Other mezzanine	1,901	45	4106.4%	1,856
Total mezzanine level	2,613	757	245.2%	1,856
Total Liabilities and Owner's Equity	**1,940,654**	**1,867,303**	**3.9%**	**73,350**

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

The dispersion across companies in both categories – with some showing higher, some lower and others no change in leverage – indicates why individual company strategies are as meaningful as aggregate 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.

Capitalization Structure

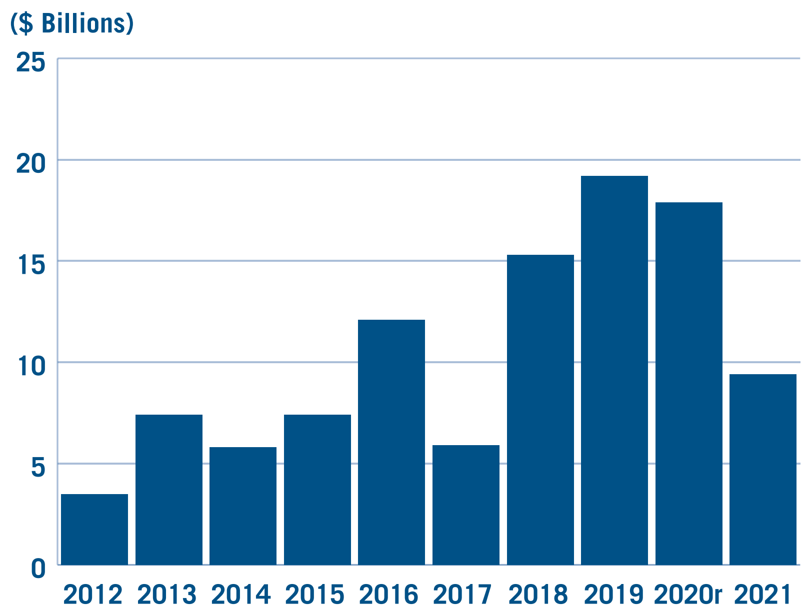
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure ($M)	12/31/2021	12/31/2020r	12/31/2019r
Common Equity	526,146	494,872	462,915
Noncontrolling Interests & Preferred Equity	36,808	42,068	29,811
Long-term Debt (current & non-current)*	736,821	695,361	627,662
Total	**1,299,776**	**1,232,301**	**1,120,389**
Common Equity %	40.5%	40.2%	41.3%
Noncontrolling Interests & Preferred Equity %	2.8%	3.4%	2.7%
Long-Term Debt (current & non-current)* %	56.7%	56.8%	56.0%
Total	**100.0%**	**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.

Proceeds from Issuance of Common Equity 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

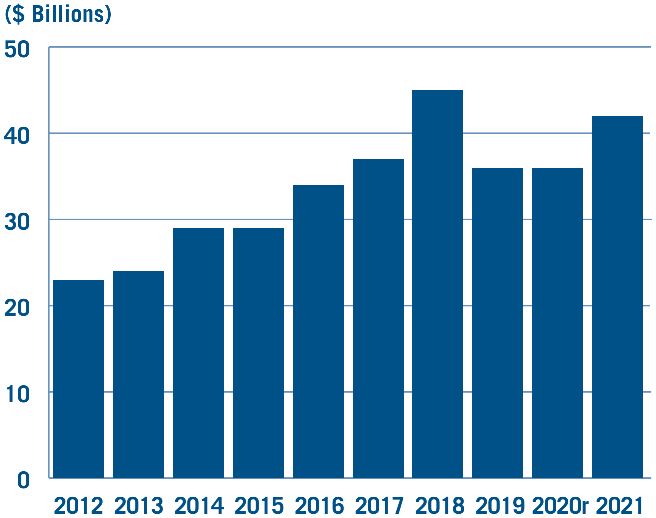


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Short-term Debt 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

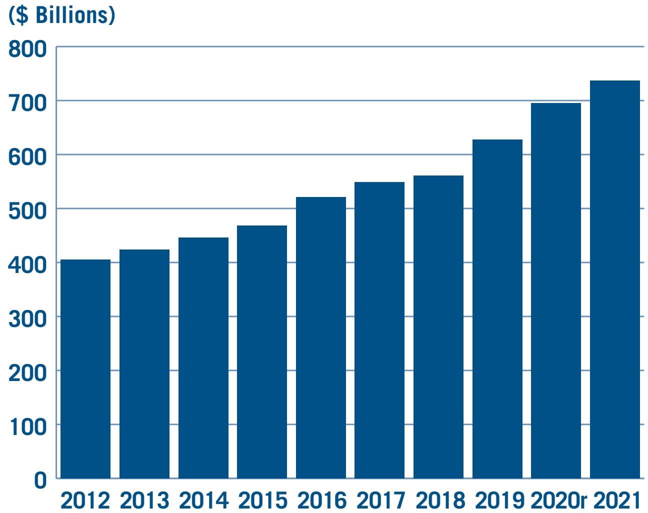


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Long-term Debt 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Debt-to-Cap Ratio by Category 2021 vs. 2020r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Total Industry	
	Number	%	Number	%	Number	%
Lower	12	34.3%	2	22.2%	14	31.8%
No Change*	8	22.9%	1	11.1%	9	20.5%
Higher	15	42.9%	6	66.7%	21	47.7%
Total	**35**	**100.0%**	**9**	**100.0%**	**44**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2021 vs. December 31, 2020. Refer to page v for category descriptions.

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure by Category 2021 vs. 2020r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated			Mostly Regulated		
	2021	2020r	Change	2021	2020r	Change
Common Equity ($M)	359,101	335,185	23,916	167,045	159,687	7,358
Total Preferred Equity	21,213	22,366	(1,152)	15,595	19,703	(4,107)
Long-term Debt (current & non-current)*	542,835	505,542	37,294	193,986	189,820	4,167
Total Capitalization	923,149	863,092	60,057	376,626	369,209	7,417
Common Equity %	38.9%	38.8%	0.1%	44.4%	43.3%	1.1%
Preferred Equity %	2.3%	2.6%	-0.3%	4.1%	5.3%	-1.2%
Long-Term Debt %	58.8%	58.6%	0.2%	51.5%	51.4%	0.1%
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.

Date	PP&E in Service, Net ($M)	% Change from 12/31/2017
12/31/2021	1,243,646	22.5%
12/31/2020r	1,196,315	17.9%
12/31/2019r	1,129,880	11.3%
12/31/2018	1,058,164	4.2%
12/31/2017	1,015,100	

Source: S&P Global Market Intelligence and EEI Finance Department.

Cash Flow Statement

- Net Cash Provided by Operating Activities decreased by $14.7 billion or 21.8%. The two primary contributors to this metric both generated cash. Cash supplied by Net Income grew 9.4% while cash supplied by Depreciation and Amortization (a non-cash expense) increased 5.3%. The 59.2% decrease in cash used for Change in Working Capital sourced mostly to accounting treatment of a 2020 restructuring at one large utility. The 40.3% increase in cash used for Other Operating Changes in Cash sourced to activity at nine relatively large utilities in 2021. Neither of these two line items reflects broad-based fundamental industry trends.

- Net Cash Used in Investing Activities decreased by $12.2 billion or 9.5%. The industry's capital spending — by far the largest component of this metric — totaled $134.1 billion in 2021, up $1.3 billion from 2020 after rising an unusually strong $8.9 billion, or 7.2%, in 2020. Industry capex has reached a new record high in each of the past ten years. Most utilities' five-year outlooks at year-end 2021 emphasized growth through rising regulated clean energy investment. Half of the utilities represented in consolidated data grew capex in 2021.

- EEI member companies continue to invest in clean energy resources and the infrastructure necessary to make the power grid more modernized, more resilient, and more 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 $9.6 billion, or 37.3%, from $25.6 billion to $35.2 billion. The increase sourced mostly to PPL's June 2021 sale of its U.K. utility business, Western Power Distribution (WPD), to National Grid for $10.4 billion. Cash used for Asset Purchases decreased by $5.3 billion, or 23.1%; this was mostly due to reduced asset purchases in 2021 at five large utilities compared to their activity in 2020.

- Net Cash Provided by Financing Activities decreased by $30.8 billion or 47.3%. The decline resulted primarily from broadly reduced debt issuance relative to 2020 as well as debt paydowns to strengthen balance sheets at a few large utilities. Twenty-five companies reported a reduction in cash provided by long-term debt. Issuance of common equity also declined, falling by nearly 50% to $9.4 million from $17.9 billion in 2020.

- Dividends Paid to Common Shareholders rose 3.3%, to $30.3 billion.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

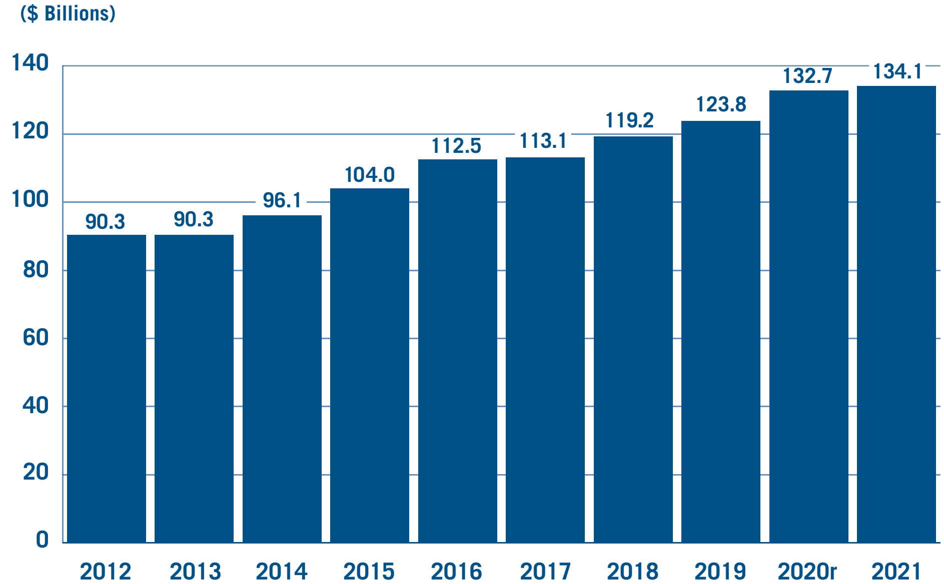
$ Millions	12 Months Ended		
	12/31/2021	12/31/2020r	% Change
Net Income	$42,277	$38,627	9.4%
Depreciation and Amortization	62,928	59,766	5.3%
Deferred Taxes and Investment Credits	5,278	4,196	25.8%
Operating Changes in AFUDC	(1,453)	(1,432)	1.5%
Change in Working Capital	(8,354)	(20,478)	(59.2%)
Other Operating Changes in Cash	(18,277)	(13,029)	40.3%
Net Cash Provided by Operating Activities	**82,400**	**67,651**	**21.8%**
Capital Expenditures	(134,056)	(132,733)	1.0%
Asset Sales	35,221	25,647	37.3%
Asset Purchases	(17,535)	(22,793)	(23.1%)
Net Non-Operating Asset Sales and Purchases	17,686	2,854	519.6%
Change in Nuclear Decommissioning Trust	(314)	(408)	(23.0%)
Investing Changes in AFUDC	49	102	(51.5%)
Other Investing Changes in Cash	754	2,081	(63.8%)
Net Cash Used in Investing Activities	**(115,881)**	**(128,104)**	**(9.5%)**
Net Change in Short-term Debt	5,043	3,182	58.5%
Net Change in Long-term Debt	45,444	68,220	(33.4%)
Proceeds from Issuance of Preferred Equity	3,783	5,364	(29.5%)
Preferred Share Repurchases	(2,100)	-	NM
Net Change in Prefered Issues	1,683	5,364	(68.6%)
Proceeds from Issuance of Common Equity	9,432	17,938	(47.4%)
Common Share Repurchases	(1,531)	(3,933)	(61.1%)
Net Change in Common Issues	7,901	14,006	(43.6%)
Dividends Paid to Common Shareholders	(30,279)	(29,319)	3.3%
Dividends Paid to Preferred Shareholders	(475)	(397)	19.9%
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(30,754)	(29,716)	3.5%
Other Financing Changes in Cash	5,112	4,219	21.2%
Net Cash (Used in) Provided by Financing Activities	**34,430**	**65,274**	**(47.3%)**
Other Changes in Cash	12	9	33.3%
Net increase (decrease) in cash and cash equivalents	$961	$4,830	(80.1%)
Cash and cash equivalents at beginning of period	$16,881	$11,574	45.9%
Cash and cash equivalents at end of period	$17,842	$16,404	8.8%

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Capital Expenditures 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

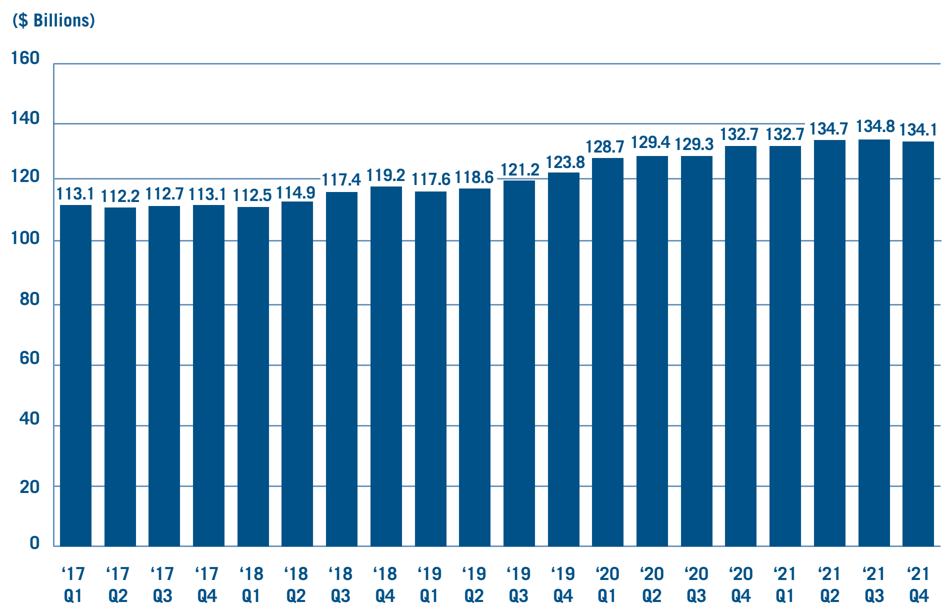


r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Spending—Trailing 12 Months

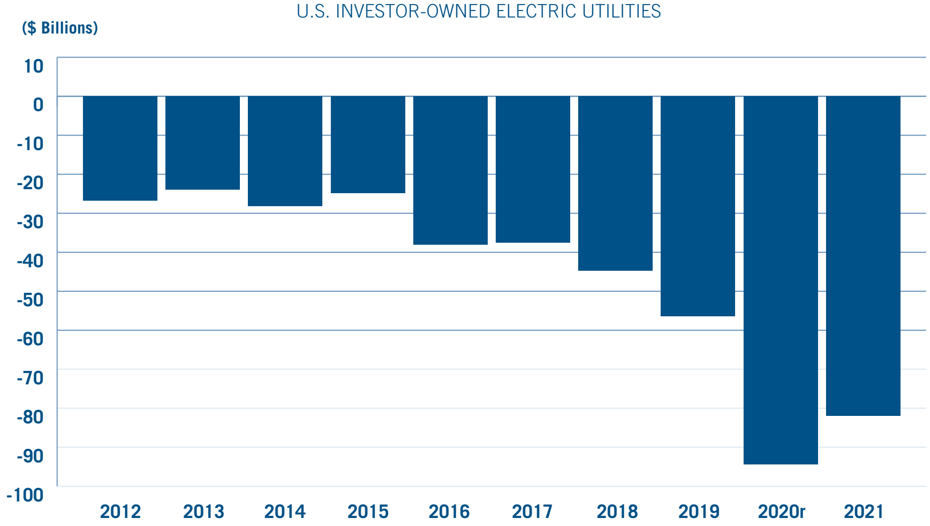
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Free Cash Flow (FCF) 2012–2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



($ Billions)	2012	2013	2014	2015	2016	2017	2018	2019	2020r	2021
Net Cash Provided by Operating Activities	84.0	87.1	89.0	101.6	98.3	101.2	100.1	95.3	67.7	82.4
Capital Expenditures	(90.3)	(90.3)	(96.1)	(104.0)	(112.5)	(113.1)	(119.2)	(123.8)	(132.7)	(134.1)
Dividends Paid to Common Shareholders	(20.5)	(20.8)	(21.1)	(22.5)	(23.8)	(25.5)	(25.6)	(27.9)	(29.3)	(30.3)
Free Cash Flow	**(26.8)**	**(24.0)**	**(28.2)**	**(24.8)**	**(38.1)**	**(37.5)**	**(44.7)**	**(56.4)**	**(94.4)**	**(81.9)**

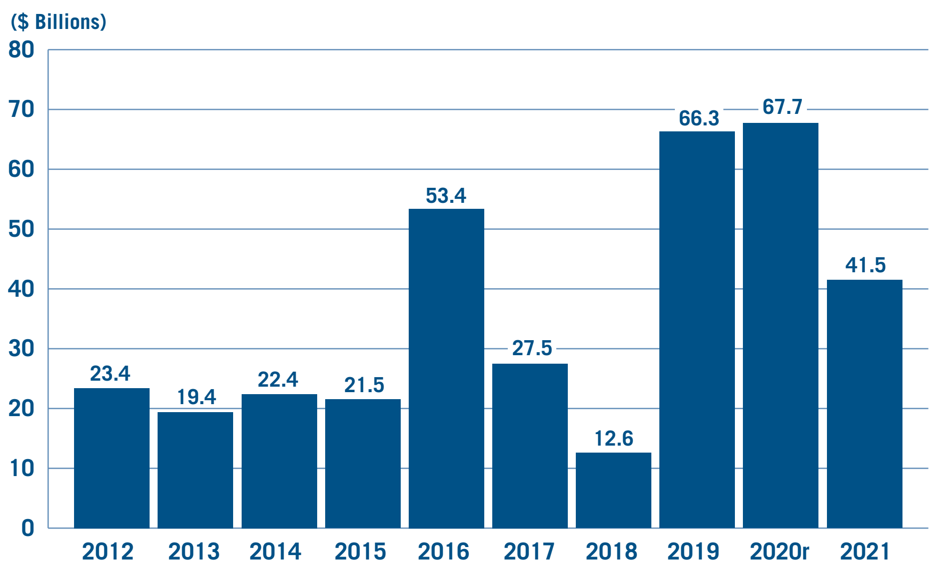
r = revised

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 2012–2021

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

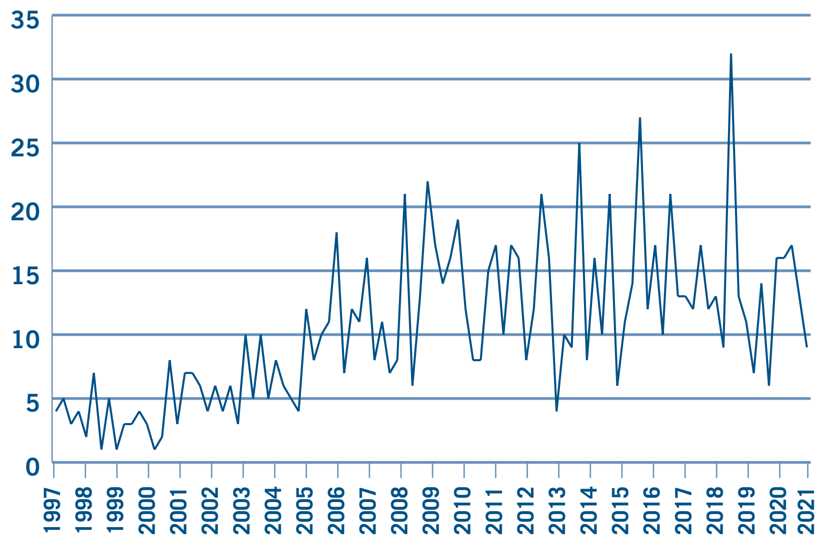
- There were approximately 28 percent more rate reviews filed in 2021 when compared to 2020. At the end of the year, there were 31 pending rate reviews while 48 rate reviews were decided.
- In total, electric companies requested revenue increases of approximately $9 billion in 2021. Of that amount, approximately $5 billion was approved.
- For 2021, the average awarded ROE was 9.40 percent, continuing a decade long downward trend. By way of comparison, for 2020, the average awarded ROE was 9.43 percent. On average, awarded ROE in 2021 was approximately 50 basis points lower than the average requested. Consistent with declining interest rates, average awarded ROEs have been under 10 percent for the electric industry for most of the last decade.
- Regulatory lag was approximately 8.41 months, which is slightly better than 2020. Commission agendas continued to be filled with numerous other regulatory filings including those related to COVID, clean energy transition, and affordability.

Key Highlights from 2021

- **COVID-Related Matters** – By the end of 2021, there were only a handful of states that had extended their disconnection moratoria until December 31. With most states having no active COVID-related disconnection moratoria, more than a dozen rate reviews had requests by electric companies to recover COVID-related costs. Most companies that sought approval to defer or amortize uncollectible expenses related to COVID-19 were successful. As a condition of settlement, some electric companies agreed to work with stakeholders to create new or expand existing income qualified programs or discount rates to assist customers that are still struggling economically due to the pandemic.
- **Affordability** – The topic of affordability is not new to regulated electric companies; however, the pandemic brought this issue to the forefront of numerous commissions. Many electric companies, that had filed or decided rate reviews in 2021, recognized the economic hardships customers were facing and utilized regulatory and accounting mechanisms to mitigate customer bill impacts. Some electric companies agreed to phase in rate increases over multiple years, offset costs through a variety of accounting mechanisms, or delay rate review requests until a later date. In addition, numerous states, like California, Connecticut, Illinois, and Pennsylvania, have continued discussions, via general dockets, around energy affordability.
- **Accelerated Clean Energy Transition** – Momentum for increased clean energy and carbon-free resources were a major focus for electric companies in 2021. The transition to clean energy requires the efficient upgrading of existing and development of new transmission in order to meet ambitious clean energy goals. Knowing that regulators, at both the state and federal level, must address numerous transmission-related issues, the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners (NARUC) established a joint-task force to increase cooperation and coordination. Meetings of this group are expected to continue throughout 2022.

Number of Rate Reviews Filed 1997–2021

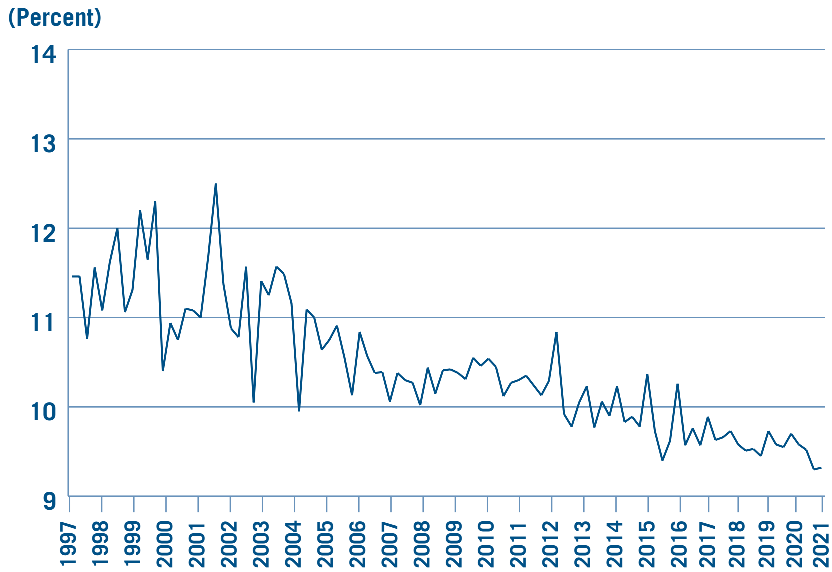
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

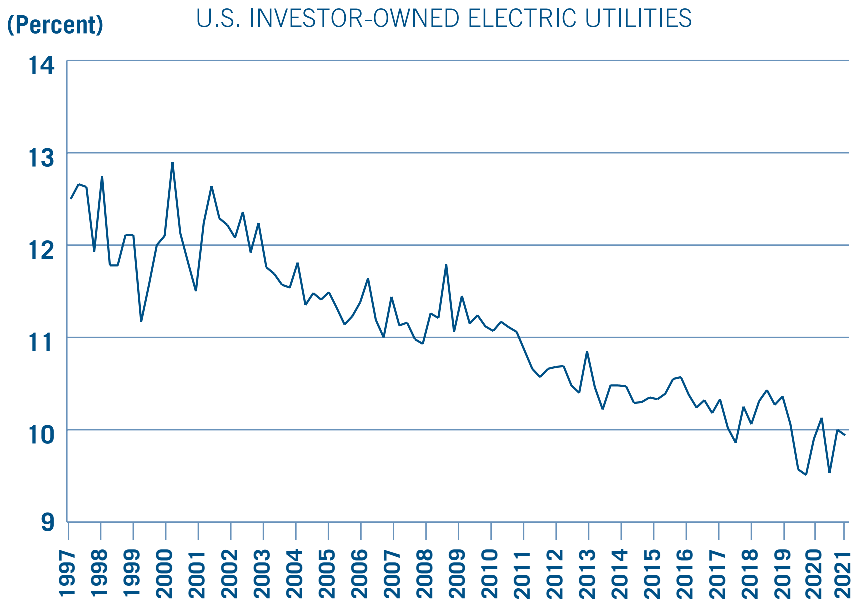
Average Awarded ROE 1997-2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



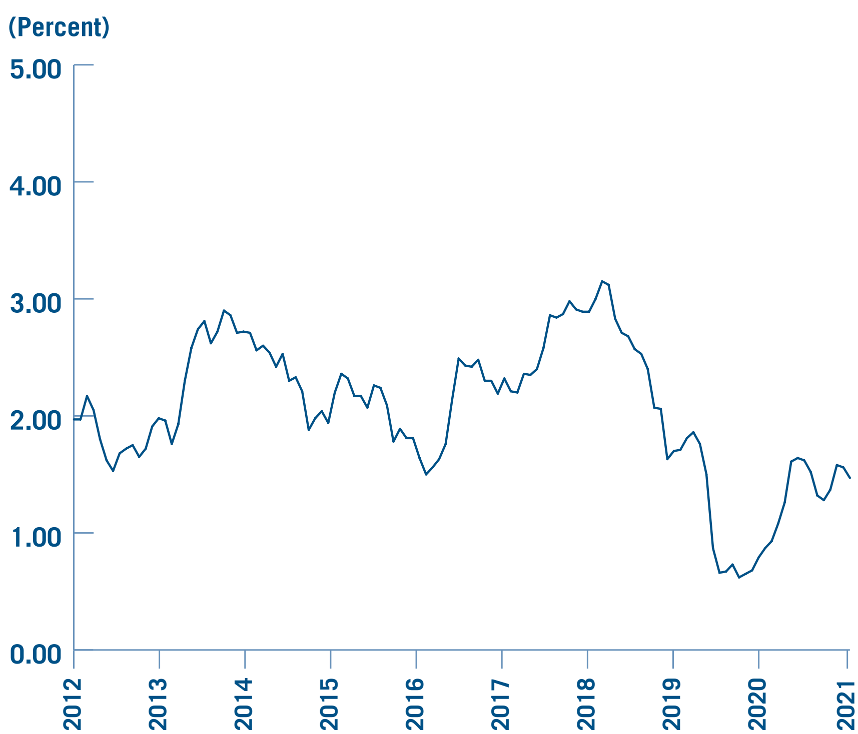
Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Average Requested ROE 1997–2021



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

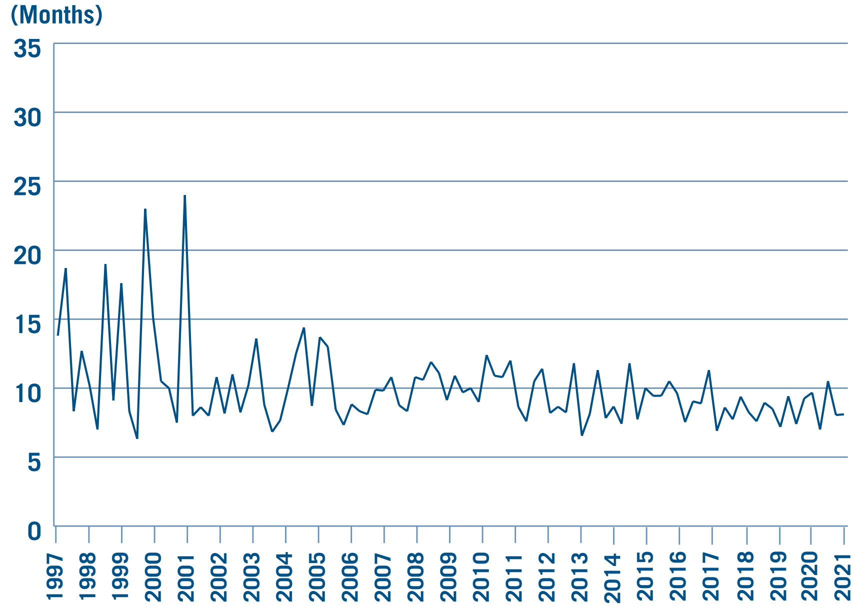
10-Year Treasury Yield
1/1/12 through 12/31/21



Source: U.S. Federal Reserve.

Average Regulatory Lag 1997–2021

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 Energy Supply & Finance Department. This group provides the 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 (listed in this section). 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 in order 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 annual fall gathering of utilities and the financial community; it is attended by more than 1,000 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Aaron Cope 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 Aaron Cope 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 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. Contact Randall Hartman 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 and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee, the Property Accounting & Valuation Committee, the Accounting Standards Committee, the Budgeting & Financial Forecasting Committee and the AGA Corporate Accounting and Property Accounting Committee, the conference provides a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries. The spring meeting is intended for all aforementioned committees, while the fall meeting is designed for the Corporate Accounting Committee and the Property Accounting & Valuation Committee. The meetings are open to members of the Committees and other employees of EEI/AGA member companies. Contact Dave Dougher for more information.

Tax School

Provides utility tax professionals with a forum to discuss developing tax issues impacting our member companies. This two and half day training is held every other year in the spring and is targeted for intermediate-level personnel. 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 Randall Hartman or 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 Randall Hartman or Dave Dougher for more information.

Property Accounting & Depreciation Training Seminar

This is a one and a half day seminar offered jointly with AGA that provides an introduction to property accounting and depreciation in the electric and natural gas utility industries. 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 Randall Hartman or Dave Dougher for more information.

Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Accounting for Energy Derivatives and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

The EEI Energy Supply & Finance Department Staff

Richard McMahon
Senior Vice President, Energy Supply and Finance
(202) 508-5571
rmcmahon@eei.org

Irene Ybadlit
Senior Coordinator, Energy Supply and Finance
(202) 508-5502
iybadlit@eei.org

Financial Analysis and Business Analytics Staff

Mark Agnew
Senior Director, Financial Analysis
(202) 508-5049
magnew@eei.org

Bill Pfister
Senior Director, Business Analytics
202-508-5531
bpfister@eei.org

Steve Frauenheim
Senior Manager, Business Analytics
202-508-5580
sfrauenheim@eei.org

Wenni Zhang
Senior Financial and Business Analyst
202-508-5142
wzhang@eei.org

Accounting and Investor Relations Staff

Randall Hartman
Director, Accounting
(202) 508-5494
rhartman@eei.org

Dave Dougher
Senior Manager, Accounting
(202) 508-5570
ddougher@eei.org

Aaron Cope
Manager, Investor Relations
(202) 508-5127
acope@eei.org

Kim King
Coordinator, Finance and Tax
(202) 508-5493
kking@eei.org

Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are upcoming meetings related to finance and accounting that may be of interest to you. For further details, contact Aaron Cope at (202) 508-5127, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

July 27-28, 2022
EEI/AGA FERC Accounting Liaison Committee Meeting with FERC Staff
EEI Office
Washington, DC

August 22-24, 2022
EEI/AGA Utility Internal Auditor's Training Courses
JW Marriott
Indianapolis, Indiana

August 22-25, 2022
EEI-AGA Introduction to Public Utility Accounting and Advance Public Utility Accounting Training Courses
JW Marriott
Indianapolis, Indiana

November 13-15, 2022
EEI Financial Conference
Diplomat Beach Resort Hollywood
Hollywood, FL

November 13, 2022
EEI Treasury Group Meeting
(Closed meeting, admittance by invitation only)
Diplomat Beach Resort Hollywood
Hollywood, FL

November 13, 2022
Chief Financial Officers Forum
(Closed meeting, admittance by invitation only)
Diplomat Beach Resort Hollywood
Hollywood, FL

November (TBD), 2022
Fall Accounting Conference and Property Accounting & Depreciation Training Seminar
Location TBD

December (TBD), 2022
Investor Relations Planning Group Meeting
(Closed meeting, admittance by invitation only)
New York, New York

December (TBD), 2022
Wall Street Advisory Group Meeting
(Closed meeting, admittance by invitation only)
New York, New York

May 21-24, 2023
Spring Accounting Conference
Grand Hyatt
Denver, Colorado

Earnings Twelve Months Ending December 31

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2021	2020r
Earnings Excluding Non-Recurring and Extraordinary Items	**53,480**	**54,217**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	(3,207)	(398)
Other Non-Recurring Revenues	1,161	—
Asset Write-downs	(2,012)	(6,704)
Other Non-Recurring Expenses	(7,875)	(8,504)
Total Non-Recurring Items	**(11,934)**	**(15,607)**
Extraordinary Items (net of taxes)		
Discontinued Operations	731	17
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**731**	**17**
Net Income	**42,277**	**38,627**
Total Non-Recurring and Extraordinary Items	**(11,203)**	**(15,589)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

U.S. Investor-Owned Electric Utilities

(At 12/31/2021)

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 Corporation
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

Alaska Power & Telephone Company
American Transmission Company
Central Hudson Gas & Electric Corp.
Cross Texas Transmission
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**.

EEI
Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696
202-508-5000 | www.eei.org

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 411

Value Line (VL)
Electric Utilities

June 13, 2023

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.

On average, this group had held up well over the first two-thirds of the year, down just a few percentage points in value. Over the past two months, the market's correction finally spread to this Industry. We view the recent correction as healthy, since this group had grown relatively expensive due to a rotation into these stocks earlier this year for their defensive fundamentals. With the price declines of late, we're now seeing opportunities for utility investors to add to their portfolios at more reasonable valuations than available in some time. In that vein, we'll discuss below some of the things we think utility investors should be considering when adding to and/or constructing their income-oriented portfolios.

The Inflation Reduction Act (IRA) of 2022 remains a topical subject for this Industry. The preliminary consensus among electric utility managements regarding the new legislation is that it's an overall positive for this Industry and cash flow accretive. It's not directly a boon to utilities, but should help to speed up the adoption of renewables/clean energy initiatives, as it makes the overall transition less painful for consumers through various tax incentives and subsidies for the next several years.

In particular, the Electric Utility Industry should benefit from the IRA based on how state political leadership reacts to the new legislation. Politicians should be more open to directing green-energy initiatives if they believe it will be less of a burden on their constituencies. State utility regulatory agencies will likely see it as such also, thereby taking that into account when setting electric rates and considering the inclusion of renewable-energy projects in a utility's rate base (the property, plant, and equipment on which utilities are allowed to earn an economic rate of return, given their status as regulated monopolies). Interestingly, the IRA apparently defines nuclear, which is "non-emitting" in terms of greenhouse gasses, as clean energy and grants tax incentives/subsidies that will help utilities make the necessary capital investments to keep their nuclear plants economically viable. (Note: renewable-energy was covered in depth in our August 12th, Utility East report.)

Considerations For Portfolio Construction

First and foremost, diversification is of the utmost importance. Whether an investor is positioned in just a few issues from this Industry or carries a portfolio mainly of utility and high-income stocks, they should have a minimum of 20 equities, and preferably more, in their portfolio, with no single issue making up much more than 5% of the whole. As investors, our tendency is to overweight our favorite ideas. Countless studies show that's not a good approach over time and can be quite detrimental.

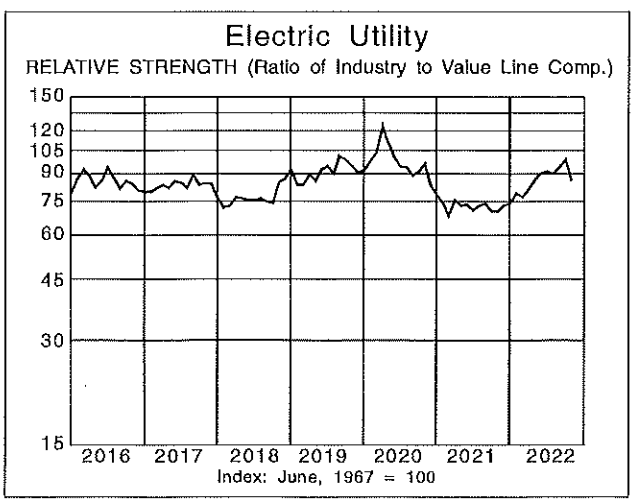
INDUSTRY TIMELINESS: 76 (of 93)

If keeping a portfolio of mainly utility stocks, that diversification should go beyond simple numbers. We'd recommend that utility investors vary their holdings with consideration to geography. For instance, we've noticed that utility stocks with geographic exposure to the oil patch have by and large done better than the group of late. It makes sense, as so goes oil prices, so goes local economies that support the utilities that serve them. A large overweighting to one geographic region, however, may create problems down the road. As an example, consider the investor who hypothetically was based in California and owned just the three major California-based issues a number of years back. All were stricken with wild-fire problems to varying degrees. PG&E filed for bankruptcy protection, and Edison International has underperformed for years.

A balanced approach regarding diversification is advised from a number of directions. Lately, renewable-energy looks very promising for this Industry. Perhaps an investor really likes solar-oriented equities or off-shore wind directed ideas. We wouldn't advise a utility portfolio too overweighted in any one of these arenas. Recently, solar-oriented equities had a bit of a scare when the U.S. Department of Commerce was considering a major tariff hike on imported solar panels that included wafers made in China. Luckily for solar-oriented companies that fiasco was narrowly averted by the Biden Administration's intervention. So balance across different business models, including keeping a core group of tried-and-true, conservatively-managed, mainly-regulated utilities versus hybrid operations, would be advisable.

Lastly, dividend growth matters. We discussed this topic at length in our most recent Utility West Industry report in Issue 11, dated October 21st, so we're not going to rehash that topic here in depth. A balanced growth- and income-oriented approach to utility selection, more weighted to growth, would be advisable. On a final note, many investors may need the dividend income from their utility holdings, but there are studies that show that this slow-growth, but steady Industry actually compares favorably over the long term to the broader market's total returns when dividend reinvestment is accounted for.

Anthony J. Glennon



ELECTRIC UTILITY (CENTRAL) INDUSTRY

All major companies in the Electric Utility (Central) Industry reported third-quarter financial results and are reviewed in this Issue.

Stocks in the the electric utility industry have been among the worst-performing sectors of the S&P 500 the past few months, but have rebounded as of late.

Through the first nine months of 2022, utilites were among the best-performing segments, highlighted by high dividend yields and the constancy of electric utilities. However, all but one equity covered in the Electric Utility (Central) Industry declined considerably in value since our last review in Septemher.

INDUSTRY TIMELINESS: 66 (of 93)

The Recent Rout

To start the year, utility stocks were a safe haven from market turmoil. Even in economic downturns, utilities have typically been among the strongest performers as the resource they provide is a necessity to customers. However, the industry could not protect investors from the latest market conditions. The Federal Reserve has continued raising interest rates aggressively, causing competition for this group. Indeed, income-oriented accounts have been increasingly attracted to the rising payouts offered by the bond market.

Stocks in the Industry have tumbled in coordination with rising bond rates. The 10-year yield on Treasury notes climbed above 4.2% in late October, and currently are around 3.7%. In contrast, most utilities lost a significant amount of value in October before rebounding in price through November. As interest rates rise, the Treasury market will present an increasingly appealing alternative to stocks particularly for income-oriented investors, and future moves from the Fed will certainly dictate the performance of utilties moving forward.

Higher Rates Continue To Drive Earnings

Rate hikes remain one of the main drivers to earnings for utilities. A majority of the equities covered in the Electric Utility (Central) Industry have subsidiaries that have pending or recently approved rate cases. In the third quarter, *OGE Energy* agreed to its $30 million rate case in Oklahoma, and implemented new fuel rates in Arkansas. *DTE Energy* recently approved its $30.6 million hike and rates went into effect in late November. Rate hikes will remain necessary and beneficial, and will continue driving earnings growth long term.

Positive Near-Term Outlook

All Electric Utility Industry stocks located in the central region of the United States reported third-quarter results. While all of the utilities, besides *Allete*, have seen their stock prices decrease significantly, the near-term financial outlook remains optimistic in most cases. In fact, *Allete* shares have risen by almost 10% since our last review. Management reaffirmed its 2022 earnings-per-share range of $3.60 to $3.90, indicating solid earnings growth throughout the full-year. *WEC Energy* shares dropped nearly 10%, but had a strong financial performance in the third quarter. Earnings per share for the period beat our forecast, and the company now expects to reach the high end of its targeted range of $4.38 to $4.40 a share. *Evergy* also delivered strong financial results and guidance. The utility posted earnings of $1.86 per share, on a top line of $1.9 billion, exceeding our and Wall Street's expectations. However, this strong performance was not enough to overcome macroeconomic headwinds and its shares dropped nearly 20% in the period.

Dividends or Treasuries

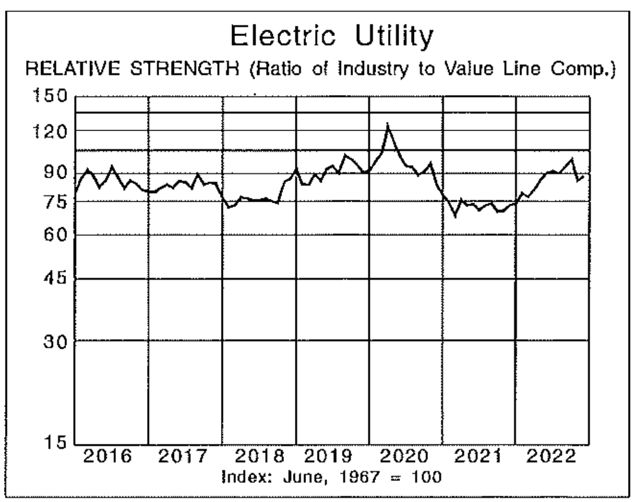
Utility stocks offer some of the highest dividend payouts in the market. The industry average of 3.2% far-outpaces the *Value Line* median yield of 2.1%, which has long-made utility stocks an enticing investment for income-oriented accounts. However, rising Treasury market yields have offered investors a much safer, alternative investment. In October, 10-year yields closed above 4%, and have since dropped to around 3.7%. The recent slip in treasury yields has already improved the trading conditions of utilities.

Conclusion

While nearly all of the stocks covered in the group lost a significant amount of value as of late, industrywide long-term capital appreciation potential remains unappealing. A number of utilities remain close to or inside our 18-month and 3-to 5-year Target Price Ranges.

Almost all of the equities in the Electric Utility Industry have been hit hard over the past three months. Utilties have long served as a strong, consistent investment to conservative accounts due to Above Average Safety ranks, and high dividend yields. As of late, however, utility stocks have lost appeal as interest rates continue to increase. Income-oriented investors are becoming more attracted to 'risk-free', climbing bond yields versus investing in individual equities. *Otter Tail Corp.*, *Evergy Inc.*, *DTE Energy*, and *MGE Energy* were among the worst performers over the past three months, each losing more than 15% in market value over that interim. Most equities have fared better recently, the Utilities Sector Fund, XLU which had fallen 18% over the three months through October, is up more than 10% since. Despite the recent price recovery, the macroeconomic climate, most notably rising interest rates, will continue to put utility stocks under duress.

Zachary J. Hodgkinson



ELECTRIC UTILITY (WEST) INDUSTRY

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 remaining Industry participants, in Issue 5.

Electric utility stocks turned in a decent performance in 2022. On average, the group held up well, down just 2% over the course of the year compared to a more than 19% decline in the S&P 500. There was a stretch from late summer to early autumn when interest rate sensitive stocks sold off severely. We viewed it as a good opportunity for utility investors to add to their holdings. Since our review three months ago, the 35 electric utilities included within *The Value Line Investment Survey* are up more than 14% on average, outperforming the S&P 500 by nearly eight percentage points.

At present, 3- to 5-year total return prospects for electrics look thin, with the median level at just 7%. Although there is a generally reduced risk level in owning utilities, given that they're regulated monopolies, we'd still like to see roughly 10% long-term total return potential in order to recommend them to utility investors. That's in line with the long-run average for the broad market. Meanwhile, the median dividend yield of electric utility stocks is 3.5%, 130 basis points above the average of all dividend-paying issues covered by *Value Line.*

Topical Considerations

The Inflation Reduction Act (IRA) of 2022 remains a topical subject for this Industry. The preliminary consensus among electric utility managements regarding the new legislation is that it's an overall positive for this Industry and cash flow accretive. While the IRA won't deliver a windfall to the companies within this group, it should help to speed up the adoption of renewables/clean energy initiatives, as it makes the overall process more palatable to consumers through tax incentives and subsidies over the next several years.

Moreover, electric utilities should in theory profit from the IRA based largely on how state political leadership reacts to the new legislation. Politicians ought to be more willing to push for renewable-energy initiatives if the transition is perceived as less burdensome on their constituencies. State utility commissions are likely to see it similarly. We expect they will take the consumer subsidies into account when setting electric rates, and considering the inclusion of renewable-energy projects in a utilities rate base (RB). (The RB is the dollar value of the property, plant, and equipment on which a utility is allowed to earn a specified economic rate of return, given its status as a regulated monopoly.)

We found it interesting that the IRA defines nuclear power, which is "non-emitting" in terms of green-house gases, as clean energy. The act grants tax incentives/subsidies that will help electric utilities make the necessary capital improvements to keep their nuclear power plants economically viable. (Note: for a more in depth discussion of renewable-energy prospects, please see our August 12th, Utility East report.)

INDUSTRY TIMELINESS: 87 (of 93)

Utility Portfolio Considerations

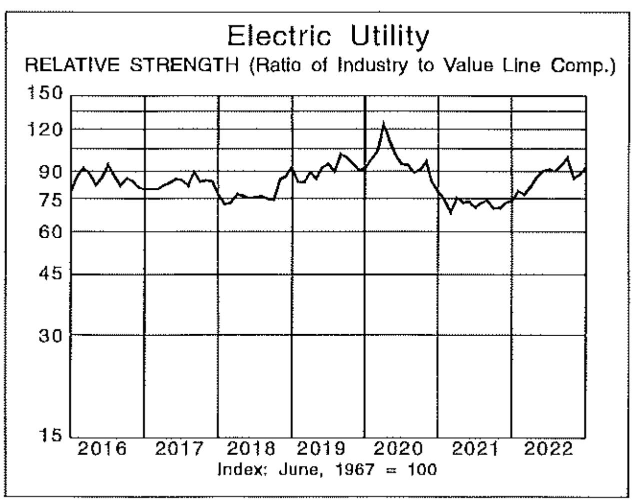
First, we want to be clear that we're not suggesting subscribers own a portfolio primarily made up of utilities. However, for those so inclined we'd like to share some considerations. Diversification is very important. Whether an investor is positioned in just a few issues from this Industry or carries a portfolio mainly of utility and high-income stocks, they should have a minimum of 20 equities, and preferably more. No single issue should make up much more than 5% of the whole. As investors, our tendency is to overweight our favorite ideas. That should be avoided. Countless studies show that approach can be quite detrimental.

If keeping a portfolio with a high weighting of utilities, diversification should extend beyond simple numbers. Investors should vary their holdings with considerations to geography. Natural disasters could wreak havoc on a portfolio with too much geographic exposure to the same area. A shift in regulatory climate could be problematic in that regard, as well.

A balanced approach to diversification from numerous directions is advisable. Lately, renewable energy looks promising for this industry. An investor may be enthused with solar-oriented equities, or offshore-wind-directed ideas. It would be better to seek diversification across various business models, including keeping a core of some conservatively-managed, mainly regulated utilities as opposed to too many hybrid operations.

Lastly, dividend growth matters. This was discussed in depth in our last Utility West Industry report, dated October 21st. A balanced growth- and income-oriented approach to utility selection, weighted more to growth is advisable. On a final note, many investors may need the dividend income from their utility holdings, but there are studies which show that this relatively slow-growth, but steady Industry actually compares reasonably well over the long run to the broader market's total returns when dividend reinvestment is accounted for. This is the power of compounding.

Anthony J. Glennon



ALLETE NYSE-ALE

RECENT PRICE **66.34** | P/E RATIO **17.7** (Trailing: 18.0 / Median: 19.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **3.9%** | VALUE LINE

High:	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7	73.1	68.6
Low:	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2	56.8	47.8

TIMELINESS 4 Lowered 11/18/22
SAFETY 2 New 10/1/04
TECHNICAL 5 Lowered 12/9/22
BETA .90 (1.00 = Market)

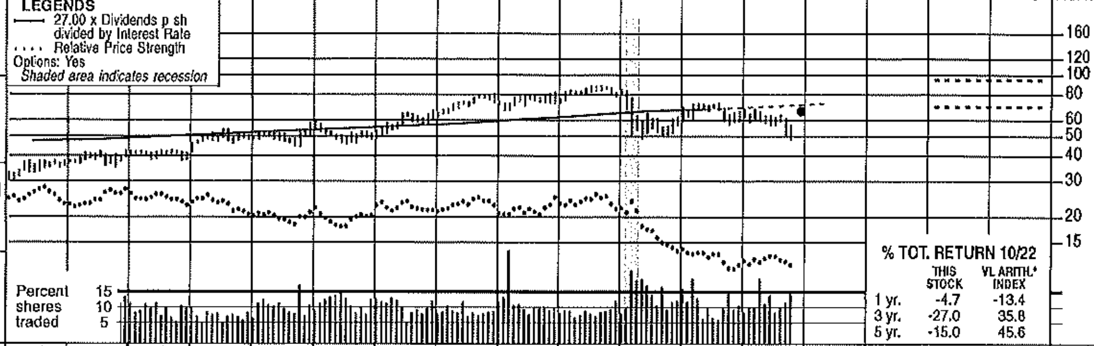
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$45-$80 $63 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+45%)	13%
Low	70	(+5%)	6%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	139	172	134
to Sell	131	103	130
Hld's(000)	39713	44326	44590



Target Price Range 2025 | 2026 | 2027

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.7	-13.4
3 yr.	-27.0	35.8
5 yr.	-15.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.23	27.33	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	*27.20*	*27.60*	Revenues per sh	*29.50*
4.14	4.42	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	*8.00*	*8.50*	"Cash Flow" per sh	*9.75*
2.77	3.08	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	*3.75*	*3.95*	Earnings per sh A	*4.75*
1.45	1.64	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*	*2.70*	Div'd Decl'd per sh B ■ †	*3.00*
3.37	6.82	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	*3.70*	*5.95*	Cap'l Spending per sh	*7.25*
21.90	24.11	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	45.38	*47.00*	*49.10*	Book Value per sh C	*54.00*
30.40	30.80	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	*57.00*	*58.00*	Common Shs Outst'g D	*61.00*
16.5	14.8	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	.94	1.10	*Value Line*		Relative P/E Ratio	*.95*
3.2%	3.6%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $2043.7 mill. **Due in 5 Yrs** $390.7 mill.
LT Debt $1653.0 mill. **LT Interest** $65.9 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/21 $745.7 mill. **Oblig** $911.7 mill.

Pfd Stock None

Common Stock 57,161,878 shs.

MARKET CAP: $3.8 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	1169.1	1419.2	*1550*	*1600*	Revenues ($mill)	*1800*
97.1	104.7	124.8	163.4	155.3	159.2	174.1	172.4	174.2	169.2	*215*	*230*	Net Profit ($mill)	*290*
28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	--	--	NMF	NMF	*NMF*	*NMF*	Income Tax Rate	*NMF*
5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	1.1%	1.5%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	41.0%	42.2%	*39.5%*	*39.5%*	Long-Term Debt Ratio	*40.5%*
56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	*60.5%*	*60.5%*	Common Equity Ratio	*59.5%*
2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	3887.8	4176.3	*4465*	*4700*	Total Capital ($mill)	*5550*
2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	4840.8	5100.2	*5215*	*5300*	Net Plant ($mill)	*5675*
5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	5.3%	4.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*7.5%*	*8.0%*	Return on Com Equity E	*9.0%*
2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	2.0%	1.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.5%*
71%	72%	67%	60%	66%	68%	66%	70%	74%	78%	*69%*	*68%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.5	-12.0	+11.5
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	1573	1588	1557
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	277	230	219

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	-2.5%	3.0%
"Cash Flow"	5.5%	2.5%	4.5%
Earnings	4.0%	1.0%	6.0%
Dividends	3.5%	4.0%	3.5%
Book Value	5.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	357.2	290.4	288.3	304.6	1240.5
2020	311.6	243.2	293.9	320.4	1169.1
2021	339.2	335.6	345.4	399.0	1419.2
2022	383.5	373.1	388.3	*405.1*	*1550*
2023	*400*	*390*	*400*	*410*	*1600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.18	.64	.60	.92	3.33
2020	1.28	.39	.78	.90	3.35
2021	.99	.53	.53	1.18	3.23
2022	1.24	.67	.59	*1.25*	*3.75*
2023	*1.30*	*.65*	*.90*	*1.10*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175	.6175	.6175	2.47
2021	.63	.63	.63	.63	2.52
2022	.65	.65	.65	.65	

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%; paper/wood products, 9%; other industrial, 8%; residential, 13%; commercial, 13%; wholesale, 14%; other, 16%. 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. '21 deprec. rate: 3.2%. 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's Minnesota Power subsidiary had its rate case hearing extended and the utility awaits a decision by the end of February, with final rates likely being implemented in mid-2023. Minnesota Power also filed a proposed agreement that would add 400 megawatts of wind energy and 300 megawatts of solar energy as the company remains committed to increasing renewable energy and providing 100% carbon-free energy by 2050. Meanwhile, Superior Water, Light and Power, the company's subsidiary in Wisconsin, expects a final order in its rate case by the end of the year. The case would generate $4.3 million of additional annual revenue if its proposed rate increase of 3.6% is approved.

ALLETE posted third-quarter earnings of $0.59 per share on net income of $33.7 million, a $6.1 million increase year over year. Interim rates at Minnesota Power, along with a strong showing from the regulated operations segment were the main drivers to an improved performance in the September period. Our earnings estimate remains at the midpoint of management's full-year updated earnings per share range of $3.60 to $3.90.

The Inflation Reduction Act should greatly improve the continued challenging operating environment. The biggest benefit should be the effect of production tax credits and investment tax credits. The tax credits will provide new investment options, especially in clean energy. The utility expects to add $45-$50 million of credits in 2023 due to the Act.

Shares of ALLETE have been downgraded to Below Average (4) for Timeliness. The stock is also trading above the midpoint of our 18-month Target Price Range due to a recent uptick in its value. In fact, these shares are up more than 8% since our last review in early September, among one of the best-performing equities in the utility industry, which has been under pressure due to rising interest rates. While long-term capital appreciation potential does not stand out, an attractive dividend yield of 3.9% is above the utility average. Too, ALLETE has a high score for Price Stability and is ranked Above Average (2) for Safety.

Zachary J. Hodgkinson *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; loss on disc. ops.: '06, 2¢. '19 EPS don't sum due to rounding. Next earnings report due early Feb. (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 '21: $9.62/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	90
Price Growth Persistence	35
Earnings Predictability	90

ALLIANT ENERGY NDQ-LNT

RECENT PRICE 55.78 | P/E RATIO 20.3 (Trailing: 21.0; Median: 20.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 4 Lowered 11/18/22

SAFETY 2 Raised 9/28/07

TECHNICAL 4 Lowered 12/9/22

BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High: $45-$80 | Midpoint (% to Mid): $63 (10%)

2025-27 PROJECTIONS

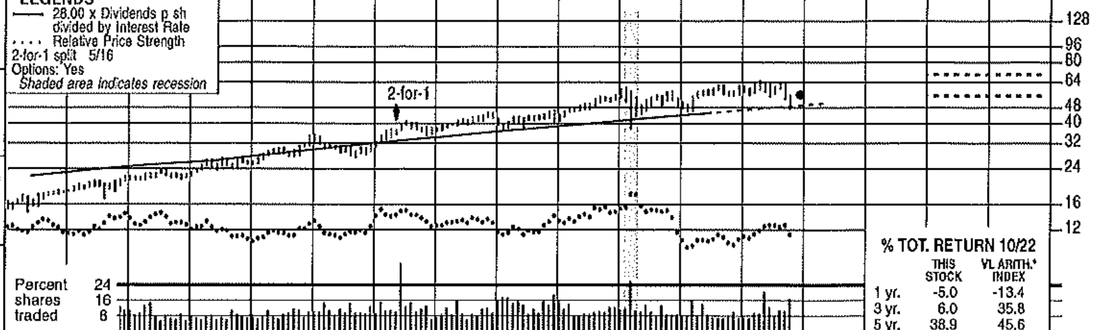
	Price	Gain	Ann'l Total Return
High	70	(+25%)	9%
Low	55	(Nil)	3%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	265	314	278
to Sell	259	232	263
Hld's(000)	195423	188290	192005

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3	65.4
Low:	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7	46.0	47.2

LEGENDS
— 28.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.0	-13.4
3 yr.	6.0	35.8
5 yr.	38.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.46	15.57	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	*16.35*	*16.90*	Revenues per sh	*18.50*
2.16	2.56	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	*5.50*	*5.75*	"Cash Flow" per sh	*6.75*
1.03	1.35	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	*2.70*	*2.95*	Earnings per sh A	*3.50*
.58	.64	.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*	Div'd Decl'd per sh B ■ †	*2.15*
1.71	2.46	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	*5.90*	*5.90*	Cap'l Spending per sh	*6.25*
11.42	12.15	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	*25.05*	*26.25*	Book Value per sh C	*30.25*
232.25	220.72	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	*251.00*	*251.50*	Common Shs Outst'g D	*253.00*
16.8	15.1	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	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.91	.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.13	*Value Line*		Relative P/E Ratio	*1.00*
3.3%	3.1%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $8611 mill. Due in 5 Yrs $2126 mill.
LT Debt $7570 mill. LT Interest $272 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $2 mill.

Pension Assets-12/21 $1011 mill. Oblig $1251 mill.

Pfd Stock None

Common Stock 251,021,830 shs.

MARKET CAP: $14.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	*4100*	*4250*	Revenues ($mill)	*4700*
337.8	382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	*700*	*745*	Net Profit ($mill)	*885*
21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	10.8%	NMF	*4.0%*	*4.0%*	Income Tax Rate	*4.0%*
6.5%	8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	*4.0%*	*5.0%*	AFUDC % to Net Profit	*6.0%*
48.4%	46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	*54.5%*	*54.0%*	Long-Term Debt Ratio	*55.0%*
48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	*45.5%*	*46.0%*	Common Equity Ratio	*45.0%*
6476.6	6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	*13875*	*14425*	Total Capital ($mill)	*17100*
7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	*16025*	*17075*	Net Plant ($mill)	*20300*
6.3%	7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.1%	11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	*11.0%*	*11.5%*	Return on Shr. Equity	*11.5%*
10.3%	11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	*11.0%*	*11.5%*	Return on Com Equity E	*11.5%*
3.9%	4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
64%	57%	60%	66%	72%	64%	62%	61%	62%	62%	*61%*	*61%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	-2.3	+3.7
Avg. Indust. Use (MWH)	11448	11134	NA
Avg. Indust. Revs. per KWH (¢)	6.98	7.55	7.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5626	5496	5486
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.6	+.8
Fixed Charge Cov. (%)	265	251	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-.5%	*4.5%*
"Cash Flow"	7.0%	7.5%	*5.5%*
Earnings	7.0%	8.0%	*6.0%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	5.5%	7.0%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	987.2	790.2	990.2	880.1	3647.7
2020	916	763	920	817	3416.0
2021	901	817	1024	927	3669.0
2022	1068	943	1135	*954*	*4100*
2023	*1100*	*925*	*1175*	*1050*	*4250*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.53	.40	.94	.46	2.33
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	*.40*	*2.70*
2023	*.80*	*.65*	*1.05*	*.45*	*2.95*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	

BUSINESS: Alliant Energy Corporation (formerly Interstate Energy) is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity to 985,000 customers and gas to 425,000 customers in Wisconsin, Iowa, and Minnesota. Electric revenue by state: WI, 43%; IA, 56%. MN, 1%. 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 revs. '21 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy came up a bit short in the September quarter. Indeed, on a reported basis, the Wisconsin-based electric utility earned $0.90 a share in the period, down 12% year over year, even as overall revenue rose 11%, to nearly $1.14 billion. Weighing on EPS was, among other things, a one-time charge below the operating line (included in our estimates). Notably, Alliant wrote down the value of tax assets on its balance sheet after Iowa's Department of Revenue announced a reduction in state levies on corporate income beginning next year. That said, operating conditions remained generally favorable, with warmer-than-normal weather driving increased air-conditioner and electricity use across Alliant's three-state footprint.

The utility's investment roadmap includes a notable amount of energy storage. In late September, Alliant filed a plan with the Public Service Commission of Wisconsin, calling for the addition of 175 megawatts of battery storage in the state. Specifically, the facilities would be located in Grant and Wood counties, alongside two previously-approved solar arrays. Importantly, they'd provide bridge power for more than 180,000 homes at times when sun- and wind-power generation is inadequate.

The Inflation Reduction Act (IRA) that was signed into law in mid-August is expected to be a big benefit. As we understand it, new financing options under the IRA will enable Alliant Energy to take full ownership of 12 solar-power farms that it currently shares with several investment partners. According to a recent report, the transition could save the utility and its customers upwards of $138 million.

Shares of Alliant Energy are ranked 4 (Below Average) for relative year-ahead price performance. At the recent quotation, we think that buy-and-hold investors will also do better elsewhere. Notably, at 3.2%, the dividend yield is below both the utility average and less-risky returns offered by United States Treasuries. Prospects over the next 18 months and the 3- to 5-year period are also subpar. Like many electric utility issues, the recent quotation is within our 2025-2027 Target Price Range.

Nils C. Van Liew *December 9, 2022*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (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	70
Earnings Predictability	95

AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE 95.22 | P/E RATIO 18.6 (Trailing: 19.7; Median: 17.0) | RELATIVE P/E RATIO 1.14 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 4/1/22

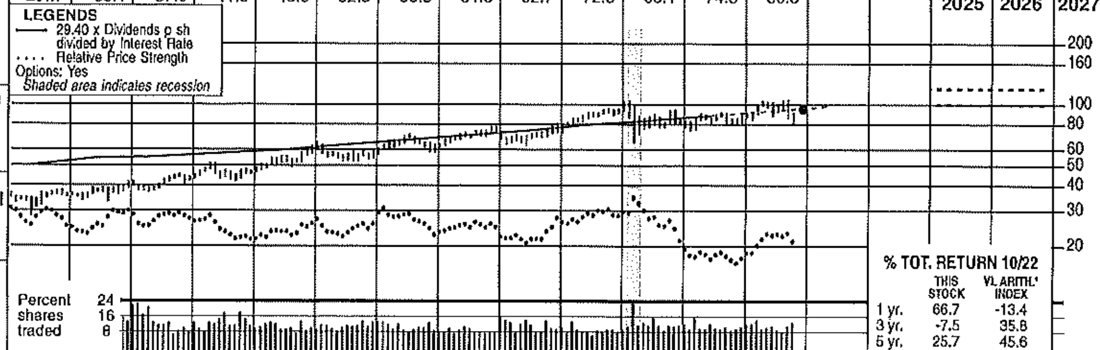
SAFETY 1 Raised 3/17/17

TECHNICAL 2 Lowered 11/18/22

BETA .75 (1.00 = Market)

High:	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	105.6
Low:	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	80.3

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High: $89-$127 — Midpoint (% to Mid): $108 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+25%)	9%
Low	100	(+5%)	5%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	673	634	624
to Sell	475	521	499
Hld's(000)	382433	385400	384675

Percent shares traded: 24, 16, 8

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	66.7	-13.4
3 yr.	-7.5	35.8
5 yr.	25.7	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.82	33.41	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	35.20	35.95	Revenues per sh	38.55
6.67	6.80	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	11.50	11.95	"Cash Flow" per sh	14.00
2.86	2.86	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	5.00	5.35	Earnings per sh A	6.50
1.50	1.58	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	3.35	Div'd Decl'd per sh B ■ †	4.00
8.89	8.88	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	15.35	14.15	Cap'l Spending per sh	14.00
23.73	25.17	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	47.30	50.30	Book Value per sh C	59.00
396.67	400.43	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	514.00	523.00	Common Shs Outst'g D	545.00
12.9	16.3	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	Bold figures are		Avg Ann'l P/E Ratio	17.0
.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.93	Value Line		Relative P/E Ratio	.95
4.1%	3.4%	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%	estimates		Avg Ann'l Div'd Yield	3.6%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $36349 mill. Due in 5 Yrs $12886 mill.
LT Debt $33647 mill. LT Interest $1067 mill.
Incl. $549.4 mill. securitized bonds. Incl. $500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $119.6 mill.
Pension Assets-12/21 $5352.9 mill. Oblig $5187.0 mill.
Pfd Stock None

Common Stock 513,863,678 shs. as of 10/27/22
MARKET CAP: $48.9 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	18100	18800	Revenues ($mill)	21000
1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	2580	2775	Net Profit ($mill)	3565
33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	7.0%	7.0%	Income Tax Rate	7.0%
11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	7.0%	7.0%	AFUDC % to Net Profit	5.0%
50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	58.0%	58.0%	Long-Term Debt Ratio	57.5%
49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	42.0%	42.0%	Common Equity Ratio	42.5%
30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	57775	62950	Total Capital ($mill)	75900
38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	70650	74600	Net Plant ($mill)	87300
6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	4.5%	4.5%	Return on Total Cap'l	5.5%
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	11.0%	10.5%	Return on Shr. Equity	11.0%
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	11.0%	10.5%	Return on Com Equity E	11.0%
3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	4.0%	4.0%	Retained to Com Eq	4.5%
63%	62%	61%	60%	54%	87%	65%	67%	65%	81%	63%	63%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	--	+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)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	3.5%
"Cash Flow"	4.5%	5.0%	5.5%
Earnings	4.5%	4.0%	6.5%
Dividends	5.0%	6.0%	6.0%
Book Value	4.0%	3.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	3341	18100
2023	4800	4300	5150	4550	18800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.41	1.02	1.33	1.24	5.00
2023	1.30	1.25	1.75	1.05	5.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	

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. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power will soon complete a divestiture, and the company is interested in shedding other assets. AEP expects to raise $1.45 billion from the sale of its Kentucky Power subsidiary. The motivation for the sale is the entity's lack of an adequate return on equity. The last remaining hurdle before the deal can go through is the approval of an application, which should be received by mid December. The transaction would then close by early January. The company has also started accepting initial bids for its 1,600-megawatt portfolio of nonregulated renewable-energy projects, either piecemeal or as a whole. Management is now moving on to the due diligence process with select bidders. It expects the process to close in the June quarter of 2023. Meanwhile, the company is conducting a strategic review of the retail business which it expects to complete in the first half of 2023. Following divestitures, AEP plans to expand its investments in regulated renewable-energy projects, which have less risk than nonutility assets, and electric transmission.

The company appears well positioned to meet or exceed its full-year guidance. American continues to realize above-forecast, weather-normalized load (the amount of electricity on the grid at any given time), which is now 2.6% above pre-pandemic levels. Year to date, residential, commercial, and industrial sales comparisons are up .3%, 3.8%, and 5.5%, respectively. This compares to the company's 2.9% (revised upward from 1.6%) retail sales forecast for 2022. The company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth. Our $5.00 GAAP earnings estimate is within management's guidance (on a GAAP basis) of $4.97-$5.07 a share. At the analyst day in early October, the company established its 2023 earnings per share guidance range at $5.19-$5.39 and the long-term bottom line growth rate at 6%-7%.

The dividend yield of this top-quality stock is at the utility average. Total return potential is unspectacular for the next 18 months and Timeliness is average. Further, the recent quotation is just below our 2025-2027 Target Price Range.

Kevin Downing — *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '07, (20¢); '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¢). Next earnings report due late Jan. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '21: $17.04/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

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

AMEREN NYSE-AEE

RECENT PRICE 87.94 | P/E RATIO 20.8 (Trailing: 22.0; Median: 19.0) | RELATIVE P/E RATIO 1.28 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 4 Lowered 12/2/22
SAFETY 1 Raised 9/10/21
TECHNICAL 4 Lowered 12/9/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$81-$129 $105 (20%)

2025-27 PROJECTIONS

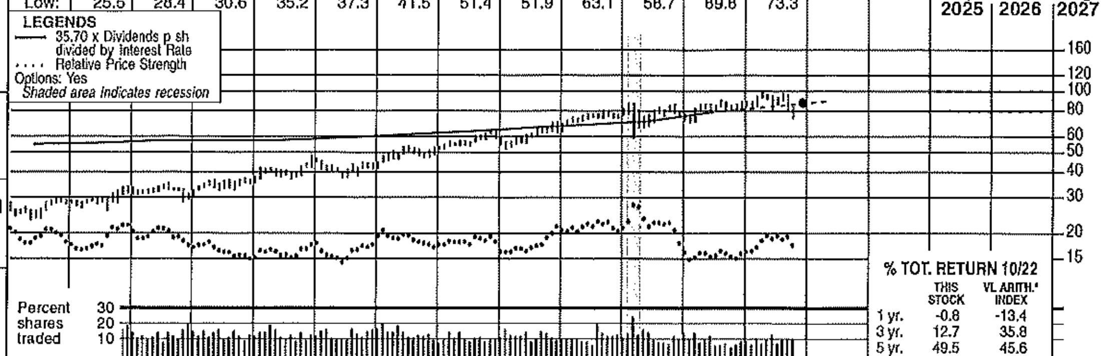
	Price	Gain	Ann'l Total Return
High	100	(+15%)	6%
Low	80	(-10%)	1%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	294	305	287
to Sell	262	257	274
Hld's(000)	200507	201631	204282

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2
Low:	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3

Target Price Range 2025 2026 2027



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.8	-13.4
3 yr.	12.7	35.8
5 yr.	49.5	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.30	36.23	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	*27.25*	*28.10*	Revenues per sh	*30.00*
6.02	6.76	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	*9.50*	*10.05*	"Cash Flow" per sh	*11.75*
2.66	2.98	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	*4.10*	*4.35*	Earnings per sh A	*5.25*
2.54	2.54	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*	Div'd Decl'd per sh B ■	*3.10*
4.99	6.96	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	*12.90*	*12.55*	Cap'l Spending per sh	*13.00*
31.86	32.41	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	*40.20*	*42.90*	Book Value per sh C	*51.25*
206.60	208.30	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	*262.50*	*267.00*	Common Shs Outst'g D	*280.00*
19.4	17.4	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.14	*Value Line*		Relative P/E Ratio	*.95*
4.9%	4.9%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $14798 mill. Due in 5 Yrs $3446 mill.
LT Debt $13577 mill. LT Interest $436 mill.
(LT interest earned: 3.8x)
Pension Assets-12/21 $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 258,522,169 shs. as of 10/31/22
MARKET CAP: $23 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	*7150*	*7500*	Revenues ($mill)	*8400*
589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	*1075*	*1165*	Net Profit ($mill)	*1455*
36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	*55.5%*	*53.5%*	Long-Term Debt Ratio	*51.0%*
49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	*44.0%*	*46.0%*	Common Equity Ratio	*48.5%*
13384	12190	12975	13968	13840	14420	15632	17116	20158	22391	*23900*	*24950*	Total Capital ($mill)	*29500*
16096	16205	17424	18799	20113	21466	22810	24376	26807	29261	*31225*	*33050*	Net Plant ($mill)	*38400*
6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
66%	76%	67%	70%	64%	64%	56%	57%	57%	57%	*58%*	*58%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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 '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*4.0%*
"Cash Flow"	3.0%	6.0%	*6.0%*
Earnings	3.0%	7.5%	*6.5%*
Dividends	3.0%	4.0%	*7.0%*
Book Value	1.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1556	1379	1659	1316	5910
2020	1440	1398	1628	1328	5794
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	*1239*	*7150*
2023	*1900*	*1700*	*2100*	*1800*	*7500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	*.59*	*4.10*
2023	*1.00*	*.90*	*1.80*	*.65*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	

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. '21 reported deprec. rates: 3%-4%. Has 9,100 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 reported in-line results for the September quarter. Earnings per share of $1.74 were a penny higher than our estimate and 5% greater than the year-ago tally. Earnings at Ameren Missouri, the largest segment, benefited from higher electric service rates. This was partially offset by higher operations and maintenance expenses derived from unfavorable market returns and company-owned life insurance investments. Earnings at the three remaining business segments were solid, primarily due to increased investments in infrastructure.

The company's guidance has improved a bit. Due to strong execution, management narrowed the 2022 earnings guidance to a range of $4.00 to $4.15 per share. This compares to the initial guidance range of $3.95 to $4.15 per share. Importantly, the year-to-date benefits it has seen from weather and higher-than-expected 30-year Treasury rates are mostly being offset by the aforementioned company-owned life insurance investment performance, as well as higher than expected short-term and long-term borrowing rates. The current five-year plan includes a 6% to 8% compounded annual growth rate for earnings from 2022 through 2026. This should be driven primarily by strong rate base growth and infrastructure investment. It expects dividend growth to be in line with long-term earnings growth and is planning for a payout ratio range of 55% to 70%.

Business investment is paying off. At Ameren Missouri, the company estimates that over 6.5 million minutes of customer outages have been avoided in 2022 due to recent infrastructure investments. Meanwhile, the Inflation Reduction Act (IRA) was enacted in August, and is designed to help reduce the cost of the clean energy transition. It provides tax credits for wind, solar, and nuclear energy centers, as well as energy storage, carbon capture utilization and hydrogen development. The incentives in the IRA align well with the companywide goal of reaching net zero carbon emissions by 2045.

The dividend yield of this high-quality stock is below the utility mean. The recent price is within our 2025-2027 Target Price Range.

Kevin Downing *December 9, 2022*

(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 mid-Feb. (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%. Regulatory Climate: MO, Average; IL, Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	95

AVANGRID, INC. NYSE-AGR

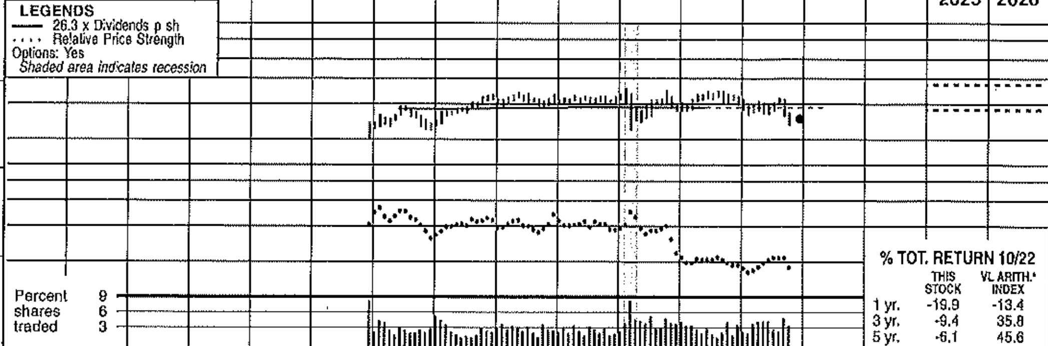
RECENT PRICE 40.68 | P/E RATIO 19.3 (Trailing: 17.2 Median: NMF) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 4 Lowered 11/4/22
SAFETY 2 Raised 2/17/17
TECHNICAL 2 Raised 11/4/22
BETA .85 (1.00 = Market)

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

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$34-$60 $47 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+45%)	13%
Low	45	(+10%)	7%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	138	155	143
to Sell	125	135	133
Hld's(000)	43102	45311	46587

Percent shares traded 9 6 3

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-19.9	-13.4
3 yr.	-9.4	35.8
5 yr.	-6.1	45.6

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.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	14.14	19.48	19.30	20.96	20.51	20.45	18.04	*19.80*	*20.15*	Revenues per sh	*21.95*
--	--	--	3.44	4.74	4.49	4.89	5.41	5.22	4.64	*5.10*	*5.15*	"Cash Flow" per sh	*6.00*
--	--	--	1.05	1.98	1.67	1.92	2.17	2.02	2.18	*2.37*	*2.30*	Earnings per sh A	*2.55*
--	--	--	--	1.73	1.73	1.74	1.76	1.76	1.76	*1.76*	*1.76*	Div'd Decl'd per sh B ■	*1.90*
--	--	--	3.50	5.52	7.82	5.78	8.87	9.00	7.70	*8.30*	*8.65*	Cap'l Spending per sh	*9.50*
--	--	--	48.74	48.90	48.79	48.88	49.31	49.21	49.35	*49.95*	*50.50*	Book Value per sh C	*52.25*
--	--	--	308.86	308.99	309.01	309.01	309.01	309.08	386.57	*386.6*	*387.00*	Common Shs Outst'g D	*387.00*
--	--	--	33.5	20.5	27.3	26.1	23.1	23.6	23.2	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
--	--	--	1.69	1.08	1.37	1.41	1.23	1.21	1.25	*Value Line*		Relative P/E Ratio	*1.10*
--	--	--	--	4.3%	3.8%	3.5%	3.5%	3.7%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
--	--	4594.0	4367.0	6018.0	5963.0	6478.0	6338.0	6320.0	6974.0	*7650*	*7800*	Revenues ($mill)	*8500*
--	--	424.0	267.0	611.0	516.0	595.0	673.0	625.0	780.0	*915*	*890*	Net Profit ($mill)	*990*
--	--	39.9%	11.3%	37.4%	32.4%	22.1%	17.0%	7.2%	6.2%	*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%	*14.0%*	*15.0%*	AFUDC % to Net Profit	*14.0%*
--	--	16.8%	23.1%	23.0%	25.6%	26.2%	30.6%	40.8%	29.3%	*31.5%*	*33.0%*	Long-Term Debt Ratio	*38.0%*
--	--	83.2%	76.9%	77.0%	74.4%	73.8%	69.4%	59.2%	70.7%	*68.5%*	*67.0%*	Common Equity Ratio	*62.0%*
--	--	14956	19583	19619	20273	20472	21953	25687	26998	*28175*	*29175*	Total Capital ($mill)	*32600*
--	--	17099	20711	21548	22669	23459	25218	26751	28866	*31000*	*33250*	Net Plant ($mill)	*40400*
--	--	3.7%	2.1%	3.8%	3.1%	3.5%	3.7%	3.0%	3.4%	*4.0%*	*3.5%*	Return on Total Cap'l	*4.0%*
--	--	3.4%	1.8%	4.0%	3.4%	3.9%	4.4%	4.1%	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%	*4.5%*	*4.5%*	Return on Com Equity E	*5.0%*
--	--	3.4%	1.8%	1.4%	NMF	.4%	.8%	.5%	.9%	*1.0%*	*1.0%*	Retained to Com Eq	*1.5%*
--	--	--	--	66%	104%	90%	81%	87%	79%	*74%*	*76%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $8586 mill. Due in 5 Yrs $3225 mill.
LT Debt $7764 mill. LT Interest $300 mill.
Incl. $95 mill. finance leases.
(Total interest coverage: 3.6x)
Leases, Uncapitalized Annual rentals $14 mill.

Pension Assets-12/21 $3079 mill. Oblig $3487 mill.

Pfd Stock None

Common Stock 386,624,231 shs.
as of 10/25/22
MARKET CAP: $15.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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)	+.8	+.9	+.1
Fixed Charge Cov. (%)	278	237	270

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	3.0%	*2.0%*
"Cash Flow"	--	3.5%	*3.0%*
Earnings	--	3.0%	*3.0%*
Dividends	--	.5%	*1.5%*
Book Value	--	--	*1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1842	1400	1487	1609	6338.0
2020	1789	1392	1470	1669	6320.0
2021	1966	1477	1598	1933	6974.0
2022	2133	1794	1838	*1885*	*7650*
2023	*2170*	*1830*	*1875*	*1925*	*7800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.71	.33	.40	.74	2.17
2020	.76	.32	.32	.62	2.02
2021	1.14	.35	.34	.44	2.18
2022	1.16	.46	.31	*.44*	*2.37*
2023	*.90*	*.46*	*.46*	*.48*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.432	.432	.432	.44	1.74
2019	.44	.44	.44	.44	1.76
2020	.44	.44	.44	.44	1.76
2021	.44	.44	.44	.44	1.76
2022	.44	.44	.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 million gas customers in New York, Connecticut, Massachusetts & Maine. Has a nonregulated generating subsidiary focused on wind and solar power generation, with 8.5 gigawatts of capacity. The Renewables segment currently accounts for roughly one third of operating income. Fuel costs: 25% of revenues. '21 reported depr. rate (utility): 2.8%. Iberdrola owns 81.5% of stock. Has approximately 7,300 employees. 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 is putting together a good year. The company has been filing for rate relief in its various territories and has received some price hikes thus far. It has also been approved to bill for late payments and arrears. Next year it faces difficult earnings comparisons due to some unusual items in the renewables segment that benefited the first quarter of this year, but AVANGRID should resume a growth trajectory in the back half of 2023.

Resolving the stalled acquisition of PNM Resources is a high priority. To recap, the company has agreed to purchase the utility holding company (parent of electric utilities in New Mexico and Texas) for $4.3 billion in cash. However, the deal was blocked by the New Mexico Public Regulation Commission (NMPRC). The state Supreme Court will rule on the case eventually, but it may not come to that. The New Mexico governor is for green energy and pro-merger. She will have the opportunity this Jannary to place her own appointments in the NMPRC.

The company is a key player in the burgeoning green-energy arena. Existing renewable generation comes from onshore wind and solar. Construction of the first U.S. large-scale offshore wind project began a year ago. Three more eastern seaboard projects are in the preconstruction phase. Over time, renewables may grow to become a larger income source, with accelerated profit growth. The PNM deal would also open up avenues of growth for AVANGRID's wind and solar operations, with some ideal areas in the Southwest for these types of projects (strong winds, sunny days, and cheap land are advantageous). Lastly, the company is partnering with Sempra Energy to explore the development of renewable energy projects using hydrogen as a fuel.

This issue offers utility investors worthwhile 18-month total returns. Although dividend growth is limited by the high payout ratio over the next few years, AVANGRID does provide sizable current income with a yield that's 50 basis points above the industry average. Utility investors who like the long-term potential of the renewable energy business may find these shares appealing. Short-term accounts should note the stock is untimely.

Anthony J. Glennon November 11, 2022

(A) Diluted EPS. Excl. nonrecurring gain (loss): '16, 6¢; '17, (44¢); '19, 9¢; '20, (14¢); '21, (21¢); 1H22, 1¢. EPS may not sum to full-year total due to rounding. Next egs. report due late Jan. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $5659 mill., $14.64/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in NY in '20: 8.8%; in CT in '17: 9.1% elec.; in CT in '19: 9.3% gas; in ME in '22: 9.25%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	80

AVISTA CORP. NYSE-AVA

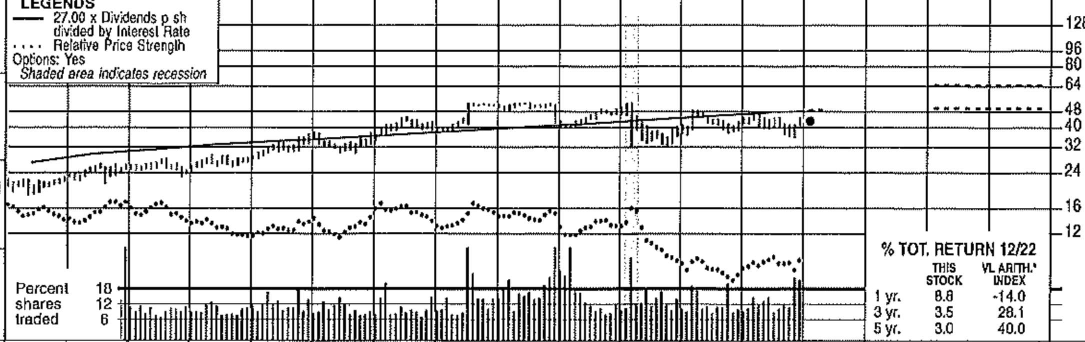
RECENT PRICE 43.10 | P/E RATIO 20.3 (Trailing: 24.2 Median: 19.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 4 Raised 1/13/23
SAFETY 2 Raised 5/7/10
TECHNICAL 4 Raised 1/20/23
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	26.5	28.0	29.3	37.4	38.3	45.2	52.8	52.9	49.5	53.0	49.1	46.9
Low:	21.1	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8	32.1	36.7	35.7

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High: $35-$55 | Midpoint (% to Mid): $45 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+50%)	14%
Low	50	(+15%)	8%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	136	135	138
to Sell	108	118	114
Hld's(000)	60407	60878	61258

Percent shares traded 18 / 12 / 6

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.8	-14.0
3 yr.	3.5	28.1
5 yr.	3.0	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
28.68	26.80	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	20.80	20.80	Revenues per sh	21.40
4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	6.06	5.18	5.34	5.25	5.80	"Cash Flow" per sh	6.75
1.47	.72	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	1.90	2.35	Earnings per sh A	2.85
.57	.60	.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	1.83	Div'd Decl'd per sh B ■	2.05
3.14	4.04	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	6.25	6.40	Cap'l Spending per sh	6.00
17.46	17.27	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	30.90	31.80	Book Value per sh C	34.95
52.51	52.91	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	74.50	77.00	Common Shs Outst'g D	83.00
15.4	30.9	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	22.3		Avg Ann'l P/E Ratio	20.0
.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	.80	1.09	1.11	1.30		Relative P/E Ratio	1.10
2.5%	2.7%	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%		Avg Ann'l Div'd Yield	3.6%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	1345.6	1321.9	1438.9	1550	1600	Revenues ($mill)	1775
78.2	111.1	114.2	118.1	137.2	126.1	136.4	197.0	129.5	147.3	140	180	Net Profit ($mill)	235
34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	13.8%	5.2%	7.5%	15.0%	15.0%	Income Tax Rate	15.0%
8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	5.5%	8.5%	7.5%	8.0%	6.0%	AFUDC % to Net Profit	5.0%
50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	49.4%	50.4%	47.5%	49.0%	49.5%	Long-Term Debt Ratio	48.5%
49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	50.6%	49.6%	52.5%	51.0%	50.5%	Common Equity Ratio	51.5%
2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	3834.6	4089.8	4104.7	4600	4900	Total Capital ($mill)	5675
3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	4797.0	4991.6	5225.5	5450	5675	Net Plant ($mill)	6225
4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	6.2%	4.2%	4.7%	4.0%	5.0%	Return on Total Cap'l	5.0%
6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.5%	7.5%	Return on Shr. Equity	8.0%
6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.2%	6.4%	6.8%	6.5%	7.5%	Return on Com Equity E	8.0%
.8%	2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	4.9%	.9%	1.4%	.5%	2.0%	Retained to Com Eq	2.0%
88%	66%	69%	70%	64%	73%	72%	52%	65%	80%	93%	78%	All Div'ds to Net Prof	72%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $2562.3 mill. **Due in 5 Yrs** $750.0 mill.
LT Debt $2281.8 mill. **LT Interest** $120.0 mill.
Incl. $51.5 mill. debt to affiliated trusts; $48.8 mill. finance leases.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $4.8 mill.
Pension Assets-12/21 $751.0 mill. **Oblig** $799.0 mill.
Pfd Stock None

Common Stock 73,775,760 shs. as of 10/28/22
MARKET CAP: $3.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+.8	-2.4	+4.3
Avg. Indust. Use (MWH)	1296	1265	1383
Avg. Indust. Revs. per KWH (¢)	6.26	6.38	6.41
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1656	1721	1889
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.8	+1.4
Fixed Charge Cov. (%)	202	221	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.5%	-3.5%	1.5%
"Cash Flow"	3.5%	2.5%	3.5%
Earnings	3.5%	3.5%	3.5%
Dividends	5.5%	4.0%	4.0%
Book Value	4.0%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	396.5	300.8	283.8	364.5	1345.6
2020	390.2	278.6	272.6	380.5	1321.9
2021	412.9	298.2	296.0	431.8	1438.9
2022	462.0	378.6	359.4	350	1550
2023	480	390	370	360	1600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.76	.38	.08	.76	2.97
2020	.72	.26	.07	.85	1.90
2021	.98	.20	.20	.71	2.10
2022	.99	.16	d.08	.83	1.90
2023	1.15	.25	.15	.80	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3875	.3875	.3875	.3875	1.55
2020	.405	.405	.405	.405	1.62
2021	.4225	.4225	.4225	.4225	1.69
2022	.44	.44	.44	.44	1.76
2023					

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: 423,000 electric, 372,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 41%; commercial, 34%; industrial, 11%; wholesale, 9%; other, 5%. Generating sources: gas & coal, 30%; hydro, 29%; purch., 41%. Fuel costs: 35% of revs. '21 reported depr. rate (Avista Utilities): 3.5%. Has 1,900 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's electric and natural gas general rate cases in Washington have received commission approval. The filing took place in June of 2022 and its settlement was signed off by the Washington Utilities and Transportation Commission in mid-December. That governing body approved increases of annual electric revenues of $38 million effective December 21, 2022 and $12.5 million effective December 21, 2023, as well as hikes in natural gas revenues by $7.5 million and $1.5 million, respectively, on the same dates. To reduce the impact on customers, an individual tax credit was approved for benefits of $27.6 million on the electric front and $12.5 million on the natural gas side of the coin. The commission passed a rate of return on the rate base of 7.03%, but there were no concrete figures for return on equity, cost of debt, or capital structure. Avista management views this as a positive outcome, as it supports ongoing investments in infrastructure.

After an expected earnings drop in 2022, we look for a bounce back this year. Operating expenses rose sharply last year, and rising interest rates made the situation even tougher. Inflation got much of the blame in a year where the top line was expected to grow by about 7%. For this year, the aforementioned rate hikes will be beneficial, and more relief should be coming in the states where Avista operates. Management's target range for EPS in 2023 is $2.27 to $2.47. Our $2.35 call (now a dime lower) falls within these parameters.

Additional financial information tied to 2023 has been provided. The current plan is to issue roughly $120 million in common stock, and long-term debt is apt to increase by $140 million. Capital expenditures will be at least $475 million, but we look for that figure to run a bit higher, especially when factoring in economic development opportunities in some service territories.

The yield for this utility is a few ticks above the industry average. From other angles, like in the 18-month window and 3- to 5-year pull, AVA's readings are well below average. The selection's Timeliness rank is also unfavorable (4: Below Average).

Erik M. Manning *January 20, 2023*

(A) Diluted EPS. Excl. nonrec. gain (loss): '14, 9¢; '17, (16¢); gains on discont. ops.: '14, $1.17; '15, 8¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due late February. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '21: $913.1 mill., $19.22/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., '21: 7.1%. Regulatory Climate: WA, Below Avg.; ID, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	40
Earnings Predictability	65

BLACK HILLS CORP. NYSE-BKH

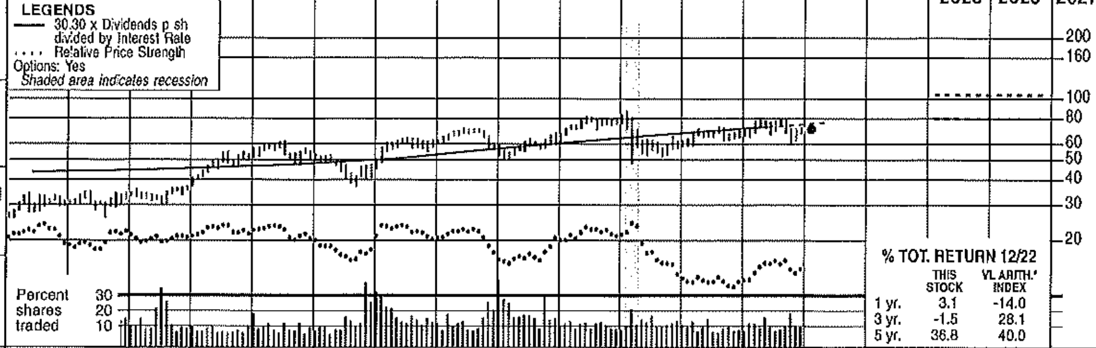
RECENT PRICE 71.17 | P/E RATIO 17.5 (Trailing: 17.8; Median: 18.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Lowered 11/18/22
SAFETY 2 Raised 5/1/15
TECHNICAL 4 Raised 1/13/23
BETA .95 (1.00 = Market)

High:	34.8	37.0	55.1	62.1	53.4	64.6	72.0	68.2	82.0	87.1	72.6	80.9
Low:	25.8	30.3	36.9	47.1	36.8	44.7	57.0	50.5	60.8	46.1	58.2	59.1

Target Price Range 2025 | 2026 | 2027

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



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$58-$99	$79 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+50%)	13%
Low	80	(+10%)	7%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	152	172	155
to Sell	139	128	142
Hld's(000)	57141	57056	58257

Percent shares traded 30 20 10

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.1	-14.0
3 yr.	-1.5	28.1
5 yr.	36.8	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.69	18.41	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	33.10	32.90	Revenues per sh	34.15
5.04	5.29	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	7.80	8.15	"Cash Flow" per sh	9.85
2.21	2.68	.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	4.05	4.20	Earnings per sh A	5.25
1.32	1.37	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	2.53	Div'd Decl'd per sh B ■	2.95
9.24	6.92	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	9.25	9.30	Cap'l Spending per sh	9.50
23.68	25.66	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	44.00	45.95	Book Value per sh C	50.75
33.37	37.80	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	66.50	67.50	Common Shs Outst'g D	71.00
15.8	15.0	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	17.7		Avg Ann'l P/E Ratio	17.5
.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98	.91	1.13	.87	.97	1.05		Relative P/E Ratio	.95
3.8%	3.4%	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%		Avg Ann'l Div'd Yield	3.2%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $4632.4 mill. Due in 5 Yrs $1850.0 mill.
LT Debt $4131.0 mill. LT Interest $165.0 mill.
(LT interest earned: 2.9x)
Leases, Uncapitalized Annual rentals $2.2 mill.

Pension Assets-12/21 $458.4 mill. Oblig $478.3 mill.

Pfd Stock None

Common Stock 65,078,259 shs. as of 10/31/22

MARKET CAP: $4.6 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1173.9	1275.9	1393.6	1304.6	1573.0	1680.3	1754.3	1734.9	1696.9	1949.1	2200	2220	Revenues ($mill)	2425
86.9	115.8	128.6	128.3	140.3	186.5	192.5	214.5	232.9	236.7	270	285	Net Profit ($mill)	375
35.5%	34.7%	33.7%	35.8%	25.1%	28.7%	19.2%	13.0%	12.2%	2.8%	8.5%	8.5%	Income Tax Rate	8.5%
5.4%	2.4%	2.4%	2.7%	5.3%	2.7%	1.4%	3.3%	2.5%	2.0%	2.0%	1.0%	AFUDC % to Net Profit	1.0%
43.2%	51.6%	47.9%	56.0%	66.5%	64.5%	57.5%	57.1%	57.9%	59.7%	58.0%	56.5%	Long-Term Debt Ratio	50.0%
56.8%	48.4%	52.1%	44.0%	33.5%	35.5%	42.5%	42.9%	42.1%	40.3%	42.0%	43.5%	Common Equity Ratio	50.0%
2171.4	2704.7	2643.6	3332.7	4825.8	4818.4	5132.4	5502.2	6089.5	6914.0	7120	7295	Total Capital ($mill)	7500
2742.7	2990.3	3239.4	3259.1	4469.0	4541.4	4854.9	5503.2	6019.7	6449.2	6775	7110	Net Plant ($mill)	8200
5.5%	5.5%	6.1%	4.9%	4.0%	5.2%	5.0%	4.9%	5.0%	4.5%	4.5%	4.5%	Return on Total Cap'l	5.5%
7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	8.0%	8.0%	Return on Shr. Equity	9.5%
7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	8.8%	9.1%	9.1%	8.5%	8.0%	8.0%	Return on Com Equity E	9.5%
1.8%	3.7%	4.3%	3.8%	3.3%	5.3%	3.9%	3.8%	3.8%	3.3%	3.0%	2.5%	Retained to Com Eq	3.5%
75%	58%	54%	57%	62%	52%	55%	58%	58%	61%	60%	60%	All Div'ds to Net Prof	56%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+2.1	-.7	+1.5
Avg. Indust. Use (MWH)	21406	21624	21358
Avg. Indust. Revs. per KWH (¢)	7.38	7.31	8.51
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1022	1050	1078
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+.9	+1.0
Fixed Charge Cov. (%)	278	285	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	--	3.0%
"Cash Flow"	4.5%	3.5%	5.0%
Earnings	8.0%	5.5%	6.0%
Dividends	4.0%	6.0%	5.5%
Book Value	4.0%	6.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	597.8	333.9	325.5	477.7	1734.9
2020	537.0	326.9	346.6	486.4	1696.9
2021	633.4	372.6	380.6	562.5	1949.1
2022	823.6	474.2	462.6	439.6	2200
2023	700	520	510	490	2220

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.73	.24	.44	1.13	3.53
2020	1.59	.33	.58	1.23	3.73
2021	1.54	.40	.70	1.11	3.74
2022	1.82	.52	.54	1.17	4.05
2023	1.75	.60	.65	1.20	4.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.505	.505	.505	.535	2.05
2020	.535	.535	.535	.565	2.17
2021	.565	.565	.565	.595	2.29
2022	.595	.595	.595	.625	2.41
2023					

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 218,000 electric customers in CO, SD, WY and MT, and 1.1 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, 31%; commercial, 34%; industrial, 19%; other, 16%. Generating sources: coal, 34%; gas, 25%; wind, 11%; purchased, 30%. Fuel costs: 38% of revs. '21 deprec. rate: 3.1%. Has 2,900 employees. Chairman: David R. Emery. President & CEO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills share earnings will likely come in at a record high for 2022. Leadership has provided a bracket of $3.95 to $4.15, and our call sits precisely at the midpoint of this spread. Rising interest rates and inflation were headwinds, but population gains in the areas the company services were a boon. All-time peak load days among its electric generating fleet, coupled with strong off-system sales of excess energy, likely contributed to a top-line gain north of 10%.

We are looking for another record-breaking year in 2023. Our fresh call is down a dime, to $4.20, to reflect the cost structure continuing to run on the high side. Still, this number equates to 4% annual growth on the earnings-per-share line, which comes close to management's annual growth range goal of between 5% and 7%. A favorable rate relief situation could lift the metric higher, as could the loftier revenue run rate brought about by will riders. These are surcharges on customers' bills. Moreover, BKH has opportunities in the cryptocurrency mining arena, though the current turbulent situation in that space could push plans back into later years.

The company is not resting on its laurels. The 2022-2026 capital plan has been raised by $250 million, to $3.5 billion. Renewable investment opportunities are a focus, and incentives from clean energy legislation will not be ignored. A 60/40 split favoring gas utilities was laid out, as was a net zero emissions rednction plan for the gas arm by the year 2035.

The dividend payout was raised 5% to finish out last year. The December stipend was upped to $0.625 a share, for an annual payout of $2.50. This raise puts Black Hills' yield almost exactly on par with the average utility stock in our coverage universe.

Outside of an average yield, there is little to get subscribers' attention. The 18-month reading is subpar, and the same can be said for capital appreciation potential three to five years hence. The equity's Timeliness rank has dropped one position to a Below Average (4) designation. It appears a lot of the favorable characteristics that BKH possesses are already baked into the quotation here.

Erik M. Manning *January 20, 2023*

(A) Dil. EPS. Excl. nonrec. gains (losses): '10, 10¢; '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¢). '19 & '21 EPS don't sum due to rounding. Next egs. report due early February. (B) Div'ds pd. early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '21: $28.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none; in CO in '17: 9.37%; earn. on avg. com. eq., '21: 8.9%. Regul. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	95

CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE 30.86 | P/E RATIO 21.3 (Trailing: 27.3; Median: 19.0) | RELATIVE P/E RATIO 1.31 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 3 Raised 3/4/22
SAFETY 3 Lowered 12/18/15
TECHNICAL 3 Lowered 12/2/22
BETA 1.10 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$26-$40 $33 (5%)

2025-27 PROJECTIONS

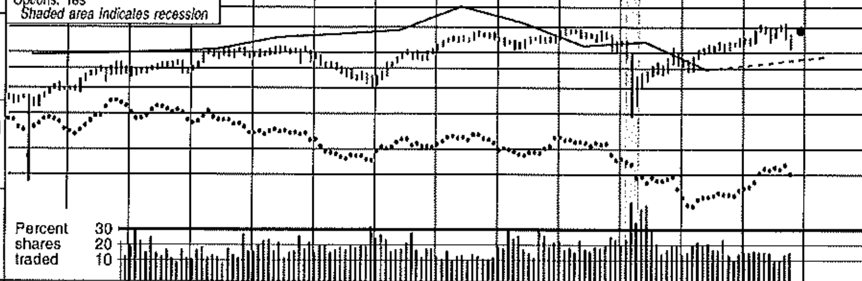
	Price	Gain	Ann'l Total Return
High	35	(+15%)	6%
Low	25	(-20%)	-2%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	295	294	256
to Sell	251	267	270
Hld's(000)	566118	560317	566702

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	21.5	21.8	25.7	25.8	23.7	25.0	30.5	29.6	31.4	27.5	28.4	33.5	
Low:	15.1	18.1	19.3	21.1	16.0	16.4	24.5	24.8	24.3	11.6	19.3	25.0	

LEGENDS
— 30.00 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 2025 | 2026 | 2027

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.5	-13.4
3 yr.	6.4	35.8
5 yr.	13.2	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
29.71	29.82	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	*14.30*	*14.90*	Revenues per sh	*16.75*
3.47	3.39	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*	*3.85*	"Cash Flow" per sh	*4.50*
1.33	1.17	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	*1.40*	*1.50*	Earnings per sh A	*1.80*
.60	.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	1.12	.86	.90	.66	*.71*	*.77*	Div'd Decl'd per sh B ■	*.95*
3.21	3.45	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	*6.10*	*7.45*	Cap'l Spending per sh	*7.25*
4.96	5.61	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	*14.75*	*15.50*	Book Value per sh C	*18.00*
313.65	322.72	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	*630.00*	*631.00*	Common Shs Outst'g D	*634.00*
10.3	15.0	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	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.90	2.00	1.04	.82	1.39	*Value Line*		Relative P/E Ratio	*.90*
4.4%	3.9%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $14913 mill. Due in 5 Yrs $7844 mill.
LT Debt $13435 mill. LT Interest $500 mill.
Incl. $240 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/21 $2072 mill. Oblig $2298 mill.
Pfd Stock $790 mill. Pfd Div'd $49 mill.
800,000 shs. 6.125%, cumulative, with liquidation value of $1000.
Common Stock 629,535,631 shs. as of 10/24/22
MARKET CAP: $19.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
7452.0	8106.0	9226.0	7386.0	7528.0	9614.0	10589	12301	7418.0	8352.0	*9000*	*9400*	Revenues ($mill)	*10600*
581.0	536.0	611.0	465.0	432.0	679.0	368.0	871.0	863.0	668.0	*950*	*1000*	Net Profit ($mill)	*1180*
33.4%	31.4%	31.0%	35.1%	37.0%	36.1%	28.4%	14.9%	13.4%	14.1%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
2.6%	3.5%	4.1%	4.7%	3.5%	2.9%	5.4%	6.7%	6.0%	9.3%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
66.0%	64.4%	63.8%	69.5%	68.5%	63.6%	51.9%	63.0%	58.0%	62.3%	*62.0%*	*59.0%*	Long-Term Debt Ratio	*60.0%*
34.0%	35.6%	36.2%	30.5%	31.5%	36.4%	37.5%	29.1%	29.9%	34.5%	*35.0%*	*38.0%*	Common Equity Ratio	*37.5%*
12658	12146	12557	11362	10992	12883	16740	22603	19869	24973	*26525*	*25725*	Total Capital ($mill)	*30400*
13597	9593.0	10502	11537	12307	13057	14044	20945	22362	23484	*25925*	*29150*	Net Plant ($mill)	*35700*
6.8%	6.3%	6.7%	6.1%	5.8%	6.8%	3.4%	5.1%	5.6%	3.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	4.6%	10.4%	10.3%	7.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	5.3%	11.5%	11.6%	6.7%	*9.5%*	*10.0%*	Return on Com Equity E	*10.0%*
5.5%	4.2%	4.5%	1.1%	NMF	4.7%	NMF	2.7%	5.0%	2.2%	*5.0%*	*5.0%*	Retained to Com Eq	*4.5%*
60%	66%	67%	92%	103%	68%	NMF	80%	66%	72%	*52%*	*53%*	All Div'ds to Net Prof	*54%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+6.7	+1.8	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.)	+7.9	+2.5	NA
Fixed Charge Cov. (%)	152	135	181

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-2.0%	-.5%
"Cash Flow"	1.0%	-.5%	4.0%
Earnings	1.0%	1.0%	6.5%
Dividends	.5%	-4.0%	2.5%
Book Value	4.5%	7.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	3531	2798	2742	3230	12301
2020	2167	1575	1622	2054	7418
2021	2547	1742	1749	2314	8352
2022	2763	1944	1903	*2390*	*9000*
2023	*2900*	*2000*	*2000*	*2500*	*9400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	.28	.33	.47	.41	1.49
2020	.56	.17	.29	.27	1.29
2021	.41	.29	.21	.03	.94
2022	.52	.28	.30	*.30*	*1.40*
2023	*.55*	*.30*	*.35*	*.30*	*1.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.2875	.2875	.2875	.2875	1.15
2020	.29	.15	.15	.15	.74
2021	.16	.16	.16	.17	.65
2022	.17	.17	.18	.18	

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.7 million customers in Houston and environs, Indiana Electric, which serves 150,000 customers, and gas utilities with 4.2 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 '21 and '22. Electric revenue breakdown not available. Fuel costs: 28% of revenues. '21 depreciation rate: 3.9%. Has 8,900 employees. Chairman: Martin H. Nesbitt. President & CEO: David J. Lesar. Incorporated: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Telephone: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy posted commendable September-period results. The top line increased 9% year over year, to $1.903 billion. The bottom line rose 43% over the year-ago tally, to $0.30 per share. The company benefited from better rate relief and improved demand for its services. Management also stayed active on the expense-cutting front to enhance profits amid an elevated cost environment.

The regulatory matter in Minnesota is moving along. CenterPoint reached a settlement calling for a $48.5 million gas rate increase, based on a 9.39% return on equity or a 6.65% overall rate of return. A written order from the state commission was issued in the third quarter. After approval of compliance filing, implementation of the new rate is anticipated by January 1, 2023.

We have maintained our 2022 and 2023 share-profit estimates at $1.40 and $1.50, respectively. Earnings are expected to stay healthy thanks to solid demand growth at the utilities. We also note that Houston Electric obtains revenues for transmission and distribution every year through regulatory mechanisms. We remain optimistic considering the latest quarter's results.

Management plans to use proceeds from previous asset sales for debt reduction and capital expenditures. CenterPoint thinks that it will not need to issue common equity through 2030 despite revising its current capital spending plan to $43 billion from $40 billion. However, the share count could rise slightly due to stock issued for options and other plans. Increased capital spending is expected to be used for investments in transitioning to clean energy and modernizing existing systems. Some initiatives include strengthening its presence in the electric vehicle market and renewable energy. Furthermore, the company remains on track to develop Houston's regional master energy plan.

Shares of CenterPoint Energy are neutrally (3) ranked for Timeliness. At the recent quotation, the equity's long-term capital appreciation potential doesn't stand out. All told, we believe there are more-attractive selections available elsewhere.

Emma Jalees *December 9, 2022*

(A) Dil. EPS. Excl. nonrecur. gains (losses): '11, $1.89; '12, (38¢); '13, (52¢); '15, ($2.69); '17, $2.56; '20, ($2.74); '22, 30¢; gain (loss) on disc. ops.: '20, (34¢); '21, $1.34. Next earnings report due late Feb. (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 '21: $10.52/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., '21: 7.9%. Regulatory Climate: TX, Avg.; IN, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	30
Earnings Predictability	50

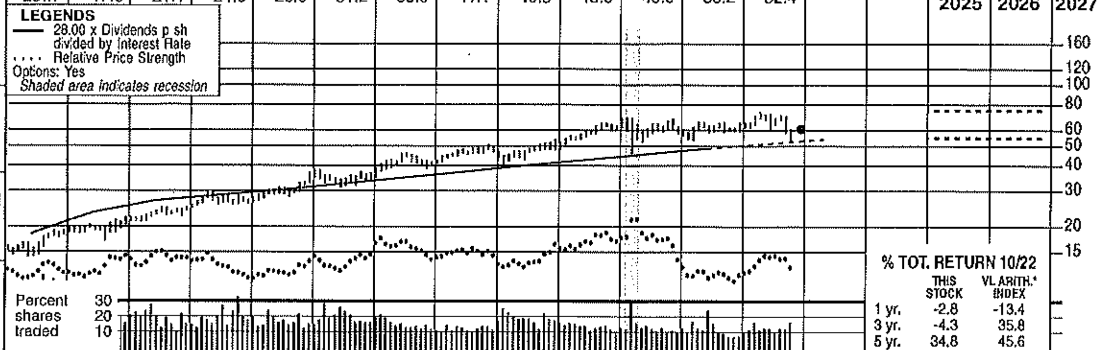
CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 60.80 | P/E RATIO 20.3 (Trailing: 22.9 Median: 20.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 4 Lowered 12/2/22
SAFETY 2 Raised 3/21/14
TECHNICAL 4 Lowered 12/9/22
BETA .80 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	22.4	25.0	30.0	36.9	38.7	46.3	50.8	53.8	65.3	69.2	65.9	73.8
Low:	17.0	21.1	24.6	26.0	31.2	35.0	41.1	40.5	48.0	46.0	53.2	52.4

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$50-$88 $69 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+25%)	8%
Low	55	(-10%)	1%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	329	310	308
to Sell	222	264	251
Hld's(000)	272596	268661	267233

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.8	-13.4
3 yr.	-4.3	35.8
5 yr.	34.8	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
30.57	28.95	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	27.60	28.30	Revenues per sh	30.75
3.22	3.08	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	7.00	7.45	"Cash Flow" per sh	8.75
.64	.64	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	2.90	3.10	Earnings per sh A	3.75
--	.20	.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	1.94	Div'd Decl'd per sh B ■	2.30
3.01	5.61	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	8.95	10.00	Cap'l Spending per sh	9.75
10.03	9.46	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	24.25	25.50	Book Value per sh C	26.50
222.78	225.15	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	290.00	290.00	Common Shs Outst'g D	300.00
22.2	26.8	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	Bold figures are		Avg Ann'l P/E Ratio	17.5
1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.07	1.10	1.29	1.20	1.26	Value Line		Relative P/E Ratio	.95
--	1.2%	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%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $13685 mill. Due in 5 Yrs $2324 mill.
LT Debt $12685 mill. LT Interest $500 mill.
Incl. $47 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/21 $3599 mill.
Oblig $3070 mill.
Pfd Stock $224 mill. Pfd Div'd $11 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 290,251,602 shs.
as of 10/10/22
MARKET CAP: $17.6 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6312.0	6566.0	7179.0	6456.0	6399.0	6583.0	6873.0	6845.0	6680.0	7329.0	8000	8200	Revenues ($mill)	9200
413.0	454.0	479.0	525.0	553.0	610.0	659.0	682.0	757.0	751.0	855	910	Net Profit ($mill)	1130
39.4%	39.9%	34.3%	34.0%	33.1%	31.2%	14.9%	17.7%	15.0%	11.5%	11.0%	11.0%	Income Tax Rate	11.0%
2.9%	2.0%	2.3%	2.7%	3.1%	1.1%	1.4%	2.1%	1.1%	1.5%	1.0%	2.0%	AFUDC % to Net Profit	1.0%
67.9%	67.5%	68.7%	68.3%	67.1%	67.3%	69.0%	70.4%	71.2%	64.5%	63.0%	62.0%	Long-Term Debt Ratio	60.0%
31.6%	32.2%	31.0%	31.4%	32.6%	32.4%	30.7%	29.4%	28.6%	34.2%	36.0%	37.0%	Common Equity Ratio	39.0%
10101	10730	11846	12534	13040	13692	15476	17082	19223	18760	19800	20050	Total Capital ($mill)	20400
11551	12246	13412	14705	15715	16761	18126	18926	21039	22352	23775	25400	Net Plant ($mill)	29900
5.9%	6.0%	5.7%	5.7%	5.8%	5.9%	5.6%	5.3%	5.2%	5.3%	5.5%	5.5%	Return on Total Cap'l	6.5%
12.8%	13.0%	12.9%	13.2%	12.9%	13.6%	13.8%	13.5%	13.7%	11.3%	11.5%	12.0%	Return on Shr. Equity	14.0%
12.9%	13.1%	13.0%	13.3%	13.0%	13.7%	13.8%	13.6%	13.7%	11.6%	12.0%	12.0%	Return on Com Equity E	14.0%
5.0%	5.2%	5.0%	5.2%	4.8%	5.2%	5.3%	4.9%	5.3%	3.8%	4.5%	4.5%	Retained to Com Eq	5.5%
61%	60%	62%	61%	63%	62%	62%	64%	62%	68%	64%	63%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.7	-3.1	+2.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.94	8.14	8.46
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	8039	8215	7951
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.0	+1
Fixed Charge Cov. (%)	235	240	223

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	--	4.0%
"Cash Flow"	5.5%	6.5%	6.0%
Earnings	7.5%	6.5%	6.5%
Dividends	9.5%	7.0%	6.0%
Book Value	5.5%	6.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2059	1445	1546	1795	6845
2020	1864	1443	1575	1798	6680
2021	2013	1558	1725	2033	7329
2022	2374	1920	2024	1682	8000
2023	2400	1950	2000	1850	8200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.33	.73	.58	2.39
2020	.85	.48	.76	.55	2.64
2021	1.09	.55	.54	.40	2.58
2022	1.20	.50	.56	.64	2.90
2023	1.25	.55	.60	.70	3.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2018	.3575	.3575	.3575	.3575	1.43
2019	.3825	.3825	.3825	.3825	1.53
2020	.4075	.4075	.4075	.4075	1.63
2021	.435	.435	.435	.435	1.74
2022	.46	.46	.46	.46	

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 1,234 megawatts of nonregulated generating capacity. Sold EnerBank in '21. Electric revenue breakdown: residential, 48%; commercial, 32%; industrial, 13%; other, 7%. Generating sources: coal, 31%; gas, 16%; renewables, 6%; purchased, 47%. Fuel costs: 42% of revenues. '21 reported deprec. rates: 3.9% electric, 2.9% gas, 9.4% other. Has 8,500 full-time employees. Chairman: John G. Russell. President & CEO: Garrick Rochow. Inc.: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy registered strong third-quarter results. The top line increased 17.3% year over year, to $2.02 billion. Meanwhile, the bottom line rose 3.7%, to $0.56 per share. The company's efforts to acquire rate relief and reduce costs benefited the overall performance. Also, favorable weather boosted gas sales more than last year's tally.

The pending electric rate case of Consumers Energy (subsidiary of CMS Energy) was revised in September. Investors may recall that Consumers filed for an electric tariff increase of $272 million, based on a 10.25% return on equity. Recently, management revised the requested rate increase to $292 million. The ruling from the commission is expected in the first quarter of 2023. We note that the subsidiary has a vast electric and gas system with several aging pieces of equipment needing replacement. Hence, the company seeks frequent rate relief to keep providing affordable customer prices.

We see a low-double-digit increase in earnings this year. Consumers' utility sales are expected to stay strong in the coming months, with electric deliveries to commercial and industrial customers especially recovering well. Furthermore, the company will benefit from the gas rate increase and ongoing cost controls. Our estimate is a cent above management's new targeted range of $2.87-$2.89 a share (raised from the previous guidance of $2.85-$2.89).

For next year, profits will likely increase further. The company stands to benefit from the revised electric rate increase. We look for a 7% rise in earnings, which aligns with management's annual-earnings growth target of 6%-8%.

The long-term growth plan involves an expanding presence in renewable energy. The company intends to grow its clean energy capacity to 30% by 2025 (from the current 14%) and 50% by 2030. CMS expects to invest $25 billion over the next 10 years to upgrade its electricity and gas infrastructure.

At present, untimely shares of CMS Energy have subpar total return potential over the 2025-2027 horizon. Investors can find better options elsewhere, in our opinion.

Emma Jalees *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢; '21, $2.08; '22, 1¢. Next earnings report due early Feb. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $7.80/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	A
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	90

CON. EDISON NYSE-ED

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
87.96	19.0 (Trailing: 19.5; Median: 17.0)	1.23	3.7%

VALUE LINE

TIMELINESS 3 Raised 9/30/22
SAFETY 1 New 7/27/90
TECHNICAL 1 Raised 10/14/22
BETA .75 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$74-$113 $94 (5%)

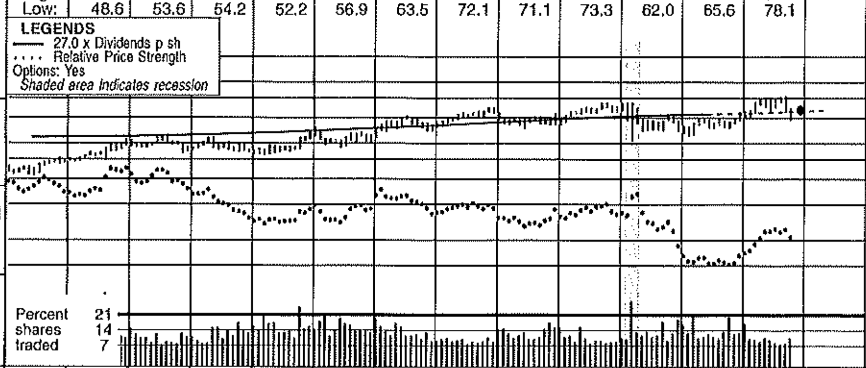
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+20%)	8%
Low	85	(-5%)	3%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	487	478	471
to Sell	367	393	404
Hld's(000)	224882	227241	229945

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9	95.0	95.1	85.6	102.2
Low:	48.6	53.6	54.2	52.2	56.9	63.5	72.1	71.1	73.3	62.0	65.6	78.1



Target Price Range 2025 | 2026 | 2027
160 120 100 80 60 50 40 30 20 15

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.9	-13.4
3 yr.	6.0	35.8
5 yr.	22.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
47.14	48.23	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	*41.00*	*42.55*	Revenues per sh	*43.50*
5.28	5.77	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	*10.55*	*11.05*	"Cash Flow" per sh	*12.25*
2.95	3.48	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*	*4.75*	Earnings per sh A	*5.50*
2.30	2.32	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*	Div'd Decl'd per sh B ■	*3.52*
7.17	7.09	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	*13.00*	*15.25*	Cap'l Spending per sh	*14.50*
31.09	32.58	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	*58.40*	*59.90*	Book Value per sh C	*67.75*
257.46	272.02	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	*355.00*	*355.00*	Common Shs Outst'g D	*380.00*
15.5	13.8	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	1.00	.92	1.05	.98	.92	*Value Line*		Relative P/E Ratio	*.95*
5.0%	4.8%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $25327 mill. Due in 5 Yrs $3994 mill.
LT Debt $22361 mill. LT Interest $904 mill.
(Total Interest Coverage: 3.0x)

Leases, Uncapitalized Annual rentals $81 mill.

Pension Assets-12/21 $18504 mill. Oblig $17357 mill.

Pfd Stock None

Common Stock 354,582,086 shs. as of 7/31/22
MARKET CAP: $31.2 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
12188	12381	12919	12554	12075	12033	12337	12574	12246	13676	*14550*	*15100*	Revenues ($mill)	*16500*
1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	1424.0	1438.0	1399.0	1528.0	*1620*	*1690*	Net Profit ($mill)	*2085*
34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	20.1%	17.5%	12.9%	16.2%	*18.0%*	*18.0%*	Income Tax Rate	*18.0%*
.5%	.5%	.3%	.7%	1.3%	1.5%	1.5%	1.9%	2.2%	2.1%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	51.1%	50.7%	52.0%	53.0%	*52.5%*	*53.0%*	Long-Term Debt Ratio	*53.0%*
54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	48.9%	49.3%	48.0%	47.0%	*47.5%*	*47.0%*	Common Equity Ratio	*47.0%*
21933	22735	24207	25058	29033	30149	34221	36549	39229	42641	*43825*	*45275*	Total Capital ($mill)	*54500*
26939	28436	29827	32209	35216	37600	41749	43889	46555	48596	*51075*	*54300*	Net Plant ($mill)	*61000*
6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	5.3%	5.1%	4.7%	4.7%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	8.0%	7.4%	7.6%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.0%*
9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	8.5%	8.0%	7.4%	7.6%	*8.0%*	*8.0%*	Return on Com Equity E	*8.0%*
3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	3.5%	2.9%	2.2%	2.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
62%	62%	69%	61%	64%	63%	59%	64%	70%	67%	*69%*	*68%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.9	-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)	13835	13170	13517
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	267	257	284

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-2.5%	2.5%
"Cash Flow"	4.5%	4.5%	4.0%
Earnings	2.5%	2.0%	4.0%
Dividends	2.5%	3.0%	2.5%
Book Value	4.0%	4.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3514	2744	3365	2951	12574
2020	3234	2719	3333	2960	12246
2021	3677	2971	3613	3415	13676
2022	4060	3415	*3635*	*3440*	*14550*
2023	*4215*	*3545*	*3775*	*3565*	*15100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.39	.58	1.54	.86	4.37
2020	1.35	.60	1.48	.74	4.17
2021	1.44	.53	1.41	1.00	4.38
2022	1.47	.64	*1.47*	*.97*	*4.55*
2023	*1.53*	*.67*	*1.53*	*1.02*	*4.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.715	.715	.715	.715	2.86
2019	.74	.74	.74	.74	2.96
2020	.765	.765	.765	.765	3.06
2021	.775	.775	.775	.775	3.10
2022	.79	.79	.79		

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 New York and New Jersey. ConEd has 3.7 mill. electric, 1.2 mill. gas customers. It also pursues competitive energy opportunities through three wholly owned subsidiaries. It entered into midstream gas joint venture 6/16; sold it 7/21. Purchases most of its power. Fuel costs: 20% of revenues. '21 reported deprec. rates: 3.1%-3.5%. Employs 13,900. Chrmn, President & CEO: Timothy Cawley. Inc.: NY. Addr.: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison is selling its renewable energy subsidiary. In October, the company announced it had agreed to sell its non-regulated solar and wind power business to RWE Renewables Americas for $6.8 billion. The transaction is expected to be completed by mid-2023. As a result of the pending deal, the company will forego its previous plan to issue up to $1.6 billion of common equity through 2024, and is now better able to self fund upcoming regulated capital projects necessary to bring about the modernization of the electric grid in its territory. The renewables segment represents about 9% of operating income. So initially, the sale will reduce earnings per share, with offsets from less financing needs and a lower share count. These changes should not impact the dividend. Our estimates won't reflect the sale until it closes.

A settlement for ConEd's primary utility's general rate case is due by year end. CECONY updated its rate requests in the spring and is now filing for a 2023 electric increase of $1.04 billion and a gas hike of $402 million. The application is based on a 10% return on equity (ROE), up from an 8.8% ROE currently. Staff at the regulatory body, New York Public Service Commission, are far apart from ConEd in their initial proposals, with no change in the existing ROE structure offered, and a 2023 recommended electric and gas hike of $278 million and $164 million, respectively. Settlement negotiations have been ongoing since July, with a joint proposal expected this month and a final rate decision due in December. While New York has traditionally represented a below-average regulatory climate for CECONY, the state now has government leadership in place that is publicly supportive of the various projects geared towards delivering clean energy, including the electrification of the transportation system. An acceptable regulatory settlement with give and take from both sides seems likely.

ConEd stock doesn't stand out at the recent valuation. Utility investors can do better elsewhere. The dividend yield is 10 basis points below the peer-group median, while growth in the disbursement will likely be constrained by the high payout ratio over the next few years.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '13, (32¢); '14, 9¢; '16, 18¢; '17, 84¢; '18, (13¢); '19, (29¢); '20, (89¢); '21, (53¢); 1Q-2Q '22, 30¢; gain on disc. operations: '08, $1.01. Next earnings report due early February. (B) Dividends historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. (C) Incl. intang. In '21: $15.17/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '20: 8.8%; 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

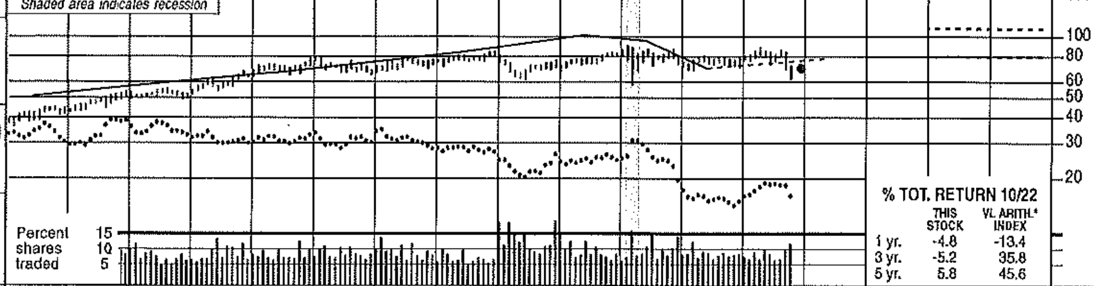
RECENT PRICE 69.97 | P/E RATIO 16.6 (Trailing: 17.7; Median: 21.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 4 Lowered 2/5/21
SAFETY 2 Raised 9/11/98
TECHNICAL 2 Lowered 11/4/22
BETA .85 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	53.6	55.6	68.0	80.9	79.9	79.0	85.3	81.7	83.9	90.9	81.1	88.8
Low:	42.1	48.9	51.9	63.1	64.5	66.3	70.9	61.5	67.4	57.8	67.9	61.7

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High: $57-$100 | Midpoint (% to Mid): $79 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+55%)	15%
Low	80	(+15%)	7%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	680	725	699
to Sell	612	617	605
Hld's(000)	558255	564157	581334

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.8	-13.4
3 yr.	-5.2	35.8
5 yr.	5.8	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.53	19.63	19.78	17.59	17.23	19.15	20.50	Revenues per sh	22.40
4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.90	7.24	7.67	7.25	7.35	7.70	8.15	"Cash Flow" per sh	9.50
2.40	2.13	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	4.10	4.35	Earnings per sh A	5.30
1.38	1.46	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	2.83	Div'd Decl'd per sh B ■	3.40
5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.54	6.25	5.94	7.47	7.35	10.30	12.25	Cap'l Spending per sh	8.85
18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	26.59	29.53	35.33	29.46	31.50	33.45	35.30	Book Value per sh C	42.00
698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	644.60	680.90	838.00	805.60	810.40	835.00	842.00	Common Shs Outst'g D	870.00
16.0	20.6	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	*Bold figures are*		Avg Ann'l P/E Ratio	18.0
.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.12	.95	.97	1.16	1.05	*Value Line*		Relative P/E Ratio	1.00
3.6%	3.3%	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%	*estimates*		Avg Ann'l Div'd Yield	3.6%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
13093	13120	12436	11683	11737	12586	13366	16572	14172	13964	16000	17250	Revenues ($mill)	19500
1594.0	1806.0	1793.0	1899.0	2123.0	2244.0	2651.0	3464.0	3071.0	3259.0	3495	3770	Net Profit ($mill)	4725
36.2%	33.0%	28.1%	32.0%	22.8%	27.2%	17.3%	20.3%	12.2%	13.7%	17.0%	17.0%	Income Tax Rate	17.0%
5.7%	3.7%	4.5%	5.3%	7.5%	10.5%	5.1%	2.6%	3.4%	3.6%	4.0%	4.0%	AFUDC % to Net Profit	3.0%
60.9%	61.9%	65.4%	65.1%	67.4%	64.4%	60.8%	51.4%	56.5%	56.4%	57.0%	56.5%	Long-Term Debt Ratio	56.5%
38.2%	37.3%	34.6%	34.9%	32.6%	35.6%	39.2%	45.0%	39.5%	38.5%	40.5%	41.0%	Common Equity Ratio	41.5%
27676	31229	33360	36280	44836	48090	51251	65818	60074	66344	69325	72475	Total Capital ($mill)	88100
30773	32628	36270	41554	49964	53758	54560	69082	57848	59774	65400	72575	Net Plant ($mill)	91200
7.5%	7.3%	6.6%	6.5%	6.0%	5.9%	6.5%	6.4%	6.3%	6.0%	6.0%	6.5%	Return on Total Cap'l	6.5%
14.7%	15.2%	15.5%	15.0%	14.5%	13.1%	13.2%	10.8%	11.8%	11.3%	11.5%	11.5%	Return on Shr. Equity	12.0%
14.9%	15.4%	15.4%	15.0%	14.5%	13.1%	13.2%	11.6%	12.7%	12.5%	12.5%	12.5%	Return on Com Equity E	13.0%
3.5%	4.2%	3.3%	2.9%	2.7%	1.8%	2.3%	1.6%	.6%	4.5%	4.5%	4.5%	Retained to Com Eq	4.5%
77%	73%	79%	81%	81%	86%	82%	87%	96%	65%	66%	66%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 6/30/22
Total Debt $42586 mill. **Due in 5 Yrs** $14043 mill.
LT Debt $36961 mill. **LT Interest** $1337 mill.
(Total interest coverage: 3.3x)
Leases, Uncapitalized Annual rentals $50 mill.
Pension Assets-12/21 $10890 mill. **Oblig** $11945 mill.
Pfd Stock $3389 mill. **Pfd Divd** $65 mill.
2 mill. shs. 1.75%, cum., conv. in 2022. 800,000 shs. 4.65%, cum., not redeem. before 12/15/24. 1 mill. shs. 4.35%, cum., with divd. rate reset every 5 yrs., not redeem. before 1/15/27.
Common Stock 832,502,797 shs. as of 8/1/22
MARKET CAP: $58.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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)	1.4%	1.4%	1.4%
Fixed Charge Cov. (%)	166	128	188

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.5%	-1.5%	3.5%
"Cash Flow"	4.0%	4.5%	4.0%
Earnings	3.5%	3.5%	5.5%
Dividends	5.5%	4.5%	1.0%
Book Value	5.0%	8.5%	4.5%

Cal-ender	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3858	3970	4269	4475	16572
2020	3938	3106	3607	3521	14172
2021	3870	3038	3176	3880	13964
2022	4279	3596	3770	4355	16000
2023	4615	3875	4065	4695	17250

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.10	.77	1.18	1.18	4.24
2020	.92	.73	1.08	.81	3.54
2021	1.09	.76	1.11	.90	3.86
2022	1.18	.77	1.13	1.02	4.10
2023	1.25	.82	1.20	1.08	4.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.835	.835	.835	.835	3.34
2019	.9175	.9175	.9175	.9175	3.67
2020	.94	.94	.94	.63	3.45
2021	.63	.63	.63	.63	2.52
2022	.6675	.6675	.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, 47%; commercial, 34%; industrial, 8%; other, 11%. Generating sources: gas, 40%; nuclear, 29%; coal, 9%; other, 5%; purchased, 17%. Fuel costs: 25% of revs. '21 reported deprec. rates: 1.8%-3.8%. Has 17,100 employees. Chairman, President & 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 is on target for a good year. The company is benefiting from rate hikes that took effect in late 2021, which continue to flow through to the bottom line. In September 2021, it received a $62 million electric rate increase in South Carolina, based on a 9.5% return on equity (ROE). Then, last November, rates were raised $29 million at its gas utility in North Carolina, based on a 9.6% ROE. Our 2022 earnings estimate of $4.10 per share is unchanged.

This utility has above-average growth prospects relative to its peer group. Management has targeted a 6.5% earnings growth rate through at least mid-decade. In our view, the goal is achievable. Volume growth and recoverable investments in distribution and transmission modernization projects are key factors. The company is seeing decent load growth, as development is ahead of national averages in many areas of the South. Preparing the grid for increased renewable sources of energy, and an electric-vehicle future, are part of the equation, as well. Having the green light to grow its rate base by adding regulated generating capacity is another plus. The majority of its capital investment plan is recoverable via real-time rate adjustments formulas, which minimizes regulatory lag, a real problem for this industry.

Dominion has a dispute with regulators regarding its large offshore wind project. Virginia officials want the utility to bare the full risk of the venture falling short of expectations in power production. The company has threatened to scrap the project under those terms. There is a lot of political posturing in this industry and it's always an ongoing negotiation. Deliberations will likely resolve this snag.

This issue offers utility investors solid 3- to 5-year total returns. The below-average (4) Timeliness rank means it's not for short-term accounts. Buy-and-hold utility investors, however, should strongly consider adding Dominion to their portfolios at the recent valuation. The healthy correction since our August report has the dividend yield about 20 basis points above the peer-group median, while the long-term growth rate in the disbursement exceeds the electric utility average.

Anthony J. Glennon *November 11, 2022*

(A) Dil. egs. Excl. nonrec. gains (losses): '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¢); 1Q-2Q '22, (93¢); gain (losses) from disc. ops.: '10, (26¢); '12, (4¢); '13, (16¢); '20, ($2.39); '21, 79¢. EPS don't add due to rnd'g. Next egs. due Feb. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $20.78/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%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	100

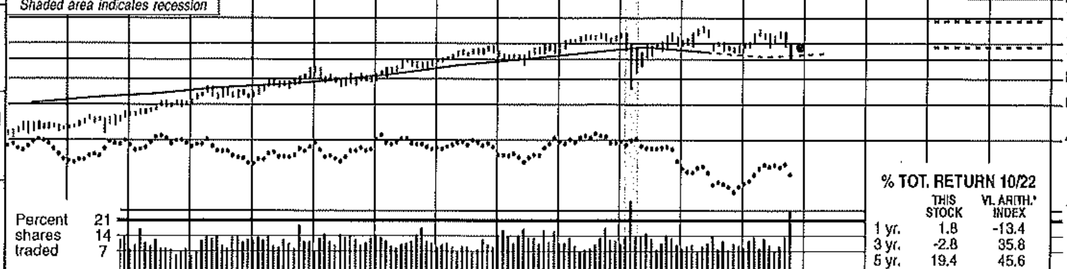
DTE ENERGY CO. NYSE-DTE

RECENT PRICE 115.30 | P/E RATIO 17.1 (Trailing: 20.0 Median: 18.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Raised 9/9/22
SAFETY 2 Raised 12/21/12
TECHNICAL 3 Lowered 11/25/22
BETA .95 (1.00 = Market)

High:	55.3	62.6	73.3	90.8	92.3	100.4	116.7	121.0	134.4	135.7	145.4	140.2		Target Price Range				
Low:	43.2	52.5	60.3	64.8	73.2	78.0	96.6	94.3	107.3	71.2	108.2	100.6		2025	2026	2027		

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$86-$143 $115 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	155	(+35%)	11%
Low	115	(Nil)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	325	363	306
to Sell	274	267	304
Hld's(000)	143321	143263	145343

Percent shares traded 21 14 7

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.8	-13.4
3 yr.	-2.8	35.8
5 yr.	19.4	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
50.93	54.28	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	87.80	90.25	Revenues per sh	93.25
8.19	8.48	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	12.65	14.10	"Cash Flow" per sh	17.00
2.45	2.66	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	5.50	6.20	Earnings per sh A	7.50
2.08	2.12	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	3.68	3.84	Div'd Decl'd per sh B ■	4.65
7.92	7.96	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	17.50	17.05	Cap'l Spending per sh	18.50
33.02	35.86	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	50.55	52.95	Book Value per sh C	60.75
177.14	163.23	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	205.00	205.50	Common Shs Outst'g D	206.00
17.4	18.3	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	Bold figures are		Avg Ann'l P/E Ratio	18.0
.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.94	.94	1.06	.84	1.60	Value Line		Relative P/E Ratio	1.00
4.9%	4.4%	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%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $18867 mill. Due in 5 Yrs $6481 mill.
LT Debt $17442 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-12/21 $5507 mill. Oblig $5857 mill.

Pfd Stock None
Common Stock 193,741,991 shs.

MARKET CAP: $22.3 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
8791.0	9661.0	12301	10337	10630	12607	14212	12669	12177	14964	18000	18550	Revenues ($mill)	19200
666.0	661.0	905.0	796.0	868.0	1029.0	1120.0	1169.0	1368.0	796.0	1125	1275	Net Profit ($mill)	1550
29.8%	27.5%	28.5%	25.6%	24.5%	21.8%	8.1%	11.5%	10.9%	- -	5.0%	5.0%	Income Tax Rate	5.0%
3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	3.8%	3.3%	3.4%	4.9%	4.0%	3.0%	AFUDC % to Net Profit	3.0%
48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	54.2%	57.7%	60.5%	62.5%	63.0%	61.5%	Long-Term Debt Ratio	61.0%
51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	39.5%	37.5%	37.0%	38.5%	Common Equity Ratio	39.0%
14387	15135	16670	17607	20280	21697	22371	27607	31426	23236	28000	28250	Total Capital ($mill)	32200
14684	15800	16820	18034	19730	20721	21650	25317	27969	26944	29150	31050	Net Plant ($mill)	36600
6.1%	5.7%	6.6%	5.7%	5.3%	5.9%	6.1%	5.3%	5.4%	4.7%	4.5%	5.0%	Return on Total Cap'l	6.0%
9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	9.0%	11.5%	Return on Shr. Equity	12.5%
9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	11.0%	9.1%	9.0%	11.5%	Return on Com Equity E	12.5%
3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	4.9%	4.1%	4.9%	.1%	2.0%	4.5%	Retained to Com Eq	4.5%
61%	67%	52%	63%	61%	58%	55%	59%	56%	99%	76%	60%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.9	-3.4	+2.1
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. (%)	260	268	233

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	3.0%	2.0%	5.0%
"Cash Flow"	3.5%	4.5%	4.5%
Earnings	5.0%	4.0%	4.5%
Dividends	6.0%	6.5%	3.0%
Book Value	3.5%	3.0%	1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3514	2888	3119	3148	12669
2020	3022	2583	3284	3288	12177
2021	3581	3021	3715	4647	14964
2022	4577	4924	5251	3248	18000
2023	4700	4150	4850	4850	18550

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2.19	.99	1.73	1.40	6.31
2020	1.76	1.44	2.46	1.42	7.08
2021	1.65	.60	.30	1.55	4.10
2022	2.03	.19	2.00	1.28	5.50
2023	2.45	1.00	1.60	1.15	6.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.945	.945	.945	.945	3.78
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				

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. '21 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 stock price has fallen over 15% since our early-September report, alongside losses by most of its peers over that interim. Indeed, the stock was trading near its all-time high just a few months ago. Recently, however, rising interest rates have plagued the entire utilities industry. Utility stocks, which have long enticed income-oriented accounts because of high dividend yields, have been among the worst-performing sectors of the S&P 500 of late. Investors are increasingly attracted to the bond market, due to its safety, as the macroeconomic climate shows few signs of improvement over the near term.

The utility posted strong third-quarter results. Earnings per share came in at $2.00 for the period, outperforming Wall Street's expectations and well surpassing our call of $1.50 a share. We have raised our 2022 profit target by $0.75 to $5.50 a share, reflecting the company's strong performance and updated guidance. Meanwhile, our full-year 2023 forecasts remain untouched. We expect a top line of $18.55 billion on profits of $6.20.

The company's electric utility subsidiary in Michigan had its rate case approved. The Michigan Public Service Commission agreed to a $30.6 million hike, a near $0.71 monthly increase for residential customers. DTE Electric initially requested a $388 million hike, based on a return on equity of 10.25%. The approved rates went into effect on November 25th. The utility also announced it will be adding 2,000 jobs in the state of Michigan through its $1.6 billion investment in new battery operations.

Despite the equity's recent price drop, capital appreciation potential remains unappealing. It is currently trading at the low end of our 3- to 5-year Target Price Range. Upside possibilities in the 18-month period are not impressive, either. In the coming six to 12 months these shares are ranked to mirror the broader market averages. DTE Energy's dividend yield is 3.3%, which is about in line with the industry average. Conservative accounts may be drawn to the stock's high mark for Price Stability and Above-Average rank (2) for Safety.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted EPS. Excl. nonrec. gains (loss): '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on discontinued operations: '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢); '21, 57¢. Next earnings report due early Feb. (B) Div'ds paid mid-Jan., Apr., July & Oct. ■ Div'd reinvestment plan available. (C) Incl. intang. In '21: $29.17/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	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	70

DUKE ENERGY NYSE-DUK

RECENT PRICE 93.18 | P/E RATIO 17.1 (Trailing: 17.7 Median: 18.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 4.3% | VALUE LINE

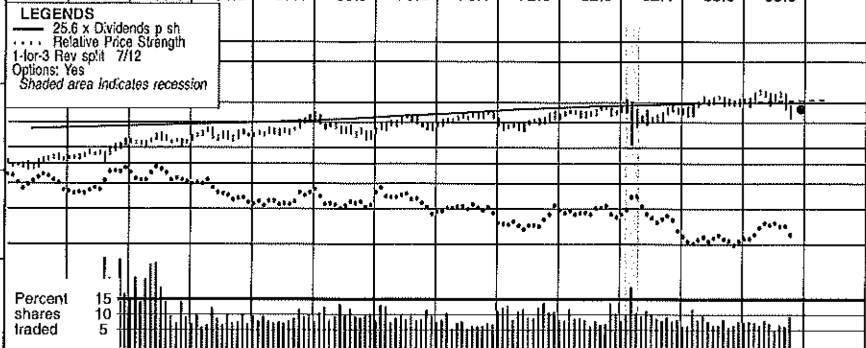
TIMELINESS 3 Raised 5/20/22
SAFETY 2 New 6/1/07
TECHNICAL 2 Lowered 11/4/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$88-$134 $111 (20%)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3
Low:	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8

Target Price Range 2025 | 2026 | 2027

LEGENDS
—— 25.6 x Dividends p sh
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+40%)	12%
Low	95	(Nil)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	934	942	877
to Sell	627	651	688
Hld's(000)	484677	487269	491735

Percent shares traded 15 10 5

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.1	-13.4
3 yr.	10.4	35.8
5 yr.	28.6	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
25.32	30.24	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	35.05	36.05	Revenues per sh	37.90
7.86	8.11	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	13.25	14.00	"Cash Flow" per sh	16.00
2.76	3.60	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	5.45	5.75	Earnings per sh A	6.50
--	2.58	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	Div'd Decl'd per sh B ■	4.30
8.07	7.43	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	16.00	16.75	Cap'l Spending per sh	16.75
62.30	50.40	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	62.75	64.50	Book Value per sh C	70.00
418.96	420.62	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	770.00	Common Shs Outst'g D	770.00
--	16.1	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	Bold figures are		Avg Ann'l P/E Ratio	17.0
--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	Value Line		Relative P/E Ratio	.95
--	4.4%	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%	estimates		Avg Ann'l Div'd Yield	3.9%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
19624	24598	23925	23459	22743	23565	24521	25079	23868	25097	27000	27750	Revenues ($mill)	29200
2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	4200	4500	Net Profit ($mill)	5040
30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	10.0%	9.0%	Income Tax Rate	9.0%
22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	8.0%	7.0%	AFUDC % to Net Profit	7.0%
47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	56.5%	58.5%	Long-Term Debt Ratio	61.0%
52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	42.0%	40.0%	Common Equity Ratio	37.5%
77307	79482	78088	77222	86609	90774	94940	101807	103589	109744	115150	124525	Total Capital ($mill)	144100
68558	69490	70046	75709	82520	86391	91694	102127	106782	111408	117725	124375	Net Plant ($mill)	141100
3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	4.5%	4.5%	Return on Total Cap'l	4.5%
5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	8.5%	9.0%	Return on Shr. Equity	9.0%
5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	8.5%	9.0%	Return on Com Equity E	9.0%
.9%	1.5%	1.7%	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	2.5%	2.5%	Retained to Com Eq	3.0%
82%	78%	76%	79%	91%	83%	74%	71%	73%	78%	76%	73%	All Div'ds to Net Prof	68%

CAPITAL STRUCTURE as of 6/30/22
Total Debt $70193 mill. **Due In 5 Yrs** $19536 mill.
LT Debt $63147 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $225 mill.
Pension Assets-12/21 $9235 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 769,968,724 shs. as of 7/31/22
MARKET CAP: $84.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.9	-2.3	+2.0
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.)	NA	NA	NA
Fixed Charge Cov. (%)	233	183	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
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
2019	6163	5873	6940	6103	25079
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6238	25097
2022	7132	6685	7255	5928	27000
2023	7250	6750	7375	6375	27750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.24	1.12	1.79	.91	5.06
2020	1.14	1.08	1.87	1.03	5.12
2021	1.26	1.15	1.88	.94	5.24
2022	1.30	1.14	1.86	1.15	5.45
2023	1.30	1.20	2.00	1.10	5.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & 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. '21 reported deprec. rate: 2.9%. 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 has a number of rate cases pending. In North Carolina, Duke Energy Progress requested a boost of $326 million (8.5%) in 2023, $151 million (3.9%) in 2024, and $138 million (3.6%) in 2025. In South Carolina, Duke Energy Progress proposed its first base rate case in four years, and expects rates to go into effect in early 2023. In Ohio, the utility is seeking a $55 million (3%) hike, as the rate case hearing nears a conclusion. Adjusted second-quarter earnings of $1.14 a share, slightly outperformed our call of $1.10. Our 2022 full-year estimate remains at $5.45 a share. Management reaffirmed a range of $5.30 to $5.60, and a long-term earnings growth rate of 5% to 7% through 2026. Rate relief and strong retail volumes were the main drivers to the bottom line in the second period. Volume growth increased 2.6% year over year, which is higher than 2019 levels.

We look for a strong earnings performance in 2023, near the company's growth target of between 5% and 7%. Higher electric volumes should continue, and Duke Energy raised its load growth prediction to 1.5%-2% from 1.5%. The utility is estimating cost mitigation of $200 million starting in 2023, due to rising interest rates and inflation.

The company is very focused on carbon reduction and the development of clean and renewable energy projects. Currently, the utility has 5,000 megawatts of Commericial wind, solar, and battery projects, ranking it within the top-10 largest renewable companies in the United States. By 2035, the company intends to reach 30,000 megawatts of renewable energy. Duke plans to invest $145 billion over the next 10 years and achieve net-zero carbon emissions by 2050 in its clean energy transition. Management expects carbon emission reduction to exceed 50% by 2030, and 80% by 2040.

The stock has dropped 20% in value since our August report, alongside losses by most of its peers over that time due to rising interest rates. Despite the stock's price reduction, its 18-month and 3- to 5-year capital appreciation potential does not stand out. Meanwhile, this issue is ranked 3 (Average) for Timeliness.

Zachary J. Hodgkinson November 11, 2022

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96¢; '20, $3.40; '21, 30¢; 1Q22, 22¢; net nonrec gain: '17, 14¢. 2021 EPS don't sum to annual due to rounding. Next egs. due early Feb. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $41.34/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. 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 **67.79** | P/E RATIO **14.6** (Trailing: 13.9; Median: 17.0) | RELATIVE P/E RATIO **0.87** | DIV'D YLD **4.4%** | VALUE LINE

TIMELINESS **4** Lowered 9/23/22
SAFETY **3** Lowered 11/23/18
TECHNICAL **3** Raised 1/20/23
BETA .95 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3
Low:	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	54.4

Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

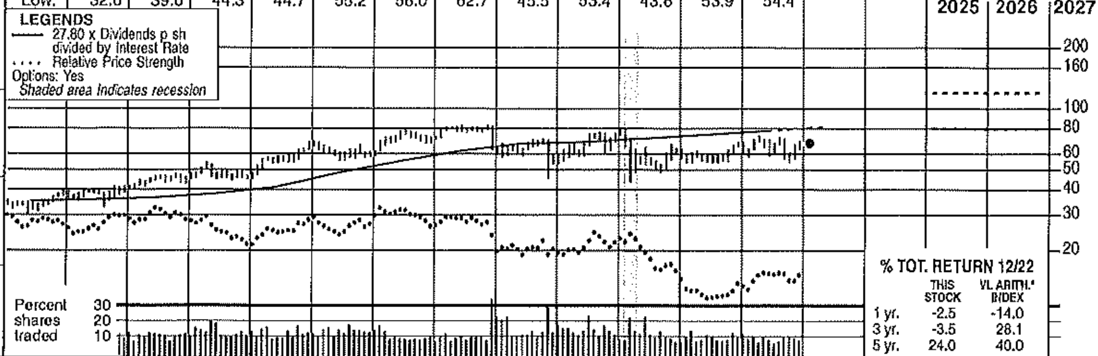
Low-High	Midpoint (% to Mid)
$50-$94	$72 (6%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+75%)	18%
Low	80	(+20%)	8%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	323	368	339
to Sell	291	254	277
Hld's(000)	332086	333217	335090



% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.5	-14.0
3 yr.	-3.5	28.1
5 yr.	24.0	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
38.74	40.25	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	*42.65*	*43.45*	Revenues per sh	*47.70*
7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.15	7.94	8.58	*11.50*	*11.85*	"Cash Flow" per sh	*13.75*
3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	3.98	1.72	2.00	*4.60*	*4.80*	Earnings per sh A	*6.30*
1.10	1.18	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	*2.80*	*2.95*	Div'd Decl'd per sh B ■	*3.50*
7.78	8.67	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	*14.80*	*15.10*	Cap'l Spending per sh	*16.50*
23.66	25.92	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	*41.90*	*44.00*	Book Value per sh C	*47.45*
325.81	325.81	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	*382.00*	*382.00*	Common Shs Outst'g D	*390.00*
13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	--	16.7	34.9	29.7	*14.1*		Avg Ann'l P/E Ratio	*16.0*
.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	--	.89	1.79	1.63	*.85*		Relative P/E Ratio	*.90*
2.6%	2.2%	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%	4.3%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $30331 mill. Due in 5 Yrs $10250 mill.
LT Debt $25145 mill. LT Interest $1030 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $623 mill.
Pension Assets-12/21 $4296 mill. Oblig $4171 mill.
Pfd Stock $3878 mill. Pfd Div'd $211 mill.
350,000 sh. 6.25%, $1000 liq. value; 638,020 sh. 5.0%-5.75%, $2500 liq. value; 1,250,000 sh. 5.375%, 750,000 sh. 5%, $1000 liq. value, all cum.
Common Stock 381,874,674 shs. as of 10/31/22
MARKET CAP: $25.9 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
11862	12581	13413	11524	11869	12320	12657	12347	13578	14905	*16300*	*16600*	Revenues ($mill)	*18600*
1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	775.0	925.0	*1760*	*1835*	Net Profit ($mill)	*2455*
14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	--	--	--	--	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	--	11.1%	22.5%	18.5%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	*56.5%*	*56.5%*	Long-Term Debt Ratio	*60.5%*
46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	*33.5%*	*33.5%*	Common Equity Ratio	*32.0%*
20422	21516	23216	24352	24362	25506	27284	33360	35581	41959	*45000*	*47500*	Total Capital ($mill)	*61000*
30273	30455	32981	35085	37000	39050	41348	44285	47839	50700	*53700*	*57300*	Net Plant ($mill)	*66600*
8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	3.4%	3.3%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	4.9%	5.2%	*11.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	4.6%	5.5%	*13.0%*	*12.5%*	Return on Com Equity E	*13.0%*
11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	NMF	NMF	*6.0%*	*5.5%*	Retained to Com Eq	*6.0%*
32%	40%	37%	44%	53%	52%	NMF	63%	NMF	125%	*61%*	*61%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	+.7	-3.9
Avg. Indust. Use (MWH)	657	589	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22009	23133	21190
Annual Load Factor (%)	49.6	46.7	52.7
% Change Customers (yr-end)	+.5	+.6	+.3
Fixed Charge Cov. (%)	172	NMF	113

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-.5%	4.5%
"Cash Flow"	--	-3.5%	8.0%
Earnings	-2.5%	-9.0%	16.0%
Dividends	7.5%	8.5%	5.0%
Book Value	1.5%	1.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2824	2812	3741	2970	12347
2020	2790	2987	4644	3157	13578
2021	2960	3315	5299	3331	14905
2022	3968	4008	5228	*3096*	*16300*
2023	*3750*	*4180*	*5400*	*3270*	*16600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	1.57	1.35	.45	3.98
2020	.50	.85	d.76	1.13	1.72
2021	.68	.84	d.90	1.38	2.00
2022	1.07	.94	1.48	*1.11*	*4.60*
2023	*1.05*	*1.00*	*1.55*	*1.20*	*4.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.6125	.6125	.6125	.6125	2.45
2020	.6375	.6375	.6375	.6375	2.55
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70	.70	2.80
2023	.738				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.2 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, 43%; commercial, 45%; industrial, 3%; other, 9%. Generating sources: nuclear, 8%; gas, 3%; hydro, 3%; purch., 86%. Power costs: 37% of revs. '21 reported depr. rate: 3.7%. Has 13,000 empls. Chairman: William P. Sullivan. Pres. & 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 likely earned about $4.60 a share in 2022. Management has provided an earnings-per-share target of $4.48 to $4.68 and our estimate falls within this spread. The long-term growth rate for annual EPS is 5% to 7%. However, that reading this year will be dramatically higher as 2021's figure (as well as 2018 and 2020) was suppressed by setbacks tied to the wildfires/mudslides that began in 2017. The ledger was decidedly cleaner in 2022, though adjustments do pop up sometimes still.

Each time the company reports quarterly results, management reviews loss estimates for the catastrophic events of 2017-2018. The third-quarter review obtained after the statute of limitations expired for plaintiffs in the Woolsey fire showed higher-than-expected costs to settle claims. The resulting net charge to earnings was $830 million ($880 million with $50 million subtracted for expected recoveries in electric rates), or just shy of $600 million on an after-tax basis. In the meantime, the wildfire mitigation plan rolls on. Southern California Edison (SCE) was set to have 4,300 miles of covered conductor in place by the end of 2022. That amount is 43% of SCE's overhead miles in high fire risk areas.

Our earnings call for 2023 is now a nickel lower, at $4.80 a share. This figure is more in line with (though slightly below) the expected annual growth rate. Still, visibility is clouded. The California Public Utilities Commission (CPUC) could trim Edison's ROE retroactively for 2022 and then set figures for 2023-2025. The regulatory climate here is average and we do not think CPUC will make changes, but nothing is yet finalized.

This utility's yield is nearly a full percentage point higher than the broader industry's average. Beginning with the January 30th payment, the quarterly stipend has been raised 5.4%, to an annual run rate of $2.95 a share (was $2.80). This is where the appeal of EIX stock ends though, as it is below the respective *Value Line* averages for both the coming 18 months and the stretch to 2025-2027..The equity also has an untimely designation (4: Below Average) for year-ahead relative price performance.

Erik M. Manning *January 20, 2023*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (15¢); '19, (21¢); '20, 25¢; gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. '19 EPS don't sum due to change in shs. Next earnings report due early February. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. in '21: $20.14/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; earned on avg. com. eq., '21: 5.4%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	30
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

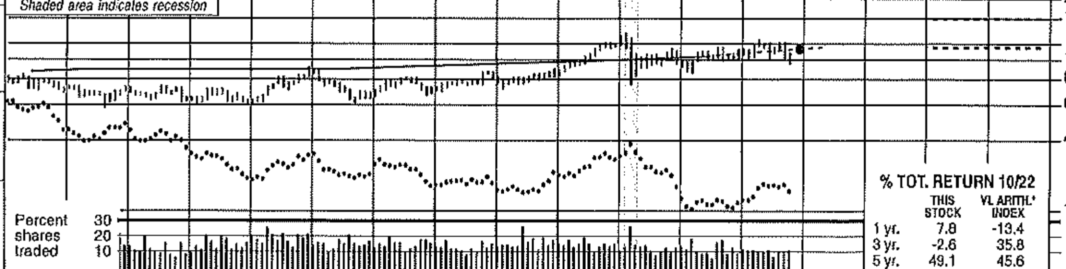
RECENT PRICE 113.25 | P/E RATIO 17.0 (Trailing: 18.1; Median: 14.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 9/2/22
SAFETY 2 Raised 12/13/19
TECHNICAL 4 Lowered 12/9/22
BETA .95 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8
Low:	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	94.9

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$99-$158 $129 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+40%)	12%
Low	115	(Nil)	5%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	327	348	348
to Sell	281	260	258
Hld's(000)	179128	184330	184841

Percent shares traded 30 20 10

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.8	-13.4
3 yr.	-2.6	35.8
5 yr.	49.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.94	59.47	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	63.10	56.45	Revenues per sh	61.50
10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	16.72	16.70	16.50	17.19	18.21	17.90	17.75	17.95	"Cash Flow" per sh	20.50
5.36	5.60	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	6.65	6.80	Earnings per sh A	8.50
2.16	2.58	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	4.30	Div'd Decl'd per sh B ■ †	5.10
9.44	10.29	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	18.15	19.00	Cap'l Spending per sh	19.75
40.45	40.71	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	60.00	63.55	Book Value per sh C	74.00
202.67	193.12	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	206.00	209.00	Common Shs Outst'g D	214.00
14.3	19.3	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	Bold figures are		Avg Ann'l P/E Ratio	16.0
.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.80	Value Line		Relative P/E Ratio	.90
2.8%	2.4%	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%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $27606 mill. **Due in 5 Yrs** $11117 mill.
LT Debt $24635 mill. **LT Interest** $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $65.3 mill.
Pension Assets-12/21 $6993.1 mill. **Oblig** $8409.6 mill.
Pfd Stock $254.4 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 203,463,660 shs. as of 10/31/22
MARKET CAP: $23.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10302	11391	12495	11513	10846	11074	11009	10879	10114	11743	13000	11800	Revenues ($mill)	13150
1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	1370	1420	Net Profit ($mill)	1845
13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	NMF	NMF	16.1%	23.0%	23.0%	Income Tax Rate	23.0%
11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	66.5%	66.5%	Long-Term Debt Ratio	66.0%
42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	32.5%	33.0%	Common Equity Ratio	33.5%
21432	22109	22842	22714	22777	22528	24602	27557	32386	36733	38050	40200	Total Capital ($mill)	47300
27299	27882	28723	27824	27921	29664	31974	35183	38853	42244	43750	45425	Net Plant ($mill)	50800
6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.8%	3.0%	4.5%	Return on Total Cap'l	5.0%
11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.6%	9.5%	10.5%	Return on Shr. Equity	11.5%
11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	9.5%	10.5%	Return on Com Equity E	11.5%
5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	3.5%	4.0%	Retained to Com Eq	4.5%
56%	68%	58%	58%	50%	68%	61%	58%	55%	57%	62%	64%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.4	-4.1	+3.2
Avg. Indust. Use (MWH)	1070	1017	1015
Avg. Indust. Revs. per KWH(¢)	5.24	4.95	5.91
Capacity at Peak (Mw)	23867	25665	NA
Peak Load, Summer (Mw)	21598	21340	NA
Annual Load Factor (%)	64	62	NA
% Change Customers (yr-end)	+.8	+1.0	+1.0
Fixed Charge Cov. (%)	165	202	243

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-3.5%	2.0%
"Cash Flow"	1.0%	-.5%	2.5%
Earnings	--	1.5%	4.0%
Dividends	1.5%	2.0%	5.0%
Book Value	1.5%	1.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2610	2666	3141	2462	10879
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	2508	13000
2023	2950	2850	3250	2750	11800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	1.78	2.84	.67	6.65
2023	1.40	1.75	2.90	.75	6.80

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.89	.91	3.58
2019	.91	.91	.91	.93	3.66
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	

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, 46%; nuclear, 30%; coal, 6%; purchased, 18%. Fuel costs: 32% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 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 Corp. recorded solid third-quarter results. Revenues expanded to $4.2 billion, aided by strong growth across its electric services business and higher energy prices. Positives included healthy demand from industrial companies, while population growth across the southern United States was positive. The company also benefited from several rate cases being approved, allowing for more recoveries, and a few projects were placed into service. Still, costs rose at a quick rate, especially those related to fuel costs, while operational maintenance was much higher. Overall, adjusted earnings rose to $2.84 per share during the quarter. The fourth-quarter performance will likely be lackluster as the company faces tough comparisons from 2021, which had cooler-than-usual weather. It exited some non-regulated nuclear operations in Michigan over the past year, and it sold some shares to fund capital expenditures. We estimate adjusted earnings will reach $0.67 per share in the final quarter of 2022.

The long-term outlook is decent. Entergy should gain from population and industrial growth across its coverage area. Additionally, it has filed for several rate cases, including for Entergy New Orleans and Entergy Texas, with a decision on the latter due in the second quarter of 2023. Additionally, the company has been investing in renewable energy projects that will come online in the years ahead, helping to bolster revenues, and regulators could approve more. Costs for fuel and maintenance will likely increase with the added operations. The company has been funding capital expenditures with debt and equity sales, which should limit profit-per-share gains. Bad-debt expenses may well pick up if the economy slows further. We project adjusted earnings per share of $6.80 in 2023 and $8.50 in 2025-2027.

The board raised the quarterly dividend by 6% to $1.07. This payout remains well covered by profits and should expand steadily in the years ahead.

Shares of Entergy Corp. are neutrally ranked for Timeliness. This stock has a good dividend yield and long-term upside potential is subpar. Overall, we think this is best suited for conservative income-seeking accounts.

John E. Seibert III *December 9, 2022*

(A) Diluted EPS. 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; '22, $1.19. Next earnings report due early Feb. (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 '21: $35.95/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '21: 12.1%. Regulatory Climate: Average.

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

EVERGY, INC. NYSE-EVRG

RECENT PRICE 58.69 | P/E RATIO 16.4 (Trailing: 17.0 Median: NMF) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 9/2/22
SAFETY 2 New 9/14/18
TECHNICAL 3 Lowered 11/18/22
BETA .90 (1.00 = Market)

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$53-$88 $71 (20%)

2025-27 PROJECTIONS

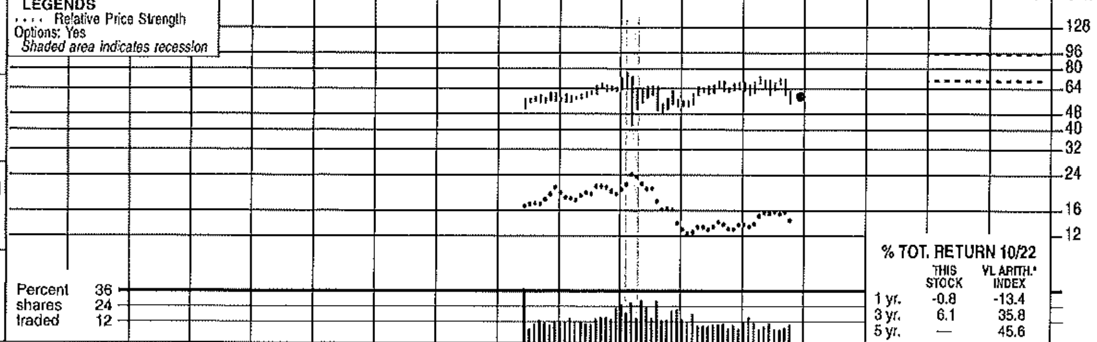
	Price	Gain	Ann'l Total Return
High	95	(+60%)	16%
Low	70	(+20%)	8%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	284	304	305
to Sell	270	252	250
Hld's(000)	196288	194242	193700

	2018	2019	2020	2021	2022
High:	61.1	67.8	76.6	69.4	73.1
Low:	50.9	54.6	42.0	51.9	54.1

Target Price Range 2025 | 2026 | 2027



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.8	-13.4
3 yr.	6.1	35.8
5 yr.	—	45.6

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.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	--	--	--	16.75	22.71	21.66	24.36	24.80	25.20	Revenues per sh	26.50
--	--	--	--	--	--	4.89	7.18	7.06	8.18	8.05	8.40	"Cash Flow" per sh	10.00
--	--	--	--	--	--	2.50	2.79	2.72	3.83	3.55	3.75	Earnings per sh A	4.75
--	--	--	--	--	--	1.74	1.93	2.05	2.18	2.33	2.46	Div'd Decl'd per sh B ■	3.05
--	--	--	--	--	--	4.19	5.34	6.88	8.60	8.60	9.20	Cap'l Spending per sh	9.50
--	--	--	--	--	--	39.28	37.82	38.50	40.32	41.40	42.70	Book Value per sh C	47.50
--	--	--	--	--	--	255.33	226.64	226.84	229.30	230.00	230.00	Common Shs Outst'g D	230.00
--	--	--	--	--	--	22.7	21.8	21.7	16.2	Bold figures are		Avg Ann'l P/E Ratio	17.5
--	--	--	--	--	--	1.23	1.16	1.11	.87	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	--	3.1%	3.2%	3.5%	3.5%	estimates		Avg Ann'l Div'd Yield	3.7%
--	--	--	--	--	--	4275.9	5147.8	4913.4	5586.7	5700	5800	Revenues ($mill)	6100
--	--	--	--	--	--	535.8	669.9	618.3	879.7	835	860	Net Profit ($mill)	1115
--	--	--	--	--	--	9.8%	12.6%	14.1%	11.7%	9.0%	9.0%	Income Tax Rate	9.0%
--	--	--	--	--	--	2.5%	2.5%	5.5%	5.0%	5.0%	6.0%	AFUDC % to Net Profit	5.0%
--	--	--	--	--	--	40.0%	50.6%	51.3%	50.1%	51.5%	51.5%	Long-Term Debt Ratio	53.5%
--	--	--	--	--	--	60.0%	49.4%	48.7%	49.9%	48.5%	48.5%	Common Equity Ratio	46.5%
--	--	--	--	--	--	16716	17337	17924	18542	19675	20175	Total Capital ($mill)	23400
--	--	--	--	--	--	18952	19346	20108	21150	22100	23150	Net Plant ($mill)	26300
--	--	--	--	--	--	4.0%	4.8%	4.5%	5.7%	5.0%	5.5%	Return on Total Cap'l	6.0%
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Shr. Equity	10.0%
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Com Equity E	10.0%
--	--	--	--	--	--	.6%	2.4%	1.8%	4.1%	3.0%	3.0%	Retained to Com Eq	3.5%
--	--	--	--	--	--	89%	69%	75%	57%	64%	65%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $11664 mill. **Due in 5 Yrs** $4388.2 mill.
LT Debt $9197.2 mill. **LT Interest** $305.5 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/21 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,536,385 shs.
as of 10/31/22
MARKET CAP: $13.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	-3.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	7.14	6.94
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. (%)	305	286	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	2.5%
"Cash Flow"	--	--	5.0%
Earnings	--	--	7.5%
Dividends	--	--	7.0%
Book Value	--	--	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1217	1222	1578	1131	5148
2020	1117	1185	1517	1094	4913
2021	1612	1236	1617	1122	5587
2022	1224	1447	1909	1120	5700
2023	1225	1450	1900	1225	5800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	.32	3.55
2023	.60	.80	2.05	.30	3.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.6125		

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, 34%; commercial, 30%; industrial, 11%; wholesale, 13%; other, 12%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '21 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 delivered strong financial results in the third quarter. Earnings of $1.86 a share, on revenues of $1.9 billion, both exceeded Wall Street's expectations and increased 75%, and 27% from the last period, respectively. The performance was due primarily to the company's improved transmission margin, along with continued favorable demand in all sectors. Total demand has grown 3% this year and 2.4% in the September-period, driven by increases in industrial demand such as the chemical and oil and gas sectors.

The company raised its 2022 earnings range from $3.43-$3.63 a share to $3.53-$3.63 due to the better-than-expected September-period showing. Management remains committed to its long-term EPS growth-rate target of 6%-8% annualy. We have adjusted our top-line estimate which now stands at $5.7 billion, up from our previous call of $5.4 billion. In 2023, we are forecasting revenues of $5.8 billion and earnings of $3.75 per share.

Evergy has hiked its dividend by 7%. The dividend yield of 4.2%, which is solid for a utility should appeal to income-oriented investors. Management is targeting a dividend growth rate in line with earnings at a 60%-70% payout.

The company hopes to get approval on its acquisition of the Permisson Creek Wind Farm by year end. The $250 million investment will boost the renewable energy business and assist the utility in its goal of net-zero carbon emissions by 2045.

Evergy shares have underperformed of late. The stock has declined more than 16% in value over the past three months, alongside losses by many of its peers. The utility industry has struggled recently due to the challenging interest-rate environment. Higher yields on Treasuries have prompted a growing number of income-oriented investors to enter the bond market, and the competition has not augured well for utilities. Due to its recent price struggles, capital appreciation potential over the 18-month span, and 3- to 5-year period have improved since our last review. Also, these shares are ranked to mirror the broader market averages over the next year. But the dividend continues to be the main attraction here.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted earnings. '19 EPS don't sum to full-year total due to rounding. Next earnings report due late February. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $4,327.7 mill., $18.87/sh. (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, '21: 9.8%. Regulatory Climate: Average.

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

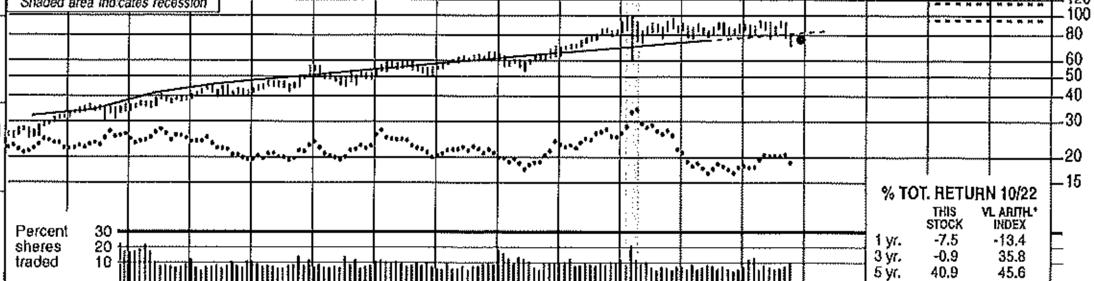
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 76.28 | P/E RATIO 18.1 (Trailing: 18.7; Median: 19.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 8/19/22
SAFETY 1 Raised 5/22/15
TECHNICAL 2 Lowered 11/4/22
BETA .90 (1.00 = Market)

High:	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6	99.4	92.7	94.6
Low:	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1	60.7	76.6	70.5

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



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

Low-High $78-$129; Midpoint (% to Mid) $104 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+50%)	14%
Low	95	(+25%)	9%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	366	412	411
to Sell	312	315	308
Hld's(000)	275552	269412	271816

Percent shares traded 30 / 20 / 10

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.5	-13.4
3 yr.	-0.9	35.8
5 yr.	40.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.64	37.27	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	*32.75*	*34.20*	Revenues per sh	*37.00*
3.69	4.82	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	*8.10*	*8.55*	"Cash Flow" per sh	*10.00*
.82	1.59	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	*4.10*	*4.40*	Earnings per sh A	*5.30*
.73	.78	.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*	Div'd Decl'd per sh B ■	*3.30*
5.49	7.14	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	*11.20*	*10.50*	Cap'l Spending per sh	*9.50*
18.14	18.65	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	*44.20*	*46.50*	Book Value per sh C	*53.75*
154.23	156.22	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	*348.00*	*351.00*	Common Shs Outst'g D	*365.00*
27.1	18.7	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	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.22	1.19	*Value Line*		Relative P/E Ratio	*1.10*
3.3%	2.6%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $21423 mill. Due in 5 Yrs $8313.5 mill.
LT Debt $20016 mill. LT Interest $619.8 mill.
(Total interest coverage: 3.9x)

Leases, Uncapitalized Annual rentals $11.1 mill.

Pension Assets-12/21 $6495.5 mill.
Oblig $6729.7 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.

Common Stock 346,443,316 shs.
as of 7/31/22
MARKET CAP: $26.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	9863.1	*11400*	*12000*	Revenues ($mill)	*13500*
533.0	793.7	827.1	886.0	949.8	995.5	1040.5	1121.0	1244.8	1337.7	*1430*	*1545*	Net Profit ($mill)	*1935*
34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	21.9%	*24.0%*	*24.0%*	Income Tax Rate	*24.0%*
2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.3%	4.2%	*5.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	54.2%	*54.5%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	45.3%	*45.0%*	*44.5%*	Common Equity Ratio	*44.0%*
16675	17544	18738	19313	19697	23018	24474	27097	29842	32233	*34325*	*36650*	Total Capital ($mill)	*44700*
16605	17576	18647	19892	21351	23617	25610	27585	30883	33378	*36025*	*38400*	Net Plant ($mill)	*44500*
4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.1%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.8%	9.1%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.8%	9.1%	*9.0%*	*9.5%*	Return on Com Equity E	*10.0%*
1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.5%	3.6%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
72%	59%	58%	61%	60%	61%	62%	60%	60%	61%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.3	-2.7	+1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	+.6
Fixed Charge Cov. (%)	319	345	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	2.0%	5.5%
"Cash Flow"	3.5%	7.5%	6.0%
Earnings	6.0%	5.5%	6.5%
Dividends	8.5%	6.5%	6.5%
Book Value	6.5%	4.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2416	1884	2176	2050	8526.5
2020	2373	1953	2344	2234	8904.4
2021	2826	2122	2433	2482	9863.1
2022	3471	2573	*2750*	*2606*	*11400*
2023	*3650*	*2700*	*2900*	*2750*	*12000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.97	.74	.98	.76	3.45
2020	1.02	.76	1.01	.85	3.64
2021	1.15	.79	1.02	.91	3.86
2022	1.30	.86	*1.03*	*.91*	*4.10*
2023	*1.35*	*.92*	*1.11*	*1.02*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535	.535	2.14
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022	.6375	.6375	.6375		

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities with 3.3 mill. electric, 887,000 gas, 226,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; 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, 53%; commercial, 33%; industrial, 5%; other, 9%. Fuel costs: 34% of revs. '21 reported depr. rate: 3.1%. Has 9,200 empls. Chairman: James J. Judge. Pres. & CEO: Joseph R. Nolan, Jr. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy is on pace for a solid year. The company is receiving a full year's effect from last November's natural gas price hike in Massachusetts, with the rate set to rise again this November. Eversource is also benefiting from transmission and distribution (T&D) capital projects, which raise the rate base (property, plant, and equipment on which utilities are allowed to earn an economic rate of return). The rising rate base increases the company's electric rates annually through a forward-looking algorithm that takes regulatory lag out of the equation for T&D investments. We expect earnings will be up about 6.5% this year to $4.10 per share. (Note: Eversource is due to report third-quarter financial results shortly after this report goes to press.)

We look for more of the same going forward. NSTAR has a pending electric rate case in Massachusetts, with a decision due in December. The utility requested increases of $46 million and $47 million at the start of 2023 and 2024, respectively, based on a 10.5% return on equity (50 basis points bigher than the rate of return granted in 2018). This may be a bit of a stretch. Nevertheless, we think a constructive outcome is likely and rates should increase in January.

Leadership has adjusted its clean-energy strategy. Eversource is shopping its stake in non-regulated offshore wind ventures, deeming them outside of its risk tolerance and too high a drain on capital. Instead, the company plans to benefit from this new power source's growth in New England through the relative safety of regulated T&D projects, such as those necessary to connect wind generation to the grid. Modernization programs that ready its territories for the electrification of the transportation system will also serve to grow its rate hase. Regulated renewable-power-generation ventures will likely remain a viable option, as well.

Total returns for this issue over the 18-month time frame look attractive. We view Eversource as a desirable holding for utility investors due to its superior earnings and dividend growth rates relative to its peer group. Its yield is 30 basis points below the industry average, but we think the valuation premium is justified.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '08, (19¢); '10, 9¢; '19, (64¢); '20, (9¢); '21, (32¢); 1Q-2Q '22, (3¢). Next earnings report due early Feb. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $9064 mill., $26.32/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (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 Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	100

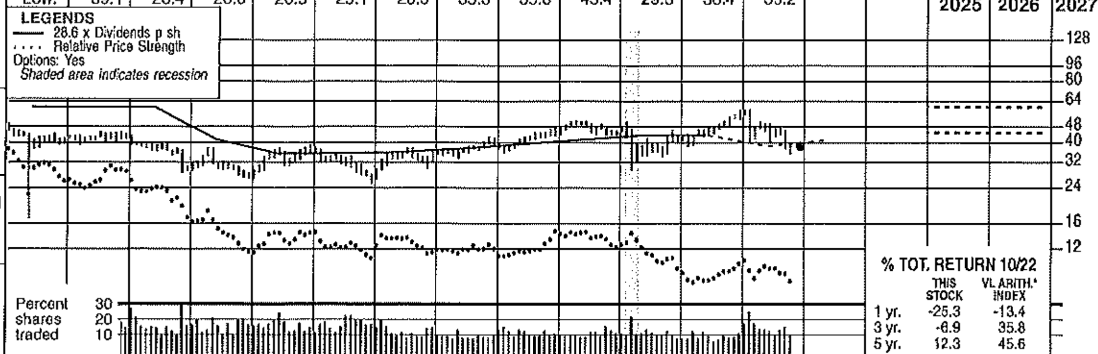
EXELON CORP. NDQ-EXC

RECENT PRICE 38.59 | P/E RATIO 17.2 (Trailing: 12.6 Median: 14.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS — Suspended 2/4/22
SAFETY 2 Raised 8/13/21
TECHNICAL — Suspended 2/4/22
BETA .95 (1.00 = Market)

High:	45.4	43.7	37.8	38.9	38.3	37.7	42.7	47.4	51.2	50.5	58.0	58.2
Low:	39.1	28.4	26.6	26.5	25.1	26.3	33.3	35.6	43.4	29.3	38.4	35.2

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



Target Price Range 2025 | 2026 | 2027
128 96 80 64 48 40 32 24 16 12

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$30-$54	$42 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+55%)	14%
Low	45	(+15%)	7%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	550	514	508
to Sell	369	438	381
Hld's(000)	793215	804098	812613

Percent shares traded 30 20 10

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-25.3	-13.4
3 yr.	-6.9	35.8
5 yr.	12.3	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.37	28.62	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	*18.70*	*19.10*	Revenues per sh	*20.50*
6.71	7.43	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	*6.55*	*6.75*	"Cash Flow" per sh	*7.50*
3.50	4.03	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	*2.25*	*2.40*	Earnings per sh A	*2.90*
1.64	1.82	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*	*1.45*	Div'd Decl'd per sh B ■	*1.75*
3.61	4.05	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	*6.85*	*6.80*	Cap'l Spending per sh	*7.00*
14.89	15.34	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	*24.10*	*25.20*	Book Value per sh C	*28.75*
669.86	660.88	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	*990.00*	*995.00*	Common Shs Outst'g D	*1000.0*
16.5	18.2	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.66	.67	.72	.78	.64	.89	*Value Line*		Relative P/E Ratio	*.95*
2.8%	2.5%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $39843 mill. Due in 5 Yrs $12334 mill.
LT Debt $35789 mill. LT Interest $1450 mill.
Includes $390 mill. nonrecourse transition bonds.
(Interest coverage: 2.7x)
Leases, Uncapitalized Annual rentals $156 mill.

Pension Assets-12/21 $20827 mill. Oblig $23846 mill.

Pfd Stock None

Common Stock 980,472,436 shs. as of 6/30/22
MARKET CAP: $37.8 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
23489	24888	27429	29447	31360	33531	35985	34438	33039	36347	*18500*	*19000*	Revenues ($mill)	*20500*
1579.0	1999.0	1826.0	2282.0	2488.0	2636.0	3026.0	3139.0	3149.0	2764.0	*2225*	*2400*	Net Profit ($mill)	*2900*
32.4%	36.5%	27.2%	32.2%	36.5%	34.2%	11.1%	19.4%	17.4%	16.1%	*13.5%*	*15.0%*	Income Tax Rate	*15.0%*
5.8%	4.5%	5.5%	5.4%	8.3%	6.5%	4.6%	5.0%	5.5%	7.4%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	52.8%	49.6%	52.1%	50.9%	*59.5%*	*61.0%*	Long-Term Debt Ratio	*64.5%*
53.5%	55.2%	52.6%	51.3%	44.5%	47.8%	47.2%	50.4%	47.9%	49.1%	*40.5%*	*39.0%*	Common Equity Ratio	*35.5%*
40057	41196	42811	50272	58053	62422	65229	63943	68068	70107	*58750*	*64125*	Total Capital ($mill)	*81000*
45186	47330	52087	57439	71555	74202	76707	80233	82584	84219	*66250*	*69175*	Net Plant ($mill)	*77600*
5.1%	5.9%	5.3%	5.5%	5.5%	5.3%	5.7%	6.0%	5.7%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
7.3%	8.7%	8.0%	8.6%	9.6%	8.8%	9.8%	9.7%	9.7%	8.0%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
7.3%	8.7%	8.0%	8.6%	9.6%	8.8%	9.8%	9.7%	9.7%	8.0%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
NMF	3.2%	3.3%	4.5%	5.1%	4.7%	5.5%	5.4%	5.1%	3.7%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
109%	63%	59%	49%	47%	47%	44%	45%	47%	54%	*60%*	*60%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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)	+.7	+.7	+.6
Fixed Charge Cov. (%)	257	211	159

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	NMF
"Cash Flow"	2.0%	6.5%	NMF
Earnings	-2.5%	4.5%	NMF
Dividends	-3.5%	4.0%	NMF
Book Value	5.0%	4.5%	NMF

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	9477	7689	8929	8343	34438
2020	8747	7322	8853	8117	33039
2021	9890	7915	8910	9632	36347
2022	5327	4239	*5000*	*3934*	*18500*
2023	*5050*	*4250*	*5250*	*4450*	*19000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.87	.60	.92	.83	3.22
2020	.87	.55	1.04	.76	3.22
2021	d.06	.89	1.09	.90	2.82
2022	.64	.44	*.70*	*.47*	*2.25*
2023	*.64*	*.49*	*.77*	*.50*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.345	.345	.345	.345	1.38
2019	.3625	.3625	.3625	.3625	1.45
2020	.3825	.3825	.3825	.3825	1.53
2021	.3825	.3825	.3825	.3825	1.53
2022	.3375	.3375			

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. '21 deprec. rates: 2.8%-8.7% elec., 2.1% gas. Has 18,700 empls. Chrmn.: John F. Young. CEO: Christopher M. Crane. Inc.: PA. Addr.: 10 S.Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Shares of Exelon Corp. have declined significantly in value since our August report. The stock has dropped nearly 20% over that interim, as all of the electric utilities (East) covered in *The Value Line Investment Survey* have experienced a substantial price drop due to rising interest rates. Second-quarter earnings per share of $0.44, slightly underperformed both Wall Street's expectations, as well as our calls of $0.45. We expect earnings performance to be much more consistent moving forward, as Exelon continues to operate exclusively as a utility holding company. Our bottom-line estimates for 2022 and 2023 are $2.25 and $2.40 a share, respectively. Management reaffirmed its 2022 projections of $2.18 to $2.32 a share, and year-to-date operating earnings of $1.08 per share are exactly in line with full-year estimates. (The company was set to report third-quarter results shortly after this report went to press.)

Exelon's utilities have made progress in several pending rate cases and higher distribution rates are a main driver of earnings growth. In Maryland, Delmarva Power received rate relief of $37.5 million over three years and new electric supply rates began in October. Delmarva also proposed a $14.5 million gas increase, based on a 10.3% return on equity, in Delaware. The company expects a final order in early 2023. In late October, the Illinois Commerce Commission approved ComEd's $50 million hike.

The company commended the recently passed Inflation Reduction Act, as it will help the transformation to cleaner energy and an improved grid. However, the act also imposes a corporate minimum tax of 15%. This could impact the utility's incremental cash tax by as much as $300 million per year, starting in 2023, offsetting the lower costs of clean energy incentivized in the bill.

Despite the recent pullback in the share price due to rising interest rates, total return potential is average in comparison to its peers over the 18-month and 3- to 5-year stretch. Due to the company spinoff of Constellation Energy in February, the stock remains unranked for Timeliness. The dividend yield also remains below the industry average.

Zachary J. Hodgkinson November 11, 2022

(A) Dil. egs. Excl. nonrec. gain (loss): '06, ($1.15); '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); 1Q22, (15¢); disc. ops. gain (loss): '07, 2¢; '08, 3¢. Next egs. report: Feb. (B) Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '21: $15.22/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; in NJ in '16: 9.75%. Regulatory Climate: PA, NJ: Average; IL, MD: Below Avg.

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

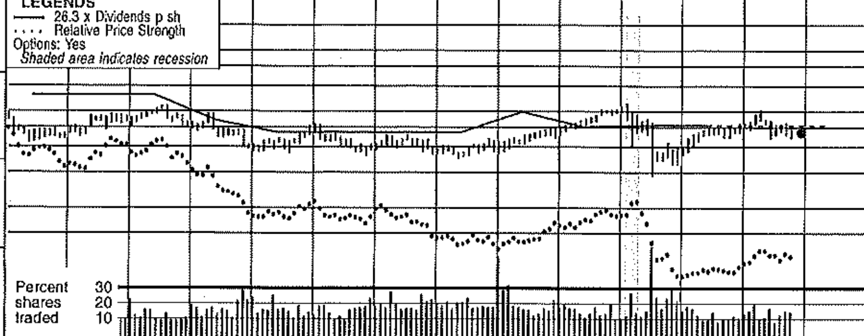
FIRSTENERGY NYSE-FE

RECENT PRICE 37.71 | P/E RATIO 15.1 (Trailing: 15.5; Median: 13.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 3/4/22
SAFETY 3 Lowered 7/31/20
TECHNICAL 2 Raised 10/21/22
BETA .85 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	46.5	51.1	46.8	40.8	41.7	36.6	35.2	39.9	49.1	52.5	41.8	48.8
Low:	36.1	40.4	31.3	30.0	28.9	29.3	27.9	29.3	36.3	22.9	29.2	35.3

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$34-$55 $45 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	40	(+5%)	6%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	349	341	318
to Sell	274	297	334
Hld's(000)	477887	479409	469796

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.7	-13.4
3 yr.	-12.4	35.8
5 yr.	39.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
36.03	42.00	44.70	41.70	43.76	36.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	20.41	19.87	19.52	*21.00*	*21.40*	Revenues per sh	*23.20*
7.22	8.34	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	5.30	*5.00*	*5.25*	"Cash Flow" per sh	*6.10*
3.82	4.22	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	*2.44*	*2.55*	Earnings per sh A	*3.00*
1.85	2.05	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*	*1.56*	Div'd Decl'd per sh B ■	*1.80*
4.12	5.36	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	*5.75*	*5.90*	Cap'l Spending per sh	*6.25*
28.30	29.45	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	*15.75*	*16.75*	Book Value per sh C	*20.50*
319.21	304.84	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	*572.00*	*575.00*	Common Shs Outst'g D	*582.00*
14.2	15.6	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	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.77	.83	.94	.87	.74	1.41	1.34	.74	.69	.63	.67	.57	.73	.91	.81	.76	*Value Line*		Relative P/E Ratio	*.85*
3.4%	3.1%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $21258 mill. Due in 5 Yrs $5795 mill.
LT Debt $20905 mill. LT Interest $972 mill.
Incl. $36 mill. finance leases.
(Total interest coverage: 2.6x)
Leases, Uncapitalized Annual rentals $54 mill.

Pension Assets-12/21 $9020 mill. Oblig $11479 mill.

Pfd Stock None

Common Stock 571,753,195 shs.

MARKET CAP: $21.6 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
15294	14903	15049	15029	14562	14022	11261	11035	10790	11132	*12000*	*12300*	Revenues ($mill)	*13500*
891.0	1245.0	1074.0	1144.0	1118.0	1213.0	1346.0	1380.0	1296.0	1419.0	*1400*	*1470*	Net Profit ($mill)	*1750*
41.1%	36.1%	28.4%	35.8%	37.4%	37.2%	28.5%	19.8%	13.6%	20.6%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
8.1%	6.0%	11.0%	10.2%	9.2%	6.5%	4.8%	5.1%	5.9%	5.3%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
53.7%	55.5%	60.7%	60.7%	74.5%	84.3%	72.3%	73.8%	75.4%	71.9%	*71.0%*	*70.0%*	Long-Term Debt Ratio	*67.5%*
46.3%	44.5%	39.3%	39.3%	25.5%	15.7%	27.4%	26.2%	24.6%	28.1%	*29.0%*	*30.0%*	Common Equity Ratio	*32.5%*
28263	28523	31596	31613	24433	25040	24565	26593	29368	30923	*30850*	*32375*	Total Capital ($mill)	*36700*
32903	33252	35783	37214	29387	28879	29911	31650	33294	34744	*36625*	*38550*	Net Plant ($mill)	*44300*
4.9%	6.0%	5.0%	5.3%	6.6%	7.0%	7.4%	6.8%	6.0%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.8%	9.8%	8.6%	9.2%	17.9%	30.9%	19.8%	19.8%	17.9%	16.4%	*15.5%*	*15.0%*	Return on Shr. Equity E	*14.5%*
6.8%	9.8%	8.6%	9.2%	17.9%	30.9%	18.9%	19.7%	17.9%	16.4%	*15.5%*	*15.0%*	Return on Com Equity E	*14.5%*
NMF	2.6%	3.8%	4.3%	8.1%	14.6%	8.4%	8.1%	6.2%	6.6%	*5.5%*	*6.0%*	Retained to Com Eq	*6.0%*
103%	74%	56%	53%	55%	53%	58%	59%	65%	60%	*64%*	*61%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	-4.0	+2.4
Avg. Indust. Use (MWH)	NMF	NMF	NMF
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)	+.3	+.6	+.4
Fixed Charge Cov. (%)	249	203	171

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.0%	-10.5%	*2.5%*
"Cash Flow"	-4.5%	-6.5%	*3.5%*
Earnings	-1.0%	-1.0%	*3.0%*
Dividends	-3.5%	1.5%	*2.5%*
Book Value	-7.0%	-10.5%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2883	2516	2963	2673	11035
2020	2709	2522	3022	2537	10790
2021	2726	2622	3124	2660	11132
2022	2989	2818	3475	*2718*	*12000*
2023	*3060*	*2880*	*3570*	*2790*	*12300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.67	.61	.76	.55	2.56
2020	.66	.57	.84	.32	2.39
2021	.69	.59	.82	.51	2.60
2022	.60	.53	.79	*.52*	*2.44*
2023	*.63*	*.55*	*.83*	*.54*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.36	.36	.36	1.44
2019	.38	.38	.38	.38	1.52
2020	.39	.39	.39	.39	1.56
2021	.39	.39	.39	.39	1.56
2022	.39	.39	.39		

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 6.2 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown: residential, 61%; commercial, 25%; industrial, 13%; other, 1%. Purchases most of its power. Power costs: 31% of revenues. 2021 reported depreciation rate: 2.7%. Has 12,400 employees. Board Chair, Interim President and CEO: John W. Somerhalder II. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

It has not been easy for FirstEnergy to move beyond the major bribery scandal that came to light in 2020. In our last report, dated August 12th, we provided a detailed progression of the new executive team's actions that have gone a long way towards turning the company around. However, in mid-September, just after the board of directors completed a review of its executive management team as part of a lawsuit settlement, the chief executive officer since March 2021, Steven Strah, retired. The company announced that John W. Somerhalder II, chair of the FirstEnergy Board of Directors, would take the helm as interim president and CEO while the board commences a search for a permanent external candidate. Meanwhile, the Department of Justice (DOJ) has asked Ohio state regulators to delay their own probes, as they may interfere with the DOJ's ongoing investigation. Lastly, the former Speaker of the Ohio House of Representatives, who is accused along with four others of accepting $60 million in bribes from FirstEnergy, has a January trial. The company has already settled with U.S. attorneys and is cooperating with the DOJ. It had seemingly settled with Ohio state regulators already as well, with agreements to refund Ohio customers significantly through yearend 2025.

In the meantime, we're projecting an earnings recovery to take hold starting next year. The recovery is partially driven by easier comparisons from diminishing annual refunds that are tied to the bribery settlement. Identifiable distribution and transmission projects throughout its vast Mid-Atlantic and contiguous network have the potential to drive rate-base growth of 6% annually, which can potentially translate to comparable earnings-per-share gains.

FirstEnergy shares do not stand out at the recent valuation. Utility investors can likely do better elsewhere in our opinion, as there are peers with higher intermediate and long-term total-return potential. This issue does, however, offer a dividend yield that's about 30 basis points above the peer-group median, and a resumption of growth in the payout by year-end 2024 seems feasible.

Anthony J. Glennon *November 11, 2022*

(A) Dil. EPS. Excl. nonrec. 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¢; 1Q-3Q '22, 49¢; gains from disc. ops.: '18, 66¢; '20, 14¢; '21, 8¢. Qtr. EPS don't sum due to chg. in shs. Next egs. report: late Jan. (B) Div'ds pd. early Mar., June, Sept., & Dec. 3 div'ds in '13, 5 in '18. ■ Div'd reinv. avail. (C) Incl. intang. in '21: $9.98/sh. (D) In mill. (E) High ROE from outsized 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	25
Earnings Predictability	100

FORTIS INC. TSE-FTS.TO [A]

RECENT PRICE 53.93 | P/E RATIO 19.0 (Trailing: 20.0 Median: 20.0) | RELATIVE P/E RATIO 1.17 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 5/13/22
SAFETY 2 Raised 7/17/15
TECHNICAL 3 Raised 11/25/22
BETA .70 (1.00 = Market)

High:	35.4	40.7	35.1	40.5	42.1	45.1	48.7	47.4	56.9	59.3	61.6	65.4	
Low:	28.2	30.5	29.6	29.8	34.5	36.0	40.6	39.4	44.0	41.6	48.7	48.2	

Target Price Range 2025 | 2026 | 2027

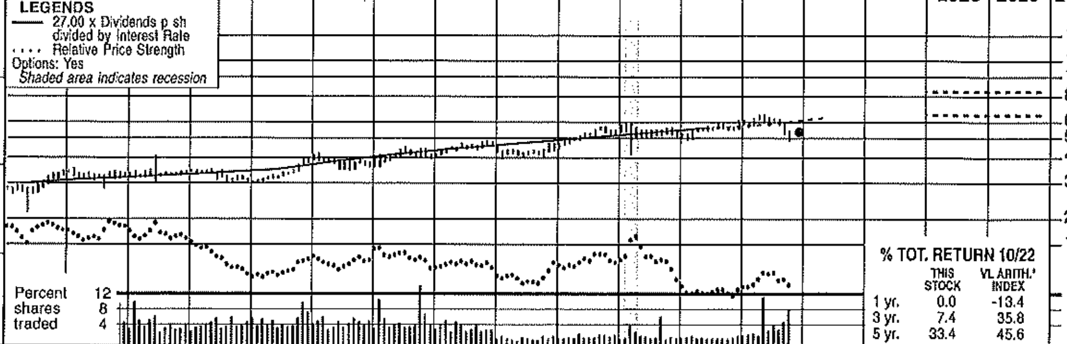
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$53-$84 $69 (25%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+60%)	15%
Low	65	(+20%)	9%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	129	141	122
to Sell	116	112	134
Hld's(000)	230539	236563	238324



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.0	-13.4
3 yr.	7.4	35.8
5 yr.	33.4	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.14	17.48	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	21.60	21.90	Revenues per sh	23.50
3.05	2.96	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	6.15	6.40	"Cash Flow" per sh	7.50
1.36	1.29	1.52	1.51	1.62	1.74	1.65	1.63	1.38	2.11	1.89	2.86	2.52	2.68	2.60	2.61	2.75	2.90	Earnings per sh [B]	3.50
.67	.82	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	2.35	Div'd Decl'd per sh [C] ■	2.60
4.80	5.16	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	8.25	7.85	Cap'l Spending per sh	8.25
12.26	16.72	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	38.75	39.25	Book Value per sh [D]	46.00
104.09	155.52	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	482.00	489.00	Common Shs Outst'g [E]	510.00
17.7	21.1	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	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	21.5
.96	1.12	1.05	1.09	1.16	1.18	1.28	1.12	1.28	.91	1.13	.84	.92	1.02	1.06	1.13	*estimates*		Relative P/E Ratio	1.20
2.8%	3.0%	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%			Avg Ann'l Div'd Yield	3.7%

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
	3654.0	4047.0	5401.0	6727.0	6838.0	8301.0	8390.0	8783.0	8935.0	9448.0	10400	10700	Revenues ($mill)	12000
	362.0	390.0	374.0	672.0	660.0	1174.0	1136.0	1238.0	1274.0	1294.0	1380	1475	Net Profit ($mill)	1845
	14.1%	7.4%	14.6%	21.3%	16.9%	25.8%	13.4%	12.5%	14.3%	14.3%	14.5%	14.5%	Income Tax Rate	14.5%
	5.0%	5.9%	7.2%	7.4%	10.0%	9.5%	8.4%	9.2%	9.3%	9.0%	9.0%	8.0%	AFUDC % to Net Profit	7.0%
	55.1%	53.5%	54.8%	53.3%	59.3%	58.4%	58.8%	54.2%	55.6%	55.5%	55.0%	53.5%	Long-Term Debt Ratio	51.5%
	35.1%	37.0%	35.7%	38.1%	36.2%	37.1%	37.2%	41.8%	40.5%	40.8%	41.5%	43.0%	Common Equity Ratio	45.0%
	11358	12892	19235	21151	35874	36108	40082	40445	42141	43328	44925	46275	Total Capital ($mill)	51900
	10249	12267	17816	19595	29337	29668	32654	33988	35998	37816	40125	42250	Net Plant ($mill)	48600
	4.8%	4.6%	3.4%	4.5%	2.8%	4.5%	4.1%	4.4%	4.3%	4.2%	4.5%	4.5%	Return on Total Cap'l	5.0%
	7.1%	6.5%	4.3%	6.8%	4.5%	7.8%	6.9%	6.7%	6.8%	6.7%	7.0%	7.0%	Return on Shr. Equity	7.5%
	7.9%	7.0%	4.5%	7.4%	4.5%	8.3%	7.2%	6.9%	7.1%	7.0%	7.0%	7.0%	Return on Com Equity [F]	7.5%
	3.7%	3.2%	1.7%	4.5%	2.1%	5.2%	4.1%	4.0%	2.5%	3.5%	3.5%	3.5%	Retained to Com Eq	4.0%
	60%	61%	68%	46%	59%	41%	46%	45%	67%	52%	47%	47%	All Div'ds to Net Prof [G]	47%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $29072 mill. **Due In 5 Yrs** $7732 mill.
LT Debt $25929 mill. **LT Interest** $945 mill.
Incl. $340 mill. finance leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $8 mill.

Pension Assets-12/21 $3722 mill. **Oblig** $3922 mill.
Pfd Stock $1623 mill. **Pfd Div'd** $65 mill.

Common Stock 480,308,482 shs.

MARKET CAP: $25.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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. (%)	204	207	211

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-1.0%	3.5%
"Cash Flow"	4.0%	6.0%	5.0%
Earnings	5.0%	8.0%	5.0%
Dividends	6.0%	6.5%	6.0%
Book Value	6.5%	5.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2436	1970	2051	2326	8783
2020	2391	2077	2121	2346	8935
2021	2539	2130	2196	2583	9448
2022	2835	2487	2553	2525	10400
2023	2900	2450	2500	2850	10700

Cal-endar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.72	.54	.63	.77	2.68
2020	.67	.59	.63	.71	2.60
2021	.76	.54	.62	.69	2.61
2022	.74	.59	.68	.74	2.75
2023	.80	.62	.70	.78	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.425	.425	.425	.45	1.73
2019	.45	.45	.45	.4775	1.83
2020	.4775	.4775	.4775	.505	1.94
2021	.505	.505	.505	.535	2.05
2022	.535	.535	.535	.565	

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. '21 reported deprec. rate: 2.6%. Has 9,100 employees. Chairman: Douglas J. Haughey. 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 through the end of this year and 2023. Third-quarter earnings of $0.68 a share narrowly beat our call for $0.67 a share, thus we are maintaining our 2022 bottom-line target of $2.75. Rate base increases will probably remain the main driver of growth during the next few years. The Inflation Reduction Act will also benefit earnings and the transition to clean energy, including the company's goal of net-zero carbon emissions by 2050. The utility is targeting 4%-6% annual dividend growth through 2027 and recently hiked its quarterly common stock dividend by 5.6%, to $0.565 a share.

However, investors do not seem to be enthusiastic about the company's prospects these days. These shares reached an all-time high of nearly $52.00 in April but have declined siginificantly as of late, along with the peer group, due to signs that the economy is decelerating. Fortis stock is down nearly 15% in value since our early September review, compared to a 10% drop in the Utilities Fund Index, XLU. Utilities, one of the most stable industries because of high-paying dividends, have been the worst-performing sector as of late and may remain under pressure for a while due to rising interest rates.

The company announced its largest ever five-year capital investment plan of $22.3 billion. Renewable and clean energy projects will receive $5.9 billion of the total. The initiative is expected to be funded primarily by cash flow from operations, thus the capital structure should not be affected. (The plan assumes inflation will return to historical averages by 2025.)

A generous dividend is this stock's most notable feature. Fortis sports an attractive yield of 4.2%, which is above average for a utility and the distribution has been raised 49-consecutive years. Meanwhile, these shares are ranked to perform in line with the broader market averages over the next six to 12 months. Given recent price weakness, our 18-month Target Price Range midpoint represents a 25% premium to the recent quotation. However, investors may want to stay on the sidelines, for now, due to the challenging macroeconomic climate.

Zachary J. Hodgkinson December 9, 2022

(A) Also trades on NYSE (FTS). All data in Canadian $. (B) Dil. egs. Excl. nonrecur. gains (loss): '07, 3¢; '14, 2¢; '15, 48¢; '17, (35¢); '18, 7¢. '19, $1.12. '19 EPS don't sum due to chng. in shs. Next egs. report due early Feb. (C) Div'ds histor. pd. early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. (2% disc.). (D) Incl. intang. In '21: $34.04/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	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

HAWAIIAN ELECTRIC NYSE-HE

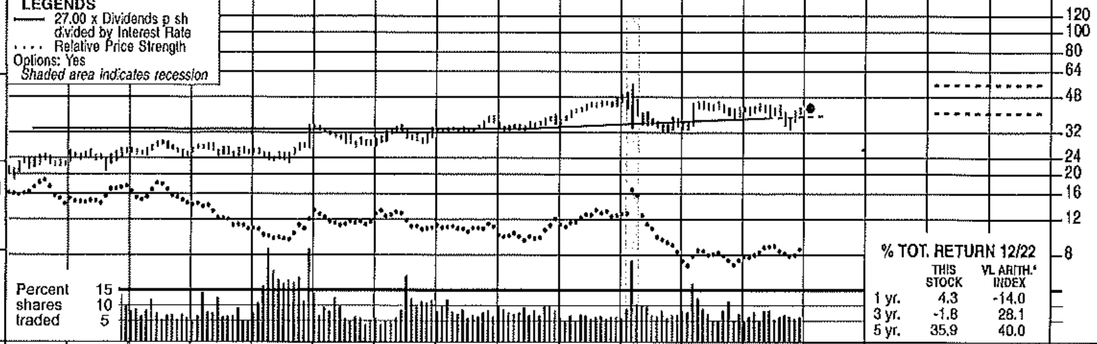
RECENT PRICE 42.45 | P/E RATIO 19.4 (Trailing: 19.5, Median: 18.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 4 Lowered 12/30/22
SAFETY 2 Raised 11/2/12
TECHNICAL 4 Raised 1/20/23
BETA .85 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	26.8	29.2	28.3	35.0	34.9	35.0	38.7	39.3	47.6	55.2	46.0	44.7
Low:	20.6	23.7	23.8	22.7	27.0	27.3	31.7	31.7	35.1	31.8	33.0	33.2

Target Price Range 2025 | 2026 | 2027

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$33-$54 $44 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	10%
Low	40	(-5%)	3%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	162	166	141
to Sell	132	117	147
Hld's(000)	58052	58364	58730

Percent shares traded 15 10 5

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.3	-14.0
3 yr.	-1.8	28.1
5 yr.	35.9	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
30.21	30.40	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	30.20	32.20	Revenues per sh	35.40
3.19	3.01	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	4.45	4.80	"Cash Flow" per sh	5.50
1.33	1.11	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	2.15	2.35	Earnings per sh A	2.60
1.24	1.24	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	1.44	Div'd Decl'd per sh B ■	1.60
2.58	2.62	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	2.90	3.35	Cap'l Spending per sh	4.00
13.44	15.29	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	20.00	21.25	Book Value per sh C	25.50
81.46	83.43	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	110.00	110.50	Common Shs Outst'g D	113.00
20.3	21.6	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	18.9		Avg Ann'l P/E Ratio	17.5
1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	1.04	1.02	1.13	1.10	1.00	1.10		Relative P/E Ratio	.95
4.6%	5.2%	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%		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $2601.4 mill. Due in 5 Yrs $800.0 mill.
LT Debt $2430.3 mill.. LT Interest $125.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/21 $2320.8 mill.
Oblig $2644.6 mill.
Pfd Stock $34.3 mill. Pfd Div'd $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ended 2018.
Common Stock 109,470,439 shs. as of 10/25/22
MARKET CAP: $4.6 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3375.0	3238.5	3239.5	2603.0	2380.7	2555.6	2860.8	2874.6	2579.8	2850.4	3320	3560	Revenues ($mill)	4000
164.9	163.4	170.2	161.8	250.1	180.6	203.7	219.8	199.7	248.1	235	260	Net Profit ($mill)	295
35.9%	34.0%	35.0%	36.5%	33.1%	34.7%	20.0%	19.0%	17.0%	20.2%	19.0%	19.0%	Income Tax Rate	19.0%
6.9%	4.8%	5.5%	5.8%	4.6%	9.6%	7.7%	7.5%	5.9%	5.2%	6.0%	7.0%	AFUDC % to Net Profit	6.0%
45.7%	44.0%	45.2%	43.5%	41.6%	43.4%	47.5%	44.6%	46.5%	46.4%	50.0%	50.5%	Long-Term Debt Ratio	50.0%
53.1%	55.0%	53.8%	55.5%	57.5%	55.7%	51.7%	54.6%	52.7%	52.8%	49.0%	48.5%	Common Equity Ratio	49.5%
3001.0	3142.9	3332.3	3473.5	3595.1	3765.5	4162.3	4176.9	4435.9	4524.1	4800	5100	Total Capital ($mill)	5950
3594.8	3858.9	4148.8	4377.7	4603.5	5025.9	4830.1	5109.6	5265.7	5392.1	5670	5755	Net Plant ($mill)	6050
6.7%	6.4%	6.2%	5.7%	7.9%	5.8%	5.9%	6.3%	5.5%	6.4%	6.5%	7.0%	Return on Total Cap'l	7.5%
10.1%	9.3%	9.3%	8.2%	11.9%	8.5%	9.3%	9.5%	8.4%	10.2%	12.0%	13.0%	Return on Shr. Equity	12.5%
10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	9.3%	9.6%	8.5%	10.3%	12.0%	13.0%	Return on Com Equity E	12.5%
4.2%	3.7%	2.3%	1.5%	6.3%	2.1%	3.1%	3.4%	2.3%	4.1%	5.0%	6.0%	Retained to Com Eq	6.5%
59%	61%	75%	83%	48%	76%	67%	64%	73%	61%	65%	61%	All Div'ds to Net Prof F	62%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+.6	-7.1	+1.7
Avg. Indust. Use (MWH)	5225	4474	4561
Avg. Indust. Revs. per KWH (¢)	25.52	24.21	26.88
Capacity at Yearend (Mw)	2254	2254	2278
Peak Load, Winter (Mw)	1601	1471	1471
Annual Load Factor (%)	65.2	66.2	67.2
% Change Customers (yr-end)	+.5	+.6	+.5
Fixed Charge Cov. (%)	368	337	393

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.5%	-.5%	5.5%
"Cash Flow"	5.0%	5.0%	3.0%
Earnings	5.5%	2.0%	4.5%
Dividends	.5%	1.5%	3.5%
Book Value	3.0%	3.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	661.6	715.5	771.5	726.0	2874.6
2020	677.2	609.0	641.4	652.2	2579.8
2021	642.9	680.3	756.9	770.3	2850.4
2022	785.1	895.6	1042.2	597.1	3320
2023	845	950	1100	665	3560

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.42	.39	.58	.61	1.99
2020	.31	.45	.59	.46	1.81
2021	.59	.58	.58	.50	2.25
2022	.63	.48	.57	.47	2.15
2023	.65	.50	.65	.55	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.32	.32	.32	.32	1.28
2020	.33	.33	.33	.33	1.32
2021	.34	.34	.34	.34	1.36
2022	.35	.35	.35	.35	1.40
2023					

BUSINESS: Hawaiian Electric Industries, Inc. 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 471,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 34%; commercial, 34%; large light & power, 32%; other, less than 1%. Generating sources: oil, 52%; purch., 48%. Fuel costs: 46% of revs. '21 reported deprec. rate (utility): 3.2%. Has 3,600 employees. Chairman: Tom Fargo. Pres. & CEO: Scott Seu. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Internet: www.hei.com.

Hawaiian Electric likely earned $2.15 a share in 2022. Utility performance has been steady even with a most unfavorable backdrop. Therefore, while revenues are apt to rise handsomely, earnings will probably be a tick lower due to the increasing costs of doing business. An example of this is the company's electric operations. During the September quarter, the top line rose an impressive 40%, but those gains were more than offset by rising expenses that were closer to the 45% level. Fuel costs were an impediment earlier in the year, and as the year progressed, inflation spread to numerous areas.

We are raising our 2023 earnings expectation by a nickel, to $2.35 a share. A performance-based rate-making policy is a strong step in the right direction for the island chain state. The new math will factor in inflation and capital spending burdens. Add to this, the banking arm should generate better returns in 2023, as interest rates are likely to remain elevated throughout the year and loan growth should be sturdy. Additionally, while the fear of a recession is very real, the Hawaiian economy has been showing resilience in terms of unemployment, housing prices, and tourism. Our $2.35 expectation reflects EPS growth of almost 10% from our anticipated 2022 figure.

The company bolstered its executive roster as 2023 began. For starters, Paul Ito was named executive vice president and CFO. Mr. Ito, who has been with HE since 2018, had been the interim CFO since July of 2022. Separately, Yoko Otani, a Citibank veteran, has been given a board seat for both Hawaiian Electric and American Savings Bank, while Mary Kipp, the president and CEO of Puget Sound Energy, also joins the board of HE.

This untimely stock has a dividend yield that lags the average utility under our coverage. The percentage of the payout was reduced with the stock price moving roughly 25% in value over the last 90 days. Elsewhere, projections for the coming 18-month window are below average and the quotation is trading within our Target Price Range out to 2025-2027. With that, long-term appreciation potential is muted. Better options are present elsewhere in the electric utilities arena.

Erik M. Manning *January 20, 2023*

(A) Diluted EPS. Excl. nonrec. losses: '07, 9¢; '12, 25¢; '17, 12¢. '19 EPS don't sum due to rounding. Next earnings report due early February. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $5.32/sh. (D) In mill., adj. for split. (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%; earned on avg. com. eq., '21: 10.4%. Regulat. Climate: Below Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	80

IDACORP, INC. NYSE-IDA

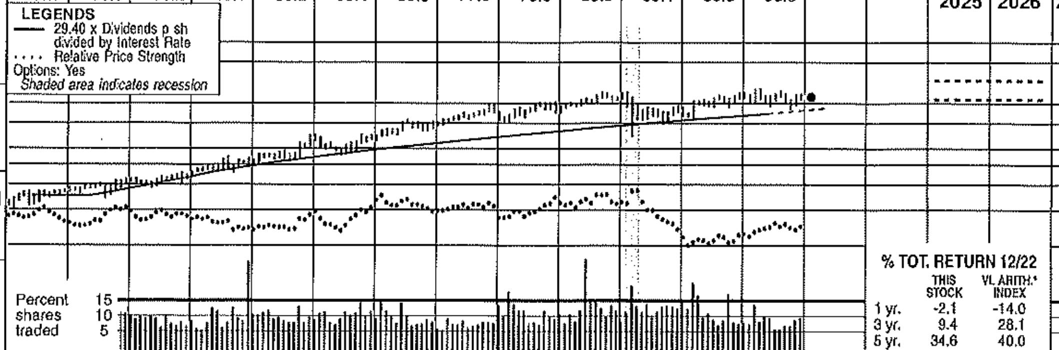
RECENT PRICE **107.84** | P/E RATIO **21.7** (Trailing: 21.9; Median: 19.0) | RELATIVE P/E RATIO **1.29** | DIV'D YLD **2.9%** | VALUE LINE

TIMELINESS 3 Raised 11/18/22
SAFETY 1 Raised 1/22/21
TECHNICAL 3 Raised 1/20/23
BETA .80 (1.00 = Market)

High:	42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9
Low:	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	93.5

Target Price Range 2025 | 2026 | 2027

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$91-$147 $119 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+20%)	8%
Low	105	(-5%)	3%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	181	174	159
to Sell	164	164	155
Hld's(000)	39894	40518	40715

Percent shares traded 15 10 5

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.1	-14.0
3 yr.	9.4	28.1
5 yr.	34.6	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.23	19.51	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	*29.60*	*30.00*	Revenues per sh	*35.10*
4.58	4.11	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	*8.70*	*9.00*	"Cash Flow" per sh	*10.40*
2.35	1.86	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	*5.10*	*5.20*	Earnings per sh A	*6.10*
1.20	1.20	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	*3.25*	Div'd Decl'd per sh B ■ †	*4.00*
5.16	6.39	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	*10.15*	*14.20*	Cap'l Spending per sh	*10.10*
25.77	26.79	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	*55.50*	*58.75*	Book Value per sh C	*67.30*
43.63	45.06	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	*50.70*	*51.00*	Common Shs Outst'g D	*52.00*
15.1	18.2	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	*21.1*		Avg Ann'l P/E Ratio	*19.5*
.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.14	*1.23*		Relative P/E Ratio	*1.10*
3.4%	3.5%	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%		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $2150.8 mill. **Due in 5 Yrs** $350.0 mill.
LT Debt $2071.4 mill. **LT Interest** $105.0 mill.
(LT interest earned: 3.8x)

Pension Assets-12/21 $984.5 mill. **Oblig** $1346.5 mill.

Pfd Stock None

Common Stock 50,561,892 shs. as of 10/28/22

MARKET CAP: $5.5 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	*1500*	*1530*	Revenues ($mill)	*1825*
168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	*260*	*265*	Net Profit ($mill)	*315*
13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	*20.0%*	*21.0%*	AFUDC % to Net Profit	*16.0%*
45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	*42.5%*	*46.5%*	Long-Term Debt Ratio	*50.0%*
54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	*57.5%*	*53.5%*	Common Equity Ratio	*50.0%*
3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	*4950*	*5625*	Total Capital ($mill)	*6775*
3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	*5250*	*5750*	Net Plant ($mill)	*6750*
6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	*6.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.5%*	*9.0%*	Return on Com Equity E	*9.5%*
5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
41%	43%	46%	50%	53%	53%	54%	56%	58%	60%	*60%*	*63%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.3	+2.0	+3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.32	5.38	5.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3242	3392	3751
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.5	+2.7	+2.8
Fixed Charge Cov. (%)	307	313	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*4.0%*
Earnings	4.5%	4.0%	*4.5%*
Dividends	8.5%	7.0%	*6.5%*
Book Value	5.0%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	350.3	316.9	386.3	292.9	1346.4
2020	291.0	318.8	425.3	315.6	1350.7
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	518.0	*279.0*	*1500*
2023	*335*	*370*	*530*	*295*	*1530*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	1.05	1.78	.93	4.61
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	2.10	*.82*	*5.10*
2023	*.65*	*1.40*	*2.20*	*.95*	*5.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75	.79	3.04
2023					

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 604,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.3 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 45%; commercial, 24%; industrial, 15%; irrigation, 13%; other, 3%. Generating sources: hydro, 30%; coal, 17%; gas, 15%; purchased, 38%. Fuel costs: 36% of revenues. '21 reported depreciation rate: 2.9%. Has 2,000 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 streak of consecutive annual earnings growth should reach 15 years when 2022 financials come in. When the report comes out in mid-February, we now think share earnings will grow 5%, to $5.10. The September quarter was particularly strong, as customer growth was evident. Also, retail sales were up with hotter weather settling in the areas the company services. Another positive contributor to 2022 results was the mid-year approval of a plan to speed up the retirement of the Jim Bridger coal plant. Management has also been quick to point out that labor-related inflation was a sizable component to increasing cost pressures, which offset some of the pluses over the course of the year.

Our earnings call for 2023 is now down a nickel, to $5.20 a share. Revenue gains are only apt to be about 2% year over year. Transmission wheeling should be steady and air condition and irrigation will likely remain drivers. Even still, we only see earnings climbing around that same 2% figure. One notable reason will be an uptick on the capital expenditures front. Here, layouts for resources related to new capacity should push the annual spend number to $725 million, up from around $500 million in 2022. Battery storage capabilities will be paid for and a new transmission line is in the works.

Still, there is upside given the tailwinds the company should enjoy in the coming years. Idaho's customer base is expanding rapidly, and the people moving to that state look to be well-heeled. Rising demand for clean energy plays into IDA's hands, as coal is phased out and management plans to provide 100% clean energy by 2045. That metric was just above 60% at the last reading.

High-quality (Safety: 1) shares of IDACORP are not all that appealing at this juncture. For starters, the yield, even with a raise to close out 2022, is noticeably below the average utility in our coverage. Add to this, the stock is neutrally ranked for year-ahead relative price performance. Too, the 18-month reading is unexciting and the quotation is trading with our Target Price Range out to 2025-2027, and thus long-term capital appreciation potential is not great.

Erik M. Manning *January 20, 2023*

(A) Diluted EPS. Excl. nonrecurring gain: '06, 17¢. '19 earnings don't sum due to rounding. Next earnings report due mid-February. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $1,462.4 mill., $28.95/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. com. eq., '21: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	100

NEXTERA ENERGY NYSE-NEE

RECENT PRICE 77.50 | P/E RATIO 25.6 (Trailing: 27.6 Median: 21.0) | RELATIVE P/E RATIO 1.66 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 9/30/22

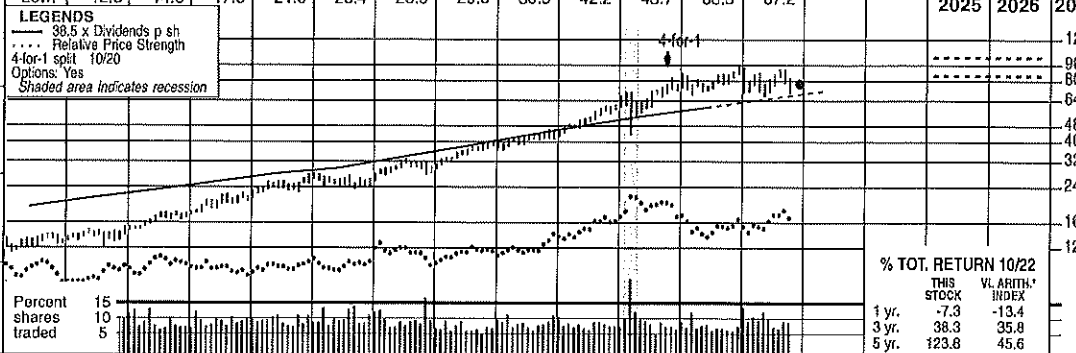
SAFETY 1 Raised 2/16/18

TECHNICAL 1 Raised 9/30/22

BETA .90 (1.00 = Market)

High:	15.3	18.1	22.4	27.7	28.2	33.0	39.8	46.1	61.3	83.3	93.7	93.6
Low:	12.3	14.6	17.5	21.0	23.4	25.5	29.3	36.3	42.2	43.7	68.3	67.2

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High Midpoint (% to Mid)

$66-$136 $101 (30%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+35%)	10%
Low	85	(+10%)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	1210	1155	1104
to Sell	831	944	949
Hld's(000)	1508954	1500092	1514051

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	-13.4
3 yr.	38.3	35.8
5 yr.	123.8	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
9.69	9.37	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	10.85	12.60	Revenues per sh	14.75
1.69	1.71	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	5.15	5.40	"Cash Flow" per sh	6.75
.81	.82	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	3.15	Earnings per sh A	4.10
.38	.41	.45	.47	.50	.55	.60	.66	.73	.77	.87	.98	1.11	1.25	1.40	1.54	1.70	1.87	Div'd Decl'd per sh B ■ †	2.50
2.31	3.08	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	8.10	8.40	Cap'l Spending per sh	10.00
6.12	6.59	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	19.70	22.75	Book Value per sh C	27.25
1621.6	1629.4	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	1980.0	2025.0	Common Shs Outst'g D	2025.0
13.7	18.9	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	Bold figures are		Avg Ann'l P/E Ratio	23.5
.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.43	1.48	1.68	Value Line		Relative P/E Ratio	1.30
3.4%	2.7%	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%	estimates		Avg Ann'l Div'd Yield	2.6%

CAPITAL STRUCTURE as of 9/30/22

Total Debt $64825 mill. Due in 5 Yrs $26264 mill.

LT Debt $54670 mill. LT Interest $1402 mill.

(Total interest coverage: 4.6x)

Pension Assets-12/21 $5688 mill. Oblig $3445 mill.

Pfd Stock None

Common Stock 1,964,779,183 shs. as of 6/30/22

MARKET CAP: $152.3 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
14256	15136	17021	17486	16155	17195	16727	19204	17997	17069	21500	25500	Revenues ($mill)	30000
1911.0	2062.0	2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	4552.0	5021.0	5750	6335	Net Profit ($mill)	8330
26.6%	26.9%	32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	13.0%	15.0%	15.0%	15.0%	Income Tax Rate	15.0%
10.8%	7.0%	6.7%	6.9%	8.2%	6.7%	6.6%	3.9%	3.8%	5.3%	5.0%	4.0%	AFUDC % to Net Profit	4.0%
59.1%	57.1%	55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	53.5%	57.8%	58.5%	56.5%	Long-Term Debt Ratio	56.0%
40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	42.2%	41.5%	43.5%	Common Equity Ratio	44.0%
39245	42009	44283	49255	52159	59671	60926	74548	78457	88162	93950	105850	Total Capital ($mill)	126100
49413	52720	55705	61386	66912	72416	70334	82010	91803	99348	110925	123300	Net Plant ($mill)	165200
6.2%	6.2%	7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	6.5%	6.4%	7.0%	6.5%	Return on Total Cap'l	7.5%
11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	15.0%	13.5%	Return on Shr. Equity	15.0%
11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	15.0%	13.5%	Return on Com Equity E	15.0%
5.6%	5.2%	6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	5.0%	5.4%	6.0%	5.5%	Retained to Com Eq	6.0%
53%	54%	51%	50%	60%	60%	66%	64%	60%	60%	58%	59%	All Div'ds to Net Prof	61%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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)	+1.8	+1.5	+1.5
Fixed Charge Cov. (%)	230	235	203

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	8.0%
"Cash Flow"	7.0%	7.0%	7.0%
Earnings	7.0%	9.5%	10.5%
Dividends	10.5%	12.0%	10.0%
Book Value	8.5%	9.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4075	4970	5572	4587	19204
2020	4613	4204	4785	4395	17997
2021	3726	3927	4370	5046	17069
2022	2890	5183	6719	6708	21500
2023	4800	5770	7455	7475	25500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.35	.64	.45	.50	1.94
2020	.59	.65	.67	.40	2.31
2021	.67	.71	.75	.41	2.55
2022	.74	.81	.85	.50	2.90
2023	.80	.88	.92	.55	3.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.3125	.3125	.3125	.3125	1.25
2020	.35	.35	.35	.35	1.40
2021	.385	.385	.385	.385	1.54
2022	.425	.425	.425		

BUSINESS: NextEra Energy, Inc. is a holding company for Florida Power & Light Company (FPL), which provides electricity to roughly 5.8 mill. customers in eastern, southern, & northwestern FL. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & renewables. Has 55% stake in NextEra Energy Partners. Acquired Gulf Power 1/19; Florida City Gas 7/18. Rev.: residential, 55%; commercial, 33%; industrial & other, 12%. Generating sources: gas, 73%; nuclear, 22%; other, 3%; purchased, 2%. Fuel costs: 27% of revenues. '21 depreciation rate: 3.3%. Has 15,000 employees. 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 well situated for sustained earnings growth. Its utility, Florida Power & Light Company (FPL), is benefiting from a very healthy local economy. The Sunshine State continues to attract strong migration, and is experiencing one of the fastest U.S. population growth rates. Florida's unemployment rate of 2.7% remains below the national average and at its lowest level in over 15 years. Meanwhile, distribution and transmission (D&T) expansion, and reliability/hardiness projects in storm-challenged Florida, are leading to rapid growth in the utility's rate base (property, plant, and equipment on which utilitites are allowed to earn an economic rate of return). FPL's territory did exceptionally well in keeping the power on and/or getting it back up following Hurricane Ian. That's going to help keep the reliability/hardiness program going strong. It's also notable that, as part of NextEra's 2021 settlement agreement with regulators, a sustained increase in 30-year Treasury Bond yields has triggered an increase in the authorized return on equity midpoint from 10.6% to 10.8%.

Renewable energy is a burgeoning market for the company and should be bolstered by the Inflation Reduction Act (IRA). FPL continues to expand its regulated solar capacity within its rate base, and the company's nonregulated subsidiary, NextEra Energy Resources, is a major player in renewable energy across the U.S. That business unit has been growing nicely in recent quarters. The company has 55% ownership in NextEra Energy Partners, LP (NYSE: NEP), which is heavily invested in renewables across 19 states. It's growing at a double-digit clip, while rapidly increasing its dividend to partners. Tax incentives for renewables were set to expire after 2025, but the IRA is expected to help keep this market flourishing for decades to come.

NextEra Energy shares offer appealing intermediate-term total returns. The below-average (4) Timeliness rank means it's likely not appropriate for accounts with an investment horizon of less than one year. Investors with a conservative bent and a dividend-growth focus should find this high-quality issue an attractive addition to their portfolios.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, $1.22¢; '18, $1.80; '20, (83¢); '21, (74¢); 1Q-3Q '22, ($1.07); disc. ops.: '13, 11¢. EPS may not some to full yr. due to rounding. Next egs. report due late Jan. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $5.94/sh. (D) In mill., adj. for stock split. (E) Rate all'd on com. eq. in '22 (FPL): 9.7%-11.7%; Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	85

NORTHWESTERN NDQ-NWE

RECENT PRICE 58.58 | P/E RATIO 17.1 (Trailing: 18.9 Median: 17.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS	4	Raised 1/20/23
SAFETY	2	Raised 7/27/18
TECHNICAL	4	Raised 1/20/23

BETA .90 (1.00 = Market)

High:	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.8	63.1
Low:	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	48.7

Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

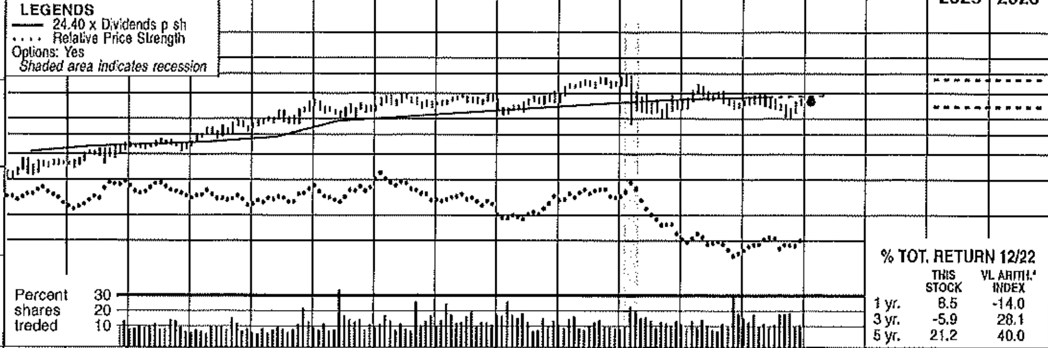
Low-High	Midpoint (% to Mid)
$45-$71	$58 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	10%
Low	55	(-5%)	3%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	154	140	176
to Sell	111	121	97
Hld's(000)	57800	56756	56117



% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.5	-14.0
3 yr.	-5.9	28.1
5 yr.	21.2	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.49	30.79	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	24.30	23.55	Revenues per sh	25.75
3.62	3.70	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	6.70	6.85	"Cash Flow" per sh	8.00
1.31	1.44	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	3.35	3.55	Earnings per sh A	4.00
1.24	1.28	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	Div'd Decl'd per sh B ■ †	2.68
2.81	3.00	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	10.05	9.10	Cap'l Spending per sh	6.50
20.65	21.12	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	44.60	46.30	Book Value per sh C	50.00
35.97	38.97	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	58.00	62.00	Common Shs Outst'g D	62.00
26.0	21.7	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	17.0		Avg Ann'l P/E Ratio	16.5
1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94	.99		Relative P/E Ratio	.90
3.6%	4.1%	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%		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $2566.1 mill. Due in 5 Yrs $1037.4 mill.
LT Debt $2418.6 mill. LT Interest $87.8 mill.
Incl. $9.6 mill. finance leases.
(Total Interest Coverage: 2.7x)

Pension Assets-12/21 $605.5 mill. Oblig $696.8 mill.

Pfd Stock None

Common Stock 57,778,743 shs. as of 10/21/22

MARKET CAP: $3.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	1410	1460	Revenues ($mill)	1600
83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	190	215	Net Profit ($mill)	250
9.6%	13.2%	--	13.7%	--	7.6%	--	1.6%	1.6%	.9%	1.5%	3.0%	Income Tax Rate	12.0%
9.4%	8.7%	8.9%	9.6%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	16.0%	14.0%	AFUDC % to Net Profit	10.0%
53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	50.0%	49.5%	Long-Term Debt Ratio	49.0%
46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	50.0%	50.5%	Common Equity Ratio	51.0%
2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	5195	5675	Total Capital ($mill)	6050
2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	5630	5980	Net Plant ($mill)	6550
5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	4.5%	4.5%	Return on Total Cap'l	5.0%
9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.5%	7.5%	Return on Shr. Equity	8.0%
9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	7.5%	7.5%	Return on Com Equity E	8.0%
3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	2.0%	2.0%	Retained to Com Eq	2.5%
65%	61%	54%	65%	58%	62%	64%	64%	74%	71%	75%	72%	All Div'ds to Net Prof	67%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+4.6	-4.4	+.7
Avg. Indust. Use (MWH)	37808	33526	31792
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2237	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.6
Fixed Charge Cov. (%)	284	237	252

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	1.0%
"Cash Flow"	3.5%	3.0%	3.0%
Earnings	4.5%	2.0%	3.5%
Dividends	5.5%	5.5%	2.0%
Book Value	6.0%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	384.2	270.7	274.8	328.2	1257.9
2020	335.3	269.4	280.6	313.4	1198.7
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	335.1	357.4	1410
2023	415	333	345	367	1460

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.44	.49	.42	1.18	3.53
2020	1.00	.43	.58	1.21	3.21
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	.47	1.22	3.35
2023	1.15	.59	.58	1.23	3.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.575	.575	.575	.575	2.30
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63	.63	2.52
2023					

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 456,000 electric customers in Montana and South Dakota and 298,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 43%; commercial, 49%; industrial, 4%; other, 4%. Generating sources: coal, 28%; hydro, 27%; wind, 6%; other, 4%; purchased, 35%. Fuel costs: 31% of revenues. 2021 reported depreciation rate: 2.8%. Has about 1,500 employees. Board Chair: Dana J. Dykhouse. Pres. & CEO: Brian B. Bird. Inc.: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern stock has been range bound for years, in line with limited earnings gains. (The annual rate of growth over the past five years was 2%, compared to the electric utility industry's median of 4.5%.) The main problem has been years of underearning its regulated ROE (return on equity). This is largely due to the relative constraints of the rate-relief mechanisms available in the utility's territories, resulting in regulatory lag. That is, NWE foots the bill for grid upkeep and rising power costs, but has to justify the higher expenses for a deferred payback. Historically, we've rated its regulatory environment as below average.

Lifting the rate base should help reignite growth. (The rate base includes the property, plant, and equipment for which a utility is allowed to earn an economic return.) NWE is in the process of adding significant gas-fired capacity in both South Dakota and Montana, enabling it to become less reliant on purchased power, while modernizing and shoring up reliability. An $83 million, 58-megawatt plant in South Dakota was completed in June. A $275 million, 175-mw facility in Montana is expected to be operational later this year. Financing was via a $200 million equity offering ($53.50 a share) completed in late 2021, with a forward sale of $300 million more in aggregate, likely by the middle of this year.

And a reasonably good outcome from an impending GRC (general rate case) decision looks feasible. NWE has already received permission to bill a sizable interim rate hike and should obtain permanent increases this year. It's also seeking pricing mechanisms that would reduce regulatory lag. Assuming NWE gets those, and the generating capacity expansions are allowed to proceed (there are environmental challenges), the gap between its earned and allowable ROE would narrow. Our projections assume an annual earnings-per-share growth rate of 3%-4% through mid-decade. It's below the peer average, but significantly better than what's transpired in recent years.

But much of the improvement the utility may garner is already reflected in its valuation. Total return potential for untimely NWE stock is unappealing.

Anthony J. Glennon *January 20, 2023*

(A) Diluted egs. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; Q1-Q3 '22, (4¢). '20 EPS don't sum due to rounding. Next egs. report due mid-Feb. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder Invest. plan avail. (C) Incl. def'd charges. In '21: $19.39/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	90

OGE ENERGY CORP. NYSE-OGE

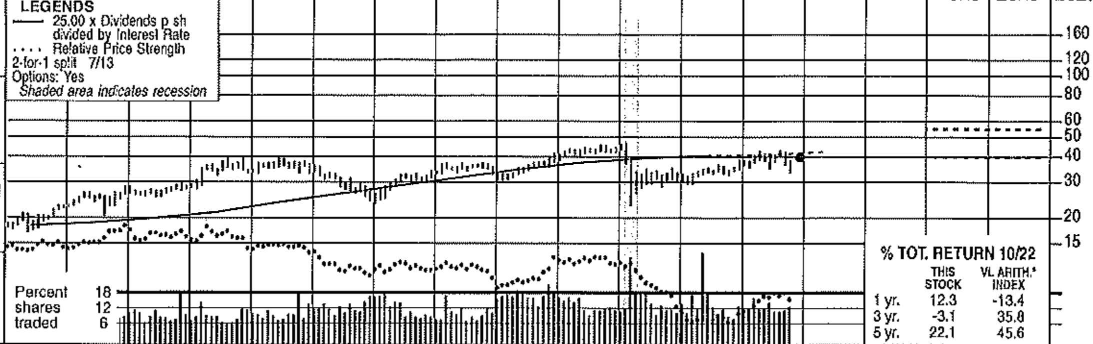
RECENT PRICE 39.75 | P/E RATIO 18.0 (Trailing: 17.5 Median: 17.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 5/20/22
SAFETY 2 Lowered 12/18/15
TECHNICAL 3 Lowered 12/9/22
BETA 1.00 (1.00 = Market)

High:	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.9					
Low:	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	36.0	23.0	29.2	33.3					

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 25.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$51	$42 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	12%
Low	40	(Nil)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	228	218	185
to Sell	170	182	192
Hld's(000)	129869	136256	136256

Percent shares traded 18 12 6

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	-13.4
3 yr.	-3.1	35.8
5 yr.	22.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.96	20.68	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	*16.00*	*16.50*	Revenues per sh	*18.25*
2.23	2.39	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	*4.45*	*4.40*	"Cash Flow" per sh	*6.25*
1.23	1.32	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*	*2.10*	Earnings per sh A	*3.25*
.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	*1.64*	*1.70*	Div'd Decl'd per sh B ■	*1.85*
2.67	3.04	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	*4.75*	*4.75*	Cap'l Spending per sh	*4.75*
8.79	9.16	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	*21.25*	*22.25*	Book Value per sh C	*26.00*
182.40	183.60	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*	*200.20*	Common Shs Outst'g D	*200.20*
13.7	13.8	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	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.76	*Value Line*		Relative P/E Ratio	*.80*
4.0%	3.8%	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%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $5279.5 mill. Due in 5 Yrs $1731.5 mill.
LT Debt $3548.0 mill. LT Interest $156.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/21 $486.0 mill. Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,202,672 shs.

MARKET CAP: $8.0 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	*3200*	*3300*	Revenues ($mill)	*3650*
355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	*450*	*420*	Net Profit ($mill)	*665*
26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	*46.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	*53.0%*	*48.0%*	Common Equity Ratio	*50.0%*
5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	*8100*	*9400*	Total Capital ($mill)	*10400*
8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	*10345*	*10830*	Net Plant ($mill)	*12075*
7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	*7.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*12.0%*	*12.0%*	Return on Shr. Equity	*13.0%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*12.0%*	*12.0%*	Return on Com Equity E	*13.0%*
7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	*4.0%*	*4.5%*	Retained to Com Eq	*5.5%*
44%	43%	47%	61%	67%	64%	64%	67%	76%	69%	*73%*	*81%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.1	-4.9	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.69	4.40	7.66
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6817	6437	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.4
Fixed Charge Cov. (%)	335	326	336

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	3.0%	*5.5%*
"Cash Flow"	3.5%	4.5%	*7.0%*
Earnings	4.0%	4.5%	*6.5%*
Dividends	8.0%	8.5%	*3.0%*
Book Value	5.5%	3.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630.6	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270.8	*536.2*	*3200*
2023	*600*	*800*	*1200*	*700*	*3300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.27	2.36
2022	.33	.36	1.31	*.25*	*2.25*
2023	*.32*	*.33*	*1.25*	*.20*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	

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. '21 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 in Oklahoma agreed to a $30 million settlement in its general rate case. The company initially requested a $164 million increase which was reduced drastically by the Oklahoma Corporation Commission after regulatory hearings. The commission is now considering spreading out monthly price increases of $9.72 over a three to four year time frame, compared to the current two-year span to help mitigate the impact on customer bills. In Arkansas, the utility implemented its new fuel rates which went into effect on November 1st. The increases will recover $40 million over the next 17 months.

We see earnings declining through 2023. Management continues to expect long-term share-earnings growth of 5%-7% annually, based off 2021 profits. (Excluding equity income.) For 2022, the company expects share earnings in a range of $2.08-$2.12 a share. Our full-year 2022 and 2023 bottom-line estimates are $2.25 a share (including equity income from Energy Transfer stake), and $2.10 a share, respectively. We have lowered our 2023 forecasts due to the macroeconomic climate, including margin pressures from rising interest rates, along with depreciation rates and pending rate reviews.

In the third quarter, OGE completed its transformation to an electric utility, after selling its Energy Transfer units. The exit from midstream operations should reduce business risk and attract investors as it becomes a pure-play electric utility. The natural gas midstream segment has long been a weakness, and the exit should improve performance.

These shares are ranked to mirror the broader market averages in the coming six to 12 months. Equities in the utilities industry have faced immense pressure as of late due to rising interest rates. Rising Treasury yields are becoming more appealing to income-oriented investors, challenging the attractiveness of the utility industry. As a result, the stock is down more than 5% in value since our last report in September. While total return potential is below average for the 18-month and 3- to 5-year period, these shares hold an attractive dividend yield that is well above the utility average.

Zachary J. Hodgkinson *December 9, 2022*

(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.: '06, 20¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $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	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 57.42 | P/E RATIO 10.3 (Trailing: 8.2 / Median: 20.0) | RELATIVE P/E RATIO 0.63 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 2 Lowered 12/9/22
SAFETY 2 Raised 6/17/16
TECHNICAL 2 Lowered 12/9/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$56-$111 $84 (45%)

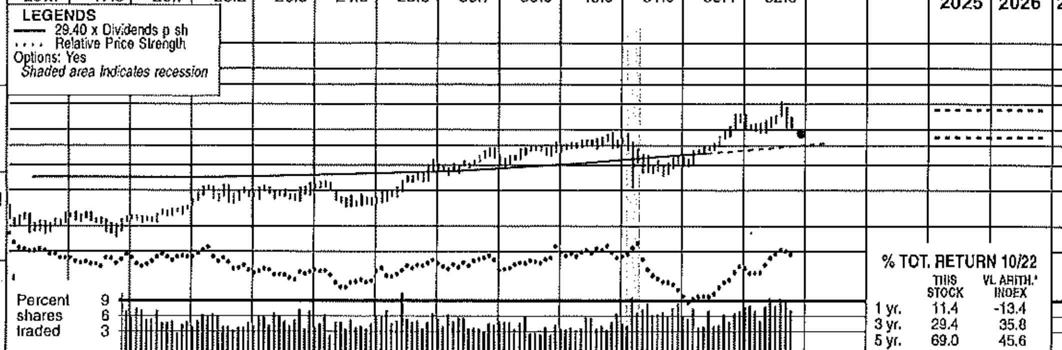
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	*10%*
Low	55	(-5%)	*3%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	121	121	140
to Sell	87	103	95
Hld's(000)	19574	20044	20598

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9	71.7	82.5
Low:	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0	39.4	52.6



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.4	-13.4
3 yr.	29.4	35.8
5 yr.	69.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.43	41.50	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	*35.45*	*29.35*	Revenues per sh	*32.25*
3.39	3.55	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	*7.75*	*6.60*	"Cash Flow" per sh	*6.75*
1.69	1.78	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	*6.60*	*4.75*	Earnings per sh A	*3.75*
1.15	1.17	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*	*1.76*	Div'd Decl'd per sh B ■	*2.20*
2.35	5.43	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	*4.35*	*5.90*	Cap'l Spending per sh	*6.25*
16.67	17.55	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	*27.55*	*29.80*	Book Value per sh C	*34.25*
29.52	29.85	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	*41.75*	*41.90*	Common Shs Outst'g D	*42.50*
17.3	19.0	30.1	31.2	NMF	NMF	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	18.3	12.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*17.5*
.93	1.01	1.81	2.08	NMF	NMF	1.38	1.19	.99	.92	1.06	1.11	1.20	1.25	.94	.66	*estimates*		Relative P/E Ratio	*.95*
3.9%	3.5%	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%			Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $823.8 mill. Due in 5 Yrs $207.8 mill.
LT Debt $823.8 mill. LT Interest $31.6 mill.
(LT interest earned: 9.7x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/21 $387.2 mill. Oblig $416.7 mill.

Pfd Stock None

Common Stock 41,630,952 shs. as of 10/25/22

MARKET CAP: $2.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
859.2	893.3	799.3	779.8	803.5	849.4	916.4	919.5	890.1	1196.8	*1480*	*1230*	Revenues ($mill)	*1370*
39.0	50.2	56.9	58.6	62.0	73.9	82.3	86.8	95.9	176.8	*250*	*200*	Net Profit ($mill)	*165*
5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	17.4%	16.9%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	6.4%	.8%	*1.0%*	*3.0%*	AFUDC % to Net Profit	*4.0%*
44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	41.8%	42.6%	*41.5%*	*41.5%*	Long-Term Debt Ratio	*42.5%*
54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	*58.5%*	*58.5%*	Common Equity Ratio	*57.5%*
959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	1495.4	1724.8	*1975*	*2140*	Total Capital ($mill)	*2525*
1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	2049.3	2124.6	*2210*	*2355*	Net Plant ($mill)	*2700*
5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	7.4%	11.1%	*12.0%*	*9.0%*	Return on Total Cap'l	*7.5%*
7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*19.5%*	*13.5%*	Return on Shr. Equity E	*11.5%*
7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*19.5%*	*13.5%*	Return on Com Equity	*11.5%*
NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	4.1%	11.3%	*13.5%*	*7.5%*	Retained to Com Eq	*5.0%*
113%	87%	78%	79%	78%	69%	65%	64%	63%	37%	*31%*	*44%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.2	-3.9	+.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)	+.1	NA	NA
Fixed Charge Cov. (%)	407	405	651

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	3.0%	*5.0%*
"Cash Flow"	7.0%	9.0%	*5.5%*
Earnings	19.0%	13.0%	*4.5%*
Dividends	2.0%	4.0%	*7.0%*
Book Value	2.0%	6.0%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	246.0	229.2	228.6	215.7	919.5
2020	234.7	192.8	235.8	226.8	890.1
2021	261.7	285.6	316.3	333.2	1196.8
2022	374.9	400.0	383.9	*321.2*	*1480*
2023	*320*	*315*	*300*	*295*	*1230*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.66	.39	.62	.51	2.17
2020	.60	.42	.87	.45	2.34
2021	.73	1.01	1.26	1.23	4.23
2022	1.72	2.05	2.01	*.82*	*6.60*
2023	*1.40*	*1.35*	*1.20*	*.80*	*4.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	1.40
2020	.37	.37	.37	.37	1.48
2021	.39	.39	.39	.39	1.56
2022	.4125	.4125	.4125	.4125	

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 (62% of '21 operating income). '21 deprec. rate: 2.9%. 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.

Shares of Otter Tail have declined significantly in value since our September report. The stock price has dropped more than 25%, compared to a 10% decline in XLU shares (an S&P utility sector fund) over that interim. In fact, in that time span the utility turned in the worst-performance out of all the companies covered by *Value Line* in the Electric Utility (Central) Industry. Too, management is concerned about near-term prospects because of resin price reductions and the weakening home improvement market. The company lowered its 2022 share-earnings target from $6.83-$7.13 to $6.42-$6.72. The Plastics segment, which has been a main driver for earnings recently, is facing a slowdown in PVC pipe demand that will likely continue to hurt profits in the future. Sales volume decreased by 15% in the third-quarter due to the headwinds previously mentioned.

Nevertheless, the company delivered strong financial results in the third quarter. Share earnings grew about 60% year over year, while revenues increased 21% over that span. Performance was well rounded, highlighted by the Plastics segment, as mentioned, despite lower-than-expected sales volumes.

The company remains committed to its long-term annual earnings growth rate target of 5%-7%, using 2024 as the base year. While this is certainly in the cards, we expect the bottom-line to decline next year as conditions normalize within the utility's Plastics division. We are looking for 2023 full-year earnings of $4.75 a share.

Otter Tail shares are best suited for accounts with a short-to-intermediate investment horizon. The stock currently carries our Timeliness rank of 2, making it a strong selection for the next six to 12 months. Too, given the aforementioned drop in its value, the utility now offers much stronger capital appreciation potential. The midpoint of our 18-month Target Price Range represents a 45% premium to its current price. Capital appreciation potential out to 2025-2027 is not appealing as these shares remain within our 3- to 5-year estimate. This stock also offers a yield of 2.9%, which is just below-average for a utility.

Zachary J. Hodgkinson *December 9, 2022*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '06, 1¢; '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 Feb. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $4.14/sh. (D) In mill. (E) Rate all'd 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	100
Price Growth Persistence	70
Earnings Predictability	70

PINNACLE WEST NYSE-PNW

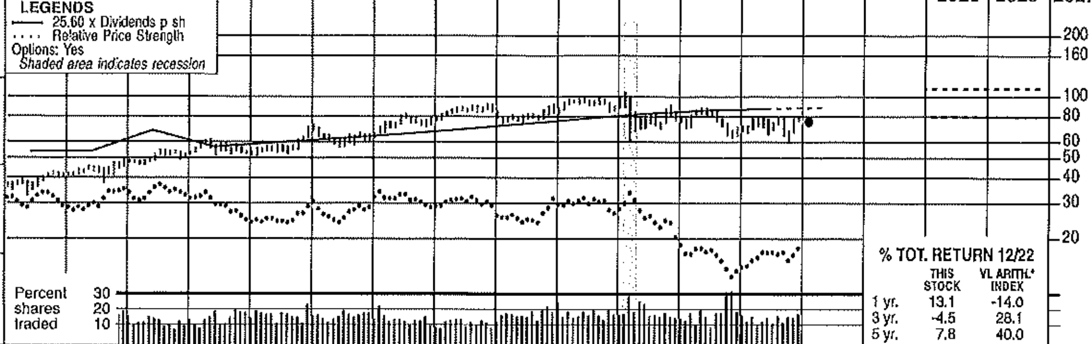
RECENT PRICE 75.55 | P/E RATIO 17.4 (Trailing: 16.0 Median: 17.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Raised 1/13/23
SAFETY 2 Lowered 10/22/21
TECHNICAL 3 Raised 1/13/23
BETA .90 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	48.9	54.7	61.9	71.1	73.3	82.8	92.5	92.6	99.8	105.5	88.5	80.6
Low:	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.4	81.6	60.1	62.8	59.0

Target Price Range 2025 | 2026 | 2027

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



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$51-$87 $69 (-10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+45%)	13%
Low	80	(+5%)	6%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	252	249	227
to Sell	212	192	208
Hld's(000)	95123	97870	97447

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	-14.0
3 yr.	-4.5	28.1
5 yr.	7.8	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
34.03	35.07	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	36.35	37.00	Revenues per sh	39.00
9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	11.41	11.13	10.86	12.23	11.30	11.75	"Cash Flow" per sh	13.75
3.17	2.96	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	4.25	4.40	Earnings per sh A	5.25
2.03	2.10	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	3.42	3.48	Div'd Decl'd per sh B ■	3.66
7.59	9.37	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	14.10	14.10	Cap'l Spending per sh	14.50
34.48	35.15	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	53.00	53.75	Book Value per sh C	59.25
99.96	100.49	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	113.20	113.50	Common Shs Outst'g D	118.00
13.7	14.9	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	17.2		Avg Ann'l P/E Ratio	18.0
.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	1.03	.86	.77	1.00		Relative P/E Ratio	1.00
4.7%	4.8%	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%		Avg Ann'l Div'd Yield	3.9%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	3691.2	3471.2	3587.0	3803.8	4115	4200	Revenues ($mill)	4600
387.4	406.1	397.6	437.3	442.0	497.8	511.0	538.3	550.6	618.7	480	500	Net Profit ($mill)	620
36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	20.2%	--	12.1%	14.8%	13.5%	13.5%	Income Tax Rate	13.5%
9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	15.2%	9.3%	9.5%	10.1%	13.0%	13.0%	AFUDC % to Net Profit	11.0%
44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	47.0%	47.1%	52.8%	53.9%	55.0%	54.5%	Long-Term Debt Ratio	54.5%
55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	53.0%	52.9%	47.2%	46.1%	45.0%	45.5%	Common Equity Ratio	45.5%
7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	9861.1	10263	11948	12820	13350	13475	Total Capital ($mill)	15425
10396	10889	11194	11809	12714	13445	14030	14523	15159	15987	16775	17525	Net Plant ($mill)	19875
6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	6.2%	6.3%	5.5%	5.8%	4.5%	4.5%	Return on Total Cap'l	5.0%
9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.0%	Return on Shr. Equity	9.0%
9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	9.9%	9.8%	10.5%	8.0%	8.0%	Return on Com Equity E	9.0%
4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	3.9%	3.8%	3.5%	4.2%	1.0%	1.5%	Retained to Com Eq	2.5%
58%	58%	62%	59%	62%	58%	60%	61%	64%	60%	80%	79%	All Div'ds to Net Prof	69%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $7782.3 mill. Due in 5 Yrs $1892.0 mill.
LT Debt $7241.3 mill. LT Interest $244.1 mill.
(Total Interest Coverage: 3.0x)

Leases, Uncapitalized Annual rentals $13.1 mill.

Pension Assets-12/21 $3812.0 mill. Oblig $3716.8 mill.

Pfd Stock None

Common Stock 113,140,203 shs.
as of 10/28/22
MARKET CAP: $8.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.4	+5.4	+2.8
Avg. Indust. Use (MWH)	714	583	808
Avg. Indust. Revs. per KWH (¢)	7.88	7.49	8.11
Capacity at Peak (Mw)	8241	9094	8726
Peak Load, Summer (Mw)	7115	7660	7580
Annual Load Factor (%)	47.1	45.5	45.9
% Change Customers (yr-end)	+2.0	+2.1	+2.2
Fixed Charge Cov. (%)	286	318	317

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	3.5%
"Cash Flow"	4.5%	5.0%	3.0%
Earnings	6.0%	5.5%	.5%
Dividends	4.5%	5.5%	2.0%
Book Value	4.0%	4.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	740.5	869.5	1190.8	670.4	3471.2
2020	661.9	929.6	1254.5	741.0	3587.0
2021	696.5	1000.2	1308.2	798.9	3803.8
2022	783.5	1061.7	1469.9	799.9	4115
2023	810	1110	1425	855	4200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.16	1.28	2.77	.57	4.77
2020	.27	1.71	3.07	d.17	4.87
2021	.32	1.91	3.00	.24	5.47
2022	.15	1.45	2.88	d.23	4.25
2023	.20	1.50	2.70	Nil	4.40

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.737	.738	.738	.782	3.00
2020	.783	.783	.783	.83	3.18
2021	.83	.83	.83	.85	3.34
2022	.85	.85	.85	.85	3.40
2023	.865				

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.3 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, 51%; commercial, 38%; industrial, 5%; other, 6%. Generating sources: gas & other, 30%; nuclear, 27%; coal, 20%; purchased, 23%. Fuel costs: 30% of revenues. '21 reported deprec. rate: 2.9%. Has 5,900 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.

Fiscal 2022 was a difficult transition period for Pinnacle West Capital. The company's late 2021 GRC (general rate case) decision went very poorly. Entering calendar 2022, the utility was operating under revised regulatory parameters that cut its allowed return on equity (ROE) from 10% to a miserly 8.7%. The change effectively reduced Pinnacle West's annual earning power by roughly $1.00 per share. While on the topic of fiscal 2022, it's worth noting that third-quarter profits benefited by $0.23 per share from the impact of excessive heat and humidity on seasonal demand. Financial penalties ensue when utilities excessively exceed their annual ROE. As such, Pinnacle West will probably post a fourth-quarter deficit when it reports its 2022 year-end financial results next month. Most likely the company pulled forward some of its O&M (operations and maintenance) work to avoid surpassing its ROE limits.

This year probably won't be significantly better. Heading into 2022 our bottom-line expectation for the year was roughly $4.00 per share. With weather on its side, the company likely did better. As a result, comparisons for this year are difficult. Weather-normalized retail volume tends to rise at a 2% clip annually, and there are pricing mechanisms that enable certain grid investments to be recouped promptly. All told, we're looking for earnings of $4.40 per share in 2023.

In late October, the company filed a new GRC with Arizona regulators. It's asking for an increase in its ROE to 10.25% from 8.7%. It is also seeking an expansion in the use of automatic pricing mechanisms to recoup investments it's planning to make in support of the state's clean-energy objectives. A decision is due in the fourth quarter. Pinnacle West is not completely without leverage. Odds favor a compromise on the ROE level.

This issue has been quite volatile over the past 18 months. Contentious testimony leading up to the last rate decision was followed by investors trying to gauge if the setback would be permanent or not. The price appears range bound between $60 and $80. We think the mid-$60 level would be a good entry point for utility investors with a long-term horizon.

Anthony J. Glennon *January 20, 2023*

(A) Diluted EPS. Excl. nonrec. gain (loss): '09, ($1.45); '17, 8¢; gains (losses) from discont. ops.: '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '19 & '20 EPS don't sum due to rounding. Next egs. report due late Feb. (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. In '21: $23.60/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on common equity in '21: 8.7%. Regulatory Climate: Below Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	95

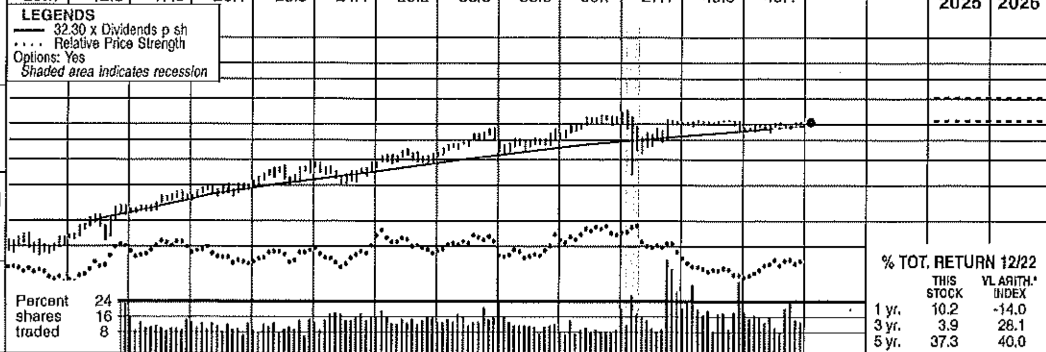
PNM RESOURCES NYSE-PNM

RECENT PRICE 49.05 | P/E RATIO 18.0 (Trailing: 17.9 Median: 19.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS — Suspended 1/20/23
SAFETY 2 Raised 4/23/21
TECHNICAL — Suspended 1/20/23
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	19.2	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0	56.1	50.1	49.3
Low:	12.8	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7	27.1	43.8	43.4

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High Midpoint (% to Mid)
$42-$58 $50 (0%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+35%)	10%
Low	50	(Nil)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	139	128	135
to Sell	107	115	99
Hld's(000)	78937	77513	77410

Percent shares traded 24 16 8

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.2	-14.0
3 yr.	3.9	26.1
5 yr.	37.3	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
32.25	24.92	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	23.60	23.60	Revenues per sh	26.65
3.57	2.54	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	6.50	6.65	"Cash Flow" per sh	8.10
1.72	.76	.11	.56	.87	1.06	1.31	1.41	1.45	1.48	1.46	1.92	2.00	2.16	2.28	2.45	2.65	2.70	Earnings per sh A	3.10
.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	1.18	1.25	1.33	1.41	1.49	Div'd Decl'd per sh B ■ †	1.80
4.04	5.94	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	10.20	10.55	Cap'l Spending per sh	9.00
22.09	22.03	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	27.00	28.60	Book Value per sh C	32.45
76.65	76.81	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	88.00	90.00	Common Shs Outst'g D	90.00
15.6	35.6	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	17.7		Avg Ann'l P/E Ratio	18.5
.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.05	1.18	1.01	1.07	1.03		Relative P/E Ratio	1.05
3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.6%	2.5%	2.6%	2.7%	3.0%		Avg Ann'l Div'd Yield	3.1%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	1457.6	1523.0	1779.9	2075	2125	Revenues ($mill)	2200
106.1	114.0	116.8	118.8	117.4	154.4	160.6	173.1	183.4	211.6	230	240	Net Profit ($mill)	280
31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	12.9%	8.1%	9.5%	13.4%	21.0%	21.0%	Income Tax Rate	21.0%
7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	12.1%	9.8%	8.9%	8.6%	9.0%	8.0%	AFUDC % to Net Profit	7.0%
50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	59.8%	56.9%	61.8%	60.0%	59.0%	Long-Term Debt Ratio	59.0%
48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	42.9%	38.0%	39.5%	40.5%	Common Equity Ratio	40.5%
3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	4207.7	4780.6	5698.6	5975	6275	Total Capital ($mill)	7225
3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	5466.0	5965.1	6752.9	7300	7900	Net Plant ($mill)	9050
5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	5.0%	5.5%	4.9%	4.6%	4.5%	4.5%	Return on Total Cap'l	4.5%
6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	9.4%	10.2%	8.9%	9.7%	9.5%	9.5%	Return on Shr. Equity	9.5%
6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	9.5%	10.3%	8.9%	9.7%	9.5%	9.5%	Return on Com Equity E	9.5%
3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	4.5%	4.8%	4.1%	4.6%	4.5%	4.0%	Retained to Com Eq	4.0%
43%	45%	51%	54%	61%	51%	53%	54%	54%	53%	53%	55%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $3953.7 mill. Due in 5 Yrs $2046.4 mill.
LT Debt $3893.5 mill. LT Interest $92.6 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $28.4 mill.
Pension Assets-12/21 $639.6 mill.
Oblig $643.7 mill.
Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 85,834,874 shs.
as of 10/21/22
MARKET CAP: $4.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+5.0	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2761	NA	NA
Peak Load, Summer (Mw)	1937	1974	1968
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	228	237	299

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-0.5%	1.5%	5.5%
"Cash Flow"	8.0%	7.0%	5.0%
Earnings	10.5%	9.5%	5.0%
Dividends	9.5%	8.5%	6.0%
Book Value	2.5%	2.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	349.7	330.2	433.6	344.1	1457.6
2020	333.6	357.6	472.5	359.3	1523.0
2021	364.7	426.5	554.6	434.1	1779.9
2022	444.1	499.7	729.9	401.3	2075
2023	465	520	680	460	2125

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.13	.37	1.29	.36	2.16
2020	.18	.55	1.40	.15	2.28
2021	.32	.55	1.37	.21	2.45
2022	.50	.57	1.46	.12	2.65
2023	.52	.62	1.40	.16	2.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.29	.29	.29	.29	1.16
2020	.3075	.3075	.3075	.3075	1.23
2021	.3275	.3275	.3275	.3275	1.31
2022	.3475	.3475	.3475	.3475	1.39
2023	.3675				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 538,000 customers in north central New Mexico, including Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 261,000 customers in Texas. Electric revenue breakdown: residential, 42%; commercial, 36%; industrial, 8%; other, 14%. Generating sources not available. Fuel costs: 36% of revenues. '21 reported depreciation rates: 2.5%-7.9%. Has 1,600 employees. Chairman and CEO: Patricia Vincent-Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

Twenty-seven months after PNM Resources agreed to be purchased by AVANGRID, the deal still has life. Subscribers may recall that this acquisition was initially proposed in October of 2020. To recap, shareholders of the Southwest-based utility are to receive $50.30 per share (all cash) from Northeast utility AVANGRID, Inc. (AGR). Regulatory approval was received from all of the necessary state and federal agencies except for one. The New Mexico Public Regulation Commission (NMPRC) voted against the merger in October 2021. The NMPRC cited concerns over AGR's track record in the Northeast, a legal investigation into the CEO of its parent company, Iberdrola (based in Spain), and potentially higher electric rates as its reasons for striking down the merger. Charges against the CEO have since been dismissed. And AGR's utility subsidiaries have actually improved in reliability metrics over the years, with electric rates below average for the region. Last February, the companies appealed NMPRC's denial to the state Supreme Court. A decision is expected some time between now and this summer.

The main stumbling block to the merger may well have fallen. Historically, the NMPRC has been a body of five commissioners with a bias towards keeping electric rates down. It hasn't been conducive for modernization or renewables. Last year, a law was passed which streamlined the commission from five to three members. The Democratic governor recently appointed three commissioners who've moved into their new roles this month. As she is for "green" energy and pro-merger, we expect policy changes that will shift the state to a clean-energy bias. The odds of a successful acquisition are also higher now in our opinion. After the recent NMPRC selections receive legislative confirmation, there appears to be no reason they could not rule favorably on a revamped merger proposal.

The shares are trading as if a consummated deal is likely. The stock has moved to within 2%-3% of AGR's offer and has held that level since early December. No new commitments should be made. PNM's Timeliness rank is suspended, as the buyout is the dominant pricing factor.

Anthony J. Glennon *January 20, 2023*

(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¢); Q1-Q3 '22, (76¢). Excl. disc. op. gains: '08, 42¢; '09, 78¢. Next egs. report due late February. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $10.86/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; Regulatory Climate: NM, Below Average.; TX, Average.

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

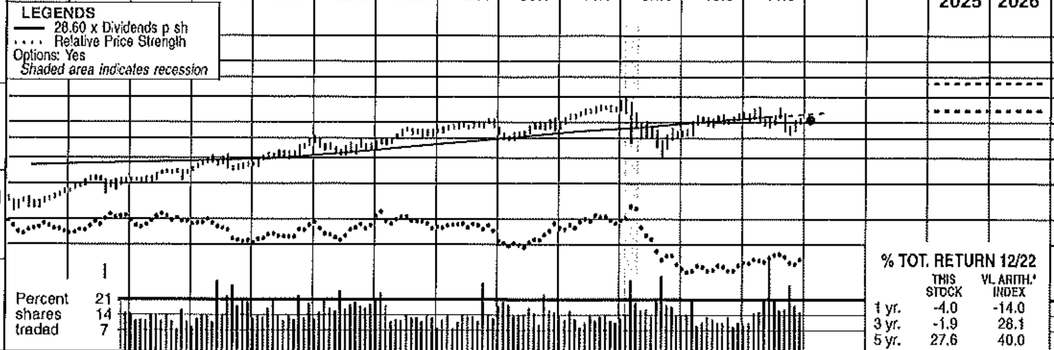
PORTLAND GENERAL NYSE-POR

RECENT PRICE 49.46 | P/E RATIO 16.9 (Trailing: 17.9; Median: 18.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 1/6/23
SAFETY 2 Raised 10/22/21
TECHNICAL 4 Raised 1/20/23
BETA .85 (1.00 = Market)

High:	26.0	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0	
Low:	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	41.6	

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$41-$68 $55 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+50%)	14%
Low	55	(+10%)	7%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	178	181	193
to Sell	142	153	150
Hld's(000)	82974	89213	87350

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.0	-14.0
3 yr.	-1.9	28.1
5 yr.	27.6	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.32	27.87	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	29.00	28.55	Revenues per sh	30.00
4.64	5.21	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	7.65	7.75	"Cash Flow" per sh	8.95
1.14	2.33	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	2.80	2.95	Earnings per sh A	3.50
.68	.93	.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	Div'd Decl'd per sh B ■ †	2.24
5.94	7.28	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	8.25	8.25	Cap'l Spending per sh	8.50
19.58	21.05	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	31.35	33.00	Book Value per sh C	37.00
62.50	62.53	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	89.30	94.50	Common Shs Outst'g D	100.00
23.4	11.9	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	17.9		Avg Ann'l P/E Ratio	18.5
1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.95	1.04		Relative P/E Ratio	1.05
2.5%	3.3%	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%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $3623 mill. Due in 5 Yrs $186 mill.
LT Debt $3582 mill. LT Interest $128 mill.
Incl. $296 mill. finance leases.
(Total Interest Coverage: 3.0x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/21 $800 mill. Oblig $972 mill.

Pfd Stock None

Common Stock 89,272,904 shs. as of 10/20/22

MARKET CAP: $4.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	2590	2700	Revenues ($mill)	3000
141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	250	270	Net Profit ($mill)	350
31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	17.5%	17.5%	Income Tax Rate	17.5%
7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	10.0%	9.0%	AFUDC % to Net Profit	9.0%
47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	55.5%	55.0%	Long-Term Debt Ratio	55.0%
52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	44.5%	45.0%	Common Equity Ratio	45.0%
3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	6325	6975	Total Capital ($mill)	8250
4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	8325	8625	Net Plant ($mill)	9525
5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	5.0%	5.0%	Return on Total Cap'l	5.5%
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	9.0%	8.5%	Return on Shr. Equity	9.5%
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	9.0%	8.5%	Return on Com Equity E	9.5%
3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	3.5%	3.0%	Retained to Com Eq	3.5%
57%	61%	50%	56%	57%	58%	59%	63%	57%	61%	64%	64%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.2	+.4	+5.1
Avg. Indust. Use (MWH)	17827	18472	20002
Avg. Indust. Revs. per KWH (¢)	4.75	4.99	5.22
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3765	3771	4447
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.5	+.6

Fixed Charge Cov. (%)	265	187	261

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	2.0%	3.0%
"Cash Flow"	5.0%	5.0%	3.5%
Earnings	5.0%	4.5%	5.0%
Dividends	4.5%	6.0%	6.0%
Book Value	3.5%	3.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	573	460	542	548	2123
2020	573	469	547	556	2145
2021	609	537	642	608	2396
2022	626	591	743	630	2590
2023	650	620	775	655	2700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.28	.61	.68	2.39
2020	.91	.43	.84	.57	2.75
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	.65	.76	2.80
2023	.78	.74	.66	.77	2.95

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	1.77
2023	.4525				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 917,000 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 it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 11%; other, 13%. Generating sources: gas, 37%; wind, 9%; coal, 8%; hydro, 4%; purchased, 42%. Fuel costs: 34% of revenues. '21 reported depreciation rate: 3.4%. Has 2,800 full-time employees. Chairman: Jack E. Davis. President and Chief Executive Officer: 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 (PGE) should post a decent bottom-line gain in the year ahead. In 2022, the utility secured a 3.2% electric rate increase, but that didn't take effect until midway through the second quarter. Thus, comparisons should be relatively easy over the first half of this year. Incremental volume gains should also be a factor.

The company raised its long-term earnings growth targets from 4%-6% to 5%-7%. Leadership cited accelerating load growth as a key factor. PGE benefits from a healthy economy in its service territory, where there is a vibrant tech sector. The payoff from renewable-energy investments is also expected to provide a lift.

The utility is in the process of adding "green" power generation projects to its rate base (RB). (The value of property on which a regulated utility is permitted to earn an economic return is its RB.) This should have dual bottom-line benefits down the road. First, whenever a utility gets the okay from regulators to expand its RB, the earnings power of the company grows. The investment is usually recouped through higher electric rates. In this instance, it may be a win for both PGE and its customers, as the utility has been paying exorbitant prices for electric power during periods of peak demand. And unlike natural gas, which is a direct pass through to customer bills in most instances, outsized electric power costs often have to be justified to regulators. PGE wants to add at least 375 to 500 megawatts of renewables and "nonemitting" annual capacity. Thus far, it's agreed to partner with NextEra Energy (NEE) to construct a 311 mw wind energy facility in eastern Montana. PGE will own two-thirds of the project and will have a 30-year contract with NEE to purchase the remaining power generated. Project completion is expected to be in December.

This issue, however, is untimely. Utility investors may find its total return prospects worthwhile at the recent quote, but we'd wait for a pullback. To secure equity financing later, PGE did a forward sale with bankers for 10.1 million shares priced at $43 each. This means there will be new supply added to the float in the next two years, which may provide a better entry.

Anthony J. Glennon *January 20, 2023*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢). Next earnings report due mid-February.
(B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available.
(C) Incl. deferred charges. In '21: $533 mill., $5.96/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	95
Price Growth Persistence	45
Earnings Predictability	95

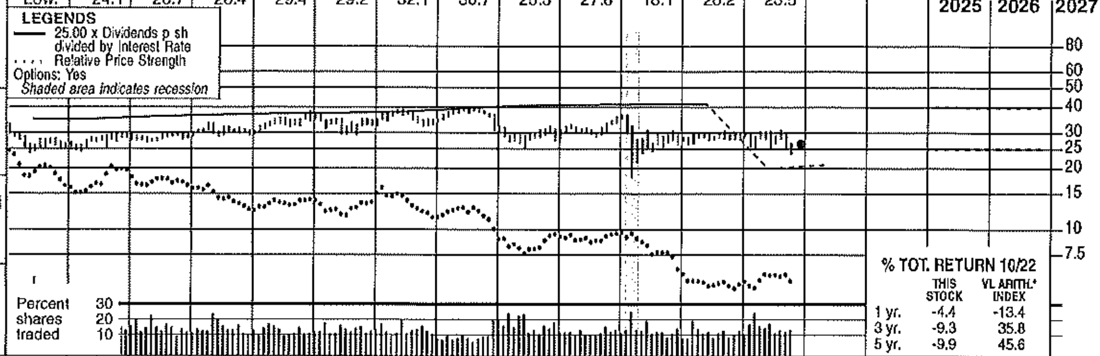
PPL CORPORATION NYSE-PPL

RECENT PRICE 26.49 | P/E RATIO 18.5 (Trailing: 23.4, Median: 13.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 9/23/22
SAFETY 3 Lowered 3/18/22
TECHNICAL 3 Lowered 11/11/22
BETA 1.10 (1.00 = Market)

High:	30.3	30.2	33.6	38.1	36.7	39.9	40.2	32.5	36.3	36.8	30.7	31.0
Low:	24.1	26.7	28.4	29.4	29.2	32.1	30.7	25.3	27.8	18.1	26.2	23.5

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High: $23-$38 | Midpoint (% to Mid): $31 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	14%
Low	25	(-5%)	3%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	377	354	345
to Sell	387	412	380
Hld's(000)	484161	488196	512086

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.4	-13.4
3 yr.	-9.3	35.8
5 yr.	-9.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
17.92	17.41	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	*10.00*	*10.30*	Revenues per sh	*11.40*
4.26	5.10	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	*3.05*	*3.30*	"Cash Flow" per sh	*3.65*
2.29	2.63	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	*1.37*	*1.55*	Earnings per sh A	*1.95*
1.10	1.22	1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	1.50	1.64	1.65	1.66	1.66	*1.07*	*.96*	Div'd Decl'd per sh B ■	*1.18*
3.62	4.51	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	*2.45*	*3.10*	Cap'l Spending per sh	*3.10*
13.30	14.88	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	*19.25*	*20.05*	Book Value per sh C	*22.35*
385.04	373.27	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	*737.00*	*739.00*	Common Shs Outst'g D	*745.00*
14.1	17.3	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	NMF	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.76	.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.89	.61	.71	.71	NMF	*Value Line*		Relative P/E Ratio	*.95*
3.4%	2.7%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $13642 mill. Due in 5 Yrs $3000 mill.
LT Debt $12153 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: 2.0x)

Leases, Uncapitalized Annual rentals $23 mill.
Pension Assets-12/21 $3887 mill.
Oblig $3989 mill.

Pfd Stock None
Common Stock 736,184,769 shs.
as of 7/29/22
MARKET CAP: $19.5 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
12286	11860	11499	7669.0	7517.0	7447.0	7785.0	7769.0	7607.0	5783.0	*7360*	*7600*	Revenues ($mill)	*8500*
1536.0	1541.0	1583.0	1603.0	1902.0	1449.0	1827.0	1746.0	1571.0	401.0	*1010*	*1180*	Net Profit ($mill)	*1455*
26.2%	23.1%	33.0%	22.5%	25.4%	24.2%	20.0%	19.0%	20.3%	23.0%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
4.1%	3.7%	2.8%	1.6%	1.6%	1.9%	2.0%	1.9%	1.8%	6.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
64.1%	62.3%	58.0%	65.2%	64.3%	64.8%	63.3%	61.5%	61.7%	43.7%	*45.5%*	*47.5%*	Long-Term Debt Ratio	*49.5%*
35.9%	37.7%	42.0%	34.8%	35.7%	35.2%	36.7%	38.5%	38.3%	56.3%	*54.5%*	*52.5%*	Common Equity Ratio	*50.5%*
29205	33058	32484	28482	27707	30608	31726	33712	34926	24389	*25975*	*27775*	Total Capital ($mill)	*31900*
30032	33087	34597	30382	30074	33092	34458	36482	38892	25470	*25900*	*26050*	Net Plant ($mill)	*25900*
7.0%	6.2%	6.5%	7.1%	8.4%	6.2%	7.2%	6.6%	5.9%	2.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
14.7%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	*7.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
14.6%	12.4%	11.6%	16.2%	19.2%	13.5%	15.7%	13.4%	11.7%	2.9%	*7.0%*	*7.0%*	Return on Com Equity E	*7.5%*
6.7%	5.3%	4.5%	6.0%	8.8%	3.5%	6.0%	4.3%	2.2%	NMF	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
54%	57%	61%	63%	54%	74%	62%	68%	81%	NMF	*78%*	*60%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.4	-5.2	+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, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	283	278	154

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.5%	-7.0%	*3.0%*
"Cash Flow"	-1.5%	-5.0%	*2.0%*
Earnings	-2.0%	-8.0%	*3.0%*
Dividends	1.5%	2.0%	*-5.5%*
Book Value	.5%	1.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2079	1803	1933	1954	7769.0
2020	2054	1739	1885	1929	7607.0
2021	1498	1288	1512	1485	5783.0
2022	1782	1696	*1930*	*1952*	*7360*
2023	*1840*	*1750*	*1995*	*2015*	*7600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	.60	.65	.48	2.37
2020	.72	.45	.50	.38	2.04
2021	.26	d.20	.27	.19	.53
2022	.37	.30	*.45*	*.25*	*1.37*
2023	*.42*	*.31*	*.54*	*.28*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.395	.41	.41	.41	1.63
2019	.41	.4125	.4125	.4125	1.65
2020	.4125	.415	.415	.415	1.66
2021	.415	.415	.415	.415	1.66
2022	.415	.20	.225		

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 Pennsylvannia. 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, 46%; comm'l, 22%; ind'l, 11%; other, 21%. Fuel costs: 25% of revs. '21 reported deprec. rate: 3.6%. Has 6,700 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.

PPL Corporation affirmed its upbeat near-term outlook with the August release of mid-2022 results. Indeed, management went on record saying it still expects full-year adjusted earnings of between $1.30 and $1.45 a share, up sharply from the low $0.53 that the electric and gas utility tallied in 2021. Importantly, the target range reflects a roughly seven-month contribution from Narragansett Electric, the Rhode Island utility that PPL acquired in late May. It is also worth noting that bottom-line comparisons are fairly easy, as 2021 results included a one-time charge related to the early extinguishment of debt.

Leadership continues to target 6%-8% EPS growth for the next several years. Key to that goal is the realization of significant cost savings. To wit, PPL expects to lower annual operating and maintenance expense as much as $60 million by the end of 2023. Furthermore, it hopes to increase that figure to $150 million 24 months thereafter. As we understand it, a good portion of the savings will come from infrastructure improvements, such as the additional "hardening" of transmission assets against, among other things, adverse weather events. To that point, over 70% of the utility's transmission structures in Pennsylvania are now made of steel, up from less than 50% a decade ago, when wood construction was more prevalent.

The utility recently solicited proposals for replacing its coal-fueled power plants. If leadership has it right, coal will represent less than 15% of PPL's overall rate base by 2026, down from roughly 21% at the end of last year. What's more, additional reductions in its carbon footprint are expected in the next decade or so. The moves may broaden PPL's appeal among institutional investors, especially those with ESG mandates.

Shares of PPL Corp. are ranked 4 (Below Average) for relative year-ahead price performance. The major draw here remains the dividend, which is well covered. Still, at 3.4%, the recent payout trails the electric utility average by several basis points. With that in mind, income-oriented investors may want to look elsewhere for now.

Nils C. Van Liew *November 11, 2022*

(A) Dil. EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); '20, (13¢); '21, (50¢); gains (losses) on disc. ops.: '07, 19¢; '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 March. (B) Div'ds paid in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $3.12/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	B++
Stock's Price Stability	75
Price Growth Persistence	15
Earnings Predictability	50

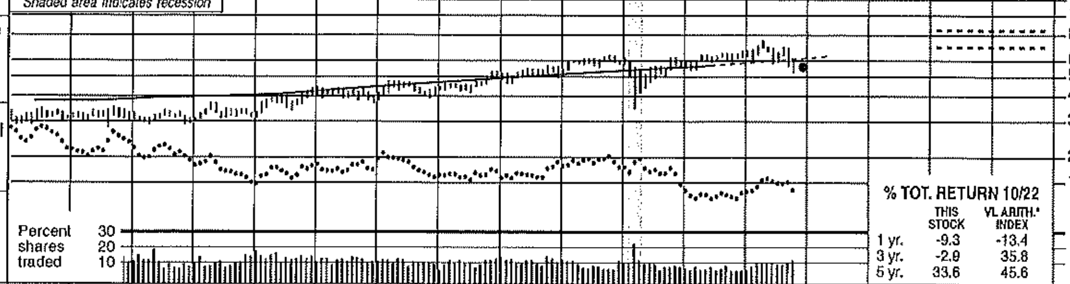
P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 56.07 | P/E RATIO 16.4 (Trailing: 15.9 Median: 15.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 3/11/22
SAFETY 1 Raised 11/23/12
TECHNICAL 2 Lowered 10/28/22
BETA .90 (1.00 = Market)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	35.5	34.1	37.0	43.8	44.4	47.4	53.3	56.7	63.9	62.2	67.1	75.6
Low:	28.0	26.9	29.7	31.3	36.8	37.8	41.7	46.2	50.0	34.8	53.8	52.5

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



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$49-$81 $65 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+50%)	14%
Low	70	(+25%)	10%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	464	469	407
to Sell	353	397	433
Hld's(000)	364212	355865	354340

Percent shares traded 30 20 10

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-9.3	-13.4
3 yr.	-2.9	35.8
5 yr.	33.6	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.07	25.28	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	*18.15*	*19.65*	Revenues per sh	*22.25*
3.91	4.36	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	*6.45*	*6.70*	"Cash Flow" per sh	*7.75*
1.85	2.59	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	*3.48*	*3.60*	Earnings per sh A	*4.35*
1.14	1.17	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*	Div'd Decl'd per sh B ■†	*2.72*
2.01	2.65	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	*6.25*	*7.55*	Cap'l Spending per sh	*7.25*
13.35	14.35	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	*27.25*	*29.00*	Book Value per sh C	*33.75*
505.29	508.52	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	*496.00*	*496.00*	Common Shs Outst'g D	*496.00*
17.8	16.5	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	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.96	.88	.82	.67	.66	.65	.81	.76	.66	.71	.80	.82	.90	.96	.81	.90	*Value Line*		Relative P/E Ratio	*.95*
3.5%	2.7%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $20984 mill. Due in 5 Yrs $9069 mill.
LT Debt $16471 mill. LT Interest $475 mill.
(Total interest coverage: 3.6x)

Leases, Uncapitalized Annual rentals $40 mill.

Pension Assets-12/21 $6906 mill. Oblig $7240 mill.

Pfd Stock None

Common Stock 498,860,141 shs. as of 7/19/22
MARKET CAP: $28.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
9781.0	9968.0	10886	10415	9198.0	9161.0	9696.0	10076	9603.0	9722.0	*9000*	*9750*	Revenues ($mill)	*11000*
1239.0	1243.0	1518.0	1476.0	1436.0	1431.0	1582.0	1666.0	1741.0	1853.0	*1750*	*1795*	Net Profit ($mill)	*2170*
36.2%	39.5%	38.2%	37.4%	31.7%	37.3%	23.7%	32.2%	14.3%	19.5%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
4.8%	4.6%	4.5%	6.2%	8.4%	10.6%	8.7%	6.5%	7.0%	5.5%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
38.3%	40.4%	40.4%	40.3%	45.3%	46.6%	47.8%	47.7%	47.6%	51.3%	*55.0%*	*55.5%*	Long-Term Debt Ratio	*57.5%*
61.7%	59.6%	59.6%	59.7%	54.7%	53.4%	52.2%	52.3%	52.4%	48.7%	*45.0%*	*44.5%*	Common Equity Ratio	*42.5%*
17467	19470	20446	21900	24025	25915	27545	28832	30480	29657	*29950*	*32325*	Total Capital ($mill)	*39500*
19736	21645	23589	26539	29286	31797	34363	35844	37585	34366	*36050*	*38350*	Net Plant ($mill)	*44300*
8.1%	7.5%	8.4%	7.6%	6.8%	6.4%	6.7%	6.7%	6.6%	7.1%	*7.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.5%	10.7%	12.5%	11.3%	10.9%	10.3%	11.0%	11.0%	10.9%	12.8%	*13.0%*	*12.5%*	Return on Shr. Equity	*13.0%*
11.5%	10.7%	12.5%	11.3%	10.9%	10.3%	11.0%	11.0%	10.9%	12.8%	*13.0%*	*12.5%*	Return on Com Equity E	*13.0%*
4.8%	4.4%	6.3%	5.3%	4.6%	4.1%	4.7%	4.7%	4.7%	5.7%	*5.0%*	*4.5%*	Retained to Com Eq	*5.0%*
58%	59%	49%	53%	58%	61%	58%	57%	57%	56%	*62%*	*63%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.9	-2.5	+1.3
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)	9753	9905	10064
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.9	+.6	+1.0
Fixed Charge Cov. (%)	361	298	273

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-.5%	*2.5%*
"Cash Flow"	2.0%	2.5%	*4.0%*
Earnings	1.0%	3.5%	*4.5%*
Dividends	3.5%	4.5%	*5.5%*
Book Value	5.0%	3.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2980	2316	2302	2478	10076
2020	2781	2050	2370	2402	9603.0
2021	2889	1874	1903	3056	9722.0
2022	2313	2076	2272	*2339*	*9000*
2023	*2500*	*2250*	*2460*	*2540*	*9750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.08	.58	.98	.64	3.28
2020	1.03	.79	.96	.65	3.43
2021	1.28	.70	.98	.69	3.65
2022	1.33	.64	.86	*.65*	*3.48*
2023	*1.20*	*.70*	*.95*	*.75*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.45	.45	.45	.45	1.80
2019	.47	.47	.47	.47	1.88
2020	.49	.49	.49	.49	1.96
2021	.51	.51	.51	.51	2.04
2022	.54	.54	.54		

BUSINESS: Public Service Enterprise Group Inc. is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.3 million electric and 1.9 million gas customers in NJ, and PSEG Power LLC, a nonregulated power generator with nuclear plants in the Northeast (sold its fossil-fuel generating plants, 2/22). PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out detailed data on electric and gas operating statistics. Fuel costs: 36% of revenues. '21 reported depreciation rates (utility): 1.8%-2.6%. Has 12,700 employees. Executive Chair: Dr. Ralph Izzo. Chair, Pres. & 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 (PSEG) has a new chief executive at the helm. Ralph A. LaRossa, who previously served as the chief operating officer, has been elevated to president and CEO. Mr. LaRossa will also have a seat on the board of directors, while the prior CEO, Dr. Ralph Izzo, will stay on as executive chair of the board. The transition has been smooth, with the succession plan having been in the works for some time. PSEG will likely remain a well-run utility.

Profits should be back on a growth trajectory in 2023. This year's decline stemmed from PSEG's February sale of its nonregulated natural-gas based generating plants. The loss of income associated with the divestiture was only partially offset on a per-share basis by stock buybacks. With the gas assets off the books for most of 2022, next year's earnings comparisons will be easier. Plus utility income is rising due to regulatory mechanisms that allow for contemporaneous returns on capital used for certain grid improvements.

New Jersey's renewable-energy transition and the Inflation Reduction Act (IRA) are positives. PSEG is practically a purely regulated utility, with only its nuclear plants likely to stay on as nonregulated assets. Thus, capital will be directed mainly at regulated ventures it earns a solid rate of return on. It's a low-risk strategy that should yield consistently good results as long as there are regulated projects to invest in. With state government officials on board, PSEG will be upgrading the grid as it prepares its territory for a renewable-energy future and the electrification of the transportation system. The IRA is expected to speed up the transition and make it less painful for consumers. The act also provides incentives that will help utilities keep their nuclear plants economically viable.

Utility investors with a long-term horizon should consider this issue. PSEG's risk-adjusted 3- to 5-year total returns compare favorably to the peer group. It's also notable that the dividend yield is 20 basis points higher than the industry median, while the payout's growth rate is about 50 basis points in excess of the peer-group average. We also like the direction of the New Jersey regulatory environment.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (35¢); '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); 1Q-3Q '22, ($2.35); disc. ops.: '06, (3¢); '07, 3¢; '08, 40¢; '10, 1¢; '11, 19¢. Next earnings report due early Feb. (B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $7.19/sh. (D) In mill., adj. for '08 split. (E) Rate base: Net original cost. Rate allowed on comon equity in '18: 9.6%; Regulatory Climate: Average.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

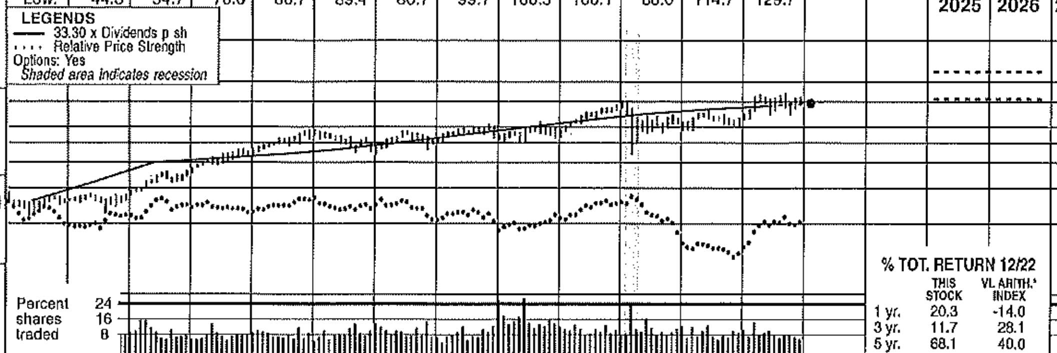
SEMPRA ENERGY NYSE-SRE

RECENT PRICE 157.13 | P/E RATIO 17.3 (Trailing: 17.4; Median: 20.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 12/30/22
SAFETY 2 Raised 7/29/16
TECHNICAL 2 Raised 1/6/23
BETA .95 (1.00 = Market)

High:	56.0	72.9	93.0	116.3	116.2	114.7	123.0	127.2	154.5	161.9	144.9	176.5
Low:	44.8	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1	88.0	114.7	129.7

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



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$115-$191 $153 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	225	(+45%)	12%
Low	165	(+5%)	5%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	476	441	476
to Sell	337	376	332
Hld's(000)	275892	268609	267683

Percent shares traded 24 16 8

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.3	-14.0
3 yr.	11.7	28.1
5 yr.	68.1	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	42.69	37.12	39.41	40.57	47.00	49.50	Revenues per sh	57.40
6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	11.14	13.22	14.17	15.20	16.60	"Cash Flow" per sh	20.15
4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	5.48	5.97	7.38	8.43	8.85	9.30	Earnings per sh A	11.25
1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	3.58	3.87	4.18	4.40	4.58	4.80	Div'd Decl'd per sh B ■	5.82
7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	13.82	12.71	16.21	15.82	16.05	13.75	Cap'l Spending per sh	13.75
28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	54.35	60.58	70.11	79.17	83.35	92.15	Book Value per sh C	102.65
262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	273.77	291.71	288.47	316.92	315.00	305.00	Common Shs Outst'g D	305.00
11.5	14.0	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	17.5		Avg Ann'l P/E Ratio	17.5
.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.20	.90	.83	1.02		Relative P/E Ratio	.95
2.5%	2.1%	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%		Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $25580 mill. Due in 5 Yrs $7358 mill.
LT Debt $23830 mill. LT Interest $791 mill.
Incl. $1335 mill. finance leases.
(Total Interest Coverage: 3.4x)

Leases, Uncapitalized Annual rentals $73 mill.
Pension Assets-12/21 $3182 mill. Oblig $3857 mill.
Pfd Stock $889 mill. Pfd Div'd $45 mill.
900,000 shs. 4.875%, cumulative.
Common Stock 314,333,363 shs.
as of 10/31/22
MARKET CAP: $49.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
9647.0	10557	11035	10231	10183	11207	11687	10829	11370	12857	14800	15100	Revenues ($mill)	17500
1079.0	1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2316.0	2701.0	2850	2940	Net Profit ($mill)	3485
18.2%	26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	18.0%	25.5%	19.0%	19.0%	Income Tax Rate	19.0%
17.2%	11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	8.7%	8.0%	8.0%	8.0%	AFUDC % to Net Profit	7.0%
52.8%	50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.2%	44.8%	46.0%	47.0%	Long-Term Debt Ratio	46.0%
46.7%	49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	44.8%	53.3%	52.5%	51.0%	Common Equity Ratio	52.5%
22002	22281	23513	24963	27400	29135	38769	40734	45174	47069	50175	52025	Total Capital ($mill)	59800
25191	25460	25902	28039	32931	36503	36796	36452	40003	43894	46950	49000	Net Plant ($mill)	54000
6.1%	6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	6.1%	6.6%	6.5%	6.5%	Return on Total Cap'l	7.0%
10.4%	9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	9.9%	10.4%	10.5%	10.5%	Return on Shr. Equity	11.0%
10.4%	9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	10.6%	10.5%	10.5%	11.0%	Return on Com Equity E	11.0%
5.1%	4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	4.8%	5.2%	5.0%	5.5%	Retained to Com Eq	5.5%
52%	58%	52%	48%	65%	65%	62%	62%	58%	52%	52%	52%	All Div'ds to Net Prof	52%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-4.3	-.4	-3.7
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	+.8	+.9
Fixed Charge Cov. (%)	181	159	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	6.5%
"Cash Flow"	4.5%	5.5%	8.0%
Earnings	5.0%	9.0%	7.5%
Dividends	9.5%	8.0%	6.0%
Book Value	6.0%	7.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2898	2230	2758	2943	10829
2020	3029	2526	2644	3171	11370
2021	3259	2741	3013	3844	12857
2022	3820	3547	3617	3816	14800
2023	3950	3600	3675	3875	15100

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.78	.85	2.00	1.34	5.97
2020	2.53	1.56	1.31	1.88	7.38
2021	2.95	1.63	1.70	2.16	8.43
2022	2.91	1.98	1.97	1.99	8.85
2023	3.00	2.10	2.10	2.10	9.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.895	.9675	.9675	.9675	3.80
2020	.9675	1.045	1.045	1.045	4.10
2021	1.045	1.10	1.10	1.10	4.35
2022	1.10	1.145	1.145	1.145	4.54
2023	1.145				

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric (SDG&E), which sells electricity & gas mainly in San Diego County, & Southern California Gas (SoCalGas), which distributes gas to most of Southern California. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texas. Customers: 5.2 million electric, 7.0 million gas. Electric revenue breakdown not available. Purchases most of its power; the rest is gas. Has non-utility subsidiaries, incl. IEnova in Mexico. Sold commodities business in '10. Power costs: 20% of revenues. '21 reported deprec. rates: 2.6%-7.2%. Has 15,400 employees. Chairman, President & CEO: Jeffrey W. Martin. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy stock was the top performer within its industry in 2022. The price was up 17%, comparing favorably to the electric utility median (-2%) and S&P 500 (-19%). Sempra's ability to prosper in difficult economic times partially explains this, although other utilities are capable of the same, and most were down in value last year. The company's liquefied natural gas (LNG) export operation has investors excited about its growth prospects, as the demand for LNG has soared with Russian gas mostly closed to the West. While the long-term fundamentals of this business look appealing, it's a methodical operation based on multiyear capital-intensive projects and long-term fixed contracts.

We think the company will deliver decent bottom-line results in 2023. With the final reporting for 2022 due late February, we expect Sempra will post earnings of about $8.85 per share. That represents 5% profit growth. This year should be a similar showing, with incremental gains coming mainly from distribution and transmission projects.

Sempra's 6%-8% long-term earnings growth target still looks achievable. Its Texas utility is apt to continue to prosper from strong demographic trends and a vibrant state economy. The company will also benefit from its utility subsidiaries in California, as they grow their rate base (property, plant, and equipment on which utilities are allowed to earn an economic rate of return) to fulfill the state's renewable-energy initiatives. The IRA (Inflation Reduction Act), with its many clean-energy incentives, should be supportive of this. Lastly, the long-term prospects of the LNG export business looks very promising, as well. Sempra has had no problem signing up customers to lengthy contracts for the future production of projects in the construction phase. The company is partnering with key industry participants such as ConocoPhillips to help develop this burgeoning market.

The shares, however, appear fairly valued from the recent quotation. The dividend yield is 50 basis points below the industry median, but growth prospects are superior to most peers. Utility investors with a long-term slant may find the 3- to 5-year total return potential worthwhile.

Anthony J. Glennon *January 20, 2023*

(A) Dil. egs. Excl. nonrec. gain/(loss): '06, (6¢); '09, (26¢); '10, ($1.04); '11, $1.15; '12, (87¢); '13, (21¢); '15, 14¢; '16, $1.22; '17, ($3.62); '18, ($2.06); '19, 16¢; '20, (80¢); '21, ($4.42); '22, ($1.64); disc. ops.: '06, $1.21; '07, (10¢); '19, $1.16; '20, $6.30. EPS may not sum due to chg. in shs. Next egs. report: Feb. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinv. avail. (C) Incl. intang. In '21: $12.57/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq.: SDG&E in '20: 10.2%; SoCalGas in '20: 10.05%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	85

SOUTHERN COMPANY NYSE-SO

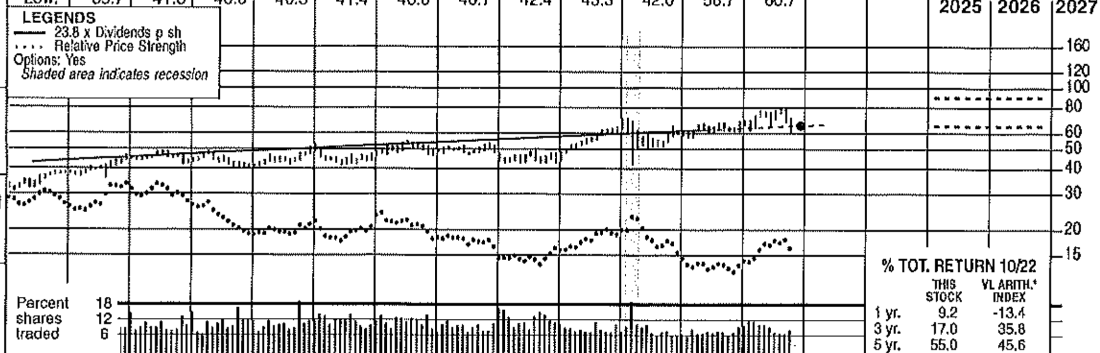
RECENT PRICE 65.48 | P/E RATIO 19.5 (Trailing: 17.3; Median: 17.0) | RELATIVE P/E RATIO 1.27 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Lowered 11/11/22
SAFETY 2 Lowered 2/21/14
TECHNICAL 1 Raised 10/21/22
BETA .95 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	46.7	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1	68.9	80.6
Low:	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0	56.7	60.7

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

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$57-$91 $74 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+35%)	12%
Low	65	(Nil)	4%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	856	770	774
to Sell	553	655	650
Hld's(000)	643341	657062	662355

Percent shares traded 18 12 6

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	-13.4
3 yr.	17.0	35.8
5 yr.	55.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.24	20.12	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	21.60	24.30	24.85	Revenues per sh	28.75
4.01	4.22	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	7.30	7.65	"Cash Flow" per sh	9.25
2.10	2.28	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	3.55	3.70	Earnings per sh A	4.75
1.54	1.60	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	Div'd Decl'd per sh B ■	3.10
4.01	4.65	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	7.55	7.85	Cap'l Spending per sh	7.50
15.24	16.23	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	27.05	28.00	Book Value per sh C	32.25
746.27	763.10	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	1070.0	1070.0	Common Shs Outst'g D	1070.0
16.2	16.0	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	Bold figures are		Avg Ann'l P/E Ratio	16.5
.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	Value Line		Relative P/E Ratio	.90
4.5%	4.4%	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%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $55066 mill. Due in 5 Yrs $15427 mill.
LT Debt $50427 mill. LT Interest $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/21 $17225 mill.
Oblig $16362 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 1,088,672,828 shs.
MARKET CAP: $71.3 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
16537	17087	18467	17489	19896	23031	23495	21419	20375	23113	26000	26600	Revenues ($mill)	30850
2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	3695	3875	Net Profit ($mill)	4980
35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	15.0%	15.0%	Income Tax Rate	15.0%
9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	8.0%	8.0%	AFUDC % to Net Profit	6.0%
49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	63.5%	64.0%	Long-Term Debt Ratio	63.0%
47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	36.0%	36.0%	Common Equity Ratio	37.0%
38653	41483	42142	46788	69359	68953	65750	69594	73336	78285	80550	83500	Total Capital ($mill)	93500
48390	51208	54868	61114	78446	79872	80797	83080	87634	91108	95150	99350	Net Plant ($mill)	110000
7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	5.5%	5.5%	Return on Total Cap'l	6.5%
12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	12.5%	13.0%	Return on Shr. Equity	14.5%
12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	13.0%	13.0%	Return on Com Equity E	14.5%
3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	3.0%	3.5%	Retained to Com Eq	5.0%
73%	75%	75%	76%	78%	72%	79%	77%	78%	76%	78%	77%	All Div'ds to Net Prof	67%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-8.5	-5.3	+2.0
Avg. Indust. Use (MWH)	2947	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.03	NA	NA
Capacity at Yearend (Mw)	41940	NA	NA
Peak Load, Summer (Mw)	34209	NA	NA
Annual Load Factor (%)	60.3	NA	NA
% Change Customers (yr-end)	-8.9	+1.3	+1.5
Fixed Charge Cov. (%)	281	270	275

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
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
2019	5412	5098	5995	4914	21419
2020	5018	4620	5620	5117	20375
2021	5910	5198	6238	5767	23113
2022	6648	7206	8378	3768	26000
2023	6700	6700	7000	6200	26600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.85	1.25	.32	3.17
2020	.81	.75	1.18	.51	3.25
2021	1.09	.67	1.22	.44	3.42
2022	.97	1.07	1.31	.20	3.55
2023	1.00	.85	1.35	.50	3.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.58	.60	.60	.60	2.30
2019	.60	.62	.62	.62	2.46
2020	.62	.64	.64	.64	2.54
2021	.64	.66	.66	.66	2.62
2022	.66	.68	.68		

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, 37%; commercial, 30%; industrial, 19%; other, 14%. Generating sources: gas, 44%; coal, 20%; nuclear, 16%; other, 11%; purchased, 9%. Fuel costs: 29% of revenues. '21 reported deprec. rates (utility): 2.7%-3.6%. Has 27,300 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Shares of Southern Company have declined significantly in value since our August report, along with many of its peers in the utilities industry. Although utility stocks have far outperformed the broader market averages this year, due to rising interest rates, it has been the worst-performing sector of the S&P 500 over the past month. However, Southern shares are outpacing their peers, as the company is up 5.5%, while the S&P Utility index is down nearly 2% this past year.

The company delivered solid financial results in the fiscal third quarter (ended September 30th). Southern posted earnings of $1.31 a share, a penny better than our estimate. Management expects adjusted full-year earnings to reach the high end of its range of $3.50 to $3.60, due to its solid first-half performance. Higher retail pricing and increased usage of utilities were the main drivers in the period. Retail sales grew 1.8% year over year and Southern Company added 11,000 electric and 8,000 gas customers in the quarter. Through the first three quarters of 2022, job additions increased 170% and business investments grew 237% compared to 2021 levels.

The utility is making progress on adding units 3 and 4 at the site of the Vogtle station. Management expects unit 3 to be placed into service by the end of the first quarter of 2023, and unit 4 is estimated by the end of next year. The project will greatly help the transition towards cleaner, more reliable energy and being carbon-free, as well as provide dividend and earnings growth moving forward. Construction timing will greatly influence growth and project delays could cause future full-year estimates to be lowered.

These shares are ranked to mirror the broader market averages in the coming six to 12 months. The stock's Timeliness rank was lowered one notch to 3 (Average). Capital-appreciation potential over the next 18 months and 3 to 5 years does not stand out compared to the industry median. On the other hand, the shares hold an Above Average (2) Safety rank, and the dividend yield of 4.2% is above the utility average of about 3.7%.

Zachary J. Hodgkinson November 11, 2022

(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-Feb. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '21: $19.83/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	95
Price Growth Persistence	45
Earnings Predictability	95

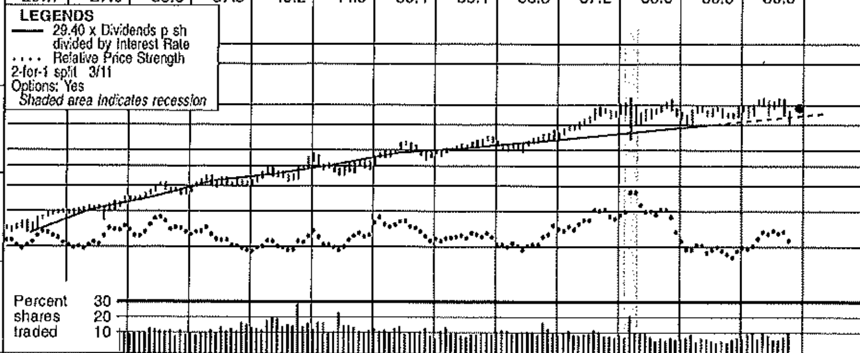
WEC ENERGY GROUP NYSE-WEC

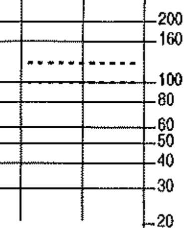
RECENT PRICE 97.54 | P/E RATIO 21.9 (Trailing: 22.3 Median: 20.0) | RELATIVE P/E RATIO 1.34 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 1/7/22
SAFETY 1 Raised 3/23/12
TECHNICAL 5 Lowered 12/9/22
BETA .80 (1.00 = Market)

High:	35.4	41.5	45.0	55.4	58.0	66.1	70.1	75.5	98.2	109.5	99.9	108.4
Low:	27.0	33.6	37.8	40.2	44.9	50.4	56.1	58.5	67.2	68.0	80.6	80.6

Target Price Range 2025 | 2026 | 2027





18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$90-$140	$115 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+30%)	9%
Low	100	(+5%)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	441	490	439
to Sell	360	340	385
Hld's(000)	233922	237581	235657

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.4	-13.4
3 yr.	4.7	35.8
5 yr.	56.2	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
17.08	16.12	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	29.20	29.50	Revenues per sh	33.00
2.90	2.98	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	8.10	8.60	"Cash Flow" per sh	10.25
1.32	1.42	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	4.40	4.70	Earnings per sh A	5.50
.46	.50	.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	3.11	Div'd Decl'd per sh B ■	3.80
4.17	5.28	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	9.35	9.30	Cap'l Spending per sh	9.25
12.35	13.25	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	35.90	37.35	Book Value per sh C	42.00
233.94	233.89	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	Common Shs Outst'g D	315.43
16.0	16.5	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	Bold figures are		Avg Ann'l P/E Ratio	20.5
.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	1.01	1.06	1.25	1.28	1.19	Value Line		Relative P/E Ratio	1.15
2.2%	2.1%	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%	estimates		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $16337 mill. **Due in 5 Yrs** $4611.7 mill.
LT Debt $14910.7 mill. **LT Interest** $452.7 mill.
Incl. $12.1 mill. finance leases.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $6.8 mill.
Pension Assets-12/21 $3328.9 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 315,434,531 shs.

MARKET CAP: $38.5 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
4246.4	4519.0	4997.1	5926.1	7472.3	7648.5	7679.5	7523.1	7241.7	8316.0	9200	9300	Revenues ($mill)	10400
547.5	576.6	589.5	640.3	940.2	998.2	1060.5	1134.2	1201.1	1301.5	1390	1485	Net Profit ($mill)	1750
35.9%	36.9%	38.0%	40.4%	37.6%	37.2%	13.8%	9.9%	15.9%	13.4%	19.0%	19.0%	Income Tax Rate	19.0%
9.4%	4.5%	1.3%	4.5%	3.8%	1.6%	2.1%	1.8%	2.4%	1.9%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
51.7%	50.6%	48.5%	51.2%	50.5%	48.0%	50.4%	52.5%	52.8%	55.3%	55.0%	55.0%	Long-Term Debt Ratio	55.5%
48.0%	49.1%	51.2%	48.6%	49.3%	51.9%	49.4%	47.4%	47.1%	44.6%	44.5%	44.5%	Common Equity Ratio	44.5%
8619.3	8626.6	8636.5	17809	18118	18238	19813	21355	22228	24467	25375	26375	Total Capital ($mill)	29800
10572	10907	11258	19190	19916	21347	22001	23620	25707	26982	28800	30500	Net Plant ($mill)	35100
7.9%	8.1%	8.1%	4.5%	6.3%	6.6%	6.5%	6.5%	6.5%	6.3%	6.5%	6.5%	Return on Total Cap'l	7.0%
13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	10.8%	11.2%	11.4%	11.9%	12.0%	12.5%	Return on Shr. Equity	13.0%
13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	10.8%	11.2%	11.5%	11.9%	12.5%	12.5%	Return on Com Equity E	13.0%
6.5%	5.9%	5.3%	2.1%	3.5%	3.6%	3.7%	3.8%	3.8%	4.1%	4.0%	4.5%	Retained to Com Eq	4.0%
51%	57%	60%	71%	67%	66%	66%	66%	67%	66%	66%	66%	All Div'ds to Net Prof	69%

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% 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 '19-'21 to '25-'27
Revenues	3.0%	2.5%	5.0%
"Cash Flow"	7.5%	9.0%	6.5%
Earnings	7.5%	8.0%	6.0%
Dividends	11.5%	7.5%	7.0%
Book Value	7.5%	6.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2377	1590	1608	1947	7523.1
2020	2108	1548	1651	1933	7241.7
2021	2691	1676	1747	2202	8316.0
2022	2908	2128	2003	2161	9200
2023	3000	1900	1950	2450	9300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.33	.74	.74	.77	3.58
2020	1.43	.76	.84	.76	3.79
2021	1.61	.87	.92	.71	4.11
2022	1.79	.91	.96	.74	4.40
2023	1.80	.95	1.05	.90	4.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.5525	.5525	.5525	.5525	2.21
2019	.59	.59	.59	.59	2.36
2020	.6325	.6325	.6325	.6325	2.53
2021	.6775	.6775	.6775	.6775	2.71
2022	.7275	.7275	.7275	.7275	

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. Sold Point Beach nuclear plant in '07. 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. '21 reported deprec. rates: 2.4%-3.1%. Has 6,900 employees. Chairman: Gale E. Klappe. President & CEO: Scott J. Lauber. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy Group posted a solid third-quarter performance and seems poised to finish 2022 on a strong note. Profits of $0.96 a share surpassed our estimate of $0.90 a share and the year-before tally of $0.92. The company continues to benefit from positive developments in its infrastructure segment as well as the passing of the Inflation Reduction Act. In late October, WEC acquired an 80% interest in the Maple Flats Solar Energy Center for $360 million. The 250-megawatt facility is the company's first solar investment in its infrastructure segment, and is expected to host 800,000 solar panels by 2024. Rate base growth was also a primary driver in the quarter and contributed $0.09 to EPS.

WEC remains commited to its goal of net-zero methane emissions from natural gas distribution by 2030 through its partnership with the Electric Power Research Institute. In November, the partnership successfully completed the largest hydrogen test on a natural gas engine. This project will provide the utility with solutions to reduce carbon emissions and support in its clean energy transition.

Management now expects the bottom-line to reach the high end of its updated guidance range of $4.38 to $4.40 a share. This is the second consecutive period that management has raised its full-year 2022 share-earnings estimates by $0.02. Our 2022 and 2023 estimates of $4.40 and $4.70, respectively, are in line with WEC Energy's annual goal of 6%-7% earnings growth.

The stock price has decreased nearly 10% in value since our early-September review, along with many of its peers. Indeed, the utilities industry has been among the worst-performing sectors recently due to rising interest rates, leading income-oriented investors to the 'risk free', climbing bond market. Despite the recent price struggles, 18-month and long-term capital appreciation potential remains subpar and the dividend yield is below-average for a utility. On the other hand, conservative investors should be drawn to the equity's strong Price Stability and Earnings Predictability scores as well as its top-notch Safety rank.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted EPS. Excl. gain on discontinued ops.: '11, 6¢; nonrecurring gain: '17, 65¢. Next earnings report due early February. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '21: $20.03/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 '22: 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	90
Price Growth Persistence	70
Earnings Predictability	100

XCEL ENERGY NDQ-XEL

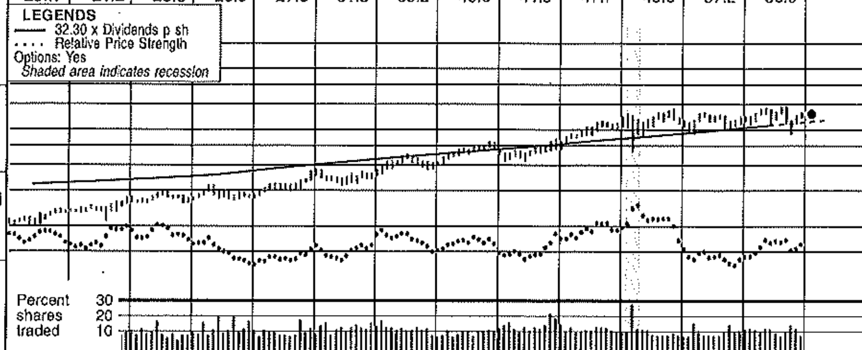
RECENT PRICE 71.98 | P/E RATIO 22.1 (Trailing: 23.5, Median: 19.0) | RELATIVE P/E RATIO 1.32 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Raised 12/31/21
SAFETY 1 Raised 5/1/15
TECHNICAL 4 Raised 1/13/23
BETA .80 (1.00 = Market)

High:	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	77.7	
Low:	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	56.9	

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

Target Price Range
2025 | 2026 | 2027
160
120
100
80
60
50
40
30
20
15



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$58-$97 $78 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+25%)	9%
Low	75	(+5%)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	458	453	436
to Sell	340	368	340
Hld's(000)	418018	424573	424931

Percent shares traded 30 20 10

% TOT. RETURN 12/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.5	-14.0
3 yr.	19.9	26.1
5 yr.	67.9	40.0

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.16	23.40	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	*26.20*	*26.35*	Revenues per sh	*28.50*
3.61	3.45	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	*7.75*	*8.25*	"Cash Flow" per sh	*10.00*
1.35	1.35	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	*3.15*	*3.35*	Earnings per sh A	*4.00*
.88	.91	.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	*2.07*	Div'd Decl'd per sh B ■ †	*2.52*
4.00	4.89	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	*9.65*	*9.00*	Cap'l Spending per sh	*9.00*
14.28	14.70	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	*30.15*	*31.65*	Book Value per sh C	*37.00*
407.30	428.78	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	*547.50*	*550.00*	Common Shs Outst'g D	*561.00*
14.8	16.7	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	*22.3*		Avg Ann'l P/E Ratio	*20.5*
.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.23	*1.30*		Relative P/E Ratio	*1.15*
4.4%	4.0%	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%		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $24118 mill. Due in 5 Yrs $4911 mill.
LT Debt $23309 mill. LT Interest $809 mill.
Incl. $73 mill. finance leases.
(Total Interest Coverage: 2.9x)

Leases, Uncapitalized Annual rentals $69 mill.
Pension Assets-12/21 $3670 mill. Oblig $3718 mill.
Pfd Stock None

Common Stock 547,248,496 shs. as of 10/21/22
MARKET CAP: $39.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10128	10915	11686	11024	11107	11404	11537	11529	11526	13431	*14350*	*14500*	Revenues ($mill)	*16000*
905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	*1725*	*1850*	Net Profit ($mill)	*2255*
33.2%	33.8%	33.9%	35.6%	34.1%	30.7%	12.6%	8.5%	8.5%	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
19018	20477	21714	23092	25216	25975	28025	30646	34220	37391	*39200*	*41600*	Total Capital ($mill)	*49200*
23809	26122	28757	31206	32842	34329	36944	39483	42950	45457	*48225*	*50475*	Net Plant ($mill)	*57000*
6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	54%	55%	57%	61%	62%	58%	58%	58%	59%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.2	-2.3	+1.4
Large C & I Use (MWH)	NA	NA	NA
Large C & I Revs. per KWH (¢)	5.96	5.78	6.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20146	19665	19849
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	272	252	262

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	*4.0%*
"Cash Flow"	6.5%	7.5%	*7.0%*
Earnings	6.0%	6.0%	*6.0%*
Dividends	5.5%	6.0%	*6.5%*
Book Value	5.0%	5.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3141	2577	3013	2798	11529
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	3751	3424	4082	*3093*	*14350*
2023	*3875*	*3450*	*4000*	*3175*	*14500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.61	.46	1.01	.56	2.64
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	1.18	*.67*	*3.15*
2023	*.75*	*.65*	*1.25*	*.70*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	1.92
2023	.4875				

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: 3.7 mill. electric, 2.1 mill. gas. Electric revenue breakdown: residential, 31%; small comm'l & ind'l, 36%; large comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 43% of revenues. '21 reported deprec. rate: 3.5%. Has 11,300 employees. Chrmn: Ben Fowke. Pres. & CEO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy should continue to prosper from rising electric rates. The company has been able to add renewable-energy projects to its rate base (the property, plant, and equipment for which a utility is allowed to earn an economic return). Xcel has also been effectively keeping its costs under control. For 2022, all that remains is the final reporting, due at the end of this month. We think the company will post full-year earnings of at least $3.15 per share, representing a 6% year-over-year gain. Profit growth this year and thereafter is based on the same factors. Namely, growing the rate base of its utility subsidiaries as Xcel works with its regulatory commissions to bring about a green-energy future within its territories. Last year's Inflation Reduction Act is supportive of this transition, as it provides plenty of tax incentives and subsidies to do so. The company's 5%-7% earnings and dividend growth objectives appear achievable. The utility has been a model of consistency with a track record few of its peers can match (see Annual Rates box). A consistently good return on equity reflects this point as well.

Xcel has multiple renewable-energy projects in the works. The Colorado commission approved the company's resource plan, which includes about 4,000 megawatts (mw) of renewable (e.g., wind and solar) additions and the conversion of a major plant from coal to natural gas. This is in addition to the approved Minnesota plan, which adds 6,000 mw of renewables. RFPs (request for proposals) are being filed and commission decisions on the finer details are expected in the second half of this year. In the electric-vehicle (EV) arena, Xcel is making progress on its goal to power 1.5 million EVs by 2030. It filed transportation plans in Minnesota and Wisconsin last summer. The utility is looking to accelerate EV adoption through the development of high-speed public charging infrastructure in its territories.
This high-quality issue, however, does not look appealing from the recent quote. We like XEL shares as a core holding for utility investors, but advise waiting for a better entry point. Risk-adjusted total return potential would be worthwhile following a 10% price correction.

Anthony J. Glennon *January 20, 2023*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '06, 1¢; '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due late January. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $2738 mill., $4.42/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	70
Earnings Predictability	100

CASE: UE 416
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 412

Company Response to: Data Requests (DR)

June 13, 2023

Topic: Consideration of Use of PGE FERC Transmission Rate Case Deferral UM 2217 Amount as Offset for PGE General Rate Case UE 416 Revenue Requirement.

PGE Response to DR 785

***Request**:*

Please provide PGE's best estimate of the dollar value of PGE's deferral as authorized in Docket No. UM 2217, by month from January 1, 2023, through December 31, 2023, with and without interest. If the balance is not projected to exceed $15 million at that time, please explain why.

Response:

Attachment 785-A provides actual amounts deferred from February 2022 through April 2023 and a monthly estimate from May 2023 through December 2023. PGE notes that May 2023 through December 2023 are rough estimates and that actual amounts will change.

–

PGE Response to DR 786

Request*:*

If the deferral balance in UM 2217 as of December 31, 2023, including interest, were to be used as a credit in UE 416, what would the resulting reduction in revenue requirement in UE 416 be?

Response*:*

Assuming an amortization period of one year and using the 2023 blended treasury rate, the estimated December 31, 2023, deferred balance provided in PGE's response to OPUC Data Request No. 785, Attachment 785-A would reduce PGE's 2024 test year request by $18,391,138 for one year.

PGE Response to DR 786 – Attachment A

Staff Note: PGE's calculations to support conclusion on prior page.

PGE UE 2217 TRC Revenue Deferral					
Month	Year	Accrual / Deferral	Amortization	Interest on Avg Balance	Balance
January	2022	-		.	-
February	2022	(846,919.95)		(642.25)	(847,562.20)
March	2022	(770,524.15)		(1,869.78)	(1,619,956.13)
April	2022	(820,042.68)		(3,078.80)	(2,443,077.61)
May	2022	(875,391.61)		(4,369.17)	(3,322,838.39)
June	2022	(567,551.00)		(5,470.03)	(3,895,859.42)
July	2022	(435,523.25)		(6,238.99)	(4,337,621.66)
August	2022	(613,057.66)		(7,043.63)	(4,957,722.95)
September	2022	(810,774.60)		(8,134.05)	(5,776,631.60)
October	2022	(781,071.77)		(9,353.54)	(6,567,056.91)
November	2022	(648,409.82)		(10,451.75)	(7,225,918.48)
December	2022	(754,955.84)		(11,531.82)	(7,992,406.14)
January	2023	(1,328,236.47)		(37,006.64)	(9,357,649.25)
February	2023	(780,171.70)		(41,671.57)	(10,179,492.52)
March	2023	(544,248.72)		(44,680.66)	(10,768,421.90)
April	2023	(569,201.39)		(47,251.67)	(11,384,874.96)
May (Estimated)	2023	(755,491.37)		(50,285.20)	(12,190,651.53)
June (Estimated)	2023	(755,491.37)		(53,729.90)	(12,999,872.80)
July (Estimated)	2023	(755,491.37)		(57,189.32)	(13,812,553.49)
August (Estimated)	2023	(755,491.37)		(60,663.53)	(14,628,708.39)
September (Estimated)	2023	(755,491.37)		(64,152.59)	(15,448,352.35)
October (Estimated)	2023	(755,491.37)		(67,656.57)	(16,271,500.29)
November (Estimated)	2023	(755,491.37)		(71,175.53)	(17,098,167.19)
December (Estimated)	2023	(755,491.37)		(74,709.53)	(17,928,368.09)

CASE: UE 416
WITNESS: ITAYI CHIPANERA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500
Redacted

Opening Testimony

Revenue Requirement Detail, Rate Base, Escalations and Income Taxes

June 13, 2023

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 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. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I am the summary revenue requirements witness. I summarize the adjustments proposed by other Staff to PGE's Test Year expense and rate base and the revenue requirement effect. I also discuss my own review of Test Year expense for income taxes, and the rates PGE uses for escalation.

Q. How is your testimony organized?

A. My testimony is organized as follows:

INTRODUCTION

Q. What is the adjustment in revenue requirement recommended by Staff?

A. Staff proposes to reduce the Company's requested revenue requirement increase from $337.8 million to $205.9 million. This is categorized into two parts, a base revenue requirement proposed by PGE of roughly $228.8 million, for which Staff proposes $121.4 in adjustments for a total base increase of $107.4 million; and, a power cost increase, of roughly $109 million, Staff adjustments of $10.5 million, and a net increase of $98.5 million. The PGE-proposed power cost increase will get updated a few times during 2023.

Q. Are additional adjustments for other issues proposed by other Staff?

A. Yes. The Company's filing is complex, and a thorough review can involve multiple Staff members looking at each issue. In particular, individual Staff are reviewing additions to different categories of utility plant (e.g. production, transmission, distribution, etc.) and the effects of escalation on individual accounts.

Q. What adjustments are you proposing to the Company's revenue requirement?

A. I am proposing a reduction to apprentice training in utility operations expenses.

SUMMARY OF REVENUE REQUIREMENT

Q. Please provide background on how the Commission reviews a utility's general rate case filing.

A. The rates charged by a utility are based on the utility's "revenue requirement." To determine a utility's revenue requirement, the Commission determines for a specified test year:

1. The utility's forecasted gross revenues;
2. The utility's operating expenses to provide utility service;
3. The rate base on which a return should be earned; and
4. The rate of return to be applied to the rate base.[1]

Once a utility's revenue requirement is established, the Commission determines the rates the utility must charge different classes of customers to collect that revenue requirement, considering the different costs different classes of customers impose on the utility's system.

Q. What is the revenue requirement increase proposed by PGE in this docket?

A. PGE proposes an overall increase of $337.8 million or 14.0 percent.[2] The Company further states that the price increase is comprised of the following: 4.5 percent Net Variable Power Cost (NVPC) and 9.5 percent base rate increase.[3]

---

1 *Pacific Power and Light*, UE 116, Order No. 01-787, pp.5-6 (September 7, 2001).
2 PGE/200, Batzler – Ferchland/2.
3 PGE/100, Pope – Sims/2.

Q. Have the parties agreed to adjust certain components of the $337.8 million overall increase?

A. No. The parties have not agreed to the resolution of any issue arising from PGE's general rate case.

Q. What is the overall adjustment to the Company's revenue requirement proposed by Staff and what specific topics are involved?

A. Staff propose to reduce the Company's revenue requirement by $131.9 million. The specific rate case topics, responsible Staff and proposed changes in revenue requirement are summarized in the following table:

Power Cost Incremental Revenue Requirement on the Company's Filed General Rate Case						**$ 109,000**
Testimony	**Staff**	**Proposed Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
100/200/300	Jent/Dlouhy/Ahmed	Net Variable Power Costs	-	(10,168)	-	(10,521)
Staff-Calculated Power Cost Revenue Requirements Change						**98,479**
Base Cost Incremental Revenue Requirement on the Company's Filed General Rate Case						**228,807**
Testimony	**Staff**	**Proposed Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
400	Muldoon	Cost of Equity	-	-	-	(34,540)
500	Chipanera	Escalations on Miscellaneous Accounts	-	(108)	-	(112)
800	Young/Stevens	Change from average of monthly averages to year end in rate base calculation	-	-	-	(21,703)
900	Beitzel	A&G Expense (1. Employee Pension and Benefits, 2. Office Supplies)	-	(3,611)	-	(3,736)
1000	Bolton	Franchise Fees & Amortization of Trojan Nuclear Decommissioning	-	-	-	-
1100	Dlouhy	Adminstrative and General Salary	-	(1,000)	-	(1,035)
1200	Farrell	Uncollectible Accounts	-	(5,289)	-	(5,473)
1300	Jent	Wages & Salaries	-	[redacted]	[redacted]	[redacted]
1500	Mondragon	Customer Service Expense	-	(2,056)	-	(2,127)
1600	Moore	Non-Fuel Material and Supplies	-	-	(1,410)	(121)
1600	Moore	Other Revenues	13,240	-	-	(13,700)
1700	Peng	Amortization Expense (Cloud Licence and Hosting)	-	-	-	-
1800	Pileggi	Faraday Resiliency and Repowering Project	-	-	[redacted]	[redacted]
1800	Pileggi	Faraday Cost of Equity Adjustment	-	-	-	[redacted]
1800	Pileggi	Cost of Debt (Includes Interest Synchronization)	-	-	-	1,214
1900	Shierman	Fleet Electrification - Fleet Charging	-	-	(6,909)	(594)
1900	Shierman	P36394 – Vintage Vehicle Replacement, P36412 – Incremental Added Vehicles and Fleet Charging	-	-	(12,203)	(1,049)
1900	Shierman	Line Extension Allowances	-	-	(212)	(18)
1900	Shierman	Capital Expenditures on Line Extension Allowances	-	-	(743)	(64)
1900	Shierman	Capital Expenditures on TE Investments	-	-	(400)	(34)
1900	Shierman	Capital Expenditure on Electric Island	-	-	(1,600)	(138)
1900	Shierman	Capital Expenditure on TE Database	-	-	(125)	(11)
1900	Shierman	TE Operating Expenses	-	(3,154)	-	(3,263)
1900	Shierman	Stranded Charging Assets	-	-	(1,700)	(146)
2000	Stevens	Vegetation Management	-	[redacted]	-	[redacted]
2100	Young	OH FITNES T&D Plant	-	-	(33,578)	(2,887)
2100	Young	T&D Plant - Project Sample Based Adjustment	-	-	(23,884)	(2,053)
2100	Young	Cloud Expenses in Rate Base	-	-	(8,277)	(712)
2700	Ankum/Fischer	Fuel Stock (Major only)	-	-	(17,413)	(1,497)
2700	Ankum/Fischer	Maintenance of Generation and Electric Plant (Major)	-	(1,015)	-	(1,050)
2700	Ankum/Fischer	MMA Deferral Balance Adjustment	-	-	95	8
Total Staff-Proposed Base Cost Adjustments						**$ (121,410)**
Total Staff-Calculated Base Cost Revenue Requirements Change						**$ 107,397**
Total Incremental Revenue Requirement on the Company's Filed General Rate Case						**$ 337,807**
Total Staff Proposed Adjustments						**$ (131,931)**
Total Staff-Calculated Revenue Requirements Change						**$ 205,876**

OVERALL RATE BASE

Q. Please summarize the Company's rate base filing.

A. The Company provides Exhibit 208 showing how rate base has changed compared to the amounts approved in UE 394.

- Plant in service increased by $1.298 billion.
- Net utility plant increased by $768 million (net of accumulated depreciation and deferred taxes).

The Company also testifies that "[t]he increase is primarily attributable to the growth in distribution plant as discussed in PGE Exhibit 700, the Faraday Repower Project as discussed in PGE Exhibit 800, and major software investments as discussed in PGE Exhibit 600."[4]

Q. Please discuss Staff's overall approach to review plant additions.

A. To determine the inclusion of new capital investment in rate base, a utility must make two showings. "First, it must show that the investment is presently used for providing utility service. Second it must show that the investments were prudently made, based on the information that it knew or should have known at the time."[5]

Q. What is the Oregon law requiring utility plant to be presently used before it may be included in rates?

A. ORS 757.355 requires utility plant to be presently used for providing utility service to customers and creates what is generally referred to as a

---

4 PGE/200, Batzler – Ferchland/25.

5 See e.g., *In the Matter of PacifiCorp, dba Pacific Power's, Request for a General Rate Revision,* UE 246, Order No. 12-493 (December 12, 2020).

"used and useful" standard, requiring the property to be placed into service prior to the effective date of the rates. ORS 757.355 provides:

> (1) Except as provided in subsection (2) of this section, a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.
>
> (2) The Public Utility Commission may allow rates for a water utility that include the costs of a specific capital improvement if the water utility is required to use the additional revenues solely for the purpose of completing the capital improvement. [1979 c.3 §2; 2003 c.202 §2]

Q. Please discuss the Commission's standard of review for prudence.

A. The purpose of the prudence review has been succinctly stated by the Commission in prior rate cases:

> [W]e take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the relevance of the decision-making process that a utility uses to make an investment.
>
> The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modern articulation of the prudence standard is as follows:
>
> 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. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether

> the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.
>
> Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness.[6]

Q. Please explain the Commission's application of used and useful standard to PGE's new plant.

A. The application of the used and useful standard supports the inclusion in rate base only of capital investment in facilities that will be used and useful in providing utility services to customers.

Q. Is Staff proposing adjustments to utility plant in service based on the used and useful standard.?

A. Yes. Several Staff are reviewing additions to different categories of utility plant. Adjustments resulting from those reviews are presented in their respective testimonies.

---

[6] Id. at 25.

ESCALATIONS

Q. Why is it necessary to evaluate the effects of escalation for particular accounts?

A. The Company does not simply escalate actual costs for the 2022 base year.

As PGE explained in testimony:

> We developed the revenue requirement based on PGE's 2023 budgets, which were originally based on a 2022 budget that reflected our best estimate of PGE's 2022 general rate case result as approved in Commission Order No. 22-129, The 2023 budgets were escalated for inflation to 2024 and adjusted for known measurable changes.[7]

Accordingly, the 2023 budget associated with a particular topic may have been increased (escalated) before PGE applied the 2024 escalation factors noted in the Company's testimony.

Q. What is the source of Staff's escalation factor?

A. Staff developed an escalation factor based on the Bureau of Labor Statistics' seasonally adjusted, "All items in the US City Average All Consumers" (All Urban CPI) consumer price index for 2022 and the Oregon Department of Economic Analysis inflation forecast for years 2023 and 2024.

Q. What is Staff's proposal regarding the escalation of costs?

A. Staff proposes using an escalation factor based on inflation measured from the mid-point of 2022 to the mid-point of 2024. The rationale for

---

7 PGE 200, Batzler – Ferchland/5-6.

selecting the change in the CPI index from the middle of 2022 is to avoid over-escalating future costs with inflation rates from the first half of 2022 when observed inflation was much higher than in the second half of the year. Using this approach, we estimate an escalation factor of 6.6 percent.

Q. Which accounts did you review escalation on?

A. I reviewed escalation on apprentice training in utility operations. PGE forecasts a total of $7.2 million on apprentice training in utility operations for test year 2024. Staff estimates an implied escalation factor of 8.1 percent over the 24-month period. Staff proposes to reduce the escalation factor to 6.6 percent, resulting in a downward adjustment of $108 thousand.

INCOME TAXES

Q. Please summarize the Company's filing related to income taxes.

A. Calculation of Test Year income tax expense of $108.8 million is presented in PGE Exhibit 205. The total tax includes a credit of $8.457 million appearing on Exhibit 205 labeled as "ITC Amortization." PGE's testimony states this amount is the ongoing return of excess deferred income taxes.[8]

PGE's Exhibit 208 presents a decrease in the amount of accumulated deferred income taxes (ADIT) from $690.748 million to $667.288 million. PGE testifies that deferred income taxes have been reduced by $18.4 million for the tax impact of production tax credits not used due to the 2020 energy trading losses.[9] Staff notes that unused PTC creates a deferred tax asset and the net deferred tax overall is a liability, removing the PTC related asset increases the net liability therefore reducing rate base.

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269:

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules**.
> (1) When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's

8 PGE/205, Batzler – Ferchland/1.
9 PGE/200, Batzler – Ferchland/26-27.

investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.

(2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:

(a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;
(b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;
(c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;
(d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;
(e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and
(f) Reflect other considerations the commission deems relevant to protect the public interest.

(3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:

(a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;
(b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or
(c) Any other considerations the commission deems relevant to protect the public interest.

(4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility's affiliated group is commercially sensitive, and public disclosure of such information could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.

(b) The commission shall adopt rules to implement paragraph (a) of this subsection that:

(A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and

(B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.

(5) As used in this section, “affiliated group” means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return. [2011 c.137 §1]

Q. Please summarize Staff’s review of income taxes in this case.

A. Staff initially reviewed tax information in the Company’s filing and reviewed the Company’s responses to data requests issued by intervening parties. Staff concludes that the Company’s provision for tax appears to be correctly calculated for rate making purposes. Staff’s examination and discovery included confirming the federal and state tax rates, apportionment calculations, calculation of current and deferred income tax expense, application of federal and state tax credits, and the ongoing amortization of excess deferred income taxes (EDIT) resulting from the 2017 Tax Act.

Q. Is Staff proposing adjustments to income tax expense other than those necessary to finalize the Company’s revenue requirement?

A. Not at this time.

CONCLUSION

Q. What are your total proposed adjustments?

A. My total proposed adjustments are a reduction to expenses of $108,000.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Itayi Chipanera

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Itayi Chipanera
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Accounting and Finance Section
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.S., Economics Idaho State University M.S., Mathematics University of Nevada – Reno M.S., Accounting Indiana University – Bloomington
EXPERIENCE:	I have been employed by the OPUC in the Safety, Rates and Utility Performance Program since April of 2023. Prior to my employment with the OPUC I was employed in various finance roles in the insurance and banking industries including Advantis Credit Union where I was employed as a Senior Risk and Financial Analyst; City of Salem, Oregon, where I was a Finance Management Analyst; and, SAIF Corporation where I was an Actuarial Research Analyst.

CASE: UE 416
WITNESS: Michelle Scala

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

OPENING TESTIMONY
Energy Justice

June 13, 2023

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 Strategy Integration 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/601.

Q. What is the purpose of your testimony?

A. The purpose of Staff's testimony is to provide and validate energy justice considerations as they intersect with the proposals and potential impacts of Portland General Electric's general rate case.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/601. .... Scala Witness Qualifications Statement
Exhibit Staff/602. .... Non-Confidential Responses to Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY AND STAFF RECOMMENDATIONS

Q. Please summarize Staff's testimony.

A. This testimony provides general guidance and elaborates on the role of energy justice in the rate case. This testimony will discuss how energy justice in ratemaking is needed to advance equitable distribution of energy costs, access, and benefits among all socioeconomic groups. It also explains the significance of energy justice in terms of ensuring that low-income and marginalized communities are not disproportionately affected by energy policies, prices, and infrastructures.

With some exceptions, specific recommendations relative to discrete issues contained in Portland General Electric's (PGE) proposed rate revision defer to other Staff exhibits and will be noted as such.

Q: Please summarize Staff's recommendations relative to this Exhibit.

A: Staff outlines its recommendations as follows:

Energy Justice in Ratemaking:

Staff strongly encourages PGE to incorporate more intentional and tangible incorporations of energy justice into the Company's future rate proposals. Recognizing the significance of energy justice in ratemaking is crucial for promoting fairness and equity among all customers.

Energy Justice in Rate Design:

Staff defers to Exhibit 2000 Stevens for specific recommendations on PGE's proposed changes to rate design, but in addition to, Staff strongly encourages parties to consider the inherent bias built into assumptions of homogeneity in the residential class, particularly regarding cost causation and cost allocation. Recognizing and challenging these biases is essential to ensure equitable outcomes in rate design.

Customer Programs:

- Staff recommends that PGE provide the commission with a low-income needs assessment that includes, but is not limited to, data on household demographics, energy burden, environmental justice metrics, and customer participation in assistance and energy assistance programs by customer segment to inform the next rate case and other proceedings.
- Staff recommends that PGE initiate a separate proceeding to implement a higher discount level into its Schedule 115 Income-Qualified Bill Discount (IQBD) program informed by community needs and the environmental justice community engagement.

Automatic Adjustment Clauses:

Staff defers to Exhibit 2200 Dlouhy-Muldoon-Scala-Stevens for specific recommendations relative to automatic adjustment clauses in this rate case, but in addition to, Staff strongly encourages future AAC requests include an inclusive discussion between parties that includes a holistic view of ongoing rate pressures on impacted customers.

Schedule 300 Customer Charges:

Staff defers, in part, to Exhibit 2400 Nottingham-Shearer regarding proposed changes to Schedule 300 Customer Charges in this rate case, but in addition to, Staff recommends PGE provide a study that assesses disparate impacts relative to pre-AR 653 reconnection charges and a discussion on alternative designs that are more responsive to equity for cost recovery associated with reconnection.

ISSUE 1. ENERGY JUSTICE IN RATEMAKING

Q. Please describe to what extent PGE's proposal in UE 416 reflects an energy justice.

A. PGE's opening testimony acknowledges the importance of affordability in rate design and recognize the need to ensure that changes in rates and charges do not disproportionately burden vulnerable customers, particularly low-income households. PGE also highlights the Income-Qualified Bill Discount (IQBD) Program as an initiative aimed at providing assistance to eligible customers facing financial challenges.

Q. Does the Company provide detailed analyses or data on the potential impacts of their proposed changes on different customer segments?

A. No. While PGE acknowledges the importance of affordability considerations, their opening testimony does not provide extensive analyses or data on the potential impacts of their proposed changes on different customer segments. PGE Exhibit 1300 included a chart visualizing customer billing data as percent of residential bills with month usage greater than 1,000 kWh in an effort to evidence the Company's assumption that "low-income customers are more likely than non-low-income customers to exceed 1,000 kWh per bill;"[1] however as Staff discusses in Exhibit 2000 Stevens, the use of IQBD participants as a proxy for low-income customers overall is vulnerable to selection bias because the higher the bill the more likely a low-income customer is likely to seek out help through support payments.

---

[1] UE 416 / PGE / 1300 Macfarlane – Pleasant / 16.

Staff is actively analyzing several data responses that provide more granular customer-level data to better understand the specific implications for different customer segments and evaluate whether the proposed changes sufficiently incorporate energy justice concerns.[2]

Q. What did Staff's data requests reveal about the information the Company collects and how does it inform this proceeding?

A. While some analyses have been performed relative to customer billing and usage data, the Company does not currently collect robust demographic information that can be integrated into a comprehensive analysis of disaggregated customer impacts. In response to Staff DR 437, PGE indicated that it collects customer data from three primary sources: directly from the customer, program enrollments and surveys.[3] Secondary and tertiary sources are through third party modeling and the U.S. Census Bureau.[4] PGE provided the following table to display demographic data points currently collected by the Company:

[2] OPUC Staff DR 325 and 779.
[3] OPUC Staff DR 437.
[4] Id.

Table 1. PGE Demographic Data Points Collected[5]

All Residential Customers	Portion of Residential Customers

• Address (PGE, new service)
• Dwelling type (PGE, new service)
• Preferred language (PGE, new account)
• Preferred communication method (PGE, new account)
• Home ownership status (3rd party)
• Household size (3rd party)
• Income range (3rd party)
• Whether household includes (3rd party):
  ○ Seniors
  ○ Children
  ○ Non-White
	• Home ownership status (PGE, surveys)
	• Household size (PGE, surveys & IQBD enrollment)
	• Household income (PGE, surveys & IQBD enrollment)
	• Respondent race (PGE, surveys & IQBD enrollment)
	• Respondent age (PGE surveys)
	• Education level (PGE, surveys)
	• Medically dependent on electricity (PGE, Medical Certificate enrollment)

To Staff's inquiry as to whether any such data was used to inform proposals in UE 416, PGE only indicated the use of PGE's IQBD participant usage as the aforementioned low-income proxy in PGE Exhibit 1300.

Q. Has PGE provided specific strategies or measures in their opening testimony to mitigate the potential disparate impacts of their proposal?

A. No. Despite acknowledging the importance of affordability, the Company does not provide specific strategies or measures to mitigate potential disparate impacts. The Company does reference the bifurcated basic charge[6] as an indirect source of relief to low-income households.[7] Staff agrees with this point to the extent that low-income households represent the majority of multi-family customers. The Company also points to the IQBD program as a means to mitigate some of the rate increase for low-income households. The IQBD

---

[5] Id.

[6] Order No. 22-129 approved a bifurcated basic charge for residential customers. Multi-family dwellings are currently charged $8.00 under PGE's current Schedule 7 tariff while Single-family homes are charged $11.00.

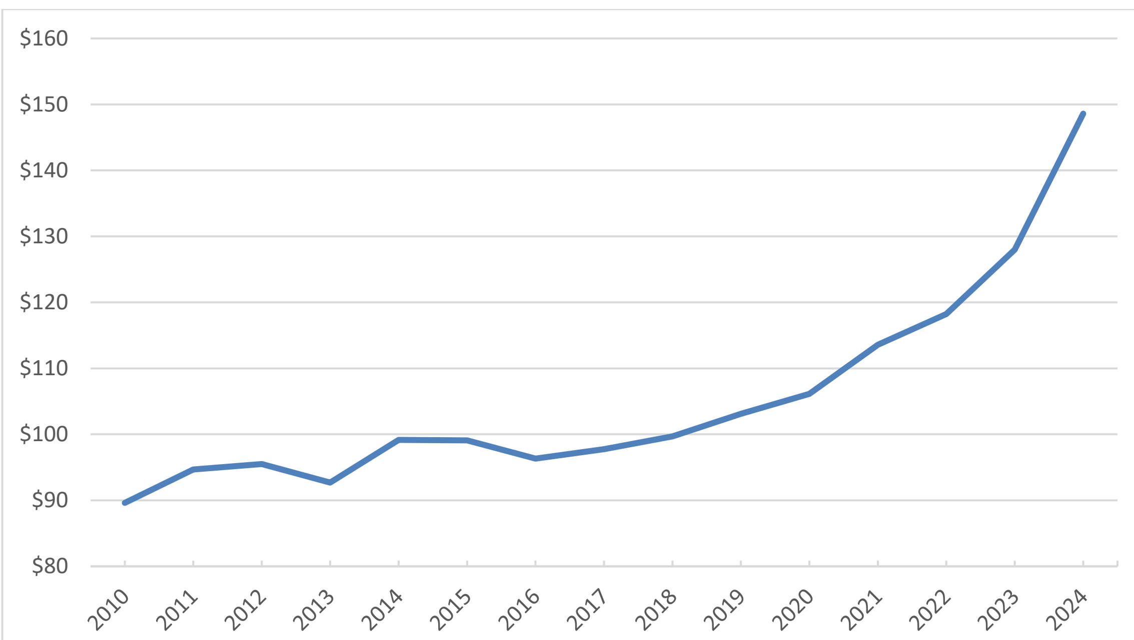
[7] UE 416 / PGE / 1300 Macfarlane – Pleasant / 14.

provides participating customers a percentage-based discount, between 15-25 percent from their monthly bill amounts.[8]

Q. Describe how energy justice is implicated in this rate case.

A. Portland General Electric's (PGE) 2023 rate revision proposal puts forth a $230 million increase to Company revenues, excluding power costs. It is the largest rate increase for PGE in the last twenty years. The proposed changes would result in a 12.1 percent increase in the average residential customer electricity bill for households served by PGE; or 16.0 percent including power costs. The UE 416 proposal continues the upward trajectory (Figure 1) of PGE's residential monthly bills, putting increasingly greater amounts of rate pressure on customers.

Figure 1. PGE Average Residential Customer Monthly Bill[9]



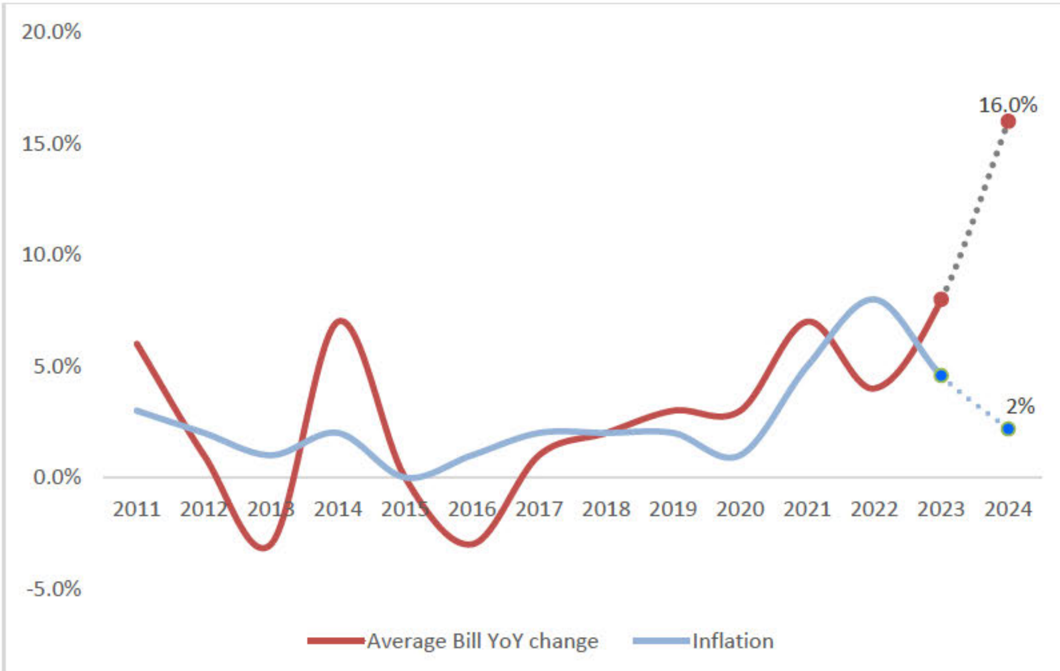
[8] Id.
[9] OPUC Staff DRs 236 and 385.

The proposed rate increases on residential bills are expected to have meaningful and disparate impacts impact across different customer groups. Considering energy justice in the context of the rate case would help inform decisions that may mitigate potential disparities.

Q. How do these rate changes trend with recent inflationary pressures?

A. Figure 2 shows average change in inflation with average change in monthly customer bill over the same time period. Staff notes that the comparison is not apples to apples, since changes to bills are influenced heavily by discrete events such as rate cases, power cost cases, or deferrals associated with extreme weather events, while inflation evolves continuously. Nevertheless, Staff is concerned about the forward outlook of PGE's rate proposal versus the Consumer Price Index (CPI) forecast. Although the historic variance between average bill change and inflation is not always consistent, the two measures have typically trended in the same direction. As of the 2022 rate increase, this relationship has diverged and now rate increases are not only outpacing inflation, but also increasing exponentially at a time when inflation is projected to cool off, thus applying more dramatic rate pressure on residential customers.

Figure 2. CPI Changes versus Average Bill Changes[10]



Q. Does energy justice in ratemaking align with current State and Commission policy?

A. Yes. Energy justice in rate proceedings is closely intertwined with State and Commission policy in Oregon. The State's policy framework plays a significant role in shaping the regulatory environment and guiding the decision-making process of the PUC regarding energy rates and practices. Some key connections between energy justice and state policy in Oregon include the following:

- Legislative Mandates: The 2021 legislature passed numerous equity focused measures impacting utility regulation; among them, House Bill

[10] CPI data sourced from: https://beta.bls.gov/dataViewer/view/timeseries/CUSR0000SA0; PGE average billing data derived from OPUC Staff DR 236 and 385.

(HB) 2021[11], which, in part, centers environmental justice communities in clean energy plans, and, significantly, HB 2475,[12] the Energy Affordability Act, which explicitly authorizes the Commission to consider energy burden in comprehensive classifications, tariff schedules, rates, bill credits, and bill reduction measures or programs. HB 2475 is of particular relevance because prior to its passage, consideration of differential energy burden and socioeconomic factors impacting affordability was determined "discriminatory." Without going into detail about the institutional biases that likely informed this language, the revisions adopted in HB 2475 represent explicit inclusion of equity considerations in rates. HB 2475 also authorizes funding to facilitate the engagement of intervenors representing environmental justice communities across PUC proceedings. Tangentially, HB 4077[13] advanced the statewide Environmental Justice Council, of whom is charged with advising the Governor on environmental justice issues and elevating the voices, experiences, and priorities of environmental justice communities.

- Policy Guidance: In 2021, the State of Oregon (State) put forward a Diversity, Equity, and Inclusion Action Plan[14] that calls for state agencies, including the PUC, to explicitly work on dismantling institutional and structural racism in state government. Among the many relevant values

[11] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[12] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2475
[13] https://olis.oregonlegislature.gov/liz/2022R1/Downloads/MeasureDocument/HB4077
[14] https://www.oregon.gov/das/Docs/DEI_Action_Plan_2021.pdf

the document outlines are the following: “[to] prioritize equity, anti-racism, and racial justice actions. Commitment to prioritizing equity and eliminating racial disparities involves taking action in our policies, budgets, decision-making and daily work.”[15] In 2020, the State also established a Racial Justice Council to use policy and budget to dismantle the structures of racism that have created disparities in virtually all our social systems and structures.[16]

- Public Interest: Members of the public present at the May 3, 2023, PGE UE 416 Public Comment hearing indicated to the Commission that affordability concerns were paramount for many households and that the proposed increases to monthly rates would be too much for some to bear. Serving “in the public interest” is largely discretionary from a regulatory decision-making standpoint; but to the extent the Commission’s interpretation aligns with statutory goals, such as those set forth in the aforementioned legislation, and wishes to be responsive to experiences shared by the public, energy justice tenets are requisite considerations.

It is evident that the state is actively pursuing racial equity and environmental justice with urgency[17] and intentionality. Excluding energy justice from rate proceedings obscures the disproportionate impacts of PUC regulatory decisions on environmental communities and disregards the state’s efforts to advance equity.

---

[15] *Id.* at page 10.
[16] https://www.oregon.gov/gov/policies/Pages/racial-justice-council.aspx
[17] https://www.oregon.gov/das/Docs/DEI_Action_Plan_2021.pdf

Q. How does energy justice in ratemaking advance State goals and mitigate potential disparities relative to the PUC?

A. Considering energy justice in rate proceedings can help mitigate potential disparities by addressing systemic issues and incorporating equity focused principles into the decision-making process. Some of the ways in which this may be achieved include:

- Equitable Rate Structures: Energy justice considerations can guide the development of rate structures that promote fairness and affordability. Flatting rates and time-of-day (TOD) rates like those proposed in UE 416 can be tailored to affect different outcomes. Under the design as proposed, the primary beneficiaries of rate flattening will be customers who consume more energy, which as Staff indicated, tend to be higher income households.[18] It is important to consider the potential for disparate impacts resulting from different energy needs, load profiles, and affordability thresholds when determining the efficacy of these and other rate designs.
- Systemic Analysis: Energy justice in rate proceedings prompts a systemic analysis of the factors contributing to disparities. It involves examining the distributional impacts of rate designs and capital investments, considering the assumptions and value estimates the Company puts forward in the marginal cost study, and evaluating the reasonableness of

[18] UE 416 Staff Exhibit 2000 Stevens.

costs and returns that will come from customers. By exploring potential root causes of disparities, decision-makers can intervene to rectify systemic imbalances and promote more equitable outcomes.

- Inclusive Decision-Making Processes: Integrating energy justice considerations into rate proceedings encourages more inclusive decision-making. Systemic barriers rooted in racial biases and socioeconomic marginalization have made it so Commission decisions are largely informed by a technocracy that lacks diversity and effect disproportionate impacts on environmental justice communities. These negative outcomes are exacerbated by the procedural injustice that can occur from unequal access, participation, and influence in regulatory proceedings.

Incorporating the energy justice principles of equity, affordability, access, environmental justice, and inclusive decision-making into the rate proceeding centers customer impacts and informs the Commission to effect outcomes that advance state policy and promote the public interest.

Q. The Commission has prioritized energy justice in other proceedings and advanced a number of equity-driven programs and decisions at the PUC, including residential bill discounts; why does the Commission need to specifically consider it in the rate proceeding.

A. While it is true that energy justice considerations are being introduced in other PUC proceedings and decisions, it is essential to address energy justice in rate proceedings as well. Relegating energy justice to ad hoc or program specific endeavors fails to recognize the significance of ratemaking on system equity.

Taking an enterprise-wide approach reflects state guidance and is crucial to advancing toward a more equitable system rather than maintaining the status quo and existing equity gaps. Discount and assistance programs, such as PGE's IQBD Program play a valuable role in addressing energy affordability and providing support to disadvantaged communities.

However, programs like the IQBD rely on participation, meaning they are only effective for those who enroll. This creates a potential limitation as not everyone who could benefit from such programs may be aware of them or able to navigate the enrollment process. While PGE has reported promising enrollment of over 50,000 participants since the launch of the IQBD in April of last year, even at full maturity, which is expected in 2026, roughly 25 percent of eligible households may still remain unenrolled.[19] Income-based bill discount programs are also limited in their ability to address energy insecurity across diverse and overlapping community groups.

For example, a household may possess multiple characteristics that are correlated with higher energy insecurity. These characteristics include race, age, disability status, and immigration status. There are also intersectional energy security impacts from environmental justice metrics such as housing quality, geographic location, and various climate related vulnerabilities.[20]

---

[19] For comparison the 2019 data on the Federal Supplemental Nutrition Assistance Program (SNAP) show a national participation rate of 82 percent with Oregon reporting approximately 100 percent participation among eligible households. To this end a higher participation rate to benchmark program maturity is achievable (https://www.fns.usda.gov/usamap).

[20] https://www.atsdr.cdc.gov/placeandhealth/eji/index.html.

Altogether, these intersections can have a multiplier effect on disparate impacts and energy insecurity.

Including energy justice considerations in rate proceedings allows for a broader evaluation of rate designs, pricing structures, and utility practices that can remove barriers and increase access to affordable energy for all customers, not just those enrolled in specific programs. By considering energy justice enterprise-wide, the Commission is better able to advance strategies that go beyond targeted assistance programs and encourage a holistic and equity conscious rate approach.

Q. Should energy justice considerations replace cost causation principles in ratemaking?

A. No. Energy justice considerations should be integrated into the decision-making process alongside cost causation principles. Cost causation allocates costs based on the causal relationship between costs and specific customer classes and their usage patterns. As a regulatory tool, it provides a rational basis for rate design and decision-making. Abandoning these principles entirely would risk compromising the economic viability and stability of the energy sector.

That said, cost-causal rates are informed by cost-of-service studies which include assumptions and resulting cost allocations are often "a zero-sum process where lower costs for any one group of customers lead to higher costs for another group."[21] Further still, as Justice William O. Douglas (1945)

[21] Regulatory Assistance Project, Electric Cost Allocation for a New Era: A Manual.

remarked, "allocation of cost is not a matter for the slide rule. It involves judgement of a myriad of facts. It has no claim to an exact science."[22] Thus, it is crucial to recognize that cost causation is not the sole factor that should inform ratemaking nor is it an infallible determination of fair cost allocation.

In addition, Staff may recommend in the future that specific schedules be established to address IQBD issues such as energy burdens. Staff envisions the design of such programs would be coordinated/accounted for in cost-based rate schedules. By having specified schedules that will offset any claims parties may have with regards to any conflict IQBD design goals with any cost-based ratemaking goals. Potential conflicts are discussed in Staff's testimony below.

Q. What additional factors should be considered?

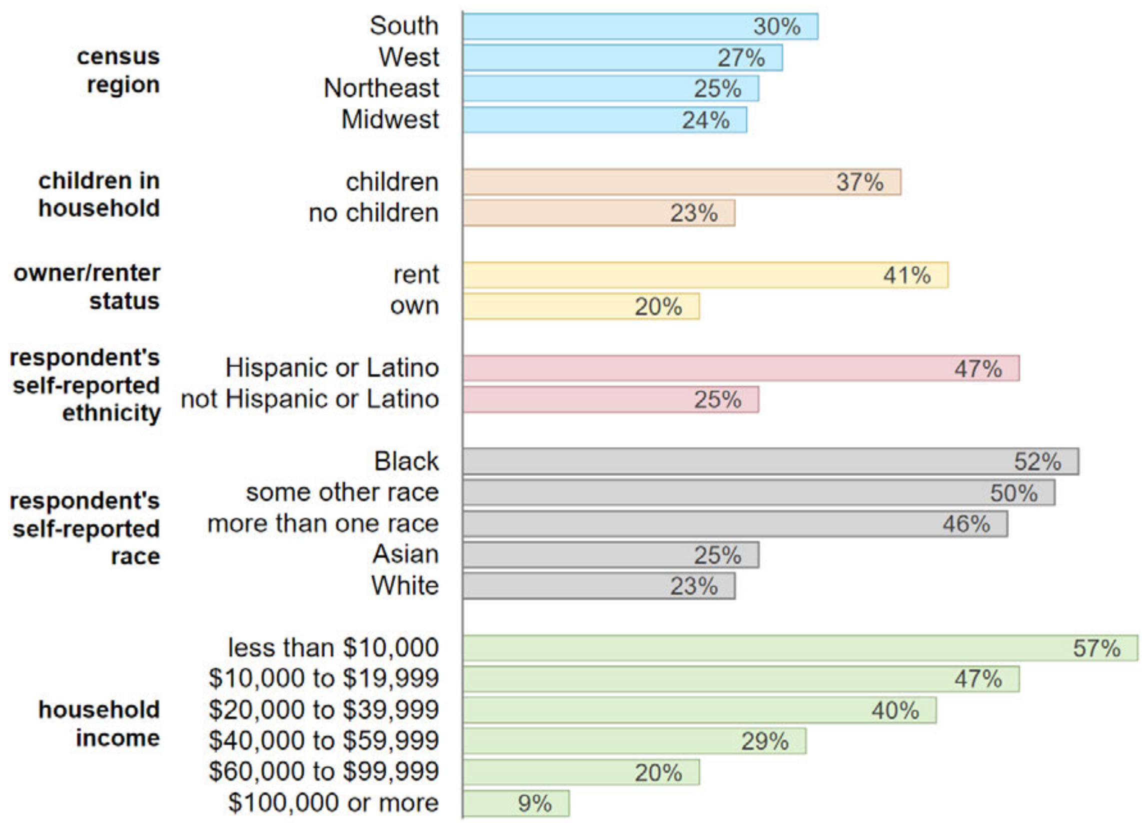
A. The benefits of service and ability to pay should also be considered as these are not uniform experiences for those subject to uniform rates.[23] It is well-established that environmental justice communities experience disproportionate rates of energy poverty and energy insecurity.

[22] Justice William O. Douglas, U.S. Supreme Court; Colorado Interstate Das Co. v. Federal Power Commission, 324 US 5581, 589 (1945).

[23] Chan, G. & Klass, A. B. (2022). Regulating for energy justice. *New York Law Review, 5*(97); https://www.nyulawreview.org/wp-content/uploads/2022/11/NYULawReview-Volume-97-Issue-5-ChanKlass.pdf

Figure 3. U.S. Households reporting some form of energy insecurity (2020)

percentage of U.S. households in each category[24]



Moreover, these same communities tend to be disproportionately represented in areas and housing stock more vulnerable to extreme temperatures, greenhouse gas levels, and historic underinvestment.[25] While energy justice may be harder to quantify in traditional economic terms using currently available data, it is essential to embrace a more comprehensive approach that considers both economic efficiency and equity. This may involve compelling the utility or Staff to adopt metrics and indicators that capture the

[24] U.S. Energy Information Administration, Residential Energy Consumption Survey (RECS).
[25] https://www.scientificamerican.com/article/past-racist-redlining-practices-increased-climate-burden-on-minority-neighborhoods/

social and distributional impacts of rate decisions, thus ensuring that the burdens and benefits are distributed more fairly across and within customer classes and communities.

Q. Are there any other points to be made with regard to how energy justice considerations are an imperative in this rate proceeding?

A. Yes. This testimony has touched on the relevance of energy justice that can be applied in all rate proceedings. This includes public policy goals, inclusive decision-making, equitable outcomes, and the importance of a system-wide approach. Two final points Staff would offer in the interest of energy justice are: 1) to highlight the weaknesses of a homogeneity assumption; and 2) to emphasize the reality of procedural injustice.

Q. Please elaborate on what is meant by "the weaknesses of a homogeneity assumption."

A. This concept can be illustrated using the example of how the revenue requirement[26] is spread in traditional ratemaking practices. Consider that current cost allocation practices determine rates based on 1) assumptions relative to the cost of serving a single, hypothetical, "average" residential customer; and 2) assigning a portion of the revenue requirement to the residential class as a whole based on total usage. This approach excludes any sensitivities that would account for the tangible heterogeneity and

[26] The revenue requirement is a dollar amount, approved by Commission, which determines how much revenue the utility is authorized to bring in each year.

disparate experiences with energy insecurity and system benefits across customer segments within the residential class.

As a result, changes to rates, in both degree and design, will have limited recognition of the unique challenges faced by distinct groups. Were the relevant data disaggregated to expose these systemic issues, higher rates and cost allocation formulas would likely face greater scrutiny as homogeneity is the enemy of equity.[27]

Q. Does PGE's residential customer base include distinct customer segments that may be disproportionately vulnerable to the impacts of this proceeding?

Yes. PGE serves approximately 44 percent of Oregon residents, comprising roughly 900,000 households. [28] Within this customer base are profound disparities relative to different demographic groups' experiences with the energy system. Notably, approximately one third of these households fall under the low-income category and are more likely to spend a greater portion of their income on their electricity bill. Moreover, EPA demographic indices reveal additional environmental justice disparities across census blocks, such as varying levels of air toxin related cancer risk, traffic proximity, particulate matter exposure, and other indicators, many of which correlate with income and measures of racial and ethnic diversity.[29] Although less granular than what is needed to fully inform this conversation, Figure 4 provides an

[27] DiAngelo, Robin (2018). *White Fragility.* Beacon Press.
[28] https://portlandgeneral.com/about/info/service-area.
[29] Environmental Protection Agency, Environmental Justice Tool Kit.

Environmental Justice Screen report revealing some of the disparities for Oregonians residing in Multnomah County relative to the State and the Nation.

Figure 4. EJ Screen Report- Multnomah County, OR[30]

Selected Variables	Value	State Avg.	%ile in State	USA Avg.	%ile in USA
Pollution and Sources					
Particulate Matter 2.5 (µg/m³)	8.62	8.69	41	8.67	51
Ozone (ppb)	36.3	37	48	42.5	15
Diesel Particulate Matter* (µg/m³)	0.651	0.337	86	0.294	90-95th
Air Toxics Cancer Risk* (lifetime risk per million)	41	32	97	28	95-100th
Air Toxics Respiratory HI*	0.58	0.47	91	0.36	95-100th
Traffic Proximity (daily traffic count/distance to road)	1400	660	88	760	86
Lead Paint (% Pre-1960 Housing)	0.42	0.24	75	0.27	67
Superfund Proximity (site count/km distance)	0.16	0.081	89	0.13	80
RMP Facility Proximity (facility count/km distance)	1.2	0.78	78	0.77	80
Hazardous Waste Proximity (facility count/km distance)	3.9	1.6	87	2.2	83
Underground Storage Tanks (count/km²)	5.6	3.8	76	3.9	79
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.0017	0.0046	76	12	54
Socioeconomic Indicators					
Demographic Index	30%	27%	64	35%	51
Supplemental Demographic Index	13%	13%	56	15%	51
People of Color	31%	25%	73	40%	51
Low Income	28%	29%	51	30%	51
Unemployment Rate	5%	5%	58	5%	60
Limited English Speaking Households	4%	2%	80	5%	71
Less Than High School Education	8%	9%	57	12%	49
Under Age 5	5%	5%	57	6%	53
Over Age 64	13%	18%	37	16%	42
Low Life Expectancy	18%	19%	41	20%	38

Recognizing and addressing these disparities constitutes a fundamental component of energy justice considerations in the rate proceeding. It necessitates moving beyond the complicit assumption of uniformity among residential customers and avoiding the moral hazard of assuming that bill discount programs alone will be sufficient to achieve energy justice for underserved communities. Instead, it is important to undertake comprehensive

[30] Id.

measures and consider rate proposals that duly account for the diverse energy needs and circumstances of different segments within the residential class. By embracing such an approach, the rate proceeding can strive to achieve an equitable distribution of costs and benefits, thereby ensuring that the burdens of rate changes are not disproportionately borne by vulnerable households and communities and that the system as a whole is moving towards a more equitable design.

Q. Please elaborate on what is meant by "the implications of procedural injustice."

A. Procedural injustice has significantly hindered the ability of energy justice perspectives to enter and wield influence within the decision-making process. Despite efforts to adjust rules and promote equity and inclusivity, the playing field remains uneven. This inequity is evident when we consider the power of precedent, whom has been at the decision-making table historically, and the inevitable disparities in skill level and familiarity with process as new perspectives enter the space.

Q. How does the power of precedent impact energy justice in rate cases?

A. The power of precedent plays a substantial role in shaping decision-making. Often parties will point to previous decisions as justification for a proposal. For example, in pursuing an increased return on equity, PGE points to national trends for similarly sized utilities. Another is in cost allocation; where, utilities and parties will often refer to what was approved in other proceedings to set a starting point for discussions. Unfortunately, historical precedent in general, often reflects biases and a lack of diverse perspectives, perpetuating the non-inclusive status quo. Energy justice perspectives with their focus on addressing disparities and systemic inequities face resistance and opposition as they challenge established norms.

Q. What about the role of the Oregon Citizens' Utility Board in the interest of energy justice?

A. Staff's perspective is that the Oregon Citizens' Utility Board (CUB) does advocate for energy justice. As a residential consumer advocate, CUB plays a valuable role in in its participation in Commission proceedings. CUB's role as a residential consumer advocate provides an essential perspective to the rate case and advances fairness and affordability for residential customers as a whole. And while Staff represents the interests of all customer classes, including residential customers in its responsibilities as a regulator, there are challenges associated with the current class and advocacy structure in allowing for differential considerations within classes. These challenges are particularly salient in a complex rate case, that covers a broad range of issues, includes settlement, and can be highly contentious.

To effectively pursue energy justice within the residential class, it is important to have dedicated advocacy, voices, and intervenors that can specifically champion the cause of energy justice. This ensures that the nuances and disparities within the residential customer base are adequately addressed and receive the attention necessary to achieve material outcomes.

ISSUE 2. ENERGY JUSTICE IN RATE DESIGN

Q. Please identify which components of PGE's proposed tariff changes relevant to this testimony.

A. Please refer to Staff Exhibit 2000 Stevens for a complete list and summary of PGE's proposed tariff changes. Staff 2000 also provides Staff's position and recommended actions. For the purposes of this testimony, Staff will be presenting energy justice considerations relative to:

- Residential Basic Charge Increase
- Flattening Residential Rates
- Time-of-Day (TOD) adoption
- Power Cost Adjustment Mechanism (PCAM)

Staff will discuss Schedule 300 changes later in testimony at Staff/600 Scala/52.

Q. Please discuss the potential energy justice implications of PGE's proposal to increase the residential basic charge.

A. Staff refers to Exhibit 2000 to introduce the equity concerns relative to PGE's proposal to increase the basic charge for residential customers. In addition to the discussion therein, Staff would make the following considerations relative to energy justice in the determination of a basic charge:

- PGE's embedded basic charge represents an average that allows for the recovery of fixed costs regardless of individual usage levels. This approach argues for a higher charge that is not necessarily proportional to the actual costs of providing service for different customer classes.

This can have regressive effects placing a larger burden on energy insecure households and exacerbating energy affordability issues.

- Low-income and other energy insecure households with lower energy consumption may bear a disproportionate burden of the basic charge as it represents a larger portion of their overall energy costs.
- Behavioral energy insecurity may drive certain households to intensify limiting their usage in an effort to off-set the increase to the fixed portion of this bill. This behavior worsens sub-optimal indoor heating and cooling conditions that contribute to heat- and cold-related illness, excess indoor moisture, mold growth, and other adverse health effects (e.g. respiratory illness and asthma).[31]
- Other states are exploring more equitable basic charge designs that incorporate equity considerations. Discussions in California have introduced the idea of an income-graduated fixed charge,[32] and some proposals include exempting the most energy insecure completely.[33] While the proposal is not without controversy, the intent is equity. An exploration of more equitable and less regressive designs relative to fixed charges is not a conversation that need wait.

[31] Cong, S., Nock, D., Xing, Bo, & Yueming, L. Q. (2022). Unveiling hidden energy poverty using the energy equity gap*. Nature Communications.* https://doi.org/10.1038/s41467-022-3014
[32] Borentein, S., Fowlie, M., Sallee, J. (2021). Designing electricity rates for an equitable energy transition. *Energy Institute at Haas.* WP 314
[33] https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/reports/220425-public-advocates-office-income-graduated-fixed-charge-qa.pdf

Q. Does Staff have any other comments relative to the proposed basic charge?

A. Yes. Staff acknowledges that the bifurcation of the basic charge between single and multi-family dwellings is both an equitable design and more reflective of cost causation, as demonstrated in UE 394. However, the current cost causation calculation does not take into account the deficiencies of distributional justice within the energy system. Many environmental justice communities are plagued by underinvestment and are paying disproportionate costs relative to their service.[34] Limitations in both infrastructure (e.g. drafty and/or leaky housing stock, heat islands) and access (e.g. energy efficiency upgrades and rooftop solar) have enabled a rate structure where certain communities are forced to pay more for less. As the Commission evaluates proposed changes to the basic charge, it should consider both the merits of both the assignment of costs and the presumed system benefits.

Q. Please discuss the potential energy justice implications of PGE's proposal to eliminate the residential increasing block rate?

A. The potential energy justice implications of removing the final inclining block in PGE's inverted residential rates are multifaceted. While Staff acknowledges PGE's argument that the inclining block may complicate the effectiveness of time-of-day (TOD) rates, it is crucial to consider the potential benefits and equity considerations associated with the inclining block.

[34] https://www.pbs.org/wnet/peril-and-promise/2020/01/redlined-neighborhoods/

Q. Can you elaborate on how the inclining block may be more useful from an energy justice perspective?

A. Research suggests that low-income customers, particularly in urban areas, tend to have lower volume and flatter load shapes, while high-volume peak usage is more likely in high-income, suburban areas. Staff's analysis of PGE's billing data, discussed in Staff Exhibit 2000, somewhat reinforces this by correlating consumption volume with volatility.

To the extent high peak usage is a large driver of system costs, these findings would suggest that low-income customers tend to overpay while high-income high-usage customers underpay for energy costs. In this regard, the inclining block structure would provide a more equitable rate structure than both the proposed flattened rate structure as it recognizes the lower system impacts of low-volume flat customer loads.

Q. PGE argues that the inclining block needs to be removed to maintain Schedule 7's revenue neutrality and effectively implement time-of-day (TOD) rates. Does Staff agree?

A. Staff discusses considerations relative to the price signal component of this argument in Staff Exhibit 2000. In addition to those points, Staff also notes that there are alternative perspectives in the available literature that support the retention of the inclining block and support energy justice considerations relative to equity. For example, the implementation of an increasing block rate offers simplicity and affordability benefits for low-use customers. This rate structure is designed around baseline consumption levels associated with essential household appliances and lighting. By focusing on these basic energy needs, customers can keep their bills stable and enjoy lower-tier rates.

As refrigeration and lighting are typically the main energy consuming elements for these low-use customers, opportunities for load-shifting are minimal, making TOD rates less effective in reducing their bills. Some studies indicate that the inclining block and TOD rates can be complementary.[35] The inclining block provides a more accessible usage-based bill management mechanism for low-usage flat load household than TOD, which tends to appeal to high-use customers with the capacity to invest in energy conservation measures, load shifting, and renewable generation without necessarily reducing load.

Q. PGE argues that low-income households are disproportionately impacted by the inclining block as they have a higher percentage of users that consume above the first discounted block. What does Staff's analysis show about this presumption?

A. Staff discusses its position regarding the weaknesses of the PGE low-income proxy earlier in this testimony and in Staff Exhibit 2000. PGE's argument relies on their low-income proxy data, which may be vulnerable to selection bias. Globally, research indicates that low-income households tend to use less energy due to multiple factors, including but not limited to smaller square footage dwellings, fewer high consumption amenities, and energy-limiting

[35] https://www.publicpower.org/blog/using-tiered-and-time-use-structures-residential-rate-design.

behaviors.[36] This suggests that low-income households are more likely to fall within the lower usage blocks and benefit from the discounted rates. Staff believes it is important to consider these broader findings and avoid drawing conclusions solely based on the data provided by PGE.

Q. Please discuss the potential energy justice implications of PGE's proposal regarding Time-of-Day (TOD) rates?

A. PGE launched its new TOD rate in May of 2021 which provided a larger differential between on- and off- peak prices, purportedly muting the conservation signal from the energy charge blocking.[37] UE 416 incorporates the TOD design into Schedule 7 as an opt-in rate, replacing legacy time-of-use rates.

Generally, TOD rates are most beneficial to customers with flexible schedules, the ability to shift their energy usage to off-peak periods, and access to energy management tools or technologies. These types of customers are best poised to take advantage of lower rates during off-peak hours. Low-income households and certain customer groups may face challenges or be disadvantaged by TOD. These include customers with limited flexibility in their energy usage due to work schedules or household routines and limited access to energy management tools or relatively more expensive appliance technology, often related to renter status or financial limitations.

---

[36] https://www.eia.gov/consumption/residential/data/2020/c&e/pdf/ce1.5.pdf.
[37] UE 416 / PGE / 1300 Macfarlane – Pleasant / 17.

There is notable disagreement among experts regarding the equity implications of TOD rates as pilot data remains limited. Even in the case of PGE, an analysis of the Company's TOD participation indicated zip codes associated with low median incomes were underrepresented while high median income zip codes were overrepresented.[38] While some findings out of a TOU pilot offered by Sacramento Municipal Utility District indicated high customer satisfaction with low opt out rates and significant load shifting, other California pilots found significant misconceptions about the benefits of TOU and that customers who use less electricity and pay the lowest rate on tiered rates will end up paying more on TOU rates because they tend to have flatter load profiles that still require some level of electricity during high-priced peak periods.

Q. Is there a way to implement TOD rates that mitigates these issues?

A. The findings suggest that customer education and the use of support programs like "energy coaches" can help improve but likely not eliminate the distributional equity of TOD benefits. For PGE, TOD rates remain an opt-in feature for Schedule 7 customers meaning households at a disadvantage with TOD can remain on the standard rate schedule. That said, the TOD rate taken together with the retirement of the inclining block, may be present a design package that seems to favor high-usage customers with flexible loads. If certain customer segments disproportionately benefit from these rates, it can exacerbate existing inequities in the energy system.

[38] OPUC Staff Exhibit 600 Scala/35 Table 2.

Q. Does Staff have any other considerations to offer regarding energy justice in rate design?

A. Yes. Staff believes an exploration of more equitable rate designs and cost allocations are crucial to a just transition and equitable energy system. For example, as briefly mentioned earlier, a separate class of customers based on characteristics that contribute to higher energy insecurity could help tailor rates and services to the specific needs of these households. In any rate design targeted based on differential energy burden, it is important to avoid the risks associated with deficit framing[39] and othering[40] community groups. These negative actions stigmatize households and provide a framework that paints them as inferior, thus exacerbating social prejudices.

There is also a risk of moral hazard that may arise if the existence of an alternate rate class leads to disregard for equity in other aspects of the utility's service. The complexities of innovative rate design that dismantles the status quo are robust and any such a change should involve a process that adheres to all the principles of energy justice, including procedural justice. This requires transparency, inclusiveness, and fairness in the decision-making process. Staff finds that with the backdrop and composition of current regulatory practices, justice would be better served by taking on major changes to rate design in the Energy Affordability Act Implementation docket, UM 2211 rather than UE 416.

[39] Trabian Shorters, "Deficit-framing is "defining people by their challenges, ignoring their aspirations or contributions, then remediating them to be less burdensome on society."

[40] Othering also involves attributing negative characteristics to people or groups that differentiate them from the perceived normative social group.

Q. Please discuss the potential energy justice implications of PGE's proposal regarding the PCAM structure.

A. Staff refers to Exhibit 2300 to discuss PGE's proposals relative to the PCAM in detail. In addition to the discussion therein, Staff would make the following consideration relative to energy justice:

- Disproportionate impacts associated with the shifting of risk: Staff's analysis of the PCAM proposal finds that if implemented, the changes would effectively shift business risk from the Company and its shareholders to customers. To the extent that Staff has established that rate and cost impacts upon the residential customer class are disproportionately born by low-income and environmental justice communities, the negative outcomes detailed in Staff Exhibit 2300 are no exception.

Q. Please elaborate on the how the negative outcomes Staff discusses in Exhibit 2300 will exacerbate intra-class disparities.

A. In Staff Exhibit 2300, Staff discusses that risk should reside with the party most empowered to manage the risk and that customers typically do not have the ability to manage unexpected power costs that the Company is endeavoring to insulate itself from with the PCAM proposal. Staff further discusses how the best way, if any at all, for customers to manage unexpected power costs would be if they chose direct access, installed energy efficiency measures, or chose to consume less energy. For residential customers, direct access is not an option. In terms of energy efficiency measures, low-income households tend to face greater barriers relative to accessing these programs. Lastly, low-income household already disproportionately engaged in energy limiting behavior, any further pressure to do so may further compromise well-being and exacerbate poorer health-outcomes.

Q. Does Staff have any recommendations on how to take a more equitable approach in the Company's PCAM proposal?

A. Staff Exhibit 2300 discusses this issue in length and does not recommend the Commission approve PGE's proposed changes to this mechanism. If Staff's recommendations are adopted, the additional risk associated with the Company's PCAM proposal described herein will be mitigated.

ISSUE 3. ENERGY JUSTICE IN CUSTOMER PROGRAMS

Q. Please summarize Staff's analysis of PGE's customer programs relative to energy Justice.

A. PGE offers several customer programs aimed at providing benefit and incentives to residential customers. Staff's analysis looked across participation rates and reviewed program offerings in terms of equitable access for customers to participate and derive the benefits as well as how they may or may not mitigate energy burden and/or system inequities.

Q. Why does this matter to this proceeding?

A. PGE typically recovers the costs for administering customer programs through rates. Consistent with Staff's arguments that ratemaking should take a more holistic and enterprise-wide approach, particularly in terms of equity, the rate case is an appropriate venue to perform a general review of equity in PGE's program offerings. Doing so allows Staff to assess whether programs are being administered equitably and to the benefit of customers.

Q. What did Staff find in terms of equitable participation in PGE's customer programs?

A. PGE does not typically collect data on customer characteristics that is tracked with program participation. An exception to this is in the IQBD program where a post-enrollment survey offers customers the option of providing additional demographic and other qualitative measures that PGE aggregates and shares with stakeholders (Figure 5). In an effort to approximate participation rates by income level, Staff used zip code level data provided by the Company and stratified participation by median income levels, as reported by the United Census Bureau using the American Community Survey. Table 2 illustrates this analysis.

Table 2. PGE Customer Program Participation Rates

Percent of Total Customers by Income Bracket									
Income Bracket		Programs							
	EA	IQBD	TPA	EP	OBR	RT SOLAR	TOU	TOD	*Total Res*
$ (10,000)	0.3%	0.1%	0.1%	0.0%	0.00%	0.0%	0.0%	0.1%	0.07%
$ 30,000	0.1%	12.5%	0.2%	0.1%	1.03%	0.2%	0.2%	0.0%	0.10%
$ 50,000	12.5%	14.7%	9.3%	4.7%	8.76%	2.0%	3.6%	3.5%	4.83%
$ 60,000	14.7%	14.8%	12.8%	9.0%	7.22%	6.1%	5.6%	6.1%	8.39%
$ 70,000	14.8%	21.0%	14.8%	12.2%	15.46%	8.2%	10.5%	9.6%	11.20%
$ 80,000	21.0%	17.9%	20.7%	21.4%	30.93%	19.3%	19.3%	19.7%	21.31%
$ 90,000	17.9%	9.3%	20.1%	22.8%	14.43%	27.0%	21.3%	19.7%	21.44%
$ 100,000	9.3%	6.6%	10.5%	11.6%	10.31%	13.4%	15.2%	15.1%	13.39%
$ 110,000	6.6%	0.4%	7.9%	11.2%	8.76%	13.3%	12.8%	13.7%	11.49%
$ 120,000	0.4%	0.2%	0.7%	1.5%	0.52%	1.7%	1.0%	1.1%	1.17%
$ 130,000	0.2%	2.0%	0.4%	0.6%	0.52%	0.7%	1.2%	1.3%	0.68%
$ 140,000	2.0%	0.0%	2.6%	4.8%	2.06%	8.1%	9.4%	10.1%	5.95%

The median income brackets serve as a proxy for differently situated participants and provided more granular data, these percentages may change. That said, the analysis does appear to approximate what Staff would expect to see in terms of higher participation rates in energy assistance programs among lower median income zip codes. The “Total Res” column to the far right depicts what portion of customers those zip code groups represent and is useful as a benchmark to compare program participation. For example, 10.1 percent of TOD participants reside in zip codes with $140,000+ median income levels, but these same zip codes only represent 5.95 percent of PGE’s residential customer base.

To this end, the high-income zip codes are overrepresented in the TOD program compared to others. The same observation can be made with TOU and rooftop solar. Conversely, low-income zip codes tend to be underrepresented in these programs. These findings suggest potential inequities. They may be the result of insufficient outreach and education regarding TOU/TOD rates among these groups or that TOU/TOD rates tend to be more beneficial for higher income high usage households. Rooftop solar participation rates are likely indicative to high barriers to entry relative to upfront costs and in some cases, historically limited access to renewable generation upgrades afforded to renters. Equal Pay is depicted as "EP" and captures levelized payment programs. This participant distribution appears to track very closely with the actual residential customer distribution across zip codes.

Q. What are Staff's findings regarding the demographic data PGE collects through IQBD post-enrollment surveys?

A. Staff finds that PGE's IQBD appears to be providing some degree of distributional equity relative to targeted relief. However, Staff notes that the post-enrollment survey data does not capture a full year of enrollments and was completed by approximately 40 percent of participants.[41] To this end, it is important that Staff continue to monitor IQBD enrollments and program performance to inform future evaluations and equity assessments. Figure 5[42] shows PGE's most recently available enrollment data, relative to demographic information.

[41] CUB DR 065 Attachment F.
[42] Id.

Figure 5. IQBD Enrollment Survey Data

Demographic Information	
The following statistics reflect cumulative enrollments as of January 31st, 2023.	
Housing Type	
Single Family	36%
Multifamily	55%
Mobile Home	9%
Household Size	
1	48%
2	18%
3	12%
4	10%
5+	12%
On a Fixed Income	
Yes	34%
No	66%
Preferred Language	
% English	89%
% Non-English	11%
Race/Ethnicity of Enrolled Applicant (optional)*	
White or Caucasian	56%
Latino/a, Hispanic, or Spanish	21%
Black or African American	8%
Asian or Asian Indian	5%
Native American and/or Alaska Native	2%
Native Hawaiian and/or Pacific Islander	2%
Slavic	1%
African Immigrant or Refugee	1%
Middle Eastern	1%
Other	4%

Q. Please elaborate on Staff's review of PGE's survey data relative to distributional equity.

A. Staff compared PGE's survey information with census data (Figure 6) to draw some high-level insights. For example, Staff reviewed the U.S. census bureau racial distribution across counties within PGE's service territory. When comparing the two information sets, Staff observed that Black, Indigenous, and People of Color (BIPOC) communities generally show a higher representation in the IQBD proportional to their population in the selected counties. Given what we know about the marginalization and historic injustices contributing to racial wealth gaps and higher rates of energy insecurity among BIPOC households, this is likely a positive sign in terms of distributional justice that mitigates disparate impacts. That said, Staff reiterates that this assessment is not absolute, nor particularly robust, given the limitations of the IQBD survey data.

Figure 6. United States Census Bureau- Quick Facts (PGE Counites)

United States Census Bureau

QuickFacts

Marion County, Oregon; Multnomah County, Oregon; Yamhill County, Oregon; Polk County, Oregon; Clackamas County, Oregon; Washington County, Oregon

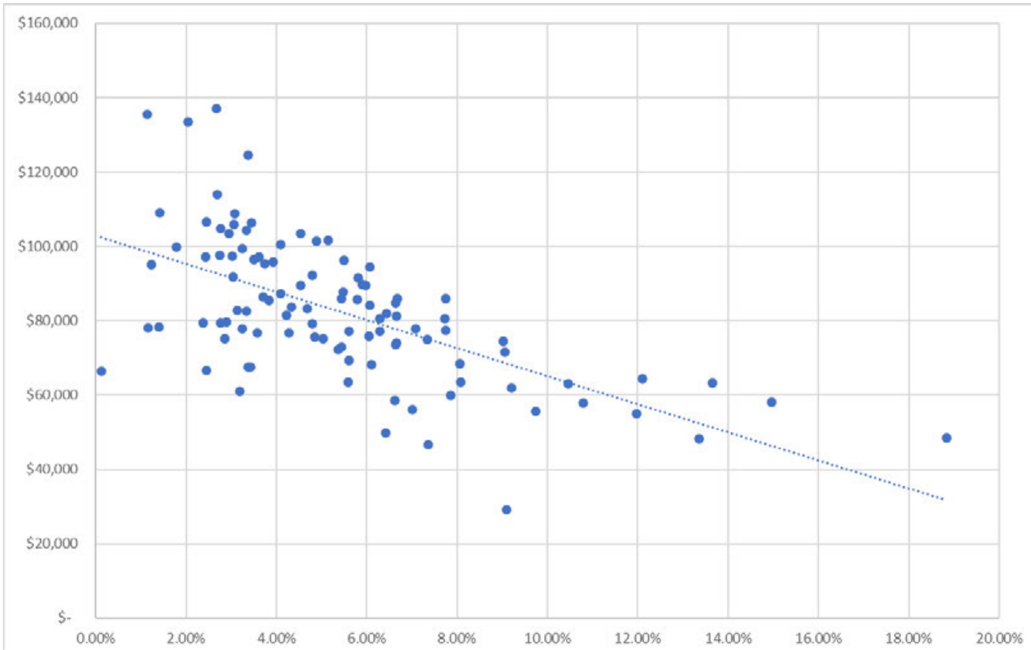
QuickFacts provides statistics for all states and counties, and for cities and towns with a ***population of 5,000 or more***.

Table

All Topics	Marion County, Oregon	Multnomah County, Oregon	Yamhill County, Oregon	Polk County, Oregon	Clackamas County, Oregon	Washington County, Oregon
Population Estimates, July 1, 2022, (V2022)	**346,703**	**795,083**	**108,226**	**89,614**	**423,177**	**600,176**
PEOPLE						
Population						
Population Estimates, July 1, 2022, (V2022)	**346,703**	**795,083**	**108,226**	**89,614**	**423,177**	**600,176**
Population estimates base, April 1, 2020, (V2022)	345,910	815,429	107,721	87,432	421,404	600,383
Population, percent change - April 1, 2020 (estimates base) to July 1, 2022, (V2022)	0.2%	-2.5%	0.5%	2.5%	0.4%	0.0%
Population, Census, April 1, 2020	345,920	815,428	107,722	87,433	421,401	600,372
Population, Census, April 1, 2010	315,335	735,334	99,193	75,403	375,992	529,710
Age and Sex						
Persons under 5 years, percent	6.0%	4.7%	5.1%	5.3%	4.9%	5.3%
Persons under 18 years, percent	24.0%	18.0%	21.4%	22.2%	21.2%	21.9%
Persons 65 years and over, percent	16.3%	14.3%	18.4%	18.5%	19.1%	14.3%
Female persons, percent	49.8%	50.3%	49.6%	50.9%	50.3%	50.1%
Race and Hispanic Origin						
White alone, percent	88.0%	78.6%	91.0%	89.2%	88.0%	78.6%
Black or African American alone, percent (a)	1.6%	6.0%	1.3%	1.2%	1.3%	2.7%
American Indian and Alaska Native alone, percent (a)	2.8%	1.5%	2.1%	2.7%	1.1%	1.2%
Asian alone, percent (a)	2.6%	8.2%	1.9%	2.2%	5.2%	12.2%
Native Hawaiian and Other Pacific Islander alone, percent (a)	1.1%	0.7%	0.3%	0.5%	0.3%	0.6%
Two or More Races, percent	3.9%	5.0%	3.5%	4.2%	4.0%	4.8%
Hispanic or Latino, percent (b)	28.2%	12.7%	16.8%	15.3%	9.5%	17.6%
White alone, not Hispanic or Latino, percent	63.4%	68.1%	76.1%	76.1%	79.9%	63.2%

Staff also combined income data from the American Community Survey with the IQBD survey to assess IQBD participation across median income levels. This analysis is displayed in Figure 7.

Figure 7. IQBD Participation Across Median Household Income



Q. What is Staff's overall assessment of PGE's IQBD and how it operates?

A. The IQBD offers a monthly discount of up to 25 percent off energy use for qualifying customers. The eligibility for this program is based on household size and the average annual gross income for all members of the household who are 18 years or older. The application process is designed to be a low barrier, requiring no financial documents from applicants. Once approved, the discount is applied for a period of two years. Customers need to re-enroll after this period, but PGE sends reminders to facilitate this process.

Q. Does the IQBD program have an impact on energy justice?

A. Yes. One of the main advantages of PGE's IQBD program is its low-barrier enrollment process. This approach, combined with the income self-attestation requirement, makes the program more accessible to those in need. Additionally, the program provides consistent assistance, rather than one-time aid, which can help households better manage their energy costs over time. Further, targeted assistance programs, such as the IQBD are often cited in the literature as a useful practice to enhance affordability and social equity within the energy sector. By mitigating energy poverty, these programs contribute to public health and housing stability. They can also reduce the incidence of service disconnections due to unpaid bills, reduce uncollectibles, and help maintain a consistent revenue stream for utilities.

Q. Are there any concerns or areas that could be improved in the IQBD program?

A. Yes. Staff believes PGE should increase the level of discounts offered using either increases within its existing three tier structure, or by the addition of a fourth discount greater than 25 percent. Although a discount of up to 25 percent may provide some relief, this is not sufficient for many energy-burdened households.

Another concern is the lack of granular data to inform equity analyses of customer groups. A comprehensive low-income needs assessment (LINA) within PGE's service territory would be of great value to Staff, stakeholders, and the utility relative to program evaluations and equitable ratemaking. Such an assessment could provide critical data on the extent and distribution of energy poverty and energy insecurity, enabling more targeted and effective interventions. This is a step that has been taken by most of Oregon's other investor-owned utilities, some of which have found that energy discounts of up to 90 percent are appropriate in areas of extreme energy poverty.

Q. Why is it so important for utilities to engage in a LINA?

A. A comprehensive LINA can provide a detailed understanding of the energy needs and burdens faced by low-income households in a utility's service area. This data can then be used to design assistance programs that are more accurately targeted to meet those needs. Without this data, there's a risk of either insufficiently assisting those in need or misallocating resources. Most of Oregon's other investor-owned utilities have conducted such assessments, and believe it is time for PGE to do the same.

Q. How could PGE improve its IQBD program to better address energy insecurity and energy burden?

A. There are a few steps that PGE could take. First, the company could conduct a comprehensive low-income needs assessment to better understand the needs of its customers. This could inform a potential adjustment in the level of the discount offered through the IQBD program.

Additionally, PGE could consider offering an additional tier with a greater discount for households with the least means to pay. This approach was adopted by both PacifiCorp and Northwest Natural absent a completed LINA at the time the discount programs were before the Commission. Moreover, Staff believes that PGE should consider the inclusion of an arrearage management program (AMP) to support the effects of the IQBD and further reduce energy insecurity. Arrearages exacerbate energy burden issues by compounding monthly bill amounts. Time payment arrangements do not include any offset to the total debt, and customers already struggling to pay will fall deeper into arrears, regardless of the bill discounts.

Q. Please describe Staff's role in supporting the IQBD.

A. The IQBD, as well as all the investor-owned utility administered bill discount programs in Oregon, was designed to provide near-term energy burden relief to customers following the implementation of the Energy Affordability Act. To this end, it is regarded as an "interim program" and a final iteration may or may not involve significant evolutions or departures from the current design. Staff intends to pursue an inclusive process with utilities and stakeholders through UM 2211, the Energy Affordability Act Implementation docket to identify relevant guidance and practices that will inform long term energy burden mitigation rates and programs.

Staff is currently partnering with the Regulatory Assistance Project to determine the scope and flow of this work and expects to engage utilities and stakeholders later this summer. Staff is also utilizing the time between the implementation of the interim designs and the UM 2211 investigation to collect and analyze utility program data, such as that displayed in Figure 5, above. Staff continues to engage with PGE and stakeholders on the perceived efficacy of the IQBD through monthly check-ins and data discussions.

Q. The IQBD is currently recovered in an automatic adjustment clause, should this program be rolled into base rates?

A. Not at this time. As noted earlier in testimony, this is an interim program that just completed its first year. Program maturity (75 percent eligible enrolled) is forecasted to occur in 2026. Thus, program costs and tier distributions are still being established. It is appropriate to monitor IQBD program costs through an AAC and associated deferral until there has been more time to review and finalize a permanent program where annual costs are well-established.

Q. Does Staff have comments regarding the current IQBD cost recovery practices in the automatic adjustment clause?

A. Yes. All customers contribute towards the costs of the IQBD programs. The Schedule 118 PGE Bill Adjustment Recovery Mechanism for the IQBD program is currently assessed at a flat rate of $1.14 per bill for residential customers and a 0.114 cent per kWh for all other schedules, up the first 877,193 kWh, effectively a $1,000 per month, per Site cap.

Q. Please explain why non-residential customers should be expected to fund residential customer assistance programs.

A. Staff is cognizant that the IQBD can only be accessed by qualifying residential households while costs are shared by non-residential household. The statute authorizing differential rates and programs states that: “the cost of tariffs, schedules, rates, bill credits or program discounts allowed pursuant to subsection (1) of this section must be collected in the rates of an electric company through charges paid by all retail electricity consumers.” To this end, and further reinforced by other residential program cost-recovery proceedings with this Commission,[43] it is appropriate for all utility customers to contribute to the costs of reducing residential energy burden.

Q. Did the Commission recently approved the current structure including the $1,000 cap?

A. Yes. The Commission approved the current Schedule 118 terms, with the $1,000 cap in ADV 1447. There was an interest in expediency for this proceeding as PGE had already begun paying into the program and Staff did not want to allow significant deferrals to accrue.

Q. What does Staff recommend regarding the IQBD cost-recovery cap?

A. Staff recommends this cap be revisited at such a time that enrollment, costs, or other relevant metrics or design elements of the IQBD have changed to warrant an adjustment to this feature.

Q. Please describe the relevance of energy efficiency programs to UE 416.

A. The Company is not proposing recovery of any energy efficiency costs through the general rate case, as all energy efficiency funds are recovered through previously approved Schedules 108, 109, and 110. PGE's Schedule 109, Energy Efficiency Customer Service, was recently approved in Docket No. ADV 1337, and Schedule 110, Energy Efficiency Customer Service, was likewise approved in Docket No. UM 2039.[44]

Effective energy efficiency programs can have meaningful implications for customers at the household level and average customer loads at the system

[43] COVID-19 Residential Bill Assistance cost-recovery.
[44] UE 416 OPUC Staff DRs 388-390

level. It has the potential to lower energy costs for low-income households, thereby reducing energy poverty and potentially peak load demands. Further, it is imperative that residential customers are afforded equitable access to energy efficiency program benefits to the extent funding is provided by a uniform rate assigned to the class of customers. To this end, Staff finds it appropriate to discuss energy efficiency programs in this proceeding.

Q. What did Staff find in its analysis?

A. In general, Staff found that there is an opportunity for the Company to initiate more robust data collection practices regarding energy efficiency that can be used to inform their program and customer coordination with Energy Trust of Oregon (ETO). Based on responses provided by the Company, Staff found that the PGE does not track energy efficiency spending at a granular level; therefore, beyond total funding and overall programming with the ETO, Staff was unable to obtain a better sense of the allocation of funds.

A recent ETO Customer Participation and Awareness survey showed a 2.7 percent statewide participation rate, but it remains unclear the percentage of PGE customers utilizing energy efficiency funds.[45] The approved 2022 ETO budget revealed that 21.8 percent of funding goes to residential customers, however, again there is a lack of granularity relative to demographic data points for customers served.[46]

[45] UE 416 OPUC Staff DR 404.
[46] UE 416 OPUC Staff DR 409.

Additionally, while the Company does use promotional advertising, business and residential outreach, and overall website content to increase the customer enrollment of energy efficiency programming, PGE does not currently track energy efficiency spending at the zip code or more granular level.[47] Nor does PGE does not track the number of Income Qualified Bill Discount customers participating in other energy efficiency programs or overall reductions in household energy usage attributable to energy efficiency programs.[48]

Q. Is PGE able to effectively provide outreach to deploy energy efficiency to its customers?

A. Partially. PGE provided Staff several examples of outreach and communications used to inform and educate its customers about energy efficiency programs and practices that would help reduce monthly energy bills.[49] PGE continues to work with ETO and external community action agencies to increase customers' awareness and participation in energy efficiency programs through marketing and outreach activities. All of these materials appeared helpful, informative, and accessible in terms of simple language and language options. PGE also uses Senate Bill 838 funding to enhance trade-ally awareness of the ETO Heat Pump program and installation standards.[50]

[47] UE 416 OPUC Staff DR 405.
[48] UE 416 OPUC Staff DRs 406-408.
[49] UE 416 OPUC Staff DR 439.
[50] UE 416 OPUC Staff DR 411.

However, as noted earlier, data on the efficacy of these measures is either not collected or not analyzed. Additionally, as noted, participation rates reported by ETO for energy efficiency programs is only 2.7 percent. To this end, Staff points out that there seem to be issues with enrollment and potentially distributional equity[51] within energy efficiency programs. These matters may be served by more intentional data collection around outreach and customer engagement in energy efficiency.

Q. Does Staff have a proposed adjustment for energy efficiency?

A. No. Staff does not currently propose any modifications or adjustments to PGE's overall energy efficiency programming. However, Staff does plan to utilize the UM 2211 investigation to explore enrollment, participation rates, program designs, and utility-ETO partnerships more deeply. Staff is interested in taking a more strategic approach to evaluating energy efficiency to improve these areas, particularly in the interest of energy justice.

[51] Distributional equity in ETO programs is currently being addressed as a result of HB 3141, where the Commission was charged with implementing equity metrics to "assess, address and create accountability for environmental justice." https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB3141.

ISSUE 4. ENERGY JUSTICE IN AUTOMATIC ADJUSTMENT CLAUSES

Q. Please summarize your testimony relative to PGE's use of Automatic Adjustment Clauses (AAC).

A. Please refer to Staff Exhibit 2200 Dlouhy-Muldoon-Scala-Stevens for a complete analysis of the role of AACs in utility regulation. Staff Exhibit 2200 also provides Staff's position and recommended actions regarding PGE's use of AACs as a cost recovery mechanism. For the purposes of this testimony, Staff will offer a limited discussion on the implications of PGE's AAC activity relative to energy justice.

Q. What perspectives do energy justice principles offer in the context of Staff's desire to more actively regulate the use of AACs for cost recovery?

A. While AACs and other single-issue ratemaking tool can be useful in some contexts, their efficacy may be tempered when implemented without earnings tests and/or in excess. For example, the absence of an earnings test can result in reduced transparency and oversight. Without adequate checks and balances, it may be challenging to ensure that costs recovered through AACs are reasonable, necessary and in the best interest of customers.

There is also an increased risk of over-recovery, where utilities may collect more revenue that justified by their actual costs. This can place unnecessary burden on customers, particularly energy burdened households. AAC regulatory proceedings are less rigorous than traditional ratemaking procedures and have a myopic lens that prevents holistic perspectives regarding rate pressures.

Q. In Staff Exhibit 2200, Staff indicates the PGE's number of AACs have more than tripled since 2010, how does this rate of growth impact customers?

A. Figures 8 and 9 depict the increasing impact of AACs on customer bills. As the portion of customer bills attributable to AACs grows, the more vulnerable rates are to the potential procedural and distributional injustices of AACs. Once an AAC has been established, parties have largely agreed on a forecast methodology and rate spread. To this end, the rate adjustment, by design, does not accommodate a robust and inclusive decision-making process relative to subsequent review and continuation of the mechanism. This deficiency (in the interest of efficiency) is exacerbated when an earnings test is not commensurate with approval. The impact on customers is greater exposure to the risk of overcollection and fragmented rate spreads that potentially exacerbate inequities.

Figure 8. Overall Residential Bill Breakdown[52]

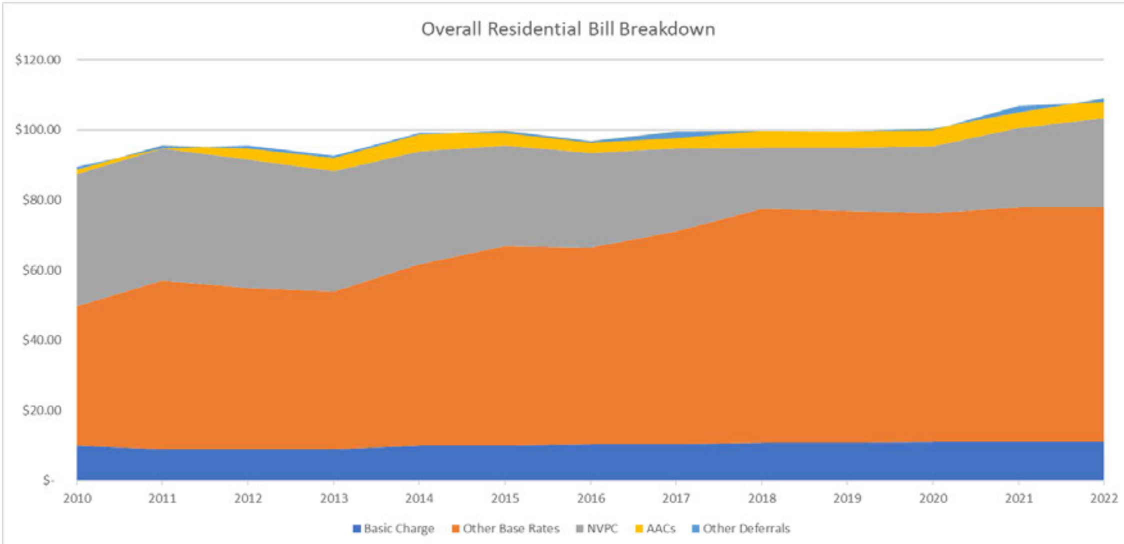


Figure 9. Percent Change in Residential Bill Component

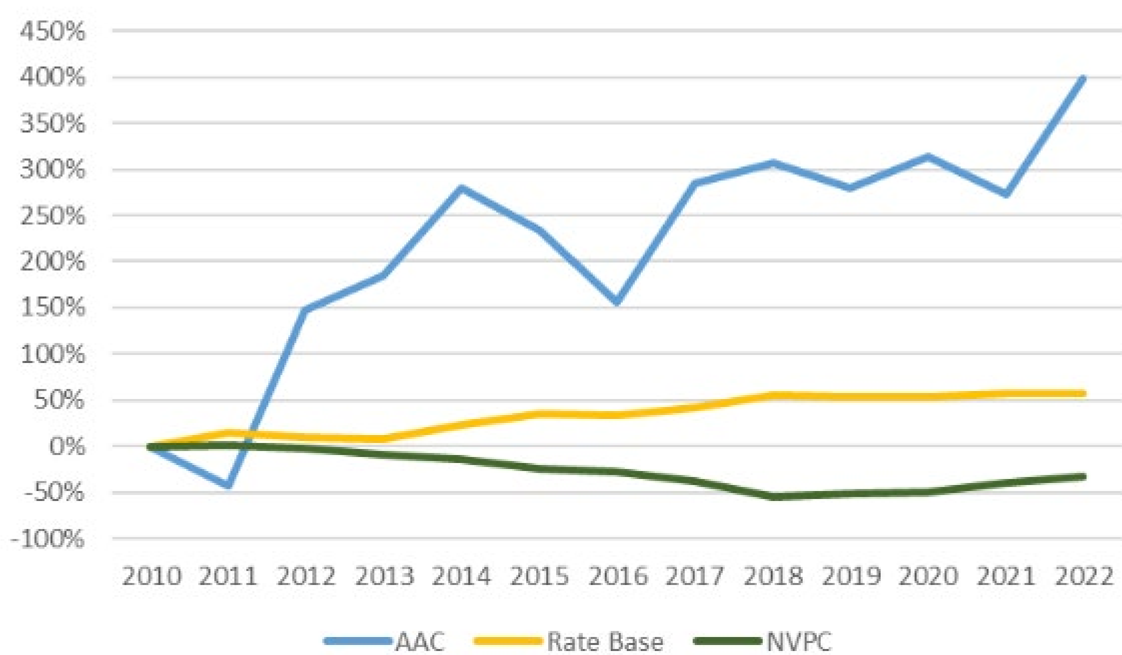
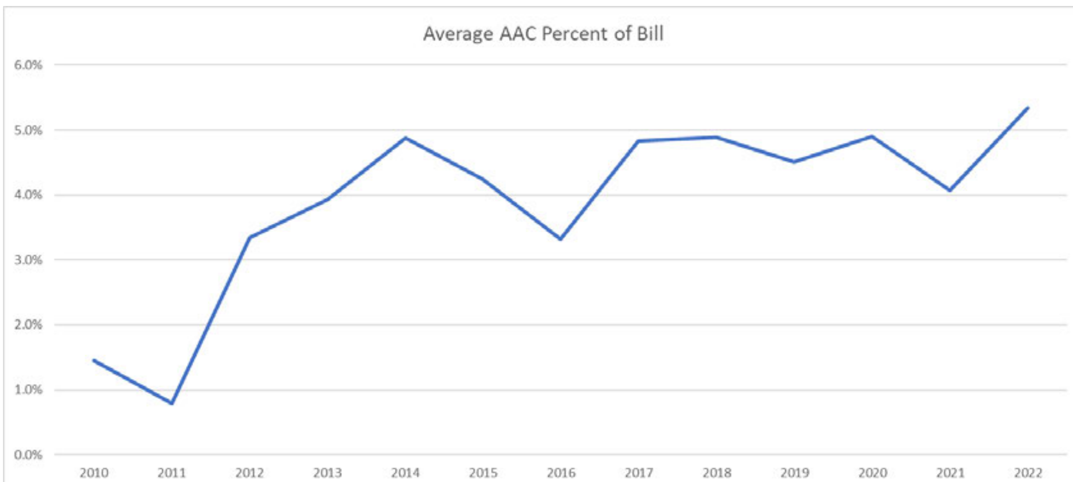


Figure 8 shows the average residential customer bill for each year beginning 2010 through 2022 by cost category, while Figure 9 captures how

[52] OPUC Staff DR 328.

elements of the residential bill have changed over the same period. As can be observed in blue line of Figure 9, the percentage change in AACs is most profound. Taken together with the large increases to base rates Figure 10, the average residential customer bill has increased a little over 20 percent. Figure 5 provides a look at AAC as a portion of the average residential customer bill.

Figure 10. Average AAC Percent of Bill[53]



Q. What risk mitigation measures does Staff recommend?

A. Staff has proposed a series of controls to help provide a regulatory strategy relative to AACs. These recommendations are detailed in Staff Exhibit 2200 Dlouhy-Muldoon-Scala-Stevens.

[53] Id.

ISSUE 5. ENERGY JUSTICE IN SCHEDULE 300 CUSTOMER CHARGES

Q. Please describe how this testimony will address PGE's proposal for Schedule 300 customer charges.

A. Please refer to Staff Exhibit 2400 Nottingham-Shearer for a complete analysis of PGE's proposed Schedule 300 changes. Staff Exhibit 2400 also provides Staff's position, recommended actions and introduces potential equity implications of PGE's proposal. For the purposes of this testimony, Staff will be presenting energy justice considerations relative to reconnection rates more generally.

Q. What are the implications of PGE's proposed increase in reconnection charges in UE 416?

A. Reconnection charges tend to be largely born by low-income households and other communities at greater risk for credit related disconnection. For example, in response to a Staff inquiry, PGE reported that approximately 11 percent of IQBD participants had experienced disconnection between August 2021 and March 2023.[54] To this end, increases to these charges will further exacerbate inequities associated with who is most likely to pay.

Similarly, Staff argues that reconnection charges can be unnecessarily punitive because they impose an additional financial burden on customers who are likely already struggling to pay. This injustice is particularly salient when the charges assessed significantly exceed the actual cost of providing the service,

---

[54] UE 416 OPUC Staff DR 447.

which appears to be the case with PGE.[55] AR 653 adopted additional customer protections adopted to provide some relief from reconnection charges for low-income customers,[56] however, the protections are limited to those who qualify under OAR 860-021-0180.

It is unclear to Staff if the level of the charge is assessed by the Company such that aggregated collections are sufficient to cover the cost of service, including no-charge reconnections (and disconnections). Staff's continued review will look into this issue further.

Q. Are reconnection charges a necessary disincentive?

A. No. Reconnection charges exacerbate disparities by imposing higher costs disproportionately on energy insecure households. Community focus groups have collectively described how disconnection resulting from inability to pay is a significant source of stress and anxiety for households. Additionally, studies have linked higher disconnection rates to poorer health outcomes and greater incidence of homelessness.[57] To this end, Staff finds these anecdotes and research outcomes contribute more to the argument that reconnection charges are unnecessarily punitive than a warranted or functional disincentive.

Q. Does Staff have any other concerns relative to Schedule 300 charges?

---

[55] Staff Exhibit 2400 Nottingham-Shearer.

[56] OAR 860-021-0330; https://secure.sos.state.or.us/oard/viewSingleRule.action;JSESSIONID_OARD=8VdEZ7rV_eKOgzASD01Qcr08MvLECDGiOrRLCFT-WKBWHxBWUgso!-1586339682?ruleVrsnRsn=294410.

[57] Hernández, Diana & Laird, Jennifer. (2021). Surviving a Shut-Off: U.S. Households at Greatest Risk of Utility Disconnections and How They Cope. *American Behavioral Scientist. 66*.

A. Yes. The proposed increases to Schedule 300 customer charges are significant. They include but are not limited to reconnection charges with graduations based on whether or not they occur at the meter base and on or outside of normal business hours and wasted trip charges. In some instances, the increases are upwards of 100 percent of the current cost.

Staff is concerned that PGE's Schedule 300 estimates, in general, are excessive and inadequately capture both the cost savings from AMI meters and the energy justice perspectives relative to nuanced charges. Staff Exhibit 2400 Nottingham-Shearer Staff's analysis of the cost savings element. To the latter point, Staff is concerned that there may be relevant correlations to the incidence of graduated reconnection charges. For example, are environmental justice communities more likely to need an off hour reconnect? Are there infrastructure deficiencies that relate to the incidence of reconnects not at meter base? What is the relationship between customer trust in the utility and not at meter base reconnects.

Staff is not aware of any data PGE collects that would sufficiently inform these concerns, however, in the context of energy justice they are relevant as significant finds would indicate intersectional disparities that exacerbate current conditions. Staff suggests that in the interest of advancing a more equitable system overall, a review of customer charge structures and practices be considered.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Michelle Scala

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Justice Program Manager
Strategy and Integration Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: BA Economics, University of Hawaii, Manoa; Honolulu, Hawaii
BA Political Science, University of Hawaii, Manoa; Honolulu, Hawaii

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since July 2020 as a Senior Utility Analyst. I initially began work at the Commission in the Energy Rates, Finance and Audit Division and later transitioned to the Strategy and Integration Division upon its inception. In May of 2022, I was made Energy Justice Program Manager to the Utility Division. I have provided expert testimony as Commission Staff in general rate cases UE 394, UG 433, and UG 435, and have consulted on others. I have over eight years of experience in policy analysis and program evaluation for state and local government. My work prior to the Commission included serving as a Senior Fiscal Analyst at the Oregon Department of Human Services and Economist at the Oregon Employment Department. Prior to that I was employed at the Hawaii State Legislature as the Senior Analyst to the Senate Committee on Ways and Means.

CASE: UE 416
WITNESS: SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Non-Confidential Responses to Data Requests

June 13, 2023

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 236
Dated March 13, 2023

Request:

Referring to the Company's testimony UE 416 / PGE / 900 / Lynn – Nestel / 17

a. Provide the underlying calculation of the each of the values listed in "**Table 2 Uncollectible Rate Forecast Itemized**" in an Excel spreadsheet. In the response, please provide the supporting summary data for each of the years 2017, 2018, 2019, 2020, 2021, 2022.

b. Explain any year-to-year variance of more than 10 percent for either the actual write-offs or revenues.

c. Please describe how PGE recovers on a rate spread basis the uncollectible revenues. For example, is each rate schedule responsible for its respective share of uncollectible revenues or is it spread across all customer classes?

Response:

PGE objects to this request for being overly broad and unduly burdensome in that it requires new analysis to be performed. Without waiving said objections, PGE states as follows:

a. The underlying calculations in Table 2 are primarily based on the most recent information available through November 2022 and do not rely on historical time series. Where data is available, historical years are also provided. Attachment 236-A shows the underlying calculations for the values listed in 900/Lynn-Nestle/17 Table 2. For the Recovery Rate Trend adder, the initial 2022 estimate of 16.5% was based on data through November 2022, 15.85% is a full year of data for 2022.

   In October 2022, there were numerous additional customer protections added into OAR Division 21 which will result in changes to uncollectibles. Particularly, Severe Weather Moratorium which added significant protections for customers from November through March and hasn't completed its first cycle since implementation. Also, Notice of Pending Disconnection perspective changing the 15-day disconnection notice to a 20-day notice will be implemented by June of 2023 however any additional time has a direct impact of increasing arrears outstanding. PGE made a good faith effort to approximate impact with the partial historical data available.

b. Please refer to UE 416 OPUC DR 235-Attach_A for the annual write-offs and revenues with explanations for annual variations greater than 10 percent.

c. PGE recovers uncollectible expense based on the Marginal Cost Study in the Allocation of Uncollectibles. Please see UE 416 PGE Exhibit 1201.

April 12, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 325
Dated March 16, 2023

Request:

Please provide raw anonymized household-level billing data for all Schedule 7 customers for the calendar year 2022. Please provide this in an MS Excel file. If necessary, multiple Excel files can be used. Please include any bill for which the billing period or due date starts or ends in calendar year 2022. An example as to how the data should generally be structured is shown in Attachment 1 of this DR. If PGE does not track any of these data elements, please indicate this in your response and return the rest of the data elements. If you have any questions about this request, please reach out to the Staff Initiator, Bret Stevens, as soon as possible. Please include the following data elements – the preferred data type are in parentheses:

a. Anonymized customer account ID (string or numeric)
   i. Anonymized site ID (string or numeric)
   ii. Please ensure that the anonymized customer ID and anonymized site ID are persistent across different bills.
   iii. Please ensure that the key linking the anonymous account and site IDs to their respective accounts and sites are retained by the company after anonymization.
b. Bill start date (string or data variable in excel)
c. Bill end date (string or data variable in excel)
d. Bill total (numeric)
e. Energy consumption for billing period (numeric)
f. Customer payments made for billing period (numeric)
g. Affected by any PSPS? (binary or string)
   i. If yes, start date of PSPS event (date or string)
   ii. If yes, end date of PSPS event (date or string)
   iii. If yes, duration of PSPS event (numeric)
h. ZIP code (numeric or string)
i. City (string)

j. Heating fuel type (binary or string)

k. Cooking fuel type (binary or string)

l. EV ownership (binary or string)

m. Multi family or single family (binary variable or string)

n. Enrolled in income qualified bill discount program? (binary or string)

o. Enrolled in bill assistance program? (binary or string)

p. Customer has been previously disconnected (binary or string)

q. Customer account has received LIHEAP (binary or string)

r. Customer arrears balance for billing period (numeric)

s. Participate in net metering? (binary or string)

Response:

PGE objects to this request on the basis that it is overly broad, unduly burdensome and calls for speculation. Subject to and without waiving said objections, PGE responds as follows:

Attachment 325-A provides the raw anonymized household-level billing data for all Schedule 7 customers for the calendar year 2022. Per a phone conversation with OPUC Staff on March 27, 2023, PGE is providing data files in a CSV format. Data on customer EV ownership status was not available for inclusion at this time and will be supplied upon approval that sharing this data, even anonymously, is permitted under any applicable limitations on sharing such information imposed by law, regulation or agreement between PGE and the Oregon Department of Transportation. Data on cooking fuel is not tracked by PGE. This data has not been prepared for analytic use and may contain anomalies.

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 328
Dated March 16, 2023

Request:

From 2010 to 2022, please provide the total annual revenue generated from rates charged to each customer class broken down base rates, power cost cases, non-power cost AACs, other deferral amortizations, and any other mechanisms not identified.

Response:

PGE objects to this request as being overly broad and unduly burdensome in that it requires the development of new information. Without waiving said objections, PGE states the following:

On March 20, 2023, PGE and Staff discussed this DR in a phone call, and Staff agreed due to time limitations that PGE could provide forecasted annual revenue.

Attachments 328-A through 328-N provide the forecasted annual revenue from 2010 to 2022 generated from rates charged to each customer class broken down by base rates, power costs, non-power cost AACs, other deferral amortizations, and other mechanisms.

PGE is providing two files for 2022. Attachment 328-M contains the forecasted revenues effective January 1, 2022. The revenues are calculated using the 2022 load forecast and present a full 12 months of revenue, but are only in effect until May 8, 2022. Attachment 328-N contains the forecasted revenues effective May 9, 2022 when the rates from UE 394 became effective. The revenues in Attachment 328-N also present a full 12 months of revenue.

April 10, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 385
Dated March 27, 2023

Request:

Please refer to Schwartz–Outama–Cristea/29-30: "Therefore, beginning January 1st, PGE must anticipate incurring a carbon obligation for many of the trades that PGE transacts under the standard Mid-C trading product, because the energy supply supporting PGE's trading activity is often the economic dispatch of PGE's thermal resources that are not located in the state of Washington (i.e., PGE would anticipate being the responsible importer)."

i. Please confirm whether it is correct to interpret the phrase "many of the trades that PGE transacts…" as saying that not all trades at Mid-C will incur a carbon obligation. If so, please provide a narrative description and workbook demonstrating how PGE models the proportion of trades that will incur carbon obligations. If not, please provide an alternative correct interpretation.

a. Please provide a monthly forecast of the total power sold by PGE in WA that will be transacted at the Mid-C trading hub broken down by thermal and non-thermal resources.

b. Please provide a monthly forecast of the total power sold by PGE to a non-WA buyer that will be transacted at the Mid-C trading hub broken down by thermal and non-thermal resources. Please discuss whether the thermal resources would be subject to a carbon obligation.

c. Please provide a monthly forecast of the total power bought by PGE from a generator in WA that will be transacted at the Mid-C trading hub broken down by thermal and non-thermal resources. Confirm whether the price PGE would payfor this energy is directly or indirectly affected by any carbon obligations.

d. From the PGE's statement above, Staff is interpreting that PGE will supply energy to WA from thermal resources located outside WA. Please confirm whether the interpretation is correct and identify which thermal resources PGE will use to supply energy to Washington.

e. Please provide the following figures by month in the following format, with cell references and formulae intact for the test period:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mid-C MWh eligible for Carbon Obligation (from resources in WA)												
Mid-C MWh eligible for Carbon Obligation (from resources outside WA)												
Total Market Sales (WA) $												
Total Market Sales (outside WA) $												
Total Market Sales (WA) MWh												
Total Market Sales (outside WA) MWh												
WA Carbon Obligation cost (generated from WA resources) $												
WA Carbon Obligation cost (generated from resources outside WA) $												
Total WA Carbon Obligation cost $												

Response:

i. Correct. Since the MONET model prices all sales at the Mid-C price curve there is an implied model assumption that transactions are executed under the standard Mid-C trading product, which is the Mid-C physical product listed on the Intercontinental Exchange (i.e., ICE). Currently, parties selling the standard product assume a carbon obligation risk, because the standard product does not preclude delivery at a Washington sink point. Therefore, the price curve used in MONET presently includes price uplift for carbon risk and this price is applied to all sales and purchases in the MONET model.

   While priced at the Mid-C price curve, PGE noted in PGE Exhibit 300 at 33 that not all sales resulting from the MONET model dispatch will ultimately sink in Washington and create a carbon obligation for PGE. PGE used its estimate of COB transactions as a basis for reducing the MONET model sales volume eligible for incurring a compliance obligation. The workbook demonstration is in the MFRs, Vol 10 - New Items and Enhancements\Step 00n - Washington Cap and Invest, file "#WA Cap and Trade".

a. The MONET model does not identify unit-specific sales. However, in the forecast of Mid-C MWh eligible for carbon obligation, PGE assigns an unspecified emission factor of 0.437 metric tons of CO_2 equivalent per MWh **to all eligible MWhs**.

   A breakdown of hourly dispatch and portfolio sales can be found in PGE's MFRs filed on February 15, 2023, folder "ToPUC", file "#2024GRC-B000n-HourlyDiagnostics", tab "hrlydiagnosticenergy".

b. A forecast for power sold by PGE to a non-WA buyer transacted at Mid-C would be 0 MWh in each month, because the modeled transactions in the MONET model are first priced at the standard Mid-C product. See PGE's response in part (i.). In practice, if PGE sells a non-standard Mid-C product (i.e., parties agree that the power will not sink in Washington) the sale will not incur a carbon obligation, including sales associated with emitting sources such as thermal resources.

c. The MONET model does not identify unit-specific purchases. See the description of how the MONET model economically dispatches PGE's portfolio in PGE Exhibit 300, Section II. As described in PGE Exhibit 300, given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve. Market purchase volumes and costs are provided in the MONET model output worksheets, "PwrEnOut", "PwrAEOut", and "PwrCsOut", under row "Market Purchases". See PGE's response in part (i.). The price curve used in MONET presently includes price uplift for carbon risk and this price is applied to all sales and purchases in the MONET model.

d. Yes. In PGE Exhibit 300 at 30, PGE is describing the fact that PGE's opportunity to sell power can be a function of PGE's thermal resources being economical for dispatch, which then results in PGE's total supply of economical dispatch being greater than its load obligation. Our examples in PGE Exhibit 300 at 30 focus on the summer months when the MONET model monetizes generation length from our peaking resources through wholesale market sales. In instances where PGE would need to import electricity into Washington to meet these modeled sales levels the source would likely be unspecified, because the source would not be known prior to time of entry into the transaction (i.e., the source would come from PGE's portfolio). In these instances, PGE's sales would carry the unspecified emission factor of 0.437 metric tons of CO_2 equivalent per MWh.

e. PGE objects to this request on the basis that it is vague. Subject to and without waiving this objection, PGE responds as follows:

   Confidential Attachment 385-A uses the MONET model results from its initial filing as the basis for populating the table provided by Staff.

   Mid-C MWh eligible for Carbon Obligation (from resources in WA): Values reported are MWhs from resources located in WA when the resource volume is produced in the same hour that a sale is made in MONET.

   Mid-C MWh eligible for Carbon Obligation (from resources outside WA): Values reported are MWhs from non-WA resources when the volume from WA resources is not large enough to meet the hourly volume sold in MONET.

   Total Market Sales (WA) $: This is all MONET sales reported in the MFR. Since MONET prices all sales at Mid-C, the dollar amount reported is for all sales.

Total Market Sales (outside WA) $: This value is 0. MONET prices sales as if all were sold at Mid-C.

Total Market Sales (WA) MWh: This is all MONET sales reported in MFR. Since MONET prices all sales at Mid-C, the MWh amount reported is for all sales.

Total Market Sales (outside WA) MWh: This value is 0. MONET prices sales as if all were sold at Mid-C.

WA Carbon Obligation cost (generated from WA resources) $: This value is 0 if the resources located in WA (i.e., hydro and wind resources) are assigned an emission factor of 0 MTCO2e/MWh.

WA Carbon Obligation cost (generated from resources outside WA) $: This value is the result of MWh from resources outside WA multiplied by an unspecified emission factor (0.437 MTCO2e/MWh) and an allowance price of $48.50 per MTCO2e.

Attachment 385-A is protected information subject to Protective Order No. 23-039.

April 11, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 388
Dated March 28, 2023

Request:

Please list and describe any energy efficiency costs the Company has proposedto recover through this docket. At a minimum please include:

a. The requested amount to be distributed to the Energy Trust of Oregon.
b. The requested amount which will be retained by the Company.
c. The requested amount to be distributed to entities administering low-income weatherization programs.
d. The requested amount to be distributed to entities administering energy efficiency in schools through ORS 757.612.
e. Explanation of the difference in amounts requested for (a) – (d) as compared to the Company's last rate case.
f. Location of the funds requested for energy efficiency in the Company's filed rate case application and/or associated tariff.
g. Please identify any prior and outstanding dockets related to the dispersal of these funds.

Response:

The Company is not proposing to recover any energy efficiency costs through this docket. Energy efficiency costs are recovered separately through Schedules 109 and 110.

April 11, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 389
Dated March 28, 2023

Request:

Please identify whether the energy efficiency funding is being recovered through base rates or an outside funding source, including an automatic adjustment clause or deferral account. If the funding is being recovered through an outside funding source, please identify the source.

Response:

Energy efficiency funding is not recovered through base rates.

Energy efficiency funding for activities conducted by the Energy Trust of Oregon (ETO) for the benefit of PGE's customers is collected through Schedule 109 and disbursed to ETO each month.

Energy efficiency funding for activities conducted by PGE to enable our customers to achieve energy efficiency is recovered through an automatic adjustment clause plus deferral. Docket No. UM 2039 for Energy Efficiency-Customer Service. The cost recovery schedule is Schedule 110.

April 11, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 390
Dated March 28, 2023

Request:

For the costs identified in DR 388, please provide total actual and budgeted expenditures for energy efficiency. Please include data on the Oregon-allocated amount of each total. Please provide the data in electronic, Excel format with all formulae and cell references intact.

For example, the level of detail requested would be satisfied by completing the following chart:

Year	**Actual ($)**	**Budget ($)**
2020		
2021		
2022		
2023	N/A	
2024	N/A	

Response:

There are no costs identified in PGE's response to OPUC Data Request No. 388 that PGE is seeking cost recovery for in UE 416.

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 404
Dated March 30, 2023

Request:

To summarize the development of energy efficiency funding and outreach over the last 10 years, please provide a table substantially similar to the table below that includes the following elements:

a. Overall Funding of Energy Efficiency Programming.
b. Percentage of Customers Served by Energy Efficiency Programming.

Response:

The table below provides the overall funding of energy efficiency programming. The percentage of customers served by energy efficiency programming is not available.

Year	Energy Efficiency Funding ($)
2013	$67,632,144
2014	$81,072,821
2015	$87,490,968
2016	$96,346,463
2017	$96,970,919
2018	$91,984,107
2019	$95,633,932
2020	$91,327,503
2021	$85,694,542
2022	$89,065,646

The funding provided above includes only Energy Trust of Oregon actuals as disclosed in their Annual Reports, not Schedule 110 promotion or outreach spend. PGE does not track the percentage of customers served by energy efficiency programming, and ETO does not provide this information by utility. Although all PGE customers, participants and non-participants, benefit from investment in energy efficiency, a recent Energy Trust 2022 Customer Participation and Awareness survey shows a 2.7% rate of participation per year statewide for 2015-2021. PGE customer participation, derived from Program Participation Information, is in line with this rate if aggregated across all segments.

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 405
Dated March 30, 2023

Request:

Please provide total energy efficiency spending by the Company in the 2022 calendar year by zip code.

Response:

PGE objects to this request on the basis that it is overly broad and unduly burdensome. Notwithstanding its objection, PGE responds as follows:

PGE does not track total energy efficiency spend at this level of granularity nor is PGE provided total spend by zip code in the monthly Program Participation Information provided to PGE from the Energy Trust of Oregon.

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 406
Dated March 30, 2023

Request:

Please provide the number of customers participating in the Income-Qualified Bill Discount program currently participating in the energy efficiency programs supported or administered by the Company.

Response:

PGE public purpose charge (PPC) dollars fund Oregon Housing and Community Services (OHCS) low-income affordable housing and low-income weatherization. The allocation for these dollars tripled following the passage of House Bill (HB) 3141 in 2021, from approximately $16M to $46M annually. These dollars are allocated to income eligible customers for: 1.) bill payment assistance via the Low-Income Home Energy Assistance Program (LIHEAP) and Oregon Energy Assistance Program (OEAP) and 2.) energy efficiency via the Weatherization Assistance Program (WAP) and Energy Conservation Helping Oregonians (ECHO). PGE's Income-Qualified Bill Discount (IQBD) program income eligibility aligns to the same 60% state median income (SMI) as the LIHEAP/OEAP programs. At present, PGE does not track the number of IQBD customers that participate in LIHEAP, OEAP, WAP, ECHO, or Energy Trust of Oregon programs, though it is piloting an effort to deploy no-cost ductless heat pumps in partnership with Energy Trust of Oregon, to IQBD customers in the 2023 planning year.

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 407
Dated March 30, 2023

Request:

Please provide the current number of customers successfully connected to energy efficiency and weatherization programs through their participation in the Income-Qualified Bill Discount program.

Response:

See PGE's response to OPUC Data Request No. 406.

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 408
Dated March 30, 2023

Request:

On average, over the 2020 to 2022 calendar period, please provide the average (in percentages) reduction household energy use for the Company's customers accessing energy efficiency programs. Please also provide the ratio of $/kwH for reduction in household energy usage for the Company's customers accessing energy efficiency programs.

Response:

PGE does not track reductions in household energy use due to participation in energy efficiency programs, generally, or Energy Trust of Oregon programs, specifically. Given PGE does not track reductions in use there is currently no ratio of $/kWh to associate. The Energy Trust of Oregon is preparing their 2022 Customer Participation and Awareness survey results which will describe bill savings per year for participants. This survey will be made available, alongside annual reports here, Documents - Energy Trust of Oregon.

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 409
Dated March 30, 2023

Request:

Please provide the calendar 2022 distribution of energy efficiency funds and participation rates across PGE's service territory by residential customer segments including but not limited to, racial or ethnic background, and income brackets.

Response:

The distribution of energy efficiency funds to the residential segment was 21.8% of the approved 2022 Energy Trust of Oregon Budget[1]. Energy Trust of Oregon has yet to release actuals in its Annual Report for 2022.

PGE does not currently track participation by racial or ethnic background nor income. Energy Trust upcoming 2022 Customer Participation and Awareness survey will provide program participation by race, income, ownership and building type. The annual report and previous annual reports can be found here, Documents - Energy Trust of Oregon.

[1] Retrieved from: 2022-Approved-Budget-Binder.pdf (energytrust.org) (p.89)

April 13, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 411
Dated March 30, 2023

Request:

Please explain the 2022 general usage of funds for energy efficiency and efforts taken by both the Company and Energy Trust to increase energy efficiency outreach and usage for the Company's customers as compared to the Company's last general rate case, Docket No. UE 394.

Response:

PGE collaborates with the Energy Trust of Oregon (Energy Trust) to increase our customers' awareness of and participation in Energy Trust residential and small-to-mid-sized business energy efficiency (EE) programs through marketing and outreach activities. In addition, PGE uses Senate Bill (SB) 838 funding to enhance trade-ally awareness of the Energy Trust Heat Pump program and Heat Pump installation standards. As a utility with existing customer relationships and communication channels, PGE can enhance SB 838-funded activity through newsletters and additional communications channels.

April 17, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 437
Dated April 3, 2023

Request:

Does the Company use demographic data or customer segmentation data to inform proposals impacting the residential customer base?

If so:

a. Please cite all demographic data sources utilized to inform the Company's on its residential customer base, including, but not limited to information on age, race, ethnicity, income, and geographic location;
b. Please indicate if the data was collected by the Company or a third-party and how; and
c. Please indicate how if at all, this data was used to inform proposals in the UE 416 rate case and cite and relative language in PGE's testimony.

If no,

a. Please describe if PGE plans to collect demographic or other customer segmentation data to inform proposals and programs in the future.

Response:

PGE objects to this request on the basis that it is vague and calls for speculation in that OPUC Staff's use of "proposals" is unclear. Notwithstanding its objection, PGE responds as follows: PGE's response is written with the assumption that "proposals" includes activity outside of UE 416.

a. PGE collects and uses customer demographic data from three primary sources.
   - One source is data collected directly from customers, at service connection, during program enrollments, and via surveys. Some data items are collected from all residential customers, while certain data points solicited via enrollment processes or surveys, are collected voluntarily only for a portion of residential customers.
   - A second source of demographic data is modeled data obtained from third party data providers.

- The third source of demographic data is that from the US Census Bureau.

For data that PGE solicits directly from customers, collection points include:

- New service connections, new accounts and account transfers.
- PGE survey research, which includes the following categories of research study:
  - Ongoing survey efforts which are conducted on a regular basis, often quarterly, an example of which is the quarterly residential tracking survey.
  - Residential customer segmentation research efforts which are conducted every few years.
  - Ad-hoc survey efforts which are executed as needed often in support of program development, program management, marketing, or other efforts.
  - OPUC mandated program evaluation surveys.
- Application to PGE's IQBD program; however, customer specific income and race data are narrowly used to inform program outreach and ensure program is reaching all of the communities we serve. These specific data points are not used to inform other programs or customer outreach efforts, as stated on the IQBD application.

Data points collected:

All Residential Customers	Portion of Residential Customers

• Address (PGE, new service)
• Dwelling type (PGE, new service)
• Preferred language (PGE, new account)
• Preferred communication method (PGE, new account)
• Home ownership status (3rd party)
• Household size (3rd party)
• Income range (3rd party)
• Whether household includes (3rd party):
  o Seniors
  o Children
  o Non-White
	• Home ownership status (PGE, surveys)
	• Household size (PGE, surveys & IQBD enrollment)
	• Household income (PGE, surveys & IQBD enrollment)
	• Respondent race (PGE, surveys & IQBD enrollment)
	• Respondent age (PGE surveys)
	• Education level (PGE, surveys)
	• Medically dependent on electricity (PGE, Medical Certificate enrollment)

b. See response to (a) above.

c. Enrollment in PGE's IQBD program was used as a proxy indicator of low income households and used to inform on the impacts of discontinuing inclining block rates for residential customers (UE 416, Exhibit 1300, pages 15-16).

April 17, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 439
Dated April 3, 2023

Request:

Please describe what PGE does to educate customers on understanding of their energy bills and the factors that impact monthly bills and price changes such as tariff riders, power cost, rate cases, etc.

Response:

PGE uses a variety of methods to communicate rate changes to residential customers, explaining high-level drivers of the changes and educating customers on ways they can help manage their consumption or participate in PGE programs to lower their electric bills.

The primary communication methods are:

- Updates to the PGE website
- Social media posts
- On-bill messaging
- Customer newsletters
- Bill inserts (both digital and print)

Residential customers can also view their own usage data by hour or day though PGE's Energy Tracker tool, illustrating when they tend to use more or less electricity.

In January 2023, given the price increase and high-load season, PGE communications focused on bill assistance, energy savings and ways homeowners and renters can reduce their bills.

1. PGE's paper and paperless bills focused on bill assistance programs directing customers to several pages on PGE's website with content on bill assistance, weatherization assistance and more, but primarily portlandgeneral.com/help/help-topics/energy-assistance-programs-residential.

    a. In 2023 Q1 we drove 27,675 distinct users to PGE's bill assistance web page, a 13% increase over the prior year's traffic at that time. The bill inserts drove 39% of this traffic and newsletters (see response 3 below) drove 52%. Visitors stayed on the page an average of 2.4 mins.

2. PGE's home page focused on energy savings; we rotated the message weekly to test message effectiveness and drive repeat attention. The hero image at the top drove customers to portlandgeneral.com/save-money/save-money-home/high-bill-help.

    a. In 2023 Q1 we drove 2,200 distinct users to that page, a 98% increase over the prior year's traffic at that time. They stayed on the page an average of 6 mins.

3. PGE's residential newsletters (print and digital) focused on energy savings and bill assistance programs. These communications featured video stories and efficiency tips for both homeowners and renters and directed customers to relevant pages on portlandgeneral.com.

    a. The homeowner-targeted web page received 3,160 unique visitors, who stayed on the page an average of 2.1 mins, with 1,492 video views across several videos.

    b. The renter-targeted web page saw 2,300 users, who stayed on the page an average of 1.4 mins, with 454 video views of the single video.

Attachments 439-A through 439-H are the customer communications referenced in this response.

May 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 779
Dated May 10, 2023

Request:

Please provide raw anonymized customer-level billing data for all Schedule 83, Schedule 85, and Schedule 89 customers for the calendar year 2022. Please provide this in an .csv file. If necessary, multiple Excel files can be used. Please include any bill for which the billing period or due date starts or ends in calendar year 2022. Please format this data similarly to the response to DR 325. Please provide the data for the data elements listed below. If PGE does not track any of these data elements, please indicate this in your response and return the rest of the data elements. If you have any questions about this request, please reach out to Staff Initiator, Bret Stevens, as soon as possible. Please include the following data elements – the preferred data type are in parentheses:

a. Anonymized customer account ID (string or numeric)
   i. Anonymized site ID (string or numeric)
   ii. Please ensure that the anonymized customer ID and anonymized site ID are persistent across different bills.
   iii. Please ensure that the key linking the anonymous account and site IDs to their respective accounts and sites are retained by the company after anonymization.
b. Bill start date (string or data variable in excel)
c. Bill end date (string or data variable in excel)
d. Bill total (numeric)
e. Energy consumption for billing period (numeric)
   i. On-peak consumption
   ii. Off-peak consumption
f. Demand (Highest metered kW reading for a 30-minute period)
   i. On-peak
   ii. Off-peak
   iii. Average of the two greatest monthly demands within a 12-month period
g. NAICS Code

Response:

Confidential Attachment 779-A provides the requested anonymized customer data for 2022, as well as fields indicating rate schedule and service delivery level (class). Regarding, part (g), PGE notes that NAICS classification accuracy is inconsistent and recommends this field be used with caution.

Attachment 779-A contains protected information and is subject to General Protective Order No. 23-039.

April 17, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 447
Dated April 3, 2023

Request:

Among IQBD participants, please provide the total number of customers and percent of IQBD participants who have been disconnected for non-payment between 2014-2023 (*noting the moratorium period and 2018 PGE billing issue as exceptions).

Response:

PGE objects to this request as it is unduly burdensome and requires new analysis. Without waiving said objections, PGE states as follows:

PGE cannot readily access and provide data on individual service points that were disconnected for non-payment prior to the COVID-era disconnection moratorium that spanned April 2020 through July 2021. The accessible data aggregates disconnection data for all residential customers by month and year.

Among the 51,444 customers who received an IQBD discount on their March 2023 bill, 5,877 had been disconnected for non-payment between August 2021 and March 2023. This equates to nearly 11% of IQBD participants.

CASE: UE 416
WITNESS: ISHRAQ AHMED

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

June 13, 2023

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

A. My name is Dr. Ishraq Ahmed. I am a Senior Utility Analyst employed in the Energy Costs Section of the Rates, Safety, and Utility Performance Program 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 qualifications statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I present Staff's analysis regarding Portland General Electric's (PGE or Company) 2024 proposal to modify the Schedule 125 guidelines to include net variable power cost (NVPC) forecast modeling enhancements in non-GRC years and an overview of PGE's plans to join the Extended Day Ahead Market (EDAM). I have made some recommendations, but I have no adjustments to the Company's revenue requirement.

Q. Did you prepare any exhibits for this docket?

A. Yes, in addition to my witness qualification statement in Exhibit Staff/701, I prepared Exhibit Staff/702, which includes non-Confidential Data Request (DR) Responses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. SCHEDULE 125 GUIDELINES UPDATE

Q. What is PGE's proposal?

A. PGE proposes to modify the Schedule 125 guidelines to include net variable power cost (NVPC) forecast modeling enhancements in non-GRC years. This would give parties the flexibility to propose modeling enhancements in Annual Update Tariff (AUT) dockets. PGE believes this allows them to address evolving market and operational challenges that can impact NVPC forecasts and suggests that the current energy market dictates that there is an increased need for year-to-year NVPC forecast modeling flexibility.[1]

Q. When did the Commission adopt the Annual Update Tariff (AUT) and Schedule 125 guidelines?

A. The Commission adopted the AUT in Docket Nos. UE 180, UE 181,and UE 184 through Order No. 07-015 and subsequently established Minimum Filing Requirements (MFRs) in Docket No. UE 198 through Order No. 08-505.

Q. What does Order No. 07-015 say concerning modeling enhancements?

A. The Commission adopted PGE's proposal "to limit the number of model enhancements. Model changes or updates could be considered, not in the Annual Update process, but in a separate docket."[2] PGE's compliance Tariff, Schedule 125, reflects this ruling, listing the permissible updates that may be

---

1 PGE/300, Schwartz-Outama-Cristea/11-12.
2 *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 180, Order No. 07-015, p. 19 (January 12, 2007).

made in the annual AUT filing and specifying “[n[o other changes or updates will be made in the annual filings under this schedule.”[3]

Q. PGE testifies that the prohibition on modeling changes and updates was adopted as a “guideline” in Order No. 08-505 when the Commission adopted the requirement for Minimum Filing Requirements. Do you agree?

A. No. I do not think this is an accurate reflection of the history. The prohibition on updates other than those specifically allowed by Schedule 125 is in the tariff itself and was specifically adopted as part of the AUT in Order No. 07-015. The language in Order No. 08-505, referred to by PGE, is intended to specify when information regarding modeling enhancements and updates must be filed. Order No. 08-505 specifies this information is not required in years when PGE only files an AUT update, presumably because such updates are not permissible in this circumstance under Order No. 07-015. However, the language in Order No. 08-505 does confirm that modeling enhancements are not permissible inyears when the AUT is updated in a stand-alone proceeding.

Q. Does it matter whether Commission policy is a prohibition or guideline with regards to when model enhancements can be proposed significant to deciding the merits of PGE’s proposal?

A. Probably not. However, Staff thought it was important to clarify the history of the limitation on updates to the AUT.

---

3 PGE Advice No. 07-05 (Schedule 125).

Q. Why is PGE proposing this change to the AUT?

A. PGE testifies that it recommended the limitation on updates and modeling enhancements when it proposed the AUT in 2006 based on its prior experience with the NVPC forecast process which indicated that any modeling changes led to very small changes in NVPC forecast at the time. PGE stated that there may be "process efficiency gains" by handling modeling enhancements in GRC years instead of AUT years, and parties would have sufficient time to evaluate changes. However, PGE now believes that in the current energy market environment, there is an increased need for year-to-year NVPC forecast modeling flexibility to address new and evolving operational challenges and market changes.[4]

Q. What is Staff's position on PGE's proposal?

A. Staff agrees with the reasons PGE states about more frequent modeling enhancements or updates for the AUT mechanism. However, Staff does not agree that the current process for stand-alone AUT proceedings is sufficent to allow parties an adequate opportunity to vet modeling enhancements.

Q. Does Staff have other concerns?

A. Yes. PGE implies that giving stakeholders the opportunity to propose modeling enhancements on an annual basis can lead to a more accurate NVPC forecast for the test year.[5] While Staff sees value in engaging stakeholders to seek modeling enhancements in stand-alone AUT years, it is unclear whether Staff

[4] PGE/300, Schwartz-Outama-Cristea/12.
[5] PGE/300, Section III.A.

and other intervenors will have an ability to propose modeling enhancements in the relatively abbreviated procedural schedule allowed for a stand-alone AUT update.[6]

Q. What is Staff's recommendation regarding the Schedule 125 update?

A. Staff only supports allowing modeling changes and enhancements under Schedule 125 and outside of a GRC, if the timing of PGE's filing is such that there is enough time for a thorough review. Staff does not believe there is sufficient time in the current process for stand-alone AUT proceedings. If PGE suggests complex modeling changes to respond to the evolving market and operational challenges as pointed out by PGE, the abbreviated schedule is likely not sufficient to allow all parties time to review changes and make recommendations. Accordingly, if the Commission agrees to PGE's proposal to allow modeling changes in years when there is no GRC, Staff recommends PGE be required to file all of its proposed modeling enhancements or changes by no later than February 15, with discovery commencing thereafter. Staff also recommends that PGE be required to hold workshops at Staff and stakeholders' request during each AUT proceeding so that all parties involved have the opportunity to raise questions and seek clarifications on modeling changes. This February 15 date applies only to the modeling changes and enhancements and not to the AUT filing date, which can remain on its current schedule.

---

[6] See Staff/702, PGE Response to DR 276.

ISSUE 2. EDAM

Q. Please describe the EDAM.

A. The proposed EDAM is a voluntary day-ahead electricity market where renewable resources will be more efficiently and effectively integrated to address operational challenges presented by what PGE describes as a rapidly changing resource mix, new technologies, and the impacts of climate change. EDAM builds on the ability of the Western EIM to increase regional coordination, support state policy goals, and meet demand cost-effectively.[7]

Q. Does PGE plan to participate in the EDAM?

A. Although the EDAM is expected to go live in 2024, PGE has not yet decided to participate. The Commission's Order in PGE's last AUT proceeding required PGE to (1) submit written quarterly updates in this docket at the same time PGE holds Quarterly Power Supply Update meetings with stakeholders; (2) hold a workshop on the CAISO EDAM before filing the 2024 AUT; and, (3) Provide testimony in the 2024 AUT regarding i) Resource Sufficiency Evaluation, Greenhouse Gas accounting and costs, and Transmission impacts; and ii) Potential costs and benefits from EDAM participation, based on the most recently available information.[8] PGE filed the reports and held a workshop on the EDAM in February 2023.

Q. What requirements would PGE need to meet to participate in the EDAM?

---

7 PGE/300, Schwartz-Outama-Cristea 48.
8 *In the Matter of Portland General Electric Company*, 2023 Annual Power Cost Update, UE 402, Order No. 22-427, p. 3 (November 1, 2022).

A. Potential EDAM participants are required to meet BAA (Balancing Authority Area) requirements in meeting forecasted demand, uncertainty, and ancillary service requirements before engaging in transfers with other participating BAAs through the day-ahead market. These requirements are summarized in the EDAM resource sufficiency evaluation (RSE). The EDAM RSE tests whether each participating BAA has sufficient capacity and flexibility ahead of participating in the day-ahead market at 10 a.m. and imposes penalties for a BAA that fails the evaluation.

The EDAM RSE in the CAISO EDAM Final Proposal outlines the following requirements to determine whether there is sufficient generation capacity available to meet forecasted demand for electricity during the day-ahead timeframe:[9]

a. Forecasted Demand

b. Imbalance Reserves

c. Flexibility Requirement

d. Ancillary Services Requirement

e. Reliability Capacity Bidding

Q. Describe Staff's analysis of EDAM.

A. Staff analyzed whether for each RSE criteria there is a benchmark used to determine whether a utility meets the critera. Staff concluded there are no static benchmarks.[10] At this time, Staff cannot tell whether PGE can meet the

---

9 See Staff/702, PGE Response to DR 292 and PGE/300, Schwartz-Outama-Cristea 49-50.

10 See Staff/702, PGE Response to DR 292.

RSE criteria. However, while PGE has not committed to joining the EDAM, they indicated that they would plan, procure, and operate to adhere to the required standards.

Q. Has Staff identified any issues that need to be considered if PGE joins EDAM?

A. Yes. PGE indicated that there could be a reduction in operational flexibility in the market if PGE participates in the EDAM.[11] It is not evident how any reduction in such flexibility from potentially joining the EDAM will affect customers. PGE notes that more time may be needed to evaluate the operational impacts of the EDAM and PGE will continue to provide EDAM updates in the Quarterly Power Supply Update (QPSU).[12] PGE indicated that since the Company has not decided yet whether it will participate in the EDAM, PGE has not estimated any impacts on the NVPC forecast yet. The Company does acknowledge that NVPC modeling may need changes in the future to address the market complexities associated with the EDAM.[13]

Q. Does Staff have any recommendations?

A. No. Staff does not have any recommendations at this time but has identified some issues that need to be considered when PGE decides to participate in EDAM. First, it is unclear how a reduction in operational flexibility from participating in the EDAM will affect customers. Since CAISO would control transmission rights available to the market by 10 a.m. every day seeking to

---

[11] See Staff/702, PGE Response to DR 293.
[12] Ibid.
[13] PGE/300, Schwartz-Outama-Cristea 51.

maximize the amount of transmission available in EDAM, this design could impact the COB margins.[14] It is therefore unclear how participating in the EDAM will lead to customers being affected by transmission being maximized in one market and not in the other. PGE indicated that it is in discussions with the CAISO to better understand the operational impacts of the EDAM on the COB and the details are not known at this time. [15]

Second, PGE did not provide information on whether it has possible plans to remedy operational constraints from joining EDAM if and when they arise. As PGE stated, they will provide EDAM updates in the QPSU.

Finally, PGE's suggestion that they may incorporate some NVPC modeling changes in the future to take into account EDAM participation may pose added complexities when all parties can review MONET modeling enhancements in non-GRC years in the timeframe PGE suggested (discussed in Issue 1. Schedule 125 guidelines update).

Q. Does this conclude your testimony?

A. Yes.

---

[14] See Staff/702, PGE Response to DR 293 and PGE/300 Schwartz-Outama-Cristea 50.

[15] See Staff/702, PGE Response to DR 293.

CASE: UE 416
WITNESS: ISHRAQ AHMED

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Dr. Ishraq Ahmed
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Costs Section
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	I have a Ph.D. in Economics from Southern Illinois University, Carbondale. I also hold a Master's degree in Economics from the University of Nottingham, UK, and a Bachelor's degree in Financial Economics with a minor in Mathematics from Centre College, KY.
EXPERIENCE:	I have been employed as a Senior Utility Analyst at the Oregon Public Utility Commission (PUC) since August 2022 in the Rates, Finance, and Audit Division where I am the Staff lead on gas utility rate issues. I have worked on annual Purchased Gas Adjustments, and Compliance filings and am currently working on Annual Power Cost filings and general rate cases UE 416 and UG 461. Before joining the PUC, I was an Assistant Professor of Economics at Black Hills State University and Dickinson College from 2017 through 2022. I have worked as a Graduate Research and Teaching Assistant during my Ph.D. training in conducting research with my Ph.D. supervisor and teaching graduate-level and undergraduate-level economics classes. I was previously employed as a Research Associate at the Institute of South Asian Studies with the National University of Singapore and before that, I served as an Economist with the Policy Research Institute coordinating a team of research assistants and working on research projects. I have additionally worked as a consultant with various multilateral organizations such as the International Labor Organization (ILO) and the World Bank.

CASE: UE 416
WITNESS: ISHRAQ AHMED

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

June 13, 2023

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 276
Dated March 14, 2023

Request:

See PGE/300, Schwartz—Outama—Cristea/11, which states, "The approval of this proposal will ensure that PGE has the modeling flexibility to address the increased operational challenges and market changes due to both new design, regulations, and fundamentals that we expect in future years and allow for a NVPC forecast that is as accurate as possible." Please elaborate and specify how modeling flexibility is increased in the context of the proposed specific modeling enhancements in this testimony.

Response:

The paragraph refers to PGE's proposal to modify Schedule 125 guidelines and allow all stakeholders to propose NVPC forecast modeling enhancements and new items in non-GRC years. The paragraph is not specific to modeling enhancements and new items proposed within the 2024 NVPC forecast.

The approval of this proposal will provide all stakeholders the flexibility to propose modeling enhancements in non-GRC years, and therefore allow PGE to address new and rapidly evolving operational challenges and market changes that are expected to impact PGE's power operations in the near-term. As described in PGE Exhibit 300, Section III.A, PGE has limited opportunity to propose modeling enhancements in AUT years, unless directed by a Commission Order or agreed between parties.

The proposed enhancements and new items for the 2024 NVPC forecast do not expand the MONET modeling flexibility but simply allow for a more accurate NVPC forecast that captures costs and benefits that are expected to be incurred in the test year.

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 292
Dated March 14, 2023

Request:

PGE / 300, Schwartz – Outama – Cristea / 49 discusses the EDAM RSE requirements, where EDAM participants have to meet BAA requirements. Regarding the maintenance of Imbalance Reserves, Flexibility Requirement, Ancillary Services Requirement, Reliability Capacity Bidding; are there stated benchmarks that PGE needs to follow? Please provide numbers and describe in detail.

Response:

"The EDAM RSE will test an EDAM entity's ability to meet its BAA requirements, including demand and ancillary service obligations, in each of the 24 hours of the day-ahead market run, as well as the flexibility to ramp between the requirements in each hour."[1] Therefore, there isn't a static benchmark that PGE would follow. PGE has not made a commitment to join EDAM. If we were to, we would plan, procure, and operate with the intention to adhere to all standards as required by the market.

The EDAM Final Proposal provides the following details regarding the EDAM RSE:

The EDAM RSE ensures that each participating BAA is separately able to meet its obligation prior to participating in the EDAM. The EDAM RSE will test an EDAM entity's ability to meet its BAA requirements, including demand and ancillary service obligations, in each of the 24 hours of the day-ahead market run, as well as the flexibility to ramp between the requirements in each hour. The following summarizes the elements of the EDAM RSE:

(1) Forecasted Demand: Each EDAM BAA's ability to meet its forecasted demand requirement ensures sufficient supply is available to meet forecasted energy usage and prevent leaning on the capacity or flexibility of other participating EDAM BAAs. The ISO will offer a demand forecast for each EDAM BAA. If an EDAM entity chooses not to utilize the ISO forecast, it can submit its own forecast with the understanding that

[1] CAISO EDAM Final Proposal at page 62, available at: http://www.caiso.com/InitiativeDocuments/FinalProposal- ExtendedDay-AheadMarket.pdf

referencing the most accurate forecast is the objective. The proposal is that the forecast contain the average loss factors as defined by each EDAM entity in its OATT; EDAM generation-only BAA's will have an average loss factor applied based on their forecast or bid in resource output. This will ensure the most accurate forecast is used for the EDAM RSE and RUC process; metrics will be maintained to ensure the most accurate forecast is being used.

(2) Imbalance Reserves: The proposal is that each EDAM BAA possess sufficient supply and flexibility necessary to meet its imbalance reserve obligations. Procuring sufficient imbalance reserves will increase the reliability of EDAM transfers, thus maximizing the chances each EDAM BAA will have sufficient reserves to cover its upward and downward uncertainty requirements. Potential generation-only EDAM BAA's may receive imbalance reserve obligations if they operate variable energy resources that drive the intraday uncertainty imbalance reserves are designed to address.

(3) Flexibility Requirement: The EDAM will create an optimal schedule across 24 hours. An EDAM BAA's ability to meet forecasted ramping requirements across the 24-hour period is an integral component of being resource sufficient. The EDAM RSE application indirectly will assess this ramping capability by testing whether an EDAM BAA has a feasible schedule, ramping between hourly requirements across this same time period.

(4) Ancillary Service Requirements: Each EDAM BAA will define its ancillary service requirements consistent with its reliability requirements. These requirements will be provided to the market operator prior to running the EDAM RSE, and the EDAM entity can update them until 9:00 a.m. when all test inputs are fixed. The EDAM RSE will then test and validate whether an EDAM BAA has self-provided sufficient capacity to meet its requirements that does not overlap with supply made available to the EDAM. The EDAM will accommodate ancillary service requirements that are satisfied through participation in a reserve sharing group. If multiple EDAM BAAs participate in a reserve sharing group, the proposal is to require them to identify the transmission that will be utilized to ensure delivery of the shown reserve capacity, consistent with existing practices the entities have in place today for delivery of the reserves. This transmission capacity will be withheld from the market optimization to ensure the deliverability of the reserve sharing obligations in real time.

(5) Reliability Capacity Bidding: The proposal is that all entities participating in EDAM that submit a day-ahead energy bid into the Integrated Forward Market (IFM) also submit a bid for a matching quantity of reliability capacity in the RUC process of the day-ahead market. Availability bids for any portion of the forecasted supply of variable energy resources will be inserted for any forecasted quantity that does not have a bid. This will ensure RUC has sufficient capacity and accurately considers the impact of variably energy resources when clearing against the forecasted obligation.[2]

[2] Supra at 62-63

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 293
Dated March 14, 2023

Request:

PGE states that there may be expected transmission constraints from participating in the EDAM and suggests the COB margins might be affected. Please explain in detail:

(6) How COB margins will be affected.
(7) What impact it will have on NVPC.
(8) How it will affect consumers.
(9) Possible plans PGE has to remedy possible constraints to meeting load.

Response:

a. PGE assumes that the referenced statement is the following: "However, this design could impact the California-Oregon Border (COB) transaction margins as CAISO would control the transmission rights available to the market by 10:00 a.m."[1] In this statement, PGE is referring to a potential reduction in operational flexibility in the market, not a "transmission constraint" which assumes congestion on a flowpath. As PGE is in active discussions with the CAISO to better understand operational impacts of the EDAM on the COB, the details of these potential changes in flexibility are relatively unknown at this point. Moreover, PGE notes that unlike the Western Energy Imbalance Market, EDAM is not an incremental market. Therefore, more time is needed to assess the potential benefits to PGE customers. PGE will continue to provide updates on the EDAM and impacts to PGE in the Quarterly Power Supply Update.

b. See part a.

c. See part a.

d. See part a.

---

[1] PGE Exhibit 300, page 50.

CASE: UE 416
WITNESSES: Bret Stevens and Robert Young

PUBLIC UTILITY COMMISSION
OF
OREGON

EXHIBIT 800

Opening Testimony

June 13, 2023

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates, Safety, and Utility Performance Program 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 qualifications statement is found in Exhibit Staff/2001.

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

A. My name is Robert Young. I am Managing Director at Economists.com, a consulting firm located in Portland, Oregon. My business address in 7380 SW Kable Lane, Portland, Oregon 97224.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2101.

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared the following supporting exhibits:

- Exhibit Staff/801, which contains Staff's revenue requirement adjustment calculation.
- Exhibit Staff/802, Which contains non-confidential PGE responses to Staff data requests.

Q. What is the purpose of your testimony?

A. We recommend the Commission reject the pre-test period snapshot (PTPSS) method used by PGE to calculate rate base for purposes of establishing the return component of PGE's revenue requirement.[1] Staff recommends the Commission calculate rate base using the "average of monthly averages" method, which historically has been the method most commonly used by the Commission.

For purposes of calculating the return component of revenue requirement PGE uses the PTPSS rate base value. The PTPSS method is more advantageous to utilities. Accordingly, using the average of monthly averages method for determining rate base will result in a reduction to the required net operating income proposed by PGE. Here, the difference between the PTPSS and the average of monthly averages methods yields a reduction to PGE's proposed revenue requirement by roughly $21.7 million.[2]

Q. Please explain the PTPSS method of rate base calculation.

A. The PTPSS method of rate base calculation uses values for gross plant, accumulated depreciation, accumulated deferred income taxes, and depreciation expense as of the year ended just prior to the proposed effective date for new rates. In UE 416, PGE's rate base calculation is based on December 31, 2023.[3] In previous cases, this method has been called the "year-end method."

---

1 This method has historically been known as the year-end method. Staff is calling this method pre-test period snapshot (PTPSS) to clarify the year-end in question is before the Test Year starts.

2 This estimate is based off 2023 forecasted depreciation expense. Staff requested forecasted depreciation expense for 2024 in OPUC DR 819. PGE misinterpreted this request. Staff will resubmit the DR and be able to provide a more accurate figure in a future round of testimony.

3 PGE/200, Batzler-Ferchland/3 (Rate base is established as of December 31, 2023).

Q. Please generally explain the average of the monthly averages method of rate base calculation.

A. Here, for the Test Year ending on December 31, 2024, the average of monthly averages rate base is calculated using a 13-month average for 2024 rate base amounts, without new capital additions that cannot be included in accordance with ORS 757.355. This 13-month average is the sum of the monthly balances from December of 2023 through December of 2024, less one-half of each December balance, divided by 12.

Q. Please elaborate on the differences between the PTPSS method PGE proposes and the average of monthly averages method that Staff has proposed?

A. To do so, we will start with the similarities. Both methods are intended to calculate the appropriate rate base for plant-in-service for the 2024 Test Year. Neither method includes plant that will not be in service by the rate effective date of January 1, 2024. The difference between the two is that PTPSS method holds the January 1, 2024, rate base level static through the Test Year, while the average-of-monthly averages method recognizes that the plant in the rate base depreciate during the Test Year.

The difference can be seen most plainly with assuming the only plant the Company has is all new plant that comes on-line in December 2023. If rate base is determined with the PTPSS method, the customer rates will be calculated assuming this new plant is not reduced due to depreciation at all throughout the Test Year. If rate base is determined with the average-of-monthly averages method, customer rates will be calculated assuming the new plant is reduced during the test year as a result of depreciation.

Q. Is it important that the Test Year rate base reflect actual depreciation during the Test Year?

A. Yes. Otherwise, ratepayers will overcompensate PGE for the return PGE is allowed to earn on its rate base. The key is that retail customers are paying for depreciation expense that occurs in 2024 but do not see any benefit of those payments in net plant and the return required associated with that net plant.

Q. Has the Commission previously recognized that it is appropriate to use the average of monthly averages method to match revenues and costs as opposed to the PTPSS (aka year-end method)?

A. Yes. In Order No. 74-898 the Commission wrote:

> The company proposes a year-end adjusted rate base of $14,117,688. Staff proposes an average of the monthly averages, which results in an adjusted rate base of $13,174,075.
>
> …Staff's method has long been approved for use in utility rate making in Oregon because an average rate base more closely relates to the operating results during the test year. The use of average rate base tends to preserve the significance of the test period as a basic regulatory tool. The average rate base is adopted.[4]

---

4 *In re Cascade Natural Gas Company,* UF 3094, UF 3129, Order No. 74–898 (November 21, 1974) (1974 WL 391913). *See also, In re:* Northwest Natural Gas Company, UF 3222, Order No. 76-954 (August 30, 1976) (1976 WL 421881) (Rate base computed on a monthly average basis).

In 1976, the Commission wrote:

> The commissioner's staff recommends adoption of an average-of-monthly averages rate base. The company's adjustments pertaining to 1974 rate base have not been subjected to audit by the commissioner's staff. The staff's average-of-monthly averages rate base approach provides the most certain method for determining the company rate base and, absent detailed and persuasive evidence from the company concerning the need for adoption of a rate base, should be accepted.
>
> An average-of-monthly averages rate base is adopted. It protects the interest of the ratepayers by preserving the relationship of known revenues and expenses to rate base. As applied in this case, it does not deny the company the opportunity to enjoy a reasonable return on its investment.[5]

Q. Are there many cases in which the Commission has discussed use of the average of monthly averages for determining rate base?

A. There are several from the 1970s. They demonstrate the average of monthly averages method was used by the Commission in dockets dating back to before 1970. For example, in Order No. 70-797, the Commissioner wrote:

> Staff, on the other hand, adopts for its computation of rate base the monthly average of the test-year months divided by twelve, or what is sometimes called 'average-of-monthly-averages' method.
>
> The commissioner has recently used the average-of-monthly-averages method in two major rate cases. Portland General Electric Company urges that the end-of-the-year method more fairly reflects plant valuation as of the effective date of new tariff schedules. No compelling reason has been presented in the instant case to justify departure from the averaging method long approved for utility rate making in Oregon.[6]

---

5 *In re Continental Telephone Co. of the Northwest, Inc.*, UF 3162, Order No. 76-061 (January 24, 1976) (1976 WL 419228).

6 *In re Portland General Electric Company*, UF 2811, Order No. 70-797 (December 11, 1970) (1970 WL 224163).

Staff is unaware of any order in an energy rate case since 1976 in which the Commission addressed whether an average of monthly averages or PTPSS calculation should be used to calculate rate base. Staff is also unaware of any docket in which the end-of-year method was used to determine rate base until PGE did so in 2014. There were multiple rate cases between 1976 and 2014 resolved by stipulations. The orders Staff reviewed in stipulated cases all reflect the stipulations were based on "average rate base." Lastly, no order in a non-stipulated energy rate case, to Staff's knowledge, addresses this issue or authorizes a utility to use the PTPSS method to calculate rate base.

Q. In what docket did PGE begin using the year-end method for the rate base calculation?

A. In 2014, in the GRC docketed as UE 283. In that case, the rate base proposed by PGE in its initial filing used the PTPSS rate base calculation.

Q. Did PGE provide a rationale at that time for departing from the average of monthly averages method?

A. No. PGE proposed the PTPSS method with a statement that rate base is calculated on a PTPSS base but did not mention that this represented a change in long established average of the monthly averages rate base calculation formula and no discussion on the reason for the change. The rate base stipulated to by parties was $80 million less than that proposed by PGE in its initial filing. Of that $80 million reduction, $42.7 million related to correcting deferred income taxes and $10 million was for removing capitalized financial incentives. The remainder of the adjustment was not supported by any rationale and the methodology used to calculate the rate base was not discussed in the stipulation or Commission order.[7]

Q. Why did Staff not oppose PGE's change in rate base change UE 283? Did Staff provide testimony opposing PGE's proposed calculation of rate base?

A. In talking with Dr. Marc Hellman, currently Administrator of the Rates, Safety and Utility Performance Division, he stated that he did not recall this change and only became aware of the change in practice in early 2023 discussions with PGE on a wildfire AAC mechanics. Those discussions led to this Staff review and testimony on the proper method to calculate rate base.

In all PGE rate cases since UE 262 filed in 2013, the rate base has been agreed to through stipulation. This means that the Commission has accepted the rate base figures as part of a package of other agreed-to terms. There has been no meaningful discussion of this issue in testimony. Staff believes that this issue is of sufficient importance to warrant a full discussion of the topic in a rate case proceeding. Whatever the Commission's choice on the method to calculate rate base, we think it is best to base it on an informed discussion and be done so explicitly and evaluated in a Commission order.

As noted above, the revenue requirement difference between the PGE-proposed and the Staff-proposed approaches is over $20 million.

---

[7] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 283, Order No. 14-422, Att. B, p. 2 (December 4, 2014).

Q. Did you review recent OPUC Orders to look for language authorizing the change from average of the monthly averages to PTPSS rate base, and did you review testimony in OPUC Dockets from 2012 to present to look for discussion either supporting or opposing the change in rate base calculation?

A. Yes. We did. Table 1 below shows the OPUC Dockets we examined between 2012 and 2023. We could not find any testimony from a utility, Staff, or any intervenor which thoroughly discusses changing the rate base calculation from average of the monthly averages to PTPSS.

Table 1. OPUC Docket Search

PGE	PacifiCorp	Avista
UE 262	UE 246	UG 201
UE 294	UE 263	UG 256
UE 319	UE 374	UG 284
UE335	UE 399	UG 325
UE 394	-	UG 366
-	-	UG 389
-	-	UG 433

Q. What is PGE's explanation its choice to use the PTPSS calculation?

A. In DR 203 Staff asked why PGE thought the PTPSS methodology was appropriate. PGE responded with the following statement:

> As we note in PGE Exhibit 200, page 3, "[r]ate base is established as of December 31, 2023." PGE selected this point in time for establishing rate base amounts because it is prior to the start of PGE's proposed price effective date of January 1, 2024. This complies with ORS 757.355(1), which states in part "…a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or

> personal property not presently used for providing utility service to the customer."[8]

Q. Does Staff agree with this logic?

A. No. While Staff agrees that capital additions in the Test Year should not be included, to be in compliance with ORS 757.355(1), Staff disagrees that it is appropriate to exclude the effects of Test Year depreciation from the Test Year rate base. Because customers are paying for the depreciation, they should get the benefit of that depreciation on its effect on rate base. The average of monthly averages approach better aligns the costs the utility incurs with the revenues it receives. In Staff's view, PGE's explanation looks like an attempt to make up a remedy for the regulatory lag that may be due to ORS 757.355(1), as opposed to calculating the rate base in the most accurate way possible in light of ORS 757.355(1).

Even if the Commission were inclined to expressly adopt PGE's proposal, Staff believes it could turn ORS 757.355 on its head in the sense that customer rates could end up higher than a world where ORS 757.355 did not exist.

Q. Are there any other considerations that argue against using the PTPSS approach given ORS 757.355(1)?

A. Yes. There are two. First, PGE is in control as to the timing of when it files its general rate cases. To the extent PGE is aware of a new large capital investment being constructed, it can time its rate case so that new rates incorporate this new capital investment. This shortens the regulatory lag

[8] Staff/802, PGE Response to Staff DR 203.

between the time that the project is completed and the effective date of the Commission-ordered rates.

The second consideration is what is known as a “tracker” which is essentially a “second” rate increase that would be authorized to go into effect after the effective date of new rates as a result of a general rate increase. Examples of recent PGE requested trackers are Carty and Faraday. Staff has been supportive of trackers if the large capital project, typically new electrical power projects, will come on-line relatively soon after the end of the suspension period. In docket UE 394, Staff was not supportive of a Faraday tracker because it was not expected to be on-line within six months of the end of the suspension period. In this sense, “relatively soon” means within six months.

Continuing with this analogy, if a tracker were to be authorized it seems particularly egregious that the revenue requirement of that new project would have rates reflect a return component that is essentially the first-day rate base value as opposed to the rate base value reflecting half a year’s worth of depreciation. In any case, the availability of trackers, further reduces any argument of unfairness of ORS 757.355 with respect to utility recovery of costs.

Q. Please summarize Staff’s position.

A. The methodology used to determine a utility’s rate base in a GRC can have a significant impact on the utility’s revenue requirement. The Commission previously determined that the average of monthly averages method is appropriate as discussed in previous Commission orders. There has not been a thorough discussion into the change in rate base calculation that PGE began using in UE 283. Staff does not support PGE's approach and recommends the Commission use its past practice of average of monthly averages method used by the Commission for decades.

Staff also is not opposed to filings that include distribution-related capital additions tied to customer load growth. For example, Avista practices this approach and Staff has agreed in prior cases. Staff recommends including these capital additions to address the lack of symmetry that would occur if PGE's revenue requirement included revenue from forecasted load growth during the test year but not new distribution facilities to serve the load.

Q. Please discuss your adjustment as it applies to this specific filing and the resulting revenue requirement reduction.

A. At this time, Staff is recommending a revenue requirement reduction of $21.7 million. This represents the reduction to PGE's required return based on Staff's proposed rate base calculation. Staff does note that this is not the final adjustment. In OPUC DR 819, Staff asked PGE for the information necessary to make Staff's preferred calculation. This request was misinterpreted by PGE and the information was not available in time for publication. Staff is following up with PGE to retrieve the requisite data. The $21.7 million adjustment Staff is proposing here is based on half of PGE's 2023 depreciation expense given in PGE/201 and Staff's proposed ROE of 9.0 percent. The calculation can be seen in Staff/801.

SUMMARY

Q. What methodology should the Commission use to calculate PGE's rate base in UE 416?

A. For the purposes of calculating PGE's required return, Staff recommends changing PGE's proposed rate base calculation to reflect an average of the monthly averages based on gross plant in service, accumulated depreciation, accumulated deferred income taxes and depreciation expense for the Test Year excluding major capital additions. This change produces an adjustment of roughly $21.7 million. Staff's adjustment is currently an estimate and will be modified in future testimony. Staff's recommendations may change based on further review and as informed by the testimonies offered by other parties.

Table 2. Staff Adjustments

Adjustment	Change to Revenue Requirement
Change from PTPSS to Average of the Monthly Averages Rate Base Calculation	$21,703,000

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESSES: Bret Stevens and Robert Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Revenue Requirement Adjustment Calculation

June 13, 2023

Exhibit 801

Adjustment to Change from Year End to Adjustment for Average of the Monthly Averages for Rate Base Calculation

PGE 2023 Depreciation	Half 2023 Depreciation	Net Income Required	Gross up Factor	Revenue Requirement Adjustment
$339,638	$169,819	$15,284	1.42	$21,703

CASE: UE 416
WITNESSES: Bret Stevens and Robert Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Non-Confidential Responses to Staff Data Requests

June 13, 2023

OPUC Data Request 203

Referring to Exhibit/200, Batzler-Ferchland/25, what method does PGE use to determine rate base value does PGE use in UE 416 to determine, in part, the net income required to provide shareholders the Commission determined cost of equity? Is it: a) December 31, 2023, rate base, (b) December 31, 2024, (c) average-of-monthly-averages for the months of calendar 2024, (d) average-of-monthly-averages for December 2023 through the months of calendar 2024 (13 months), or (e) some other rate base value? If the answer is (e), please explain the methodology used by PGE.

a) Please explain why this is the appropriate rate base amount from a conceptual viewpoint.
b) Please explain why each of other options identified are not appropriate.

PGE Response to OPUC Data Request 203

a) As we note in PGE Exhibit 200, page 3, "[r]ate base is established as of December 31, 2023." PGE selected this point in time for establishing rate base amounts because it is prior to the start of PGE's proposed price effective date of January 1, 2024. This complies with ORS 757.355(1), which states in part "…a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."

b) PGE objects to this data request on the basis that it calls for speculation. The request seeks an analysis on matters that we did not express an opinion and is consequently irrelevant. Without waiving said objections, please see the response to request (a) above.

OPUC Data Request 819

Referring to PGE/200 Exhibit 20. Please provide this schedule with Accumulated Depreciation, Accumulated Deferred income taxes and depreciation expense calculated using the average of the monthly averages methodology last used by PGE in UE 262. Please provide all supporting work papers for the calculation in an Excel file with all formulas and links intact.

PGE Response to OPUC Data Request 819

PGE objects to this request as it is overly burdensome and requires significant new work. Subject to and without waiving its objection, PGE responds as follows:

The above requests information that PGE has not prepared or forecast and that is not included within this proceeding. Specifically, using an average of averages for 2024 accumulated depreciation and accumulated deferred income taxes (ADIT), requires a monthly forecast of plant closings from January 1 through December 31, 2024, which PGE has not yet developed as PGE has based its current request on plant closings as of December 31, 2023. Furthermore, as described in PGE

Exhibit 200, normalization rules in the Internal Revenue Code, Section 168(i)(9) require consistency in the calculation of tax expense, book depreciation expense, accumulated book depreciation, and ADIT for ratemaking purposes. As such, if PGE were to have the necessary information to perform the above requested calculation, it would also be necessary to consistently apply this methodology to PGE's rate base and depreciation expense.

CASE: UE 416
WITNESS: Russ Beitzel

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

June 13, 2023

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

A. My name is Russ Beitzel. I am a Senior Utility Analyst in the Rates and Telecommunications Section of the Rates, Safety, and Utility Performance Program 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 qualifications statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. I present Staff analysis in the general category of non-labor administrative and general expenses (A&G).

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/902. .... PGE Responses to Staff Data Requests

ISSUE 1. A&G EXPENSES (NON-LABOR)

Q. Please summarize Staff's adjustments for A&G expense.

A. Staff recommends two separate adjustments to 2024 non-labor A&G expenses totaling ($3,610,613). These adjustments, and Staff's recommendations on each of the accounts reviewed herein, may change as a result of reviewing other parties' testimonies filed in this docket.

Q. What are A&G expenses?

A. Administrative and general (A&G) expenses include human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, information technology (IT), research and development (R&D), employee benefits and incentives, support services, and regulatory fees that fall within the Federal Energy Regulatory Commission's (FERC) definition of A&G.[1]

Regarding non-labor A&G expenses, Staff performed individual analysis on various subcomponents of A&G. In my testimony, I address the following A&G subcomponents: Office Supplies and Expenses (FERC 921), Administrative Expenses Transferred – Credit (FERC 922), Outside Services Employed (FERC 923), Property Insurance (FERC 924), Injuries and Damage (FERC 925), Employee Pension and Benefits (FERC 926), Regulatory

---

[1] Code of Federal Regulations (CFR), title 18, Chapter I, Subchapter C, Part 101 - Uniform System of Accounts (USOA) Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Accounts 920 – 935. Available at: https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

Commission Expense (FERC 928), Miscellaneous General Expenses (FERC 930.2), and Memberships.

Q. Please summarize the Company's overall request for A&G expenses.

A. In the Company's filing, PGE reports actual A&G expenditures (inclusive of Labor costs) of $213.4 million in 2022 and a forecasted 2024 Test Year amount of $209.9 million. According to PGE, the primary drivers of the $3.5 million decline in Test Year A&G expenses (from 2022 actuals to the 2024 Test Year) are reductions to corporate and incentives expense of $6.8 million and $22 million, offset by increases to other A&G expense, most notably a $4.2 million increase to insurance expense and a $16.2 million increase to benefits expense.[2]

Without Labor included,[3] Staff's calculation of PGE's A&G expenses related to FERC Accounts 920–935 shows actual expense of $155 million in 2022, a budget of $154.8 million in 2023, and a forecasted 2024 Test Year amount of $140.9 million. The reduction of $14.1 million will be discussed in more detail below.

Q. How did Staff analyze A&G expenses?

A. Staff analyzes the labor and non-labor components of A&G separately and by FERC account. Labor expenses receive specific Staff review and analysis and are addressed by Staff witness Julie Jent in Staff/1300. Additionally, certain

[2] See PGE / 600, Ajello – Batzler / 2, Table 1.
[3] PGE Response to SDR 058, Attach A.

labor loading expenses (i.e. pension and retirement benefits, payroll taxes, incentive pay, etc.) are analyzed separately by various Staff.

To determine the reasonableness of the Company's Test Year forecast for non-labor A&G, Staff often relies on its analysis of actual A&G expense in previous years and compares Base Year actuals to the Company's forecasted Test Year expense. To do this, Staff reviews PGE's expenses by FERC account. OAR 860-027-0045 specifies that PGE must adhere to the Uniform System of Accounts (USOA) adopted by FERC for accounting. Under USOA, expense for A&G is recorded in FERC Accounts 920–935.

To facilitate its review of the labor and non-labor components of A&G, Staff created Standard Data Requests (SDRs) that each utility must answer at the time it files a general rate case (GRC). SDR 057 requires the Company to provide all of its actual non-labor expenses and revenues, by FERC account, for the Base Year. SDR 058 requires the Company to provide forecasted summaries of expense for the Test Year, by FERC account. SDR 058 also requires the Company to provide all expenses and revenues, by FERC account, for the Base Year and the preceding two years. SDR 057 instructs that only non-labor expenses be reported, and SDR 058 instructs utilities to separately report labor and non-labor expenses.

Q. How did Staff review PGE's non-labor A&G expenses at issue in Testimony?

A. Staff relied on PGE's actual expenses recorded in the FERC accounts to review year-to-year changes in non-labor expenditures for major functional areas by FERC account. Staff issued 28 DRs related to A&G expenses and used the responses as part of the overall analysis.

Staff also relied upon the Company's responses to SDR 057 to verify SDR 058 Base Year non-labor dollar figures for 2022 and to investigate expense recorded in A&G accounts by line-item cost detail information using individual cost elements (CE).

Q. What are Staff's conclusions related to the significant A&G FERC accounts?

A. Staff's conclusions are noted below by FERC account and detail any proposed adjustments.

Q. What is Staff's conclusion regarding FERC Account 921, A&G Office Supplies?

A. The net Non-Labor reduction of $3.1 million from 2022 to 2024 in A&G Office Supplies is related to:[4]

- A one-time COVID-19 deferral write-off in 2022;
- Fewer IT costs allocated to account 921 compared to 2022; and
- Savings from switching to a lower-cost enterprise printer/copier vendor in 2022.

Staff has no adjustment related to this expense.

Q. What is Staff's conclusion regarding FERC Account 922, A&G Admin Expense Transfer?

[4] See Staff/902, PGE Response to DR 126, page 1.

A. This is a credit allocation account, so a reduction in the credit amount increases the expense for the account. The net credit decrease (expense increase) of $4.6 million from 2022 to 2024 in A&G Admin Expense Transfer is related to:[5]

- Miscellaneous accounting adjustments and Non-Labor allocations related to corporate governance expenses; and
- A $3 million pre-filing incentives adjustment.

Staff notes that allocations do not change the overall expenses for a company, just where the expenses are shown on the income statement. The incentives adjustments are noted above in FERC Account 920 and reflect a change of where the expense resides. Staff has no objection to this reduction in expense allocation.

Q. What is Staff's conclusion regarding FERC Account 923, A&G Outside Services?

A. Staff continues to analyze this issue and has not yet reached a conclusion.

Q. What is Staff's conclusion regarding FERC Account 924, A&G Property Insurance?

A. The Non-Labor increase of $3.7 million from 2022 to 2024 in A&G Property Insurance is related to yearly increases in property insurance premiums. PGE expects premiums to increase at a 27.6 percent annualized rate.[6]

---

5 See Staff/902, PGE Response to DR 127, page 2.
6 See PGE / 600, Ajello – Batzler / 5-6.

Staff accepts that insurance premiums are increasing in essentially all categories. Staff notes that in response to a Staff DR about the Company investigating a 'self-insured' model of Property Insurance, the Company stated:[7]

> PGE annually investigates self-insurance cost-savings strategies. PGE incorporates self-insurance into portions of our insurance program through various self-insured retentions (SIRs) and deductibles.
>
> In the 2022 policy year, PGE raised our property insurance deductible from $2.5 million to $5.0 million to reduce premium expenses. When evaluating higher SIRs and deductible options, PGE must weigh the potential premium savings against the amount of risk assumed.

Staff does not have an adjustment to PGE's proposed increase in Property Insurance.

Q. What is Staff's conclusion regarding FERC Account 925, A&G Injuries and Damages?

A. The Non-Labor increase of $2.5 million from 2022 to 2024 in A&G Injuries and Damages is related to:[8]

- Increase in Workers' Compensation administration fees;
- Accrual expenses related to injuries and damages insurance; and
- Amortization of expenses related to injuries and damages insurance.

Staff does not have an adjustment to the increase in Injuries and Damages.

Q. What is Staff's conclusion regarding FERC Account 926, A&G Employee Pension and Benefits?

---

[7] See Staff/902, PGE Response to DR 554, page 7.
[8] See Staff/902, PGE Response to DR 129, page 3.

A. The Non-Labor increase of $15.7 million from 2022 to 2024 in A&G Employee Pension and Benefits is related to:

- Post-Retirement benefits related to 401(K) increase of $12.3 million;
- Post-Retirement benefits related to pension decrease of $5.2 million; and
- Health and Dental Plan increase of $7 million.

Staff notes that the Company explains at length the change in employee demographics related to increase in 401(K) contributions vs. pension expenses.[9] As employees turn over or retire, the legacy pension plan expenses decrease while the 401(K) expenses increase. Additionally, the Company chose to increase the matching percentage for the 401(K) plan by one percent as an incentive to employees.

Staff has no objection to these changes related to post-retirement benefits.

Below, Staff discusses proposed adjustments to the Health and Dental portion of FERC account 926.

Q. Please provide more information related to Staff's position on Health and Dental expenses.

A. Related to the Health and Dental portion of Employee Pension and Benefits, Staff did not find the Company's justification sufficient to warrant such a large increase, specifically in 2024. Staff issued several DRs related to this topic

[9] See PGE/500, Mersereau - Neitzke/34-39.

requesting detailed calculations and narrative justification of the proposed increase.

The Company provided the sub account balances, showing yearly amounts in spreadsheet form, but provided no evidence for how the amounts were calculated. Similarly, the Company deferred to its health and welfare benefits provider (Mercer) for the narrative justification beyond what was provided in the Company's application; but PGE provided no calculations for the increase.

Q. To what does PGE, or its provider, attribute the increase?

A. PGE responded to Staff's inquiry for numeric justification with a narrative response that included "Overall inflation, contract increases due to general inflation, healthcare wage inflation, etc., pent-up demand, a potential rush on services if there is a recession, lower utilization due to a continued shortage of healthcare workers, and lower utilization of preference sensitive services when in a recession".[10]

Q. What issues does Staff have with the proposed increase in Health and Dental expenses?

A. Based on the numeric information provided by the Company (see Table 1 below), Staff finds inconsistency in the application of the narrative justification found in the Company's application.

[10] See Staff/902, PGE response to DR 245, page 4.

	Table 1						
	2020	**2021**	**2022**	**2023**	**2023 Staff**	**2024**	**2024 Staff**
9260018: BenefitExp-EmployeeWellness	91,039	8,663	2,421	153,075	89,075	155,028	91,028
9260004: Benefit Exp - Medical Union	15,516,602	15,461,666	15,177,563	15,227,200	15,227,200	16,701,270	15,562,198
Vs. Prior Year		-0.4%	-1.8%	0.3%	0.3%	**9.7%**	**2.2%**
9260005: Benefit Exp - Medical NonUnion	32,959,915	30,355,423	33,320,188	34,796,400	34,796,400	37,878,200	35,561,921
Vs. Prior Year		-7.9%	9.8%	4.4%	4.4%	**8.9%**	**2.2%**
9260031: OtherPostEmplBene-ServiceCost	79,446						
9260032: OtherPostEmployBene-NonSvcCost	(936,018)	(1,046,413)	(730,770)				
Grand Total	47,710,985	44,779,340	47,769,403	50,176,675	50,112,675	54,734,498	51,215,147
Staff Proposed Adjustment					(64,000)		(3,519,351)
Total Adjustment							(3,583,351)

Staff notes that despite the narrative justification, using the Willis Towers Watson (WTW) survey of health care inflation being 9.1 percent, 9.4 percent and 6.5 percent for 2021-2023 respectively,[11] the actual costs and budgeted amounts for Health and Dental expenses are significantly different, based on the Company's information summarized above in Table 1.[12] If the Company is using the WTW survey as noted in its application for health care inflation percentages, then Staff would expect to see similar amounts in the actual costs and budget request for 2021 to 2023. As shown in Table 1, these inflationary amounts and actual costs do not match. For example, despite the WTW survey showing health care inflation being 9.1 percent in 2021, PGE's actual expenses went down compared to 2020 for medical union and non-union. While health care inflation isn't the only component of the Health and Dental expenses, it should be similar in form if it's being used as a justification for future increases.

Q. Do you have other concerns with PGE's support for the increase to Health and Dental expenses?

[11] See PGE / 500, Mersereau - Neitzke / 32.
[12] See Staff/902, PGE response to DR 547, Attach A, page 5.

A. Yes. PGE relies on speculation regarding future costs, citing to "deferred treatment,"[13] "[a] potential rush on services if there is a recession,"[14] and "pent-up demand"[15] for portions of the proposed increase without corresponding numeric components. In Staff's opinion, speculation about possible health care trends is not sufficient to support an increase in expense paid for by customers. Staff rejects the narrative information provided by Mercer without corresponding calculations when the terms mentioned above are used.

Further, Staff notes that under Wellness (9260018 below) an Employee Picnic is requested for 2023 and 2024. While aspects of employee health and wellness are important, Staff does not agree that a picnic provides a medically beneficial justification and suggests removing that amount as noted in Table 1.

Q. Does Staff have a proposed adjustment related to FERC Account 926, A&G Employee Pension and Benefits?

A. Yes. Staff proposes using the full year predicted inflation rate related to the All Urban CPI for 2024 of 2.2 percent, as compared to PGE's proposed rates of 9.7 percent and 8.9 percent for Medical Union and Non-Union benefits expense. With this rate and the removal of Company Picnic mentioned above, the proposed adjustment is a reduction of $3,583,351.

Q. What is Staff's conclusion regarding FERC Account 928, Regulatory Commission Expense?

---

13 See PGE / 500, Mersereau - Neitzke / 32.
14 See Staff/902, PGE response to DR 245, page 4.
15 Id.

A. The Company removed the revenue sensitive regulatory fees related to the Oregon Public Utility Commission. These fees are automatically calculated for the rate case based on the proposed revenue.

Staff has no adjustment to this account.

Q. What is Staff's conclusion regarding memberships included in various A&G accounts?

A. Staff requested and received detailed information regarding the memberships and the corresponding amounts related to the Test Year. The Company's DR responses allowed Staff to verify both the amount included in FERC account 930.2, Miscellaneous General Expense, and those membership embedded in other FERC accounts.

Q. Does Staff have a proposed adjustment related to Memberships?

A. Yes. Based on the Company's DR response, Staff calculated a reduction of $27,262 related to Memberships.[16] This amount is accumulated for those memberships that were not utilized in 2022 or were forecasted to have significant increases in 2024 related to the actual 2022 expense. Staff removed all amounts related to memberships that had no corresponding expenses in 2022 and the full amount for a membership labeled 'Opera'. There were two memberships that had significant increases without a provided justification that Staff reduced to the 2022 amounts.

Q. Please summarize Staff's adjustments to the Test Year forecast for non-labor A&G expense.

---

[16] See Staff/902, PGE response to DR 550, page 6.

A. Staff proposes two separate A&G adjustments.

Adjustment No. 1. Reduce the increase in Health and Dental expenses by $3,583,351.

Adjustment No. 2. Reduce the amount associated with Memberships by $27,262.

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Related to the Non-Labor A&G accounts, Staff proposes a total reduction, as detailed above, of $3,610,613.

As noted earlier in my testimony, my recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: RUSS BEITZEL

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Russell (Russ) Beitzel
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Telecommunications and Water Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science in Accounting, Otterbein University

EXPERIENCE:

I have been employed with the Public Utility Commission of Oregon since 2018. I am currently a Senior Utility Analyst in the Rates and Telecommunications Section of the Rates, Safety, and Utility Performance Program. Regarding water utilities, I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, revenue requirement calculations, deferred tax calculations, rate spread, and rate design. I have also served as case manager on multiple water rate cases, and have provided testimony in UW 185, UW 182, UW 175, UW 177, UE 374, and UG 388.

Additionally, I worked at Ashland, Inc. for twenty years as a manufacturing and corporate accountant and business analyst for a business unit with approximately one billion dollars in global annual sales. My accountant duties included product cost analysis, general ledger account analysis, SOX compliance, and internal and external audit compliance. My analyst duties included budgeting, forecasting, financial statement analysis, acquisition tracking, and division financial support for a global business unit.

CASE: UE 416
WITNESS: Russ Beitzel

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

DR Responses

June 13, 2023

March 22, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 126
Dated March 8, 2023

Request:

Related to the Company's response to SDR 58, please provide a narrative explanation for the causes of the year over year 2023 decrease and 2024 increase for account 921 Non-Labor.

Response:

The year-over-year 2023 decrease for account 921 Non-Labor is primarily driven by:

a) A one-time COVID-19 deferral expense write-off in 2022;
b) Fewer IT costs allocated to account 921 Non-Labor in 2023 compared to 2022 actuals, which were higher than expected as a result of IT contract labor coupled with outside services to support cloud-based solutions (e.g., payments to Amazon for end-user application and other IT support on an as-needed basis); and
c) Savings from switching to a lower-cost enterprise printer/copier vendor in mid-2022.

The year-over-year 2024 increase for account 921 Non-Labor is primarily driven by increased IT costs allocated to account 921 Non-Labor in 2024 as a result of increased software and hardware license expenses coupled with increased outside services expenses to support PGE's cybersecurity programs and processes.

PGE would like to note that administrative and general (A&G) IT costs (direct and allocated), which include account 921 Non-Labor, are expected to decrease by approximately $0.2 million from 2022 to 2024 as shown in PGE Exhibit 601.

PGE Exhibit 500, Section III details PGE's labor budgeting further. PGE Exhibit 600, Section III details PGE's IT allocation methodology further.

March 22, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 127
Dated March 8, 2023

Request:

Related to the company's response to SDR 58, please provide a narrative explanation for the year over year 2023 and 2024 credit decreases for account 922 Non-Labor.

Response:

The year-over-year 2023 increase (i.e., credit decrease) for account 922 Non-Labor is primarily driven by:

a) Miscellaneous accounting adjustments related to the allocation of corporate governance expenses;[1] and
b) Non-labor allocations related to corporate governance expenses.

The year-over-year 2024 increase for account 922 Non-Labor is primarily driven by an approximate $3.0 million pre-filing incentives adjustment as shown in PGE Exhibit 200 Workpaper "Exhibit Support_2024" tab "A&G" column E.

Without this adjustment, account 922 Non-Labor decreases by approximately $0.4 million from 2023 to 2024, primarily driven by similar miscellaneous accounting adjustments related to corporate incentive expenses and non-labor allocations related to corporate governance expenses.

PGE's response to OPUC Standard Data Request No. 080, Attachment 080-A provides a detailed description of PGE's Corporate Governance allocation.

PGE Exhibit 500, Section IV provides further detail on incentives adjustments.

[1] Corporate governance expenses are associated with activities such as cash management, financial management, processing and reporting functions, corporate credit risk management, purchasing, accounts payable, business support, internal auditing, technology maintenance, mail services, corporate phone and conference room management and employee communications.

March 22, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 129
Dated March 8, 2023

Request:

Related to the company's response to SDR 58, please provide a narrative explanation for the year over year increases in 2023 and 2024 for account 925 Non-Labor.

Response:

The year-over-year increase in 2023 for account 925 Non-Labor is primarily driven by:

a) Outside services expenses associated with workers' compensation administrative fees; and
b) Accrual expenses related to insurance, specifically injuries and damages.

The year-over-year increase in 2024 for account 925 Non-Labor is primarily driven by amortization expenses related to insurance, specifically injuries and damages.

PGE Exhibit 600, Section II and Confidential Exhibit 603 provide further detail on insurance cost increases, including workers' compensation coverage.

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 245
Dated March 13, 2023

Request:

See PGE/500 Mersereau—Neitzke/12, which discusses how a Willis Towers Watson survey of healthcare providers had results that are consistent with projections provided by your health and welfare benefits provider. Can you provide these projections in an electronic workbook with all cells and formulae intact and detail the steps that were used to arrive at your projections?

Response:

The projections were not provided to PGE in a workbook format. Through discussions with Mercer, PGE's health and welfare benefits provider, Mercer indicated that an 8-9% renewal increase (2023 to 2024) for both Kaiser and Providence plans was a reasonable expectation. This aligned with their balance of 2023 self-funded trend guidelines and anticipated impacts to trends. Some factors impacting their view of 2024 trends were:

- Overall inflation
- Contract increases due to general inflation, healthcare wage inflation, etc.
- Pent-up demand
- A potential rush on services if there is a recession
- Lower utilization due to a continued shortage of healthcare workers
- Lower utilization of preference sensitive services when in a recession

Confidential Attachment 245-A contains communications with Mercer, PGE's health and welfare benefits provider, including future cost projections.

Attachment 245-A contains protected information and is subject to General Protective Order No. 23-039.

Compensation Subtotal in Level 2 of Compensation Subtotal Tree	Account	CE Source	Acct WO	a-Dec - 2020	a-Dec - 2021	a-Dec - 2022	Dec - 2023		Dec - 2024	Base Year-Test Year Delta	Base Year-Test Year Annual %
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	1313: Paid Time Off - Hourly	3000001871: PTO - Annual Sick Leave		188						
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2101: Storerm Material Issue/Returr	N/A: N/A	(0)							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2110: Other Materials & Equipment	7000000845: Employee Wellness RBOCH	290	89	275	5,675		5,674	5,399	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2110: Other Materials & Equipment	7000001235: Personal Protective Equipment	535							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2200: Outside Services	7000001237: Occupational Fitness				20,000		20,768	20,768	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2250: Other Outside Services	7000000210: Workers Comp - Medical Costs	7,119							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2250: Other Outside Services	7000000845: Employee Wellness RBOCH	36,035	1,490						
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2250: Other Outside Services	7000001237: Occupational Fitness	25,885							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2250: Other Outside Services	N/A: N/A	7,343	6,060						
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2400: Business Expense	N/A: N/A				35,836		36,506	36,506	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2401: Mileage - Non-taxable	7000000845: Employee Wellness RBOCH	14							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2401: Mileage - Non-taxable	N/A: N/A	235							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2403: Lodging	N/A: N/A	1,401							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2404: Business Meals & Entertainme	N/A: N/A	878							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2406: Airfare	N/A: N/A	674							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2407: Conf and Course Rgst Fees	7000000643: Employee Training KTRNG	70	714	577				(577)	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2411: Other Business Travel Expense	N/A: N/A	103							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2450: Other Employee Business Exp	7000000643: Employee Training KTRNG			93				(93)	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2450: Other Employee Business Exp	7000000845: Employee Wellness RBOCH		123	281				(281)	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2450: Other Employee Business Exp	N/A: N/A	10,425							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2701: Memberships	7000000552: Individual Utility Memberships			725				(725)	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2850: Other Miscellaneous Expense	3000000482: O&M Budget Transfer				27,564		28,080	28,080	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2850: Other Miscellaneous Expense	7000000552: Individual Utility Memberships			420				(420)	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2850: Other Miscellaneous Expense	7000000845: Employee Wellness RBOCH	17		50				(50)	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	2850: Other Miscellaneous Expense	7000002028: Company Picnic				64,000		64,000	64,000	
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	5106: Payroll Taxes	3000001964: COVID Vaccine pay								
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	5599: Non-Labor Allocation	N/A: N/A	15							
Employee Wellness Pr	9260018: BenefitExp-EmployeeWellness	N/A: N/A	N/A: N/A						(0)	(0)	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2200: Outside Services	3000001703: COBRA coverage under VERIP an				75,000		75,000	75,000	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2200: Outside Services	7000001219: Health & Dental Admin Fees				225,500		225,500	225,500	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2202: Accting Audit Actuarial Srvcs	N/A: N/A	72,078	65,940	69,510				(69,510)	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2250: Other Outside Services	7000000708: Non Union Prepaid Medical	(270)							
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2250: Other Outside Services	7000001219: Health & Dental Admin Fees	174,295	282,240	220,350				(220,350)	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2300: Other Products and Services	N/A: N/A				14,926,700		16,400,770	16,400,770	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2301: Health Insurance	7000000712: Union Health and Dental Plan	15,326,545	15,113,486	14,887,703				(14,887,703)	
Health & Dental Plan	9260004: Benefit Exp - Medical Union	2301: Health Insurance	N/A: N/A	1,076							
Health & Dental Plan	9260004: Benefit Exp - Medical Union	5404: Accrual	7000001992: Union Health Reimbursement	(57,121)							
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2250: Other Outside Services	7000000845: Employee Wellness RBOCH		(117)						
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2250: Other Outside Services	7000001219: Health & Dental Admin Fees	70,995	66,056	66,398				(66,398)	
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2250: Other Outside Services	N/A: N/A		(863,537)	(1,122,395)				1,122,395	
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2300: Other Products and Services	7000000709: NU Health and Dental Plan				34,796,400		37,878,200	37,878,200	
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2301: Health Insurance	7000000708: Non Union Prepaid Medical	1,908,816	1,904,417	1,727,193				(1,727,193)	
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2301: Health Insurance	7000000709: NU Health and Dental Plan	31,039,848	29,216,808	31,690,593				(31,690,593)	
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2301: Health Insurance	7000000712: Union Health and Dental Plan	412,634		958,400				(958,400)	
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	2301: Health Insurance	7000001219: Health & Dental Admin Fees	(161,527)							
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	5404: Accrual	7000001991: NonUnion Health Reimbursemen	(310,851)	27,000						
Health & Dental Plan	9260005: Benefit Exp - Medical NonUnion	5498: Misc Accounting Adjustments	N/A: N/A		4,796						
Health & Dental Plan	9260031: OtherPostEmplBene-ServiceCos	5404: Accrual	1000008210: 12OPEB Non-Svc Cost Medical Ur	79,446							
Health & Dental Plan	9260032: OtherPostEmployBene-NonSvc(	5404: Accrual	1000008210: 12OPEB Non-Svc Cost Medical Ur	48,030	(13,126)	(13,143)				13,143	
Health & Dental Plan	9260032: OtherPostEmployBene-NonSvc(	5404: Accrual	1000008211: OPEB Non-Svc Cost Medical Nonl	(18,671)	(212,594)	(119,300)				119,300	
Health & Dental Plan	9260032: OtherPostEmployBene-NonSvc(	5406: Amortization	1000008210: 12OPEB Non-Svc Cost Medical Ur	(87,447)							
Health & Dental Plan	9260032: OtherPostEmployBene-NonSvc(	5406: Amortization	1000008211: OPEB Non-Svc Cost Medical Nonl	(877,930)	(820,693)	(598,327)				598,327	
			Grand Total	**47,710,985**	**44,779,340**	**47,769,403**	**50,176,675**		**54,734,498**	**6,965,095**	**7.04%**
						1.067			**2020-2024 CAGR:**		**3.49%**

April 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 550
Dated April 14, 2023

Request:

See attached related to the Company's response to DR 133 Attach A, for all FERC Account/Dept ID combinations except account 930.2, Staff has modified the spreadsheet to show all Dept IDs that have budget and forecast amounts (shown in red) without corresponding amounts in 2022 or there was a significant increase. Please provide a narrative explanation for all items shown in red related to why they are forecasted without corresponding amounts in 2022. If there was an amount in 2022, but it's still shown in red, please provide a narrative justification for the increase.

Response:

The following narrative explanations pertain to items shown in red and are related to FERC Account/Dept ID combinations with no corresponding amounts in 2022 or significant increases:

Rows 14, 17, 65, 67, 92, 170, 237, 257, 260, and 275 - These are legacy budget items associated with individual employee memberships that were not utilized due to staffing changes or turnover. As a result, there was no activity in 2022 for these rows.

For the items below, the budget was allocated to FERC Account 921, but the actual payments were inadvertently made from different FERC accounts:

- Row 11: $940 actuals paid to FERC Account 557
- Row 81: $383 actuals paid to FERC Account 426.5
- Row 97: $668 actuals paid to FERC Account 924
- Row 174: $3,939 actuals paid to FERC Account 184
- Row 204: $682 actuals paid to FERC Account 924
- Row 286: $2,550 actuals paid to FERC Account 930
- Row 323: $1,549 actuals paid to FERC Account 926
- Row 414: $4,295 actuals paid to FERC Account 930

These discrepancies explain the red-highlighted items with no corresponding amounts in 2022 or those that show significant increases.

April 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 554
Dated April 14, 2023

Request:

Staff notes that seemingly across the board insurance rates are increasing at rates higher than even the recently high inflation rates (e.g. property insurance and injuries and damage insurance). In general, has the Company investigated the cost to switching to a self-insured model? If the answer is no, please explain why. If the answer is yes, please provide a narrative explanation for why that option wasn't chosen.

Response:

PGE would like to note that comparing insurance rates to inflation rates is not a like-for-like comparison, as they are fundamentally different in terms of their underlying drivers, objectives, influencing factors, purposes, time horizons, and sensitivities to economic changes and risk factors, rendering them incomparable on a direct basis.

Yes. PGE annually investigates self-insurance cost-savings strategies. PGE incorporates self-insurance into portions of our insurance program through various self-insured retentions (SIRs) and deductibles. Additionally, PGE benchmarks insurance limits and deductibles against peer utilities each year. The average deductible among our peer group (15 utilities[1]) is approximately $5.12 million, with a median of $5.0 million.

In 2020, we increased the self-insured retention for Auto & General Liability from $2.0 million to $5.0 million, and we continue to be a qualified self-insured employer for Workers' Compensation. In the 2022 policy year, PGE raised our property insurance deductible from $2.5 million to $5.0 million to reduce premium expenses. When evaluating higher SIRs and deductible options, PGE must weigh the potential premium savings against the amount of risk assumed. Generally, a payback period exceeding four to five years may not be financially prudent. In fact, increasing the property insurance deductible above $5.0 million would result in a payback period of 6.1 years, indicating that the premium savings did not justify assuming an additional $5.0 million of risk.

[1] PGE participates in an annual Risk Management Survey conducted by Edison Electric Institute (EEI) and identifies peers based on similar market capitalization and asset base.

CASE: UE 416
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

Opening Testimony

June 13, 2023

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

A. My name is Madison Bolton. I am a Senior Energy and Policy Analyst employed in the Utility Strategy and Integration 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 qualifications statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. I describe Staff's analysis of issues including Trojan Nuclear Decommissioning Trust, Unbundling, and Franchise Fees for direct access.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1002, PGE responses to Staff data requests, Exhibit Staff/1003 PGE confidential responses to Staff data requests, and Exhibit Staff/1004, PGE's Errata 2024 ROO workpaper.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. TROJAN NUCLEAR DECOMMISSIONING TRUST

Q. Please describe the Trojan Nuclear Decommissioning Trust (Trojan NDT).

A. PGE is required to maintain a financial assurance mechanism for decommissioning obligations for the Trojan nuclear generating unit, consistent with federal Nuclear Regulatory Commission (NRC) requirements.[1] The Trojan NDT was established as an external sinking fund to be separate from PGE's assets and outside PGE's administrative control. PGE collects funds at an annual accrual rate that is sufficient to pay for radiological decommissioning costs. NRC Regulation 10 CFR 50.75(e)(1)(ii) includes the requirements for the management of an external sinking fund, stating:

> An external sinking fund is a fund established and maintained by setting funds aside periodically in an account segregated from licensee assets and outside the administrative control of the licensee and its subsidiaries or affiliates in which the total amount of funds would be sufficient to pay decommissioning costs at the time permanent termination of operations is expected. An external sinking fund may be in the form of a trust, escrow account, or Government fund, with payment by certificate of deposit, deposit of Government or other securities, or other method acceptable to the NRC. This trust, escrow account, Government fund, or other type of agreement shall be established in writing and maintained at all times in the United States with an entity that is an appropriate State or Federal government agency, or an entity whose operations in which the external linking fund is managed are regulated and examined by a Federal or State agency.

Q. What types of decommissioning costs does the Trojan NDT pay for?

[1] Staff/1002, Bolton/1, PGE Response to Staff DR No. 311.

A. The Trojan NDT pays for some non-radiological decommissioning costs such as building demolition and site restoration after the spent nuclear fuel is transferred away from the site. The trust also pays for radiological decommissioning expenses in Independent Spent Fuel Storage Installation (ISFSI) Construction. These include:

- Costs for infrastructure to enable the transfer of spent fuel via rail cars to a United States Department of Energy (DOE) facility.
- Costs for the long-term storage of the spent fuel until it is transferred to a DOE facility.
- A contingency amount in case of unexpected variation in future estimated costs.[2]

Q. What expenses has the Company proposed to amortize related to the Trojan NDT?

A. PGE has requested that the $1.9 million annual collection rate be maintained for the Trojan NDT.[3] This is the same accrual rate allowed in UE 394 and originally agreed upon by parties in the second partial stipulation in UE 335.[4] In the stipulation, parties agreed that the annual collection rate should be decreased from $3.5 million to $1.9 million to account for expected reimbursements from the United States DOE for ISFSI costs.

---

[2] Staff/1002, Bolton/2, PGE Response to Staff DR No. 313.
[3] PGE/200, Batzler – Ferchland/15.
[4] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 335, Order No. 18-464, at 6.

For the current case, PGE conducted an analysis of the latest Trojan NDT balances, the expected rate of return on trust assets, United States DOE reimbursements, and cost estimates, which did not indicate that any change to the accrual rate was necessary.

Q. Please describe Staff's analysis.

A. Staff reviewed the assets in the Trojan NDT compared to the cost estimates and financial assumptions in the Company's response to Staff DR No. 317.[5] The trust is made up of 100 percent fixed income assets including corporate bonds, government bonds, mortgage-backed securities, collateralized mortgage obligations, municipal bonds, and cash.[6]

Staff did not find any significant outliers in the Company's analysis of cost estimates and assumptions. Staff reviewed the ISFSI-related decommissioning expenditure schedule containing historical and projected data up to year 2059. The Company's financial assumptions used in the calculation of the accrual rate appear reasonable compared to current market conditions. Staff did not find any irregularities between the projected DOE reimbursements, assets in the trust, or in the application of the allowed NRC growth rate for annual collection in decommission trust funds. This growth rate is specified in NRC Regulation 10 CFR 50.75(e)(1)(ii), which states: "A licensee that has collected funds based on the formulas in § 50.75(c) of this section may take credit for collected earnings on the decommissioning funds using up to a

---

5 Staff/1003, PGE confidential Response to Staff DR No. 317, Attachment A.
6 Staff/1002, Bolton/3, PGE Response to Staff DR No. 316.

two percent annual real rate of return up to the time of permanent termination of operations. A licensee may use a credit of greater than two percent if the licensee's rate-setting authority has specifically authorized a higher rate."

Q. What is your recommendation for the amortization of Trojan NDT expenses?

A. Staff does not propose any adjustments for the Trojan NDT at this time but may alter this recommendation after reviewing other parties' testimony.

ISSUE 2. UNBUNDLING AND FRANCHISE FEES

Q. Please describe the Company's unbundling requirements.

A. The Commission's rules for unbundling and franchise fees are located in Oregon Administrative Rules (OAR) Division 38, which pertain to Oregon's direct access program. More specifically, 860-038-0200 requires the revenue requirement be unbundled into functional categories. The rules also specify allocation methodology including direct assignment of costs to the functional areas when possible.

Franchise fees are also required to be unbundled and are applied to the distribution category as directed by OAR 860-038-0200(9)(c)(B)(i)(IV).

Q. Please compare the Company's unbundled revenues in this case to the UE 394 filing.

A. Staff reviewed the Company's Results of Operations (ROO) summaries and provides the differences below:

UE 394			UE 416			
Function	Proposed		Function	Proposed		Variance
Production	1,117,765	53%	Production	1,472,190	55%	2%
Transmission	87,205	4%	Transmission	106,751	4%	-0.2%
Distribution	723,480	34%	Distribution	882,240	33%	-1%
Ancillary	5,119	0.2%	Ancillary	8,450	0.3%	0.1%
Billing	37,795	2%	Billing	47,205	2%	0.0%
Metering	6,216	0.3%	Metering	3,386	0.1%	-0.2%
Consumer	127,424	6%	Consumer	153,623	6%	-0.3%
Total Regulated	2,105,003	100%	Total Regulated	2,673,845	100%	
Franchise Fees	157,051		Franchise Fees	192,628		

Staff found very minimal variance in the overall percentage of each function out of total revenue. The source of variance is further informed by

OAR 860-038-200(9)(d), which states that "required revenues must be calculated for each unbundling category using the traditional revenue requirement calculation methodology (recovery of costs plus a return on investment). For reporting purposes, revenues must be assigned to the appropriate category per the underlying tariff for which they were collected. Common revenues that cannot be directly assigned must be functionalized using the Net Plant allocation factor."

The variance in the unbundled results is mostly proportional to the share of rate base in a functionalized area. Any remaining variance is due to the Company's other allocation methods such as using the net plant factor or labor allocator.[7] Staff notes that production, transmission, and distribution make up about 92 percent of the unbundled functions. Staff verified with the Company that the unbundling methodologies used in this case are consistent with the methodologies used in UE 394.[8]

Q. Please explain some of the increases in certain functional categories.

A. Staff noted that the distribution and transmission categories have increased due to higher O&M costs including additional wildfire mitigation procedures. Staff believes that higher power costs compared to previous cases are applicable to a portion of the increase in the production category.

Franchise fees increased in part because of a slightly higher fee rate than in UE 394 (a 0.09 percent increase). However, the Company explains that

[7] PGE/200, Batzler – Ferchland/29.
[8] Staff/1002, Bolton/4, PGE response to Staff DR No. 321.

because franchise fees are a function of PGE's revenue requirement, most of the increase is tied to the overall increase in revenue requirement.[9]

Pursuant to OAR 860-038-0200, franchise fees are calculated as a percentage of applicable city revenues based on three years of historical data. Staff verified the accuracy of the Company's calculation for both the franchise fee rate and the total franchise fee amount included in the ROO.

Q. Did Staff have any concerns with the unbundling workpapers?

A. Staff initially found an error in multiple rows of the Company's "2024 Unbundled ROO" workpaper that caused certain transmission revenues to be allocated to the distribution function. The Company was aware of this error at the time of Staff's discovery and corrected the mistake in an errata filing on April 21, 2023.[10] Staff examined the errata and reviewed all of the individual unbundled transactions data for accuracy. Staff did not find any further errors.

Q. Is the Company's unbundling methodology in accordance with OAR 860-038-0200?

A. After reviewing the work papers and verifying the Company's calculations, it appears that the Company has met the unbundling requirements in the Division 38 OARs.

Q. What is your recommendation on this issue?

---

9 PGE/200, Batzler – Ferchland/23, at 11-14.
10 Staff/1004, PGE's Errata 2024 ROO workpaper.

A. Staff does not propose an adjustment to the Company's unbundling methodology at this time. However, Staff may change this recommendation after reviewing other parties' testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Madison Bolton
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy & Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.A. Carroll College, Helena, Montana Major: Biology, 2017 M.ENV. University of Colorado, Boulder, Colorado Specialization: Renewable and Sustainable Energy, 2020
EXPERIENCE:	Since September 2021, I have been employed by the Oregon Public Utility Commission. I currently hold the position of Utility Analyst 3 in the Utility Strategy and Integration Division, where I've evaluated utility voluntary renewable energy products and direct access issues. I have provided witness testimony on multiple general rate case and power cost dockets, including: UG 433, UG 435, UE 399, UE 400, and UE 402. From 2019 to 2020 I worked as a graduate research analyst at E Source where I conducted research for utility clientele on large non-residential energy consumers. Additionally, in 2020 I assisted Camus Energy in researching the feasibility of electric grid management software.

CASE: UE 416
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Responses to Staff Data Requests

June 13, 2023

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 311
Dated March 15, 2023

Request:

Please provide a narrative description of the purpose of the Trojan Nuclear Decommissioning Trust (NDT).

Response:

PGE is required to provide financial assurance for decommissioning obligations for the Trojan nuclear generating unit, consistent with federal Nuclear Regulatory Commission (NRC) requirements. As allowed by 10 CFR 72.30(e)(5), PGE provides ISFSI radiological decommissioning funding assurance using the method provided in 10 CFR 50.75(e)(1)(ii). Specifically, PGE has established and maintains an external sinking fund in the form of a trust, which is segregated from PGE's assets and outside PGE's administrative control, and into which funds are set aside such that the total amount of funds will be sufficient to pay radiological decommissioning costs.

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 313
Dated March 15, 2023

Request:

Please provide a narrative description of the types of expenses paid with Trojan (NDT) funds.

Response:

The expense categories of the Trojan NDT are as follows:

- Non-Radiological Decommissioning: Represents the cost of building demolition and site restoration once all the spent nuclear fuel has left the site.
- Independent Spent Fuel Storage Installation (ISFSI) Construction: Represents the expected amounts to be incurred to decommission the Trojan ISFSI.
- ISFSI Long-term: These costs include the following: (1) ISFSI-NRAD DECO, (2) ISFSI-LONG, and (3) PMRESERVE.
  - ISFSI-NRAD DECO; This represents the non-radiological decommissioning for the ISFSI, which includes the cost of constructing (and removing) various infrastructure to facilitate the transfer of the spent fuel to rail cars for transportation to a Department of Energy (DOE) facility. This also includes the cost for transferring the sealed multi-purpose canisters from the concrete casks to a rail car.
  - ISFSI-LONG: This represents costs for the long-term management of the spent fuel, until it is shipped to a DOE facility.
  - PMRESERVE: Following Nuclear Regulatory Commission (NRC) guidance, PGE includes a contingency amount to account for major unexpected variations in future estimated costs.

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 316
Dated March 15, 2023

Request:

Please provide a percentage breakout of NDT assets by asset type/class and the values of those assets.

Response:

The asset allocation of the Trojan Nuclear Decommissioning Trust (NDT) Qualified and Non-Qualified NDT plans consists of 100% Fixed income. Within the fixed income there are Corporates, Government, Mortgage-Backed securities, Collateralized Mortgage Obligations, Municipal bonds, and Cash.

Confidential Attachments 316-A and 316-B provide the Trojan (NDT) non-qualified and qualified outstanding securities as of December 31, 2020. The asset summary included in each of these documents provides the types of assets and what percent of the portfolio they represent.

Attachments 316-A and 316-B are protected information and subject to Protective Order No. 23-039.

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 321
Dated March 15, 2023

Request:

Please explain whether PGE has changed any of the methodologies used in unbundling the revenue requirement since the Company's previous rate case.

Response:

PGE's overall methodology for unbundling has not changed since Docket No. UE 394.

CASE: UE 416
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

PGE Confidential Response to Staff DR No. 317, Attachment A

June 13, 2023

STAFF EXHIBIT 1003
IS CONFIDENTIAL AND FILED IN
ELECTRONIC FORMAT

PROTECTIVE ORDER 23-039

CASE: UE 416
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1004

PGE’s Errata 2024 ROO Workpaper

June 13, 2023

STAFF EXHIBIT 1004 IS IN ELECTRONIC SPREADSHEET FORMAT ONLY

CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony
Grid Modernization Operations and Maintenance (O&M), and
Proposed Schedule 122 Update

June 13, 2023

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

A. My name is Curtis Dlouhy. I am an economist and senior utility analyst employed in the Utility Strategy and Integration 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/301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address two issues:

1. Transmission and Distributions Operating and Maintenance Expense
2. Proposed Schedule 122 Update

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/1101, Non-Confidential Responses to Data Requests used in Support of Testimony,
- Exhibit Staff/1102, Confidential Data Responses used in Support of Testimony,
- Exhibit Staff/1103, News Used In Support of Testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. GRID MODERNIZATION O&M

Q. Please describe the components of the Company's grid modernization initiative that you will address in your testimony.

A. The Company's grid modernization initiative is a broad, long-term effort to evolve the capabilities of its grid through physical infrastructure and information technology. These capabilities range from planning and forecasting to controls and automation. One focus of the strategy is enabling and managing distributed energy resources (DER), which is reflected in many interconnected investments and activities. In this testimony, I will address only the O&M components associated with grid modernization. The Company proposes to spend approximately $14.0 million in grid modernization O&M in 2024, which is an increase of approximately $3.4 million from the actual 2022 amount spent.[1]

Q. What is driving the $3.4 million increase?

A. The increase is driven by filling four unfilled positions that were included in the Company's last general rate case as well as requesting funds to fill eight additional positions related to the Company's proposed virtual power plant (VPP) and the Advanced Distribution Management System (ADMS) which is needed to implement the VPP among other grid modernization investments and activities.[2]

1 PGE/700, Bekkedahl – Jenkins/21.
2 Id.

Q. Do you take issue with the Company requesting funding for eight new positions when it was unable to fill four positions in 2022?

A. Yes. Staff questions why the Company is expecting that the four unfilled positions would be filled *and* an additional eight new positions. Holding aside these concerns about whether the Company is even able to fill these twelve total positions, Staff has also reviewed the Company's proposal on merit.

Q. What is a VPP and how large is PGE's current VPP?

A. A VPP is a set of DERs and flexible load that can be managed by the Company to provide services valuable to the grid, such as ramping up to meet load during high demand times of day where renewable resources are not producing. PGE's current VPP is 230 MW consisting of a combination of customer-sited diesel generators, batteries, flexible load, and demand response programs.[3]

Q. Are the current programs associated with the 230 MW able to operate without the VPP investments and added O&M expenses?

A. Yes. The Company is currently able to operate these components without any of the new requested VPP positions. The VPP desk and newly created positions work only to centralize the dispatch of these various pilot programs and DERs. While this may assist in the expansion of the VPP, the VPP is currently functioning at its current level without the eight requested additional positions or dispatch desk.

[3] PGE/700, Bekkedahl – Jenkins/22.

Q. Does PGE include any VPP investments in this rate case?

A. No. As stated in the Company's opening testimony, the Company does not plan on the VPP platform being operational until the first quarter of 2024, which is after the rate effective date of this general rate case.[4]

Q. What is the VPP platform?

A. As described in the Company's opening testimony, the VPP platform will allow the Company to centrally operate all the disparate customer-sited generation, DER, and DR programs that make up the current VPP portfolio.[5]

Q. Is the Company currently able to operate these disparate programs without a VPP platform?

A. Yes. Even without a central location to dispatch the 230 MW that make up the Company's current VPP, the Company is able to operate these programs.

Q. Has the Company discussed the VPP with the Commission in any other contexts?

A. Yes. The VPP was presented to the Commission as part of the Flexible Load Multi-Year Plan in November 2021 in Docket No. UM 2141.[6] In a September 2022 filing in UM 2141, the Company outlined its Flexible Load Multi-Year Plan timeline that includes a goal of integrating various Energy Partner assets into a VPP in the 2024 calendar year.[7] The VPP was also introduced as a non-wires solution in the Company's Distribution System Plan (DSP) Part 1 and Part II

4 PGE/700, Bekkedahl – Jenkins/24.
5 PGE/700, Bekkedahl-Jenkins/23.
6 See page 30 of the Company's November 3, 2021, UM 2141 filing here.
7 See Table 3 of the Company's September 23, 2022, UM 2141 filing here.

filings in UM 2197, where the Company's Action Plan states that designing a VPP with expansion capabilities will be needed to meet HB 2021.[8] The VPP has also been briefly presented in the Company's ongoing Integrated Resource Plan (IRP), LC 80, but is not included in the modeling or action plan.

Q. Have any of these proceedings weighed in on the prudency of investing into a VPP?

A. No. Order No. 22-023, the Commission approved some budgets associated with pilot programs that will eventually feed into the VPP but did not make any determination of whether investing in a VPP platform to aggregate these DER and DR programs was a prudent investment. The DSP Part I and Part II filings were accepted, but acceptance does not carry the same weight when discussing prudence. Further, Staff notes in its February 21, 2023, Staff report on UM 2197 that the DSP Action Plan does not provide specific actions regarding grid modernization and recommends that the Company provide better clarity and specificity in a future action plan.[9] As stated previously, these pilot programs are currently able to provide flexible load benefits without a centralized VPP framework.

8 See page 22 of the Company's DSP Part II filing here.
9 See page 21 of the February 21, 2023, UM 2197 Staff Report here.

Q. Has the VPP been introduced in any proceeding that has weighed the costs, risks, and benefits of the VPP as a component of the Company's resource strategy?

A. Indirectly, yes. The Company's 2023 IRP was filed on March 31, 2023, and describes the VPP in its description of resource options.[10] While the Company's IRP does not model the VPP as a resource option, the portfolio modeling:

- reflects customer-sited DER growth in its needs assessment;
- includes demand response (DR), DER, Community-Based Renewable Energy (CBRE), and battery proxies; and
- assumes that all resource types can be integrated into PGE's system and orchestrated to deliver their full potential system value.

The IRP further states that the VPP platform is required to ensure realization of the full value of its DER resources.[11]

The resulting IRP Action Plan does not request acknowledgement of a VPP action, but includes the acquisition of 211 MW of summer DR, 158 MW of winter DR by 2028, 155 MW of CBRE by 2030, and over 600 MW of additional capacity actions by 2028.[12] In its Action Plan, the Company explains that, "While the CBRE and other energy resources described previously could help

---

10 See page 193 of the Company's 2023 IRP here.
11 Id.
12 See Section 12 of the Company's 2023 IRP here.

meet this need, resource additions beyond the CBRE and energy actions are required to maintain resource adequacy."[13]

Q. Have any parts of the Company's 2023 IRP been acknowledged?

A. No. As previously stated, the Company filed its 2023 IRP in Docket No. LC 80 on March 31, 2023. Staff has just filed its initial Phase 0 comments on the Company's 2023 IRP on May 4, 2023. Acknowledgement decisions on the Company's IRP are scheduled to occur in January 2024 after the rate effective date of this rate case proceeding.

Q. What does this mean for the prudency of the VPP and PGE's overall grid modernization investments included in the Company's general rate case?

A. The timing of the IRP and the lower "acceptance" threshold of the DSP Part I and Part II filings means that the Company is proposing to integrate costs related to the VPP before the Commission, Staff, or stakeholders have had a chance to rigorously weigh in on the reasonableness of pursuing a VPP as part of its resource and grid modernization actions. Furthermore, even acknowledgement of an IRP is not a prudence decision on its own.

Further, the investment associated with the VPP is not scheduled to be operational until well after the rate effective date. Although the Company is not requesting to include the VPP capital in rates, I find it to be inconsistent to allow O&M costs associated with an asset that will neither be operational by the rate effective date nor has been part of an acknowledged IRP. Based on

---

[13] See page 310 of the Company's 2023 IRP here.

this, I believe that it is premature to put any O&M costs associated with the VPP into rates.

Q. Do you believe that the VPP should be placed into rates at a later date?

A. Perhaps, if the company can demonstrate it is prudent, used and useful to do so and expanding VPP capabilities is part of an acknowledged resource or grid modernization strategy. However, I do not recommend the company try to make this case until the Commission makes an acknowledgement decision in the Company's 2023 IRP and the Company articulates the role that a VPP will play in its roadmap of decarbonization resource actions.

Q. Given that you believe that it is premature to put any VPP O&M costs into rates, what do you recommend be done to the Company's grid modernization O&M costs?

A. I recommend that the eight new positions related to the grid modernization not be placed into rates. According to the Company's response to Staff DR 303, this amounts to approximately $1 million.[14]

Q. What is your overall recommended adjustment to grid modernization O&M?

A. I recommend decreasing the grid modernization O&M expense by $1 million to reflect disallowing the cost of the eight new positions.

[14] Staff/1101, Dlouhy/1.

ISSUE 2. PROPOSED SCHEDULE 122 UPDATE

Q. What is PGE's Schedule 122?

A. PGE's Schedule 122 contains its Renewable Resources Automatic Adjustment Clause (RAC). The RAC was put into place in response to SB 838 in 2007, which established the state's renewable portfolio standard (RPS) and required the Commission to establish an automatic adjustment clause (AAC) or other mechanism that allows timely recovery of costs prudently incurred by an electric company for acquiring renewable energy resources and for associated transmission.[15] In 2016, SB 1547 raised the state RPS requirements and modified the AAC language to allow associated storage to be included.

Q. What is the exact language that allows the inclusion of associated storage in the RAC?

A. The exact language can be found in ORS 469A.120, which is contained in the Chapter 469A rules governing Renewable Portfolio Standards. The language reads:

> The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources [and for], costs related to associated electricity transmission and costs related to associated energy storage.

[15] ORS 469A.120(2).

Q. How does PGE propose modifying the RAC?

A. PGE asks that the Commission clarify that standalone storage be considered "associated energy storage" and therefore qualify as an asset whose costs can be recovered in the RAC.[16] In its opening testimony, PGE states that it believes an on-system energy storage facility provides system benefits by firming and integrating renewables.

Q. Did SB 838 mandate that the Commission necessarily create an AAC?

A. No. Much like the modifications that were put into statute due to SB 1547, SB 838 only mandates that the Commission establish an AAC or "another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission." Staff reads this to mean that the Commission has discretion to allow some other form of recovery that could use other ratemaking mechanisms.

Q. Do you agree with the Company's assertion that standalone storage investments are high priority elements of PGE's near-term resource strategy?

A. Yes. It is now common knowledge that one of the largest hurdles to fully decarbonizing the utility sector is the intermittency of renewable energy sources. As such, one of the solutions to this intermittency is to invest in energy storage options in tandem with renewable resources. PGE has already done so with its Wheatridge Renewable Energy Facility, which combines 350

[16] PGE/130, Macfarlane – Pleasant/45.

MW of renewable energy with a 30 MW four-hour battery.[17] The Wheatridge Renewable Energy Facility was included in the RAC as part of Commission Order No 20-321, although the Commission noted that it would take into consideration fair allocation of risk when it comes to cost recovery in the future.[18] When discussing regional solutions to resource adequacy in their 2023 IRP filing, the Company states that the policy landscape "will likely accelerate the transition from coal and natural gas fired generation to wind, solar, storage and other non-emitting resources."[19]

Q. Based on this, do you believe that the Commission should clarify that standalone storage be included in the RAC?

A. No. I do not think a standalone storage asset clearly qualifies for the RAC in the same way that Wheatridge did based on the language included in ORS 469A.120. Given this gray area, the Commission's discretion in interpreting ORS 469A.120 and current rate pressure, I recommend that the Commission not allow standalone storage into the RAC. Further, I recommend that the Commission should consider how the RAC should be used most optimally moving forward.

Q. Why do you believe that the language of ORS 469A.120 permits the exclusion standalone storage assets?

A. Staff believes that the rule governing the RAC leaves a lot of room for discretion. The language of ORS 469A.120 reads that the RAC will be used to

---

17 See the fact sheet on PGE's website here.
18 See Commission Order No 20-321, Page 12 here.
19 See PGE's 2023 IRP filing, Page 25 here.

recover costs used to "construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage." This implies that a storage resource co-located with renewable generation should be allowed, not unlike the Wheatridge Renewable Energy Facility that was allowed into the RAC in Commission Order No. 20-321. A standalone storage facility that is not fed directly from a renewable energy generation facility could in fact be charged by energy from the grid does not seem to have such a clear classification and can be up for interpretation. Given this gray area and Staff view that the Company relies too heavily on AACs in general, Staff recommends against allowing standalone storage to qualify for the RAC.

Q. Why does Staff believe that the Company relies too heavily on AACs in overall ratemaking?

A. Staff explains In Staff Exhibit 2200 that the Company's total number of AACs outside of power costs have risen from four to 13 since 2010 and now make up over 5 percent of a residential customer's bill. In that testimony, Staff recommends that more guardrails should be placed on the Company's ability to use AACs, such as by using earnings more frequently tests and more periodically moving things into base rates. I believe that it is inconsistent to condemn the overuse of AACs in general while also permissive about which resources that qualify for the RAC.

Q. Are there arguments for using a broader definition of "associated storage" that may have merit?

A. Given changes to the policy landscape, using a broader definition would recognize the interdependence of renewable resources, standalone storage, and transmission investments in a cost-effective, reliable near-term resource strategy. It would also align with changes other policy makers are making to the applicability of polices to standalone storage.

For example, prior to the passage of the IRA, energy storage resources were only eligible to receive investment tax credits (ITCs) if they were co-located with renewable generation. That has since changed, with standalone storage now eligible to receive ITCs between 30 and 70 percent of the project's total cost as part of the IRA.[20]

These arguments, however, are not compelling enough to subject ratepayers to the risks of including more resource types in the RAC. Were the Commission to consider incorporating standalone storage in a single-issue ratemaking mechanism, it should only do so if the mechanism helps the utility be nimbler in its decarbonization investment strategy, while applying greater cost and risk protections for customers. It should also consider if there are differences in the ability of on-system and off-system standalone storage to integrate renewables.

[20] Staff/1103, Dlouhy/1.

Q. Why do you still believe that the RAC should not allow standalone storage even with the change in ITC eligibility?

A. As stated previously, I recommend against allowing standalone storage in the RAC at this time because of the risks to ratepayers from the over-proliferation of AACs in overall ratemaking and because the Commission has the discretion determine whether standalone storage qualifies for the RAC. For these reasons, I still believe it to be problematic to consider standalone storage as "associated energy storage" for the purposes of the RAC.

Q. Even if ORS 469A.120 is interpreted to allow stand-alone storage, are there other reasons that the Commission should limit the ability of to allow a standalone energy storage resource to be recovered through the RAC?

A. Yes. I have previously discussed that allowing standalone storage would be improper and violate both the intent of the RAC and the assumed allocation of risk between customers and shareholders. Further, expanding the use of the RAC at this time increases customer rate pressure at a time when the Company is proposing many new items that exacerbate this rate pressure. Staff Witness Michelle Scala discusses the overall rate pressure in her testimony and the rate pressure caused by the over-proliferation of AACs is discussed in Exhibit Staff 2200. Given the rate pressures faced by current customers, the use of the RAC to recover costs associated with standalone storage seems to unfairly shift risk from shareholders to ratepayers.

Q. Given that the IRA appears to now treat standalone storage similarly to co-located storage and that you believe it is possible that the Commission has the authority to apply an AAC to standalone storage, why do you recommend against the Commission clarifying that standalone storage can be recovered through the RAC or another mechanism?

A. I recommend against using the RAC or a similar mechanism to recover costs associated with standalone storage for three main reasons:

1. The RAC was established as an instrument to recover costs associated with Renewable Portfolio Standards (RPS) compliance, but the Company is clearly acquiring standalone storage for non-RPS reasons given how little RPS is driving resource acquisition.
2. Allowing standalone storage in the RAC could undermine key aspects of the rate case process and fundamentally shifts cost recovery risk from shareholders to customers.
3. The Commission has discretion to define “associated storage” under ORS 469A.120, and the Commission should take a limited interpretation to mitigate the over-proliferation of AACs in ratemaking by the Company.

Q. Please explain your first point that the RAC is an instrument to recover costs associated with RPS compliance?

A. SB 838 was fundamentally a bill that establish RPS standards in Oregon, and the section of SB 1547 that modified the RAC to include “associated energy storage” is titled the “Recovery of Costs for Complying with Renewable

Portfolio Standards". This indicates that the RAC's initial intention was to tie it directly to costs associated acquiring resources for RPS compliance.

Q. Why do you say that storage is being acquired for non-RPS reasons?

A. While utilities are still obligated to meet its RPS needs, the requirements for HB 2021 essentially make RPS irrelevant in resource acquisition. The existing RPS levels approved in SB 1547 call for 35 percent of the Company's generation to come from renewable sources by 2030, while HB 2021 requires that 80 percent of the Company's generation come from renewable sources. Therefore, any resources acquired that are meant to meet this 2030 target are necessarily being acquired for HB 2021 reasons or as a general least-cost, least-risk portfolio. While it may be the case that RPS levels could be driving resource acquisitions prior to 2030 and that *a portion* of the cost of a standalone battery could be attributed to meeting RPS compliance, this does not appear to be the case.

Q. Why do you believe that current RPS levels are not driving resource acquisition and that a standalone battery cannot be even partially attributed to meeting RPS compliance?

A. Based on PGE's most recent RPS compliance docket, UM 2241, PGE's RPS obligation was 3,631,537 MW in 2021. The Company met this obligation using approximately 1.6 million MW of banked, bundled RECs and 400,000 banked, unbundled RECs.[21] Based on the Company's response to Staff DR 752, **[BEGIN CONFIDENTIAL]** [redacted]

[21] See Commission Order No. 22-433, Appendix A Page 3, here.

[redacted] **[END CONFIDENTIAL]**, enough to meet its RPS obligation for multiple years without any additional generation.[22] This large cushion of banked RECs indicates that RPS obligations are not currently driving resource acquisition in the near term, indicating that any near-term acquisition of storage – which is not currently an RPS-eligible resource – is not done for RPS purposes and should not qualify for the RAC.

Q. What non-RPS reasons exist that the Company would continue to acquire renewable resources and storage?

A. The Company could be acquiring these resources for HB 2021 compliance or simply as a part of a least-cost, least-risk portfolio. Renewable resources have become cost effective with thermal resources when discussing available incentives and total power generated, making them easy candidates for a preferred portfolio regardless of renewable energy generation mandates. Pairing renewables with standalone storage may prove to be at least as cost effective as a thermal generator.

Storage could also be acquired for HB 2021 compliance. Asdiscussed above, the obvious drawback of renewable resources in their current form is their intermittency, which has the potential to cause large reliability concerns during peak demand hours. This concern should be evident given the recent rise of Energy Emergency Alerts referenced by the Company in its opening

22 Staff/1102, Dlouhy/1.

testimony[23] and the many regionwide resource adequacy initiatives, such as the Western Resource Adequacy Program. A possible zero-carbon way to firm and integrate renewables is through storage installations, much like the Company proposes to do in its IRP. On-system storage can also mitigate the serious hurdle that transmission constraints pose to electric decarbonization, which is examined at length in the Company's current IRP and associated Clean Energy Plan.

Q. Does this prevent the Commission from authorizing the use of the RAC for the cost recovery of renewable-related assets acquired for other purposes?

A. No, it does not. The statute leaves the definition of associated storage to the Commission. The Commission could choose to allow utilities to use the RAC to do so in lieu of creating another mechanism meant to recover costs for HB 2021 compliance. However, I recommend against making a determination on that issue in this docket, as the Company has not proposed any changes to the RAC that would be needed to protect ratepayers under a landscape of frequent clean resource procurements. In addition, a decision in this docket would not consider the perspective of PacifiCorp and its stakeholders.

---

[23] PGE/300, Schwartz – Outama – Cristea/20.

Q. The Commission has generally been permissive about allowing renewable investments into the RAC. Are you advocating that the Commission rethink its approach to the RAC?

A. Yes. As I've pointed out previously, I believe the Commission has broad discretion to interpret ORS 469A.120 and determine what to allow in the RAC and whether to modify the current AAC structure. Since its creation in 2007, the RAC has changed very little, but the policy landscape around the RAC has changed dramatically with the passage of HB 2021 and vastly different resource economics. Now is an ideal time to rethink how to use and possibly restructure the RAC with input from other stakeholders and utilities.

Q. Regarding your second point, why do you say that allowing standalone storage in the RAC in this rate case could undermine the rate case process and fundamentally shift cost recovery risk to customers?

A. Taking a permissive interpretation of ORS 469A.120 may incentivize the Company to stay out of rate cases for abnormally long stretches of time during a period of accelerated investment. If the Commission were to allow standalone storage in the RAC, then the Company would be able to recover essentially all new energy and capacity resources outside of the rate case. The same logic used to justify that standalone storage in the RAC could then be used to justify essentially any transmission line should also go into the RAC, which is another large area of investment in the Company's 2023 IRP.

If these two items were allowed in the RAC, there could be long stretches where the Company has no substantive reasons to come in for a rate case, potentially saddling customers with an unrepresentative capital structure, ROE, O&M allocation, escalation factor, or series of mature investments that would otherwise be taken out of rates much sooner.

Q. Based on your view that the standalone batteries should not qualify as "associated energy storage" in the RAC, that the RPS obligations are not driving resource acquisition, and that the Company's proposed changes would shift cost recovery risk, what is your recommendation regarding the RAC in this rate case?

A. I recommend that the Commission clarify that standalone storage does not qualify for the RAC at this time. I also recommend that the Commission not authorize the creation of an alternative cost recovery mechanism for standalone storage in this docket.

Q. Do you recommend that the Commission look into the use of the RAC outside of this docket?

A. Yes. I do not think that the RAC necessarily needs to be entirely eliminated as a ratemaking tool and can in fact still be beneficial. However, as I've previously stated, the RAC is not something specific to just PGE and should therefore be handled outside of this general rate case to allow stakeholders and PacifiCorp to engage with changes to the RAC more substantively.

Q. Why do you believe that the RAC might be beneficial?

A. When it was first introduced in 2007, the RAC was meant to aid in the procurement of renewable resources in a changing policy landscape. Although RPS legislation has now been around for many years and might not deserve such generous cost recovery options, HB 2021 is a new policy that may deserve the same treatment. While I am not necessarily advocating for this outcome at the moment and believe that customer protections should be a key part of the conversation, adapting the RAC to be a mechanism meant to enable the utilities to remain nimble in their investments during an aggressive decarbonization push may prove to be valuable in a post-HB 2021 Oregon.

Further, there are possible downstream externalities of providing more secure financing in large and risky utility investments. For example, bond rating agencies tend to look more favorably on utilities that employ AACs, which can in turn lower the utility's cost of issuing debt. While Staff has taken the stance that the Commission-regulated utilities are overusing AACs, Staff believes that AACs still serve a purpose in overall ratemaking, as evidenced in Staff Exhibit 2200.

It is unclear whether the potential downstream effects of lower cost of debt and aiding the decarbonization push outweigh the shift of cost-recovery risk from shareholders to ratepayers. These outstanding concerns and other possible future outcomes of the RAC are best explored outside of this rate case where other utilities and stakeholders can fully participate.

SUMMARY.

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. I recommend reducing the Company's Grid Modernization O&M Expense by $1 million to reflect disallowing the costs associated with the eight new positions meant to support the virtual power plant.

I also recommend that the Commission not allow standalone storage to qualify for Schedule 122 at this time. Given that the policy landscape around renewable generation and decarbonization has changed substantially since the implementation of the RAC, I also recommend that the Commission reevaluate the role of the RAC in a proceeding that contains both stakeholders and PacifiCorp.

My recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS:CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Non-Confidential Responses to Data Requests

June 13, 2023

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 303
Dated March 14, 2023

Request:

Refer to PGE/700, Bekkedahl – Jenkins/21. Please provide the position description, posted salary, and initial position listing date for each of the unfilled positions referenced.

Response:

The cited testimony references an increase in 2024 forecast grid modernization operations and maintenance costs of $3.4 million compared to 2022 actuals, driven by labor costs.

The table below summarizes the drivers of the increase:

Category	**$ millions***	**Notes:**
Eight incremental Grid Modernization positions	$1.0	*See*, PGE's response to OPUC Data Request No. 304
Delays in staffing the Outage Communications department (RC 039)	$0.3	
Grid Modernization positions that were unfilled for six or more months	$2.2	*See*, Confidential Attachment A
TOTAL	**$3.4**	

** May not sum due to rounding*

Confidential Attachment A provides the position descriptions for the Grid Modernization positions that were unfilled for six or more months.

Attachment 303-A contains protected information and is subject to General Protective Order No. 23-039.

CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Confidential Responses to Data Requests

June 13, 2023

[redacted]

CASE: UE 416
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

News in Support
Of Opening Testimony

June 13, 2023

SPONSORED

IRA sets the stage for US energy storage to thrive

Published Nov. 7, 2022

Daniel Balakov via Getty Images

SPONSORED CONTENT BY CONVERGENT

The Inflation Reduction Act (IRA) signed into law in August significantly improves the economics for large-scale battery storage projects in the U.S. For the first time, standalone storage systems will be eligible for a 30 percent investment tax credit (ITC) — and up to 70 percent with additional incentives.

"It's a really big deal," said Peter Cavan, Director of Market Development for battery storage developer Convergent Energy and Power. "Previously federal tax credits were only available for storage when it was paired with renewable generation, like solar. This change will likely drive up to $1 trillion in storage investments by the early 2030s."

From an investment standpoint, the potential impact of the IRA is largely due to the mid-term certainty it creates. Rather than renewing investment and production tax credits for only a year or two, as Congress has repeatedly done in the past, the IRA cements the incentives in place through 2032. This gives investors and developers a generous timeline for generating returns. In addition, the new law expands the limits of what can be included in calculating total project costs. According to Cavan the tax credit will now cover interconnection, microgrid controllers and a broader scope of components often used in clean energy systems.

Behind the ITC numbers

To maximize tax credits under the IRA, energy storage projects must meet two labor requirements. The first ensures that developers and operators pay prevailing wages — as determined by the Secretary of Labor — during the construction and first five years of system operation. The second requires projects to meet registered apprenticeship requirements. (Companies can find information on joining or creating an apprenticeship program at apprenticeship.gov.)

If projects meet the wage and apprenticeship requirements, they can then potentially boost the tax credit eligibility as high as 70 percent through three potential further incentives – domestic content, energy communities and low-medium income (LMI) projects.

One of the bonus incentives, worth an additional 10 percentage points, is for projects constructed with equipment and material produced in the U.S. This follows a long-term trend in U.S. policy previously bolstered by the Biden Administration in 2021 with the Infrastructure Investment and Jobs Act (IIJA). That law created a new Made in America Office under the Office of Management and Budget (OMB), which is tasked with updating and streamlining how domestic content requirements will be calculated in the years ahead.

“Currently, it’s difficult to meet domestic content requirements for storage due to the lack of domestic production,” Cavan said. “But it should be substantially easier by the second half of this decade, as domestic battery manufacturing ramps up and manufacturing for other components returns to the U.S.”

Another incentive, also worth 10 percentage points, is for projects located in so-called "energy communities." An energy community is defined as a brownfield site; the site of a coal mine or coal-fired power plant; or an area that has or had direct employment or local tax revenue related to oil, gas, or coal activities (Further guidance on the employment and revenue requirements will likely be issued before the end of 2022.)

Finally, storage projects paired with wind or solar and installed in low-income communities or on tribal land can receive an additional 10 percentage points. Or, the project can receive an additional 20 percentage points — for a possible total of a 70 percent ITC — if they are part of a low-income residential building project or qualified low income economic benefit project.

Applying the ITC for storage

The ITC for energy storage created by the IRA will be similar to current law with a five-year period for modified accelerated cost recovery system (MACRS), which is a more beneficial approach that allows for faster depreciation in the first years of an asset's life. The law also aims to simplify investment structures behind clean energy projects through the transferability of tax credits.

Previously, clean energy developers often had to partner with larger corporations or financial institutions, because they often do not have significant tax liabilities to take full advantage of the tax credits their projects produced. "This treatment is unnecessarily complicated and requires a battalion of lawyers," Cavan said. "Going forward it should be simpler and more cost-effective for a developer like us to monetize the tax credits by having the option to transfer them when the project size or capital expenditure doesn't justify entering into long-term partnerships with tax equity investors that come with complicated deal structures."

The IRA also has a "direct pay" option for state or local governments, which don't have tax obligations, to take advantage of the ITC. These entities would essentially receive refund checks from the federal government after their systems are in service.

The impact on utilities and operators

Beyond the nuts-and-bolts logistics of the ITC, the changed playing field has larger implications for utilities and for the owners and operators of energy storage. "The ITC for energy storage will ultimately require utilities to rethink what their systems look like — what they're paying for and rate basing and what they're expecting customers and third-parties like us to do," Cavan said. "Some utilities are reopening their integrated resource plans and preparing to engage regulators in setting new terms."

More energy storage will eventually mean greater resilience and carbon reductions for the power grid. But it also means an upsurge in citing, permitting and interconnections — challenges the industry is working hard to overcome. "We already have interconnection queues at the wholesale and utility levels that will take years to work through at the current pace," Cavan said. "The hope is that new rules and processes, like FERC's RM22-14, will pave the way for faster deployment."

As more energy storage comes online, Cavan said it will also change the market dynamics for storage system operators. Currently, the highest revenue opportunities for large-scale battery systems are in supplying ancillary services, like frequency regulation and non-spinning reserve, to the grid. "As more storage increases competition for ancillary services, their price will be driven down," Cavan said. "That will be the next phase in the maturity of our industry, as battery storage systems focus more on other areas such as arbitrage to shift renewable generation to when it is most useful."

The Biden administration's goal is for the U.S. power sector to operate without carbon emissions by 2035. Ultimately, that will require massive amounts of energy arbitrage to store renewably generated electricity from the time when it is produced by wind and solar, to the time when it is needed by residential and commercial users. The IRA sets the stage for the energy storage industry to step into this critical role over the next decade.

Filed Under: **Energy Storage, Regulation & Policy**

CASE: UE 416
WITNESS: Bret Farrell

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

OPENING TESTIMONY
Uncollectible Expense, Level III Outage Accrual Mechanism, and Research and Development

June 13, 2023

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 Utility Strategy and Integration 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 qualifications statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's proposals for Uncollectible Expense, Level III Outage Accrual Mechanism, and Research and Development.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff Exhibit 1201 – Witness Qualifications
- Staff Exhibit 1202 – PGE Response to OPUC Data Request 236
- Staff Exhibit 1203 – PGE Response to OPUC Data Request 595
- Staff Exhibit 1204 – Staff Workpaper
- Staff Exhibit 1205 – PGE Response to Staff Data Request 599
- Staff Exhibit 1206 – PGE Response to Staff Data Request 598
- Staff Exhibit 1207 – PGE Response to Staff Data Request 600
- Staff Exhibit 1208 – Staff Workpaper
- Staff Exhibit 1209 – Staff Adjustment Workpaper
- Staff Exhibit 1210 – PGE Response to Staff Data Request 354, Attachment A
- Staff Exhibit 1211 - PGE Response to Staff Data Request 354, Attachment A
- Staff Exhibit 1212 – PGE Response to OPUC Data Request 354, Attachment B

- Confidential Staff Exhibit 1213 – PGE Response to Staff Data Request 356

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. UNCOLLECTIBLE EXPENSE

Q. Please provide a summary of the Commission's historical treatment of uncollectible expense.

A. It is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the Test Year uncollectible expense for a utility's revenue requirement.[1] Commission Staff also examines other evidence to determine whether this approach results in a reasonable forecasted Test Year result. The amount included in a utility's revenue requirement for uncollectible expense is revenue sensitive because it depends on the amount of forecasted revenue. That is, the total uncollectible expense included in the revenue requirement is a function of the Test Year revenue and the uncollectible rate.

Q. Describe the Company's proposal for Test Year uncollectible expense.

A. The Company's 2024 Test Year forecast for uncollectible expense is $13.4 million which is $6.4 million higher than 2022 uncollectible expense of $7.0 million. The Company forecasts a Test Year uncollectible rate of 0.5272 percent but states that "to mitigate the customer price increase in 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 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).

GRC, we have assumed a lower uncollectible rate of 0.5 percent which is applied to the 2024 Test Year revenue requirement."[2]

Q. Does the Company use the three-year average methodology to derive its proposal for the Test Year uncollectible expense?

A. No. The Company's proposed 2024 uncollectible expense is calculated using an uncollectible rate that is forecasted using a combination of historical uncollectible rate trends, with adjustments for forward looking economic conditions, Division 21 rulemaking changes, and factoring in bill assistance programs.[3]

Q. Please explain the Company's process for forecasting the 2024 uncollectible rate.

A. The Company's starting point for the uncollectible rate forecast is the UE 335 approved uncollectible rate which is also the three-year average of the uncollectible rate between 2015-2017 (0.3262 percent). The Company claims this period of time is a proxy for an uncollectible rate during strong economic conditions.[4] The Company then adds seven distinct adjustments to the baseline uncollectible rate of 0.3262 percent, six of which increase the uncollectible rate. The Company's adjustments are as follows:

- Economic Conditions
- Covid Bill Assistance Expiring
- Deposit Adder

---

2 PGE/900, Lynn-Nestel/16-17.
3 PGE/900, Lynn – Nestel/16.
4 PGE/900, Lynn – Nestel/17, Table 2.

- Division 21: Weather Disconnect Protections
- Division 21: 15-day notice to 20-day notice
- Collection Agency Recovery Rate
- Income-Qualified Bill Discount (IQBD) Program

Figure 1 provides an overview of the Company's proposed adjustments and the associated calculated adjustment amount to the baseline uncollectible rate.

Figure 1.

Description	Uncollectible Rate
UE-335 (2019 GRC Workpaper, used in the 2022 GRC), Uncollectible Rate in Strong Economic Conditions	0.3262%
Impact of mild recession/balanced economic conditions assumption	0.0842%
COVID bill assistance going away	0.0265%
Deposit Adder	0.0258%
Division 21: Weather Disconnect Provisions	0.0544%
Division 21: Notice perspective 15 day to 20 day	0.0272%
Collection Agency Recovery Rate trending lower	0.0545%
IQBD (lowers bill amounts)	-0.0716%
Forecasted Uncollectible Rate	**0.5272%**
Proposed Uncollectible Rate in Revenue Requirement	**0.5000%**

Q. Please describe the Company's Economic Conditions Adjustment.

A. The Company states in testimony that "[u]ncollectible expense typically increases during periods of economic downturn and is lowest during strong economic conditions."[5] In the Company's response to Staff Data Request 236,[6] the Company provides the calculation for the 0.0842 percent increase in the uncollectible rate which they believe represents the impact of a

5 PGE/900, Lynn – Nestel/17.
6 Staff/1202, PGE Response to OPUC Data Request 236.

mild recession. The Company uses the average uncollectible rate between 2013-2017 as the base period then uses the average uncollectible rate between 2008-2011 as a proxy period for an economic downturn. The Company then takes the difference between these two values and reduces it by 50 percent to arrive at a 0.0842 percent increase in the baseline uncollectible rate.

Q. Does Staff agree with the Company's proposed Economic Conditions adjustment?

A. No. Staff believes that the Company fails to adequately justify the use of the "proxy period for economic downturn" used in the calculation for the Economic Conditions adjustment. The Company states in response to Staff Data Request 595[7] that "the time period of 2008 to 2011 was chosen as representative of recessionary or weak economic conditions."

The Company claims that "[t]he 2008 recession officially began in December 2007 and officially ended in June 2009, according to the National Bureau of Economic Research US Business Cycle Dating Committee. A four-year time period was also chosen so as to not overly bias the recessionary period to the worst year of the economic downturn (depth of the recession)."

Staff believes the time period selected by PGE represents too severe of an economic recession to be used by PGE in the calculation for this rate case. The 2008 recession saw US gross domestic product (GDP) decrease by 4.3 percent, making it the deepest recession since World War II.

[7] Staff/1203, PGE Response to Staff Data Request 595.

Although the recession technically ended June 2009, many significant economic indicators took several years to return to their pre-recession levels. For example, real GDP fell $650 billion (4.3 percent) and did not recover its $15 trillion pre-recession level until 2011.[8] Household net worth, which reflects the value of both stock markets and housing prices, fell $11.5 trillion (17.3 percent) and did not regain its pre-recession level of $66.4 trillion until 2012.[9] Even with the Company applying a 50 percent weighting to the uncollectible rate experienced in the 2008 recession Staff finds the use of this time period improper and over states any needed adjustment.

Q. Please describe the Company's adjustment for COVID Bill Assistance Expiring.

A. The Company states in testimony that "the expiration of COVID-19 bill assistance will increase the uncollectible rate by approximately 0.0265%. There was approximately $1.5 million in write offs that were associated with accounts that received bill assistance after February 2021. During that same time period, there were $18.5 million in gross write offs. Therefore, gross write offs would have been 8.1% higher. Applying the 2021 collection agency recovery percentage of 28.5% results in a 2.6% increase. The COVID-19

---

8 U.S. Bureau of Economic Analysis (January 1, 1947). "Real Gross Domestic Product". *FRED, Federal Reserve Bank of St. Louis*. Retrieved January 16, 2019.

9 Board of Governors of the Federal Reserve System (US) (October 1, 1945). "Households and Nonprofit Organizations; Net Worth, Level". *FRED, Federal Reserve Bank of St. Louis*. Retrieved January 16, 2019.

related bill assistance was in addition to strong federal fiscal policies that also mitigated gross write-offs over the past two years."[10]

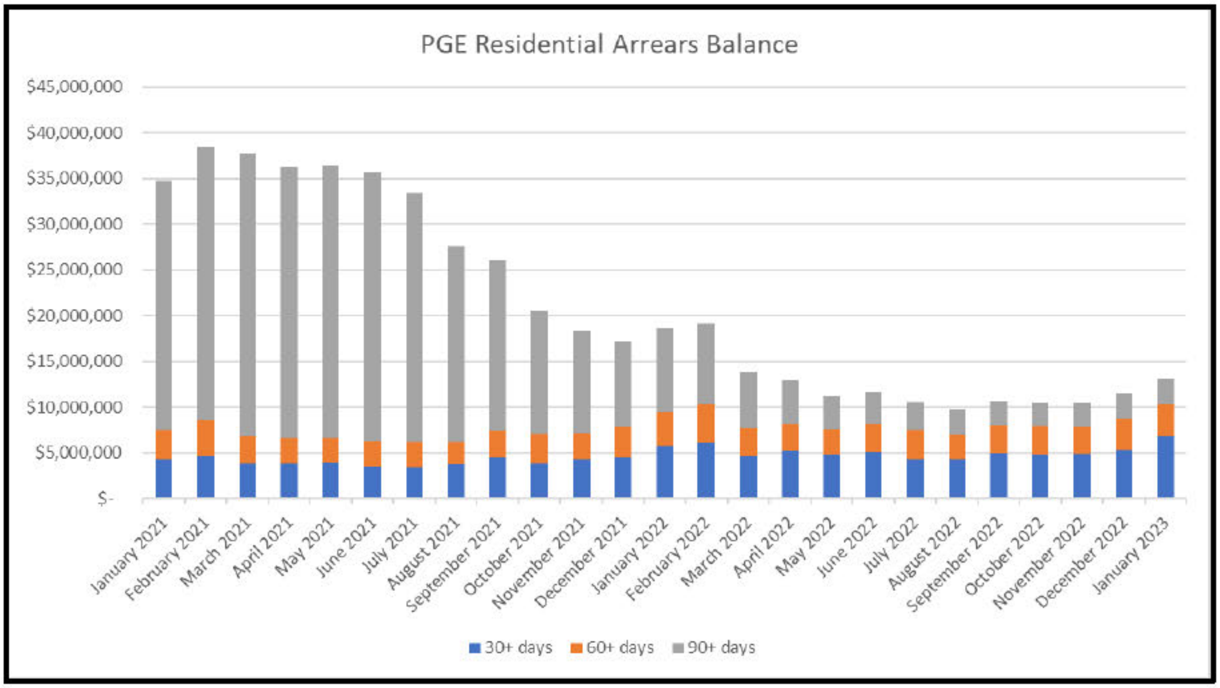
Q. Does Staff agree with the Company's proposed COVID Bill Assistance Expiring Adjustment?

A. No. The Company argues that due to the expiration of the funds provided to customers through the Company's Arrearage Management Program (AMP) the uncollectible rate will increase. The Company's AMP was developed in response to the economic hardship faced by many individuals who lost the ability to pay their utility bills due to the COVID-19 pandemic. The AMP was meant as a temporary stopgap measure to alleviate arrears balances which had increased during the pandemic. The expiration of the program does not necessarily indicate that the uncollectible rate will increase. The economic conditions that caused arrears to increase during the pandemic have subsided, and the Company's arrears have come down considerably since its peak in February 2021.[11] (See Figure 2.)

---

10 PGE/900, Lynn – Nestel/18-19.
11 Docket No. RE 188, PGE COVID-19 Monthly Report.

Figure 2.

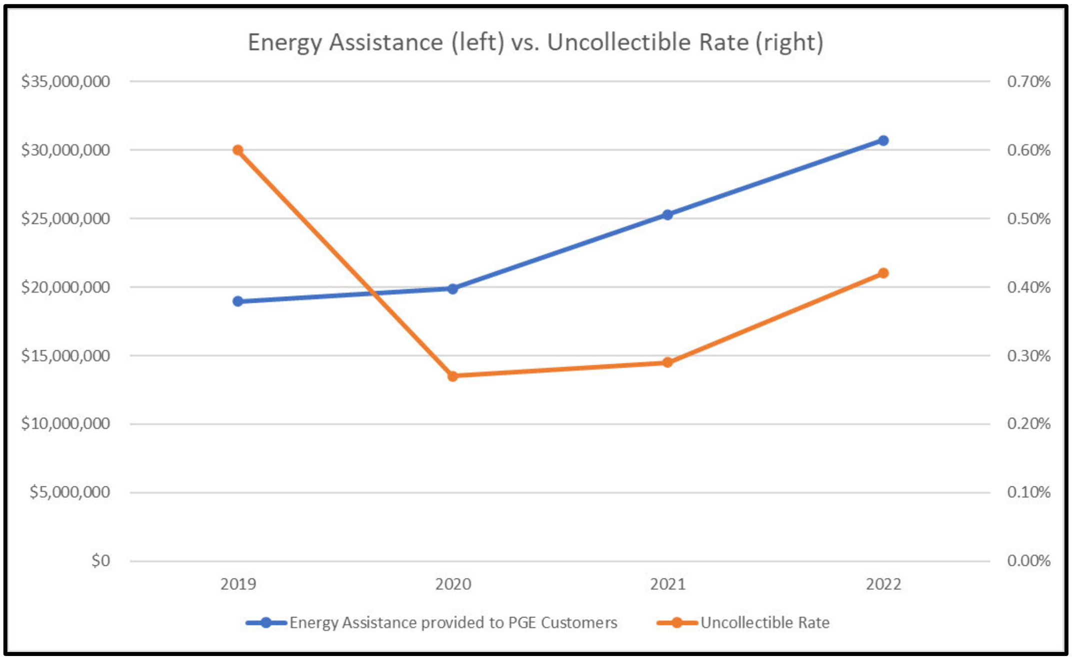


Additionally, when looking at historical PGE energy assistance data, the uncollectible rate stayed relatively low even during years of lower energy assistance (See Figure 3).[12]

---

[12] Staff/1204, Staff Workpaper.

Figure 3.



Therefore, Staff believes that the Company has not provided sufficient evidence that the expiration of these programs will lead to an increase in uncollectible expense.

Q. Please describe the Company's Deposit Adder Adjustment.

A. The Company states in testimony that "[w]ith respect to the end of deposits for residential customers, an adjustment of 0.026% was added to the uncollectible rate. This represents the residential deposits that were associated with write offs in 2019, the last year before the COVID-19 pandemic. In 2019 there were approximately $0.5 million deposits paid that were associated with write offs. Thus, these balances were deducted from PGE's write offs."[13]

[13] PGE/900, Lynn – Nestel/19.

Q. Does Staff agree with the Company's proposed Deposit Adder Adjustment?

A. No. The Company fails to provide any evidence that the end of deposits has led to an increase in uncollectible expense to date. Additionally, the Company's deposit adder adjustment calculation assumes that the level of write-offs associated with residential deposits that occurred in 2019 will remain constant and unchanged into the Test Year. The Company's calculation does not allow for any year-over-year variance and fails to consider that the end of deposits coupled with other measures targeted at alleviating residential customers' energy burden will lead to a lower overall level of write-offs for customers.

Q. Please describe the Company's Division 21 Weather Disconnection Protection Adjustment.

A. The Company states in testimony that "[w]ith respect to the weather credit limitations, an adjustment of 0.054% was added to the uncollectible rate. This represents 90 extra days of balance rollover caused by the expected reduced ability to disconnect in the winter months."[14] The Company is referring to updated rules adopted by the Commission in Order No. 22-353 that established protections for customers during severe weather conditions. The updated rules require a disconnection moratorium for residential customers

[14] PGE/900, Lynn – Nestel/19.

anytime a temperature of less than 32 degrees is forecasted to occur in an area.[15]

Q. Does Staff agree with the Company's proposed Division 21 Weather Disconnection Protection Adjustment?

A. No. The Company claims that "additional weather disconnection protections will delay and not reduce the number of disconnects. The longer customers are not disconnected will increase the arrears on accounts that become uncollectible."[16] The Company provides no data to validate the claim that these protections will increase the uncollectible rate. The Company's adjustment calculation broadly assumes that all customers will accrue balances uniformly and that these protections will have no effect at reducing overall disconnections. Staff finds this adjustment to be presumptuous and not backed by any evidence to date. Staff believes that the impacts of the rule change on the uncollectible rate is yet to be fully understood and therefore disagrees with the proposed adjustment.

Q. Please describe the Company's Division 21 Notice Prospective 15 to 20 Day Adjustment.

A. The Company states in testimony that "[w]ith respect to the additional notification days, an adjustment of 0.027% was added to the uncollectible rate. This represents five extra days of balance rollover caused by the expected

---

15 *In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections,* AR 653, Order No. 22-353 (September 29, 2022).

16 Staff/1205, PGE Response to OPUC Data Request 599.

inability to disconnect in the winter months."[17] The Company is again referring to updated rules adopted by the Commission in Order No. 22-353. This update to Division 21 rules requires that energy utilities provide written notice to the customer at least 20 days before disconnecting residential service, previously the notice was provided 15 days before disconnection.[18]

Q. Does Staff agree with the Company's proposed Division 21 Notice Prospective 15 to 20 Day adjustment?

A. No. The Company argues that increasing the disconnection notice period from a 15-day notice to a 20-day notice will increase the number of billing days written off by an additional five days, or 8.33 percent increase.[19] Similarly to the weather disconnection protection adjustment, the Company does not provide any evidence that the updated rules have increased uncollectible expense to date. PGE fails to consider that the updated Division 21 rules were designed to offer greater protection to customers and ultimately help avoid further disconnections. The increased notice period may allow customers more time to make payments and ultimately avoid disconnection, thereby avoiding becoming uncollectible expense. Staff believes that the impacts of the rules change on the uncollectible rate is yet to be fully understood and therefore disagrees with the proposed adjustment.

---

[17] PGE/900, Lynn – Nestel/19.
[18] *In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections,* AR 653, Order No. 22-353 (September 29, 2022).
[19] Staff/1206, PGE Response to OPUC Data Request 598.

Q. Please describe the Company's Collection Agency Recovery Rate Adjustment.

A. The Company states in testimony that "[w]e have seen a reduction in collection agency recovery percentage in recent years. Additionally, in response to inflationary pressures, the Federal Reserve has implemented policies and Federal Fund Rate increases to raise interest rates. Higher interest rates and economic uncertainty reduces collection agency recovery rates. Changes to Fair Debt Collection Regulation enacted in late 2021 have further eroded collection agency recovery rates through provisions addressing and limiting collectors' use of email, text messages, and other electronic media. With respect to reduced collection agency recovery percentage, an adjustment of 0.055% was added to the uncollectible rate. This represents the change from a recovery percentage in 2021 of 28.5% to 16.5% in 2022."[20]

Q. Does Staff agree with the Company's proposed Collection Agency Recovery Rate adjustment?

A. No. The following formula displays the calculation for how the Company arrives at an increase in the uncollectible rate of 0.0575 percent attributed to the collection agency recovery rate trending lower:[21]

$$\left(\frac{Write\ Offs\ in\ Rates\ (base\ year)}{(1-2021\ Recovery\ Rate)}\right) * \ (1-2022\ Recovery\ Rate) - Write\ Offs\ in\ Rates\ (base\ year)$$

[20] PGE/900, Lynn – Nestel/20.
[21] Staff/1202, PGE Response to OPUC Data Request 236.

The Company's calculation uses only two years of collection agency recovery rates to arrive at the recommended increase in the uncollectible rate. Staff believes that the inclusion of only the 2021 and 2022 recovery rates in this calculation is insufficient to justify the Company's proposed increase. Staff has examined the historic trend of recovery rates provided by the Company in Staff Data Request 600,[22] and while there is a decrease in 2021 and 2022, there is not a long enough time trend from which to infer that the recovery rate will not return to a historic baseline. The Company argues that the use of only the 2021 and 2022 recovery rates is due to the timeframe of the implementation of new Fair Debt Collection Act regulations.[23] However, Staff believes that there has not been adequate data to evaluate whether the Fair Debt Collection regulations will impact collection agency recovery rates at the same levels moving forward.

Q. Please describe the Company's IQBD Adjustment.

A. The Company states in testimony that "[t]he Income Qualified Bill Discount Program (IQBD) reduces the billed amount for certain eligible residential customers. While this program has not had a discernible impact on the uncollectible rate so far, a program that reduces billed amounts could lower uncollectible expense in the future. Therefore, we decreased the estimated uncollectible rate by −0.072 percent to take into account the potential impact from IQBD. This was estimated by extrapolating the potential reduction in

[22] Staff/1207, PGE Response to OPUC Data Request 600.
[23] Staff/1207, PGE Response to OPUC Data Request 600.

uncollectible expense based on enrollees in IQBD which are 61 plus days arrears."[24]

Q. Does Staff agree with the Company's proposed IQBD adjustment?

A. No. Staff believes that the methodology used by the Company to arrive at the IQBD adjustment fails to accurately capture the impact the program will have on the uncollectible rate. The Company's calculation fails to include any growth in the IQBD program participation between December 31, 2022, and the Test Tear.[25] Staff believes there is insufficient data to date to be able to accurately assess the total impact of the IQBD program on the uncollectible rate. If IQBD program participation increases at a faster rate than anticipated by the Company, PGE's proposed adjustment may be vastly underestimating the impact of the program on the uncollectible rate.

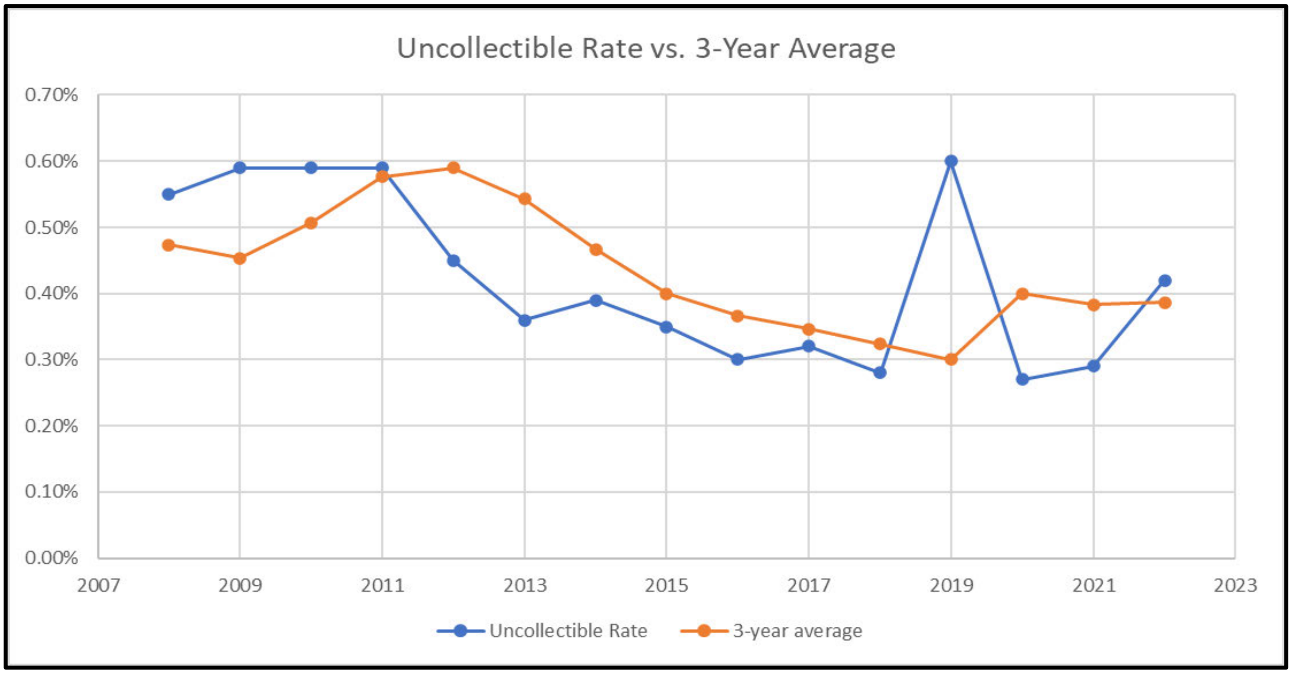
Q. Please summarize Staff's analysis of the overall methodology PGE uses to forecast the uncollectible rate.

A. Staff finds that the methodology put forth by the Company to forecast the uncollectible rate using distinct itemized adjustments is not sufficiently robust to justify deviating from the Commission's historic precedent of a three-year average. Historically, the three-year average has tracked the overall trend of the uncollectible rate while smoothing out year-over-year variances. Figure 4 shows the Company's actual uncollectible rate plotted against the average uncollectible rate of the three preceding years.[26]

---

[24] PGE/900, Lynn – Nestel/20.
[25] Staff/1202, PGE Response to OPUC Data Request 236.
[26] Staff/1208, Staff Workpaper, Uncollectible Rate.

Figure 4.



Q. What is Staff's proposed adjustment for the uncollectible rate and uncollectible expense for the 2024 Test Year?

A. Staff proposes using the three-year average of the uncollectible rate between 2020-2022. PGE provided this average, an uncollectible rate of 0.33 percent, in response to Staff Data Request 595.[27] 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 2024 Test Year. At this time, based on the Company's proposed general revenues in its Exhibit 201,[28] Staff proposes a decrease to the Company's Test Year uncollectible expense of $5,289,000.[29]

27 Staff/1203, PGE Response to OPUC Data Request 595.
28 PGE/201, Batzler-Ferchland/1.
29 Staff/1209, Staff Adjustment Workpaper.

ISSUE 2. LEVEL III OUTAGE ACCRUAL MECHANISM

Q. Please describe PGE's Level III Outage Mechanism.

A. In 2010, the Commission authorized PGE to collect $2.0 million annually in rates to pay for service restoration following severe outage events, referred to as Level III storms or outages.[30] At least one of the following criteria must be met for an event to be considered Level III outage:[31]

1. Impacts at least 50,000 customers;
2. Qualifies for Institute of Electrical and Electronics Engineers (IEEE) Major Event Day exclusion; or
3. Several substations and feeders are out of service.

The annual amount included in PGE's Test Year is based on a rolling 10-year average of Level III outage costs, adjusted to reflect present value costs. To the extent that amounts collected are not used in a given year, the funds are accrued and used to offset costs related to Level III outages in future years. In Docket No. UE 319, the Commission approved the parties' stipulation increasing the annual amount recovered in rates from $2.0 million to $2.6 million based on an updated rolling 10-year average of Level III outage costs from 2007-2016. In Docket No. UE 335, the Commission increased the amount recovered annually for Level III outage costs to $3.8 million, based on an updated 10-year rolling average. In both UE 319 and UE 335, the Commission rejected PGE's request to create a "balancing account" that would

---

30 Docket No. 215, Commission Order No. 10-478.
31 PGE/800, Bekkedahl-Jenkinds/60.

allow PGE to defer costs that exceed those PGE had accrued for Level III outages and offset them against future accruals.

Q. Please describe the most recent updates to the Company's Level III Outage Accrual Mechanism.

A. In Order 22-129 (Docket No. UE 394), the Commission adopted changes to the Level III Outage Accrual Mechanism that allow PGE to carry a negative balance for the Level III account, subject to a hard cap of twice the annual accrual. This altered previous Commission precedent that did not allow PGE to carry a negative balance. The Commission also found that the Level III outage events can include wildfire impacts that meet the definition of a Level III outage. However, to the extent that a state of emergency is declared as a result of the weather event or PGE has insurance coverage for the damage, PGE may not recover through the Level III mechanism any costs associated the event.[32]

Q. Please describe PGE's proposal for the Level III Outage Accrual Mechanism.

A. The Company states in testimony that "PGE experienced a number of significant storms during 2022 that increased the current ten-year moving average by approximately $2.7 million resulting in an updated annual accrual of approximately $6.2 million."[33] The Company is not requesting any changes to the structure of the Level III Outage Accrual Mechanism in this case.

---

32 *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 394, Order No. 22-129, pp. 31-32 (April 25, 2022).
33 PGE/700, Bekkedahl – Jenkins / 20.

Q. What is the Company's proposed balance for the Level III Outage Accrual Mechanism?

A. The Company's proposed balance for the Level III Outage Accrual Mechanism for 2022 would be ($7,050,700). This would be the first time that the Company's balance for the mechanism would be negative, following the Commission's Order adopted in Docket No. UE 394 (see Figure 5). The proposed 2022 balance is less than twice the annual amount and therefore within the bound of the changes adopted in Commission Order 22-129.

Figure 5.[34]

	Collection	Withdrawals	Balance
2011	$ 2,000,000	$ -	$ 2,000,000
2012	$ 2,000,000	$ -	$ 4,000,000
2013	$ 2,000,000	$ -	$ 6,000,000
2014	$ 2,000,000	$ 5,623,875	$ 2,376,125
2015	$ 2,000,000	$ 5,161,601	$ -
2016	$ 2,000,000	$ 4,504,081	$ -
2017	$ 2,000,000	$ 11,351,424	$ -
2018	$ 2,600,000	$ -	$ 2,600,000
2019	$ 3,804,696	$ 1,772,198	$ 4,632,498
2020	$ 3,804,696	$ -	$ 8,437,194
2021	$ 3,804,696	$ 3,594,072	$ 8,647,818
2022	$ 3,618,465	$ 19,853,552	$ (7,050,700)

Q. Please describe Staff's analysis of the Company's Level III Outage Accrual Mechanism proposal.

A. Staff reviewed the descriptions and impact of each event as described by PGE in the response to Staff Data Request 354 to ensure that each event qualified as a Level III event.[35] There were six storms that PGE lists as Level III Events:

---

34 Staff/1210, PGE Response to CUB DR 031.
35 Staff/1211, PGE Response to OPUC Data Request 354, Attachment A.

four of the six impacted at least 50,000 customers, and all six rendered a minimum of 11 feeders out of service and qualified as Major Event Days. Figure 6 outlines each of the storms considered to be Level III events.

Figure 6.

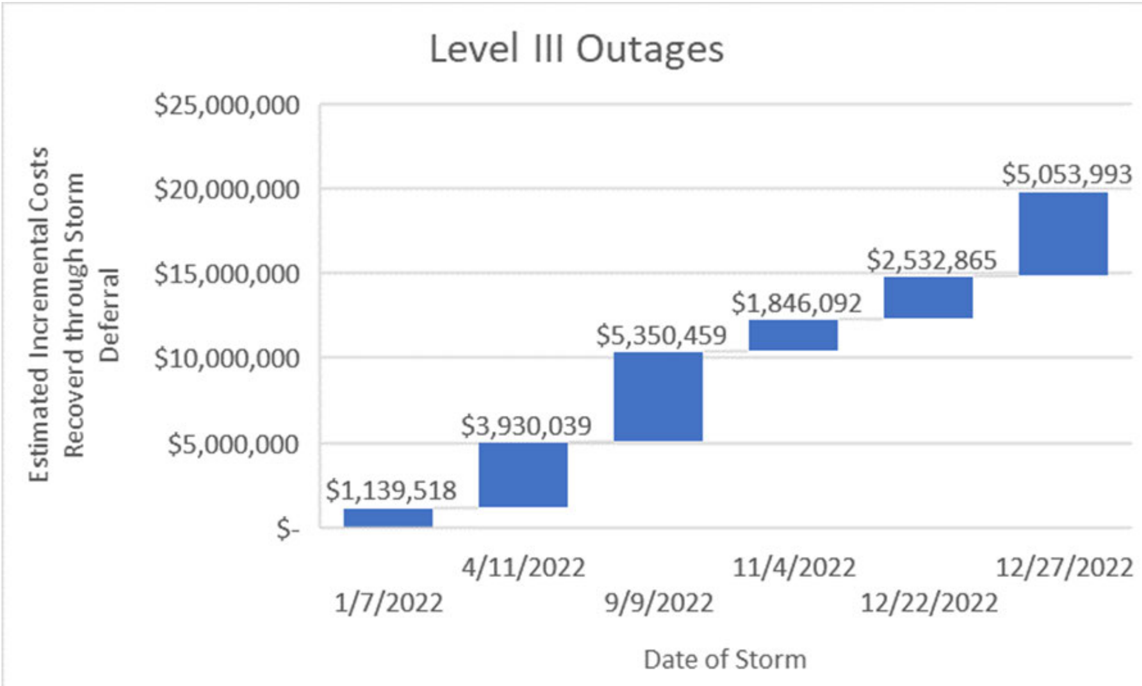
Event	Customers Impacted	Major Event Days (TMED = 6.5 SAIDI)	Substations Out of Service	Feeders Out of Service
Wind Storm - January 7th, 2022	31,294	1/7/22 - 8.97 SAIDI	1	11
Snow/Rain Storm - April 11th, 2022	50,201	4/11/22 - 29.2 SAIDI	0	11
Wind Storm/Public Safety Power Shutoff (PSPS) - September 9th, 2022	38,057	9/9/22 - 88.5 SAIDI	1	17
Wind/Rain Storm - November 4th and 5th, 2022	69,035	11/4/22 - 14.62 SAIDI 11/5/22 - 11.9 SAIDI	2	31
Wind/Freezing Rain/Snow Storm - December 22nd, 2022	63,881	12/22/22 - 17.78 SAIDI	1	17
Wind/Rain Storm - December 27th, 2022	156,761	12/27/22 - 125.28 SAIDI	3	46

Staff found that all events met the criteria of a Level III outage. Additionally, Staff reviewed historic Level III event costs and detailed restoration costs associated with each Level III event in 2022. Unlike in previous years,[36] there was not one significant storm in 2022 that encompassed most of the restoration costs. The total restoration costs for Level III storms in 2022 was $19.9 million (see Figure 7). The two highest cost events were the September 9, 2022, Public Safety Power Shutoff (PSPS) that was initiated due to high winds, and the December 27, 2022, wind and snowstorm, each of which had roughly $5.0 million in restoration costs.[37]

[36] See *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 394, Order 22-129 (February 2021 Ice Storms).

[37] Staff/1212, PGE Response to OPUC Data Request 354, Attachment B.

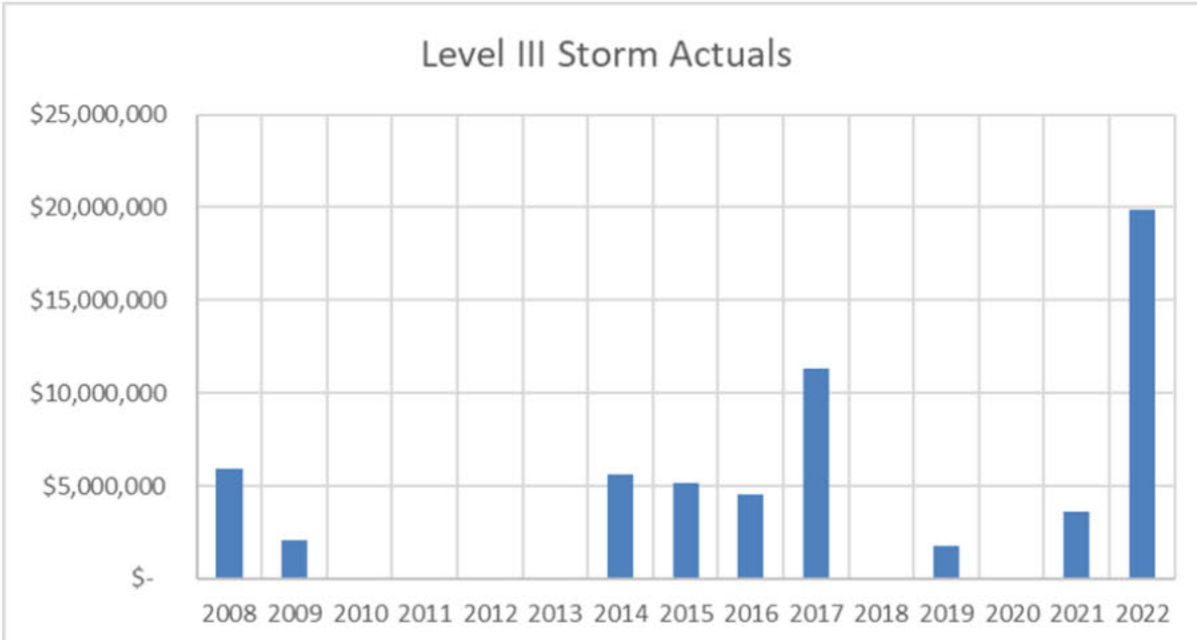
Figure 7.



Historically, 2022 represents the highest Level III storm costs incurred by PGE in the last 14 years. Both 2020 and 2021 would have been higher, but costs associated with wildfires and major ice storms ultimately did not go through the Level III storm mechanism and were separately deferred.[38] (See Figure 8.)

[38] See *In the Matter of Portland General Electric Company, Application for Deferral of Wildfire Emergency Costs and Lost Revenues*, UM 2115, Order No. 20-389 (October 27, 2020); and *In the Matter of Portland General Electric Company, Application for Authorization to Defer Emergency Restoration Costs*, Docket No. UM 2156, Order No. 22-020, (January 26, 2022).

Figure 8.[39]



Q. Please summarize Staff's review of the Company's Level III Outage Accrual Mechanism.

A. Staff found that each of the events listed by the Company in the response to Staff DR 354 met the necessary definition of a Level III event.[40] Furthermore, Staff found that a state of emergency was not declared for any of the events listed by the Company and therefore are allowed to be put through the Level III mechanism.

Q. Does Staff have a proposed adjustment for the Level III Outage Accrual Mechanism?

A. No. Staff has no proposed adjustment at this time.

---

39 Staff/1210, PGE Response to CUB DR 031.

40 Staff/1211, PGE Response to OPUC Data Request 354, Attachment A.

ISSUE 3. RESEARCH AND DEVELOPMENT

Q. What are R&D expenses?

A. R&D expenses are expenses for research, development, and demonstrations that are related to the utility's current or future business. These expenses include work with technologies that are not yet technically and commercially viable. These activities may be conducted directly by the utility or through a third party.

Q. Please summarize the Company's overall request for R&D expense.

A. The Company is proposing an R&D budget increase from $2.8 million in 2022 to $3.3 million in 2024.[41]

Q. How did the Company calculate the budget for R&D expenses?

A. The Company used the methodology stipulated in UE 335:

> PGE will determine the percentage of fixed Transmission and Distribution ("T&D") and Generation Operations and Maintenance ("O&M") costs (excluding Boardman) in the test year forecast that $2.6 million represents and the Stipulating Parties agree to apply that percentage from this rate case to determine a presumptive reasonableness of R&D costs in PGE's next three rate cases, or 10 years, whichever occurs first.[42]

---

41 PGE/201, Batzler-Ferchland/1.
42 Order No. 19-129, UE 335, Appendix A, pages 2-3.

In Docket No. UE 335 the stipulated $2.6 million budget represented 0.825 percent of final UE 335 T&D and generation fixed O&M, excluding Boardman. The Company applied this percentage to the 2024 Test Year forecast and calculated an R&D budget of $3.3 million.

Q. How did Staff review these costs?

A. Staff reviewed the data provided by the Company in response to Staff DR 356 and additional DRs.[43] Staff reviewed historic R&D costs and individual R&D project costs for 2022 to determine if costs are appropriately categorized for R&D spending. Staff reviewed relevant processes the Company established to manage the R&D budget.

Q. Is Staff proposing adjustments for R&D costs?

A. No. The method to calculate a presumptive reasonable budget amount was set in UE 335 for this rate case, and the amount proposed by the Company appears to be consistent with this presumed reasonable amount.[44] As a result, I propose no adjustments in my testimony.

Q. Does this conclude your testimony?

A. Yes.

---

[43] Staff/1213, PGE Response to OPUC Data Request 356.
[44] Order No. 19-129, UE 335, Appendix A, pages 2-3.

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualification Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Bret Farrell
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Strategy Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	BA Economics, Illinois State University, Normal, IL MS Applied Economics, Illinois State University, Normal, IL
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission since April 2019. My responsibilities include research, statistical analysis, and recommendations on a range of regulatory issues. I have provided testimony before the Commission in several general rates case proceedings and performed numerous analyses including economic, financial, and statistical with regard to public utilities.

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1202

PGE Response to OPUC Data Request 236

June 13, 2023

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 236
Dated March 13, 2023

Request:

Referring to the Company's testimony UE 416 / PGE / 900 / Lynn – Nestel / 17

a. Provide the underlying calculation of the each of the values listed in "**Table 2 Uncollectible Rate Forecast Itemized**" in an Excel spreadsheet. In the response, please provide the supporting summary data for each of the years 2017, 2018, 2019, 2020, 2021, 2022.

Response:

PGE objects to this request for being overly broad and unduly burdensome in that it requires new analysis to be performed. Without waiving said objections, PGE states as follows:

a. The underlying calculations in Table 2 are primarily based on the most recent information available through November 2022 and do not rely on historical time series. Where data is available, historical years are also provided. Attachment 236-A shows the underlying calculations for the values listed in 900/Lynn-Nestle/17 Table 2. For the Recovery Rate Trend adder, the initial 2022 estimate of 16.5% was based on data through November 2022, 15.85% is a full year of data for 2022.

   In October 2022, there were numerous additional customer protections added into OAR Division 21 which will result in changes to uncollectibles. Particularly, Severe Weather Moratorium which added significant protections for customers from November through March and hasn't completed its first cycle since implementation. Also, Notice of Pending Disconnection perspective changing the 15-day disconnection notice to a 20-day notice will be implemented by June of 2023 however any additional time has a direct impact increasing arrears outstanding. PGE made a good faith effort to approximate impact with the partial historical data available

PGE Response to OPUC Data Request 236, Attachment A is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

PGE Data Response to OPUC Data Request 595

June 13, 2023

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 595
Dated April 20, 2023

Request:

As it pertains to PGE's response to Staff DR 236 Attachment A, Part A, tab "236.a Economic Conditions":

a. Please explain the Company's rationale for using the years 2013-2017 as a "base period" for strong economic conditions.
b. Please explain the Company's rationale for using the 2008-2011 as a "proxy period for economic downturn".
c. Please explain the Company's rationale for using 50% of the write off increase that was calculated.
d. Does the Company believe that the economic conditions in the test year (Proposed uncollectible rate of 0.5000%) will be worse than the economic conditions during the Company's proxy period for economic downturn (Uncollectible rate of 0.4923%)?
e. Has the Company ever had an uncollectible rate higher than 0.5000%? If yes, please provide a narrative explanation of the causes which led to the rate.
f. For the years 2000 to 2021, please provide the Company's uncollectible rate.

Response:

In email conversations, OPUC Staff agreed to a one-week extension to allow PGE additional time to respond to this request.

a. PGE used the 2013-2017 time period for the uncollectible rate in the past two general rate cases. This is due to the anomalous write off and collection process in 2018 and 2019 following the billing system implementation, for the 2019 General Rate Case (UE 335) and due to the COVID-19 pandemic, where PGE did not propose a change in the uncollectible rate in the 2022 GRC (UE 394) to mitigate the customer price increase. The years 2013-2017 also happen to coincide with extremely strong economic conditions as shown in standard economic measures such as GDP, unemployment, inflation, labor force growth.

   The time period of 2008 to 2011 was chosen as representative of recessionary or weak economic conditions since the impact of a recession on write offs can have lingering impacts. The 2008 recession officially began in December 2007 and officially ended in June 2009, according to the National Bureau of Economic Research US Business Cycle Dating Committee. A four-year time period was also chosen so as to not overly bias the recessionary period to the worst year of the economic downturn (depth of the recession).

b. PGE applied a 50% weighting to the uncollectible rate experienced in the 2008 recession to reflect more balanced economic conditions compared to the strong economic conditions in the 2013-2017 timeframe. This has the effect of averaging out economic conditions into the uncollectible rate and was chosen as another way to reduce and mitigate the adder for economic conditions.

c. PGE relies on economic forecasts from IHS Markit and the Oregon Office of Economic Analysis. These forecasts were predicting a mild recession in 2023 into 2024 which would not be worse than the 2008 recession as measured by GDP, unemployment, however inflation and interest rates are expected to be higher in the test year. The proposed uncollectible rate is higher than in the 2008 recession not just from economic conditions, but also due to changes in the credit and collection processes which have significant impact on arrears and uncollectibles.

d. Yes. PGE had an uncollectible rate of 0.61% in 2005. PGE had an uncollectible rate of 0.55% in 2008 and 0.59% each year from 2009 through 2011 due to the 2008 economic recession. PGE had an uncollectible rate of 0.60% in 2019, as a result of suspending certain credit and collection activities following the implementation of a new billing system. Attachment 595-A provides these rates by year. PGE does not have data regarding the uncollectible rate prior to 2005.

e. PGE objects to this request on the basis that it is unduly burdensome. Notwithstanding this objection, PGE responds as follows:
Attachment 595-A provides PGE's bad debt (i.e., uncollectible) rates from 2005 to 2022.

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1204

Staff Workpaper

June 13, 2023

Staff Workpaper is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1205

PGE Response to OPUC Data Request 599

June 13, 2023

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 599
Dated April 20, 2023

Request:

As it pertains to PGE's response to Staff DR 236 Attachment A, Part A, tab "236.a Div 21 Weather Protection":

a. Please explain the rationale for the methodology used to arrive at the Company's calculation of a 0.0544% increase.
b. Does the Company believe that additional weather disconnection protections will reduce the number of disconnections and therefore reduce the amount of uncollectible expense?

Response:

In email conversations, OPUC Staff agreed to a one-week extension to allow PGE additional time to respond to this request.

a. The rationale in this methodology reflects that weather protections will have the impact of increasing the number of (unpaid) billing days before disconnection an additional 30 days for four months of the year. Unadjusted billing days to disconnection are assumed to be 60 days, making the 30-day increase a 50% increase in the number of billing days before disconnection. Since this will only affect 33.33% of the year, an annual increase to billing- days-before-disconnect is calculated as 16.7% (50% x 33.33%).

b. PGE believes that additional weather disconnection protections will delay and not reduce the number of disconnects. The longer customers are not disconnected will increase the arrears (outstanding balance) on accounts that become uncollectible.

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1206

PGE Response to OPUC Data Request 598

June 13, 2023

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 598
Dated April 20, 2023

Request:

As it pertains to PGE's response to Staff DR 236 Attachment A, Part A, tab "236.a Div 21 15-20 day notice":

a. Please explain the rationale for the methodology used to arrive at the Company's calculation of a 0.0272% increase.
b. Does the Company believe that the increased notification period will have any effect on the number of customer accounts becoming uncollectible?

Response:

In email conversations, OPUC Staff agreed to a one-week extension to allow PGE additional time to respond to this request.

a. The rationale in the methodology reflects that increasing the notification period from 15 to 20 days will increase the average written off balance amount from 60 days to a total of 65 days. Increasing the 15-day notice to a 20-day notice is assumed to increase the number of billing days written off by an additional five days, or 8.33% increase.

b. PGE does not necessarily believe that the number of accounts that become uncollectible will increase. Rather, PGE believes that the longer notification period will increase the arrears (outstanding balance) on accounts that become uncollectible. It is the higher balances accruing and not the number of uncollectible accounts that was considered by PGE in the forecast.

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1207

PGE Response to OPUC Data Request 600

June 13, 2023

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 600
Dated April 20, 2023

Request:

As it pertains to PGE's response to Staff DR 236 Attachment A, Part A, tab "236.a Recov Rate Trending":

a. Please explain the rationale for the methodology used to arrive at the Company's calculation of a 0.0575% increase.
b. Please explain the Company's rationale for using only the recovery rate in the years 2021 and 2022 in the calculation.
c. Please provide the Company's recovery rate for the years 2000 to 2022 in an excel format.

Response:

In email conversations, OPUC Staff agreed to a one-week extension to allow PGE additional time to respond to this request.

a. See UE 416 /PGE / 900 Lynn-Nestel /20 lines 10-19.

b. The rationale for using the recovery rate in 2021 and 2022 in the calculation is due to the corresponding time period with the implementation of new Fair Debt Collection Regulation guidelines. See UE 416/PGE/900 Lynn-Nestel/20 lines 10-19.

c. PGE objects to this request as it is overly broad, unduly burdensome and to the extent it requests data that is not available. Subject to and without waiving its objection, PGE responds as follows: Attachment 600-A provides the recovery rate calculated from calendar year gross placements and calendar year recoveries for 2015 to 2022. PGE notes that based on additional review of data from one of the collection agencies, the 2021 recovery rate is revised from 28.5% as stated in UE 416/PGE/900/Lynn—Nestel/20/19 to 31.6%.

PGE Response to OPUC Data Request 600, Attachment A is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1208

Staff Uncollectible Rate Workpaper

June 13, 2023

Staff Uncollectible Rate Workpaper is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1209

Staff Adjustment Workpaper

June 13, 2023

Staff Adjustment Workpaper is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1210

PGE Response to CUB DR 031, Attachment A

June 13, 2023

PGE Response to CUB DR 031 Attachment A is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1211

PGE Response to OPUC Data Request 354, Attachment A

June 13, 2023

PGE Response to OPUC Data Request 354, Attachment A is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1212

PGE Response to OPUC Data Request 354, Attachment B

June 13, 2023

PGE Response to OPUC Data Request 354, Attachment B is provided in Electronic Format

CASE: UE 416
WITNESS: BRET FARRELL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1213

CONFIDENTIAL PGE Response to OPUC Data Request 356, Attachment A

June 13, 2023

CONFIDENTIAL PGE Response to Staff DR 356 Attachment A is provided in Electronic Format

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

June 13, 2023

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

A. My name is Julie Jent. I am a Senior Economist employed in the Energy Costs Section of the Rates, Safety and Utility Performance Program 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 qualifications statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Staff's analysis of the Company's forecast of Test Year Wages & Salaries, Full-Time Employees (FTEs), and non-labor Generation Overhead and Maintenance (O&M) expense and PGE's proposal to modify its Automatic Update Tariff (AUT) to create a total pass-through of costs PGE incurs to purchase from Qualifying Facilities. I separately filed testimony on this year's NVPC Update under the AUT (Staff/100) on May 24, 2023, and am filing joint testimony with other Staff on PGE's proposed changes to its Power Cost Adjustment Mechanism (PCAM) (Staff/2300). My recommendations, along with other Staff recommendations, may change based on further review and based on the testimonies offered by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. QF PASS THROUGH PROPOSAL IN NVPC

Q. Does Staff have any additional discussion topics regarding the Company's AUT filing aside from what is included in Staff/100?

A. Yes. As discussed in testimony submitted by Ishraq Ahmed in Staff/200, proposed changes to the AUT itself are appropriately addressed in a General Rate Case to allow more time to investigate and review the proposed changes than is offered in the more abbreviated process for reviewing NVPC updates. For this reason, Staff did not respond to PGE's Qualifying Facility pass through proposal in testimony evaluating PGE's updates to NVPC filed on May 24, 2023. Staff addresses PGE's proposal here.

Q. Why is PGE proposing a change to the AUT related to QF costs?

A. As was discussed in PGE's most recent AUT proceeding, in Docket No. UE 402, forecasts of QF costs in PGE's NVPC forecast have been historically inaccurate. QF forecasting began in 2009. Figure 1 below summarizes the Company's forecasted QF costs and actual QF costs since 2015, highlighting how the Company has **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

<u>CONF FIGURE 1. QUALIFYING FACILITIES FORECAST AND ACTUALS</u>[1]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL][2]

Due to the nature of the contracts, QF costs can be more difficult to forecast accurately than other power costs. The uncertainty creates significant incentive for the Company to over forecast QF costs in the AUT, as it has frequently done over the past decade. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[3]

---

1 *See* Staff/1302, PGE CONF response to Staff DR 330 Attachment A (electronic spreadsheet), which was used to create this chart.

2 Staff was concerned that this table from Staff DR 330-A did not match Staff's analysis from UE 402 using DR 22 and 23. *See* Staff/1302, PGE CONF response to Staff DR 584 (pdf) for a response. It is important to note that there were two reasons why these numbers do not match. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3 See CONF PGE Work paper Table 9 Comparison NVPC.

Q. What is the Company's proposal to address the issue identified above?

A. The Company proposed adjusting the treatment of QF costs in PGE's AUT filing by introducing the following pass-through mechanism.[4] The Company's proposed methodology would work as follows:

- PGE would forecast QF costs for the following NVPC test year based on the rolling average of the most recent full years of QF generation, up to three historical years.
- PGE would file a deferral application to defer for later recovery or to refund the variance between forecasted and actual QF costs.
- After the conclusion of the forecasted year, PGE's actual QF costs would be compared to forecasted costs.
- The resulting surplus or deficit would be passed through to customers the following AUT proceeding as either a charge or a refund to customers based on the difference between the contract price collected from customers in the NVPC forecast and the day-ahead Mid-C power price. Additionally, this variance would capture any delay damages the QF pays for failing to meet the contractual online date.
- The price for the Mid-C would include a weighting of the light load and heavy load hours by the respective hours in the day.

[4] See UE 416/PGE/300, Schwartz—Outama—Cristea/51. However, this was proposed initially by Staff in UE 402.

Q. Staff made a QF cost pass-through proposal in PGE's last AUT Update in UE 402. Does the Company's proposal differ from Staff's?

A. Yes. Staff proposed to address the variance in the PCAM, whereas PGE proposes to address any over or under forecast in a subsequent AUT. PGE states that its proposal would ensure that any variations are not subject to the PCAM framework and would avoid additional administrative burden since PGE already uses the annual AUT to amortize deferred amounts from the QF track and true-up mechanism used to capture variances between the forecasted and actual costs of new QFs.[5]

Q. What is Staff's position on the need for a pass-through for QF costs?

A. Staff agrees with PGE that it is appropriate to treat QF costs differently than other power costs and that a pass-through mechanism is a reasonable approach. The forecasting of QF costs in the AUT has been a contentious issue for many years, and has required significant input from Staff, parties, and the Commission each year. A pass-through will remove the incentive to over-forecast costs, and by establishing a set procedure for calculating the forecast and pass-through payments, this proposed approach will ultimately benefit consumers by reducing the workload of intervening parties in each docket. Therefore, Staff approves PGE's recommendation.

Q. What is the overall effect of Staff's approval of PGE's recommendations for the 2024 QF Generation forecast?

---

[5] *See* Staff/1301, PGE Response to Staff DR 331 (pdf).

A. During this GRC, PGE will determine the 2024 QF generation forecast based on a rolling average. Before the end of 2023, PGE will submit a request for deferred accounting reauthorization under UM 1988, to ensure all QF generation and cost is subject to deferred accounting. At the end of 2024, PGE will compare forecast QF generation with actual and will calculate a collection to or refund from customers. Any collection or refund will be amortized in the 2026 NVPC forecast to be processed during 2025. In addition, a QF track and true-up mechanism would no longer be necessary. Therefore, PGE would stop tracking and trueing up new QFs coming online in the test year.[6]

6 PGE/300 Schwartz—Outama—Cristea/52-53.

ISSUE 2. WAGES & SALARIES, BONUSES, INCENTIVES

Q. Please summarize Company's proposal for wages, salaries, incentives and overtime expense in this case.

A. The Company's 2024 Test Year includes $433 million in wages and salaries (base pay), $20.3 million in incentive compensation, and $19.8 million in overtime.[7] The Oregon allocation factor is 100 percent with a 59.1/40.9 percent split for O&M and Capital.[8] The Company claims to have removed all incentive compensation paid to the executive group as well as 50 percent of non-officer incentives based on 2022 actuals, a reduction of $22.1 million, as illustrated below in Figure 2.[9]

FIGURE 2. TOTAL COMPENSATION AS PER PGE

Table 1
Estimated Total Compensation Costs ($Millions)

Component	2022 Actuals	2024 Test Year	2022-2024 Delta
Total Labor	$428.1	$433.0	$4.9
Incentives	$42.4	$20.3	($22.1)
Benefits	$93.8	$106.8	$13.0
Total Compensation*	**$564.3**	**$560.1**	**($4.1)**

** Numbers may not sum due to rounding.*

Q. How does the Company determine the compensation for employees?

A. PGE testifies that it compares its wages and salaries to relevant markets using compensation surveys via third-party consulting companies.[10] The Company

---

7 PGE/500, Mersereau—Neitzke/19.
8 See Staff/1301, PGE Response to Staff DR 93 (pdf).
9 PGE/500, Mersereau – Neitzke/2.
10 See Staff/1301, PGE response to Staff DR 248 (pdf), which lists these surveys.

uses these data points to benchmark the salaries of positions and roles against similar PGE positions, determining a midpoint for each compensation grade within the pay structure. Pay ranges are then established around the midpoint and actual salaries for each position level must fall within a specific range of PGE's pay structure as determined by these mid-points. Pay above or below the median may still occur based on experience, scope, and impact of the role.[11] In 2022, the Company adjusted the midpoints of its pay structure to align with the market, which increased by an overall average of 3.87 percent.[12]

In terms of incentives, the Company now offers three types:

- Annual Cash Incentive (ACI) Plan,[13] which offers cash payouts to eligible employees tied to several goals such as Corporate Strategy, Customer Satisfaction, Electric Service Power Quality and Reliability, and Generation Availability and Financial Performance;
- Long-Term Stock Incentive Program, which provides directors, officers, and key employees with long-term incentives paid out in three-year cycles; and
- One-time recognition and Miscellaneous, which provides employees individualized cash rewards based on exceptional performance.[14]

---

[11] PGE/300, Mersereau – Neitzke/17.
[12] PGE/300, Mersereau – Neitzke/18.
[13] PGE/500, Mersereau—Neitzke/23. PGE previously utilized two different incentive programs, the Annual Cash Incentive (ACI) for executives and key non-represented employees and the Performance Incentive Compensation (PIC) for all other incentive-eligible employees. These are now both joined together under the ACI program.
[14] PGE/500, Mersereau – Neitzke/24.

Q. What adjustments did the Company make to its actual 2020 Base Year salaries and wages to forecast the 2022 Test Year?

A. The Company escalates its 2022 Base Year pay of non-union employees by four percent in 2023 and four percent in 2024. For union wages and salaries, PGE started with a 2022 Base Year and also applied a rate of four percent for 2023 and 2024 based on expected collective bargaining increases for the Company's two unions in IBEW Local No. 125.[15] PGE has also reduced its Test Year O&M expenses by $11.8 million to account for vacancies or unfilled positions.[16]

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for wages, salaries, incentives, and overtime expense.

A. The Commission's methodology has many components. The Commission determines the appropriate level of wages and salaries for employees in the Test Year using its three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[17,18] The model determines an appropriate level Test Year expense and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual

---

15 PGE/500, Mersereau – Neitzke/19.

16 PGE/500, Mersereau – Neitzke/20.

17 *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999), *In the Manner of PacifiCorp,* Docket No. UE 375, Order No. 20-473 at 102 (December 18, 2020).

18 See *Pacific Power & Light,* UE 116, Order No. 01-787 at 40; In the Matter of Northwest Natural, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

changes to the All Urban CPI and applying a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility.

To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased earnings, which benefits shareholders.[19] It is also Commission policy to disallow 75 percent of performance-based bonuses because they are generally focused on increased earnings and therefore bring more benefit to shareholders. The Commission disallows 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers. Union bonuses are treated in the same manner as non-union bonuses.[20]

Finally, the Commission determines the appropriate ratio of expense and capital to apply to the total forecasted compensation and applies it to determine what compensation expense that is included in Test Year expense and what compensation is included rate base.

Q. What additional claims does PGE make regarding wages and salaries?

A. PGE claims that, "if they were to increase wages strictly based on CPI and OEA nominal wage forecasts were to come to fruition, PGE would be at a great disadvantage in the job market and would likely face a higher level of turnover

[19] See Order No. 99-033 at 62; and *In the Matter of the Application of US West*, Docket No. UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

[20] See Order No. 20-473 at 97; Order No. 99-697 at 44-45; Order No. 99-033 at 62.

difficulties filling key positions, leading to inefficiencies and likely greater costs for customers in the long-term."[21]

Q. Why has the Commission used the W&S model to determine Test Year expense for non-union wages and salaries?

A. The Commission has explained its rationale in previous orders. For example, in an order issued in 1999, the Commission explained:

> The [Three Year] model incorporates actual market-based data by using, as a starting point, actual historic wages. We also agree with Staff's use of the All-Urban CPI index to adjust historic wages and salaries. Adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs. Contrary to the assertions by NW Natural, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey. Moreover, Staff's method of sharing the difference between payroll projections equally between ratepayers and shareholders also allows NW Natural some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation.[22]

Moreover, the All-Urban CPI captures local economic conditions as the Bureau of Labor Statistics includes Oregon prices in its survey.[23] Further, the methodology of equally dividing between ratepayers and shareholders the difference between the utility's Test Year forecast and the forecast obtained by the model allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[24]

---

21 *See* Staff/1301, PGE response to Staff DR 246 (pdf).
22 *Ibid.*
23 *Ibid.*
24 Order No. 95-322 at 10.

Wages, Salary, and Overtime

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for wage and salary levels for the Test Year.

A. As previously stated, PGE escalated its Base Year 2022 non-union and union wages and salaries by four percent for 2023 and 2024.[25] Staff, consistent with the W&S model, starts with a Base Year that is three years prior to the Test Year (2021), and escalates to the Test Year using All-Urban CPI (CPI) rates, which are 8.0 percent for 2022, 3.9 percent for 2023, and 2.2 percent for 2024.[26] Staff escalated union salaries and wages in the same manner as the Company, applying a rate of 7.0 percent for 2022 and 4.0 percent for 2023 and 2024 based on expected collective bargaining increases.[27]

Staff then applied the sharing principle to its and the Company's projected 2024 test year amounts. The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, results in a reduction to Staff's projection.

Q. What is Staff's recommendation for Test Year wages and salary, including overtime?

A. Based on application of the Three-Year Wages and Salary Model, Staff proposes the following adjustments to PGE's proposed wages and salaries levels: ($52 thousand) to Officer salaries, ($110,000) to Exempt salaries, and

---

25 PGE/500, Mersereau – Neitzke/19.
26 Oregon Economic & Revenue Forecast March 2023, Volume XLIII, No. 1, Table A.4, page 44.
27 Staff/1301, PGE response to Staff DR 94 (pdf) and 95 (pdf).

($1.26 million) to non-Exempt salaries. This results in an overall adjustment of ($1.43 million). Lastly, Staff made no adjustments to union salaries or overtime since the Company's filed proposal was less than Staff's calculation.[28]

FIGURE 3. W&S MODEL ADJUSTMENTS

Description	Officers	Exempt	Non Exempt	Union	Total
Actual Base Payroll (2021) calendar year	$ 4,793,841	$ 196,141,176	$ 23,765,080	$ 67,081,985	$ 291,782,082
Ave. # of Employees (FTE) (2021)	11	1675	404	630	2719
Average Salary	$ 443,874	$ 117,127	$ 58,825	$ 106,564	
Allowable % Increase	1.14680664	1.14680664	1.14680664	1.157312	
Ave. # of Employees (FTE) (Test Year)	10	1881	435	680	3006
Projected Payroll	**$ 5,090,379**	**$ 252,660,154**	**$ 29,345,242**	**$ 83,862,823**	**$ 370,958,597**
Test Period Payroll	**$ 5,193,708**	**$ 252,881,730**	**$ 31,870,957**	**$ 80,991,764**	**$ 370,938,159**
Total Difference for Sharing	$ 103,329	$ 221,576	$ 2,525,715	$ -	
10% Band - Allowable	$ 509,038	$ 25,266,015	$ 2,934,524	$ -	
50% Sharing of Lesser of Difference or Band	$ 51,665	$ 110,788	$ 1,262,857	$ -	
Staff Proposed Level	**$ 5,142,043**	**$ 252,770,942**	**$ 30,608,100**	**$ 80,991,764**	**$ 369,512,849**
Net Payroll Adjustment	$ (51,665)	$ (110,788)	$ (1,262,857)	$ -	**$ (1,425,310)**

Incentives[29]

Q. What does PGE propose for employee incentives?

A. For non-Officer incentives, PGE includes $20.3 million in the Test Year. PGE testifies that it removed 50 percent of its budgeted Non-Officer Incentives to be consistent with the Commission's policy regarding incentives and 100 percent of officer incentives.

Q. Does Staff agree with PGE's removal of 50 percent of non-Officer Incentives?

28 See Staff/1303, Staff electronic work paper, UE 416 Exhibit 1303 Wage and Salary Model CONF.xlsx, tab PUC 3-year W&S. Historically, the adjustments from Staff's model have been public/non-confidential but the model itself is published as confidential.

29 See Staff/1301, PGE Response to Staff DR 255 attachment A (electronic spreadsheet) provides underlying data for incentives and Response to DR 256 Attachment A (electronic spreadsheet), which provides the information on total aggregate labor costs by division.

A. Staff agrees with the underlying principle of removing 50 percent for non-officers, but believes PGE started with an unreasonably high forecast of incentives for the 2024 Test Year, similar to what was found in UE 394. Accordingly, PGE's downward adjustment of half of that forecast ($22.1 million) still leaves an unreasonably high forecast expense of the Non-Officer Incentives that are recoverable in rates.[30] It appears the Company's base calculation of non-Officer incentives was based upon its 2023 Budget and not its 2022 actuals, as illustrated below in Figure 4.

The Company has stated that they take the projected base pay for 2024 and forecast incentives utilizing the bonus target percent for each position, with the assumption that final payouts will meet the target.[31] Because the increases starting in 2020 were 41.8 percent to 2021 and negative 6.85 percent to 2022—having an expected increase of 21.91 percent to 2023 and only 5.26 percent to 2024, seem low. Its 2024 Forecast represents what the Company has left in the revenue requirement for Non-Officer Incentives.

FIGURE 4. NON-OFFICER INCENTIVES (ACTUALS, BUDGET, FORECAST)

Employee Class	2020Actual	2021 Actual	2022 Actual	2023Budget	2024ForecastAdjusted
Exempt	$ 23,072,047	$ 32,481,003	$ 30,559,188	$ 37,227,773	$ 19,427,632
Hourly	$ 990,113	$ 1,638,690	$ 1,223,445	$ 1,519,340	$ 965,224
Officer	$ 5,512,715	$ 10,215,340	$ 10,606,729	$ 9,137,580	
Union	n/a	n/a	n/a	n/a	n/a
Total	$ 29,574,875	$ 44,335,033	$ 42,389,362	$ 47,884,694	$ 20,392,856
Total (non-officer)	$ 24,062,160	$ 34,119,693	$ 31,782,633	$ 38,747,113	$ 20,392,856

30 Staff/1301, PGE Response to Staff DR 92 Attach A (pdf). *See also* Staff electronic work paper, UE 416 Exhibit 1303 Wage and Salary Model CONF.xlsx, tab Nonofficer Incentive Analysis. See also Staff/1301 PGEs response to DR 255 Attach A (electronic spreadsheet).

31 Staff/1301, PGE response to Staff DR 416 (pdf).

Q. Does Staff propose an adjustment?

A. Yes. Staff averaged the actual amounts of incentives paid to non-officer and non-union employees in 2020, 2021, and 2022 to forecast the amount of incentives PGE would pay to non-Officer employees in the Test Year and halved that amount, to arrive at Test Year expense of $15 million. Accordingly, Staff proposes a ($5.4 million) adjustment to PGE's 2022 Test Year expense for non-Officer incentives.

FIGURE 5. STAFF NON-OFFICER INCENTIVES ADJUSTMENT

Non-Officer Incentives	Amounts
2020-2022 Average	$ 29,988,162
50% of Actuals	$ 14,994,081
PGE's TY Non-Officer Incentives	$ 20,392,856
Staff Adjustment	$ (5,398,775)

ISSUE 3. FULL-TIME-EQUIVALENTS (FTES)

Q. What is the Company's main claim with regards to FTE?

A. PGE claims that it should analyze overall employee compensation and no longer focus on determining Test Year expense by the number of FTEs.[32] PGE states it would like to focus on total labor dollars instead of FTE in terms of defining total labor requirements, as this is more consistent with the approach their management takes when viewing resources.[33] That is, total labor dollars are more in line with PGE's "continually shifting and evolving project work" from lower wage developers to highly skilled analysts to temporary contract employees. Labor dollar metrics allows the flexibility for managers to continually change their workforce composition. PGE claims looking at FTEs in isolation tends to mask overall changes to labor needs as contractor hours and overtime hours are excluded.[34]

PGE provided work papers with Exhibits 600, 700, 800, and 900 to provide account detail by operating unit, department, and accounting work for all total labor expense requested in PGEs case.[35]

Q. Does Staff agree with PGE's proposal to shift focus away from FTEs to determine appropriate levels of Test Year expense for PGE's revenue requirement?

32 It in this context is referring to PGE, itself.
33 PGE/500, Mersereau – Neitzke/14.
34 *Ibid*.
35 See Staff/1301, PGE response to Staff DR 244 (pdf).

A. No. First, it is unclear whether there has always been a high correlation between FTE and salary totals, given that PGE failed to provide a year-by-year breakdown, but they did identify that salaries and FTE have a correlation of 0.80. Given this high correlation, Staff believes the increase in labor needed by PGE is being captured by their total number of FTE.[36] Second, using FTE allows Staff to more easily identify how many positions have gone unfilled. For example, as discussed below, PGE states that the increase in grid modernization O&M costs is driven by filling positions that were included in the last GRC but have gone unfilled due to a tight labor market for required skillsets and adding eight new positions.[37] In their DR response, PGE failed to reject Staff's assumption that the cost for these positions were collected in rates but absorbed by the Company in other capacities given that these positions were not filled.[38] Third, Staff does not just focus on FTE, but also evaluates labor dollars in our wages and salaries model by escalating the values by the all-urban CPI. Our analysis does not limit the Company choosing to allow more contract labor, for example, so business needs can still be met without any issues.[39] Lastly, there would be an increase in administrative burden given that the current standard data requests (SDRs) are focused on evaluating both FTE and dollar value totals. Staff finds that use of FTEs does not detract from the evaluation of wages and salaries.

---

36 See Staff/1301, PGE Response to Staff DR 363 (pdf).
37 PGE/700, Bekkedahl—Jenkins/21.
38 See PGE/700 Bekkedahl—Jenkins/21. See also Staff/1301, PGE response to Staff DR 249 (pdf).
39 See Staff/1301, PGE response to Staff DR 244 (pdf).

Q. Has PGE been correct in assessing how many FTE they need to operate?

A. No. PGE states, "We spent approximately $10.7 million on grid modernization O&M in 2022. We expect to spend $14.0 million in 2024, which is an increase of $3.4 million. The increase in grid modernization O&M costs is driven by filling positions that were included in the last GRC but have gone unfilled due to a tight labor market for the required skillsets and adding eight new positions."[40] The Company also did not answer the DR directly when asked whether Staff is correct in their assumption that the cost for these positions was collected in rates but absorbed by the Company in other capacities given that these positions were not filled.

Q. Please provide the background for this issue.

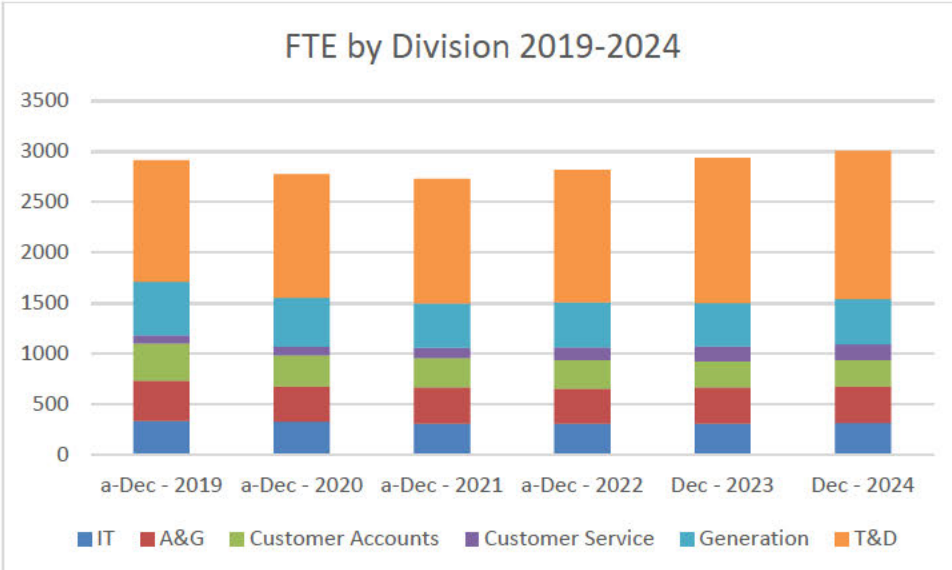
A. PGE's 2024 Test Tear forecast includes costs for approximately 190 more FTE than its most recent year of actuals (2022) and an additional 97 more FTE than its 2021 actuals.[41] The proportion of FTE by Division is illustrated in the chart below. Noteworthy is the significant growth of Transmission and Distribution (T&D) and Customer Service.

---

40 See PGE/700 Bekkendahl—Jenkins/21. See also Staff/1301, PGE Response to Staff DR 249 (pdf), DR 250 (pdf), and DR 250 Attachment A (electronic spreadsheet). Attachment 250-A provides the number of FTE, straight-time labor, overtime labor, and contract labor dollars request for PGE's previous four general rate cases along with the respective actual amounts over the same time period. Note that the general rate case amounts provided are what PGE included within its initial filing and do not include any adjustments made during the proceeding to PGE's initially filed amounts.

41 Staff/1301, PGE Response to Staff DR 92 Attach A (pdf).

FIGURE 6. FTE BY DIVISION[42]

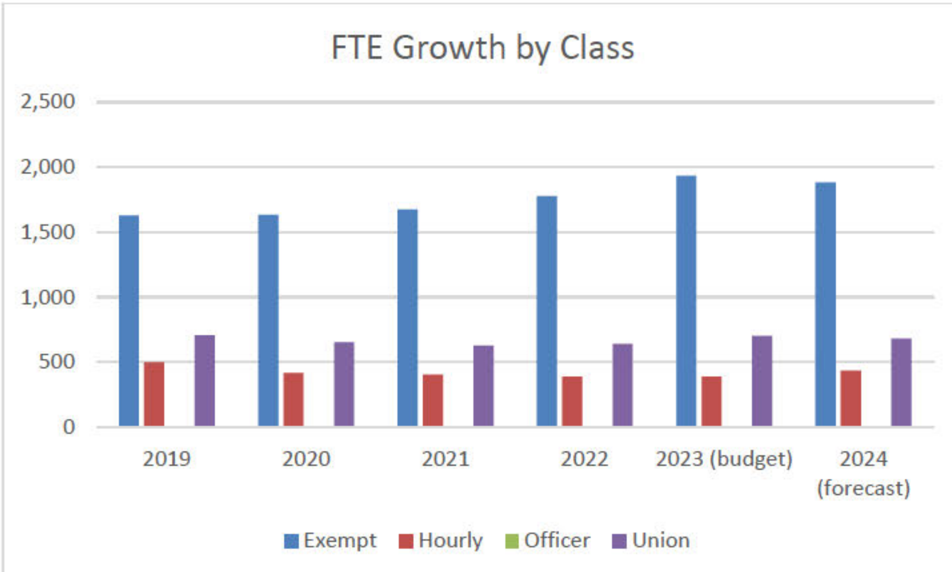


Division	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23	Dec-24
IT	337	329	311	309	309	317
A&G	398	348	356	345	358	359
Customer Accounts	370	307	293	286	258	259
Customer Service	78	86	101	121	149	154
Generation	528	483	437	445	429	450
T&D	1206	1222	1230	1312	1433	1466
Total	2916	2775	2728	2818	2936	3006

The growth in FTEs has been concentrated in the Exempt or Straight-time/salaried category as illustrated by the chart below, which examines actuals from 2019 to 2022 alongside budgeted 2023 FTE and adjusted 2024 FTE (FTEs after PGE's O&M reduction). While officer and union have remained somewhat stable, hourly and exempt FTEs have proliferated in recent years.

42 See Staff/1301, PGE Response to Staff DR 258 Attachment A (electronic spreadsheet). The chart is from DR 258 Attachment A which appear to not have exact whole numbers for FTE at one point in time but rather an average for the year.

FIGURE 7. FTE GROWTH BY CLASS



Q. Why is Staff concerned about the FTE increase?

A. Staff has noted its concern in PGE's FTE growth since Docket No. UE 319 in which "PGE proposed growing its FTE by 270 FTE from 2016 to its 2018 test year."[43] Moreover, PGE has historically budgeted more FTEs than is necessary as can be shown from an examination of its Budgeted and Actual FTE where PGE overestimated its 2020, 2021, and 2022 budgets by 292, 276, and 121 FTE, respectively.[44]

Q. Has the increase in payroll costs been offset by a reduction in contractor costs?

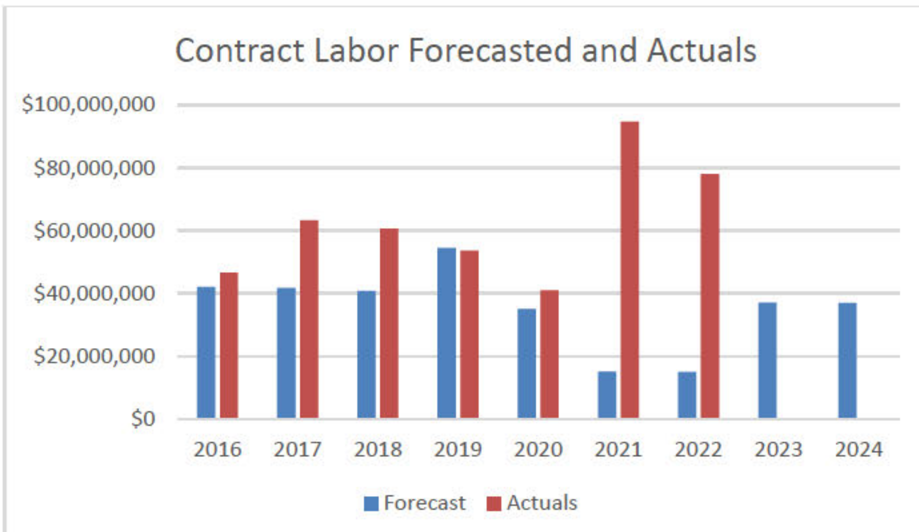
A. While PGE does project a decrease in contract labor from $77 million in 2022 actuals to $36 million in the test year (see below), comparisons between

43 UE 319 Staff/400, Gardner/37 at 15-19 and /38 at 1-23.

44 See Staff/1301, PGE Response to Staff DR 250 Attachment A (electronic spreadsheet) and DR 418 Attachment A (electronic spreadsheet).

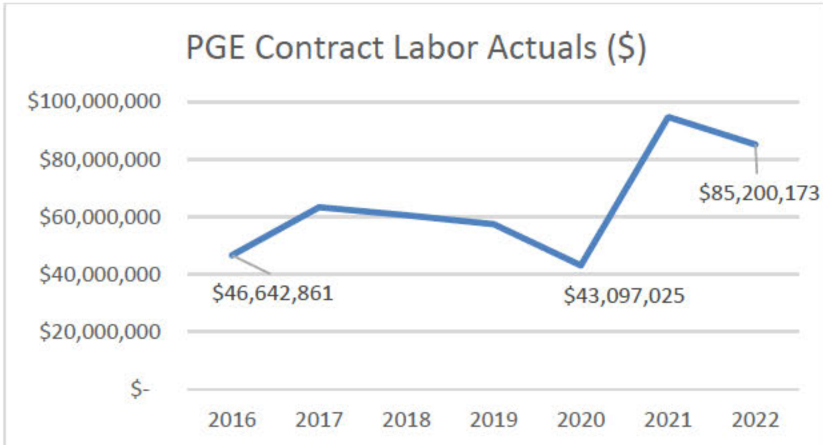
budgeted and actual labor does not bear this out. From Figure 8 below, we can see two issues. One, contract costs have continually increased in their actual dollar values—indicating that rising payroll costs for FTEs are not replacing contracted costs. Two, the Company has consistently under forecasted costs for contract labor.

FIGURE 8. CONTRACT LABOR[45]



[45] See Staff/1301, PGE Response to DR 250 Attach A revised (electronic spreadsheet). This was submitted since DR 250 Attach A inadvertently included both Level III storm amounts and FERC Accounts 417, 418, and 426 in actuals and PGE exhibit 500 did not. They were properly excluded from Attachment 256-A.

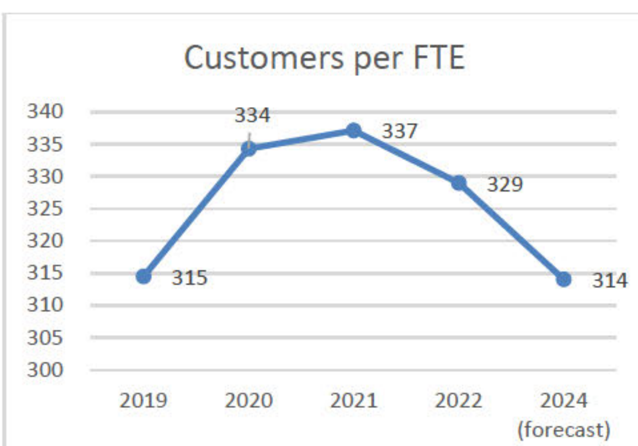
FIGURE 9. PGE CONTRACT LABOR

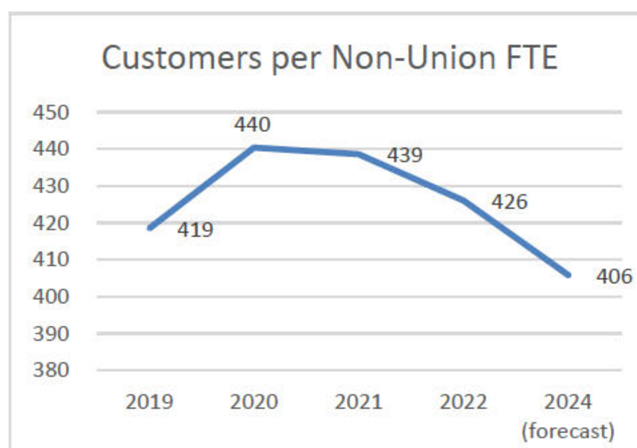


Q. How does this increase in FTEs impact customers?

A. Not only do customers have to bear the brunt of excessive labor spending, but the ratio of customers per FTE has actually declined since 2020; this issue was also identified in their last GRC. A more pronounced drop in the number of customers per FTE is seen when viewing customers per non-Union FTE, as indicated in the charts below.[46]

FIGURE 10. CUSTOMERS PER FTE[47]





46 *Ibid.*
47 See Staff/1301, PGE Response to Staff DR 366 Attach A (electronic spreadsheet).

Q. Does Staff propose an adjustment to the proposed 2024 test year FTE?

A. Given the trend of PGE over forecasting FTEs, Staff proposes an adjustment to PGE's FTE level as included in this general rate filing. Staff proposes reducing the Company's FTE count down to its most recent head count (in March), a difference of 91 from the Hourly and Exempt category. This excludes any reduction to union FTE numbers. The adjustment is in alignment with the Commission's conclusion in UE 116, which supported Staff's reduction of PacifiCorp's manpower levels to actual levels. The resulting Order No. 01-787[48] stated that employee levels should be based on actual levels at a specified date. Staff recommends a reduction of 34 exempt positions, or $4.57 million, and 57 hourly positions, or $4.01 million.[49] Together, this is an adjustment of 91 FTE and $8.58 million.

Q. Summarize Staff's adjustments.

A. In summary, Staff's adjustments to salary, wages, incentives and FTE are:

- Decrease salaries by $1.4 million (allocated $842 thousand O&M and $582 thousand Capital).
- Decrease incentives by $5.4 million (allocated $3.2 million O&M and $2.2 million Capital).
- Decrease FTE by $8.6 million (allocated $5.1 million O&M and $3.5 million Capital).

---

48 Order No. 01-787 at 41-42.

49 See Staff electronic work paper, UE 416 Exhibit 1303 Wage and Salary Model CONF.xlsx, tabs FTE adjustment, FTE.

- Small decreases for payroll taxes ($76 thousand) and Depreciation ($175 thousand). Commensurate with the wage and salary model, Staff adjusts the test year payroll tax to reflect the decrease in taxable gross wages while also reducing depreciation expenses to reflect the reduction in capitalized compensation.[50]

[50] See Staff electronic *work paper*, UE 416 Exhibit 1303 Wage and Salary Model CONF.xlsx, tab PUC Misc. Labor.

ISSUE 4. GENERATION EXPENSES (NON-LABOR)

Q. Describe PGE's proposal for generation expenses (non-labor).

A. Generation non-labor operations and maintenance (O&M) expense reflects the non-labor costs required to perform corrective and preventative maintenance on generation assets, site and equipment management, and health and safety measures. This includes costs reflected in FERC Accounts 500 through 557. PGE's proposal for generation expenses in non-labor for test year 2024 is $86.5 million (including IT expenses of $15.1 million), this is an increase of $15.4 million, or 21.6 percent.[51]

FIGURE 11. GENERATION NON-LABOR O&M CHANGES

Table 2*
Generation Non-Labor O&M Changes ($ millions)**

Operating Area	2022 Actuals	2024 Forecast	Delta 2022 vs. 2024	Annual % Change
Gas-Fired Plants	$14.8	$19.8	$5.0	15.8%
Hydro Plants	$5.3	$3.9	($1.4)	-14.1%
Wind Plants	$15.7	$17.5	$1.8	5.5%
Major Maintenance Accrual	$13.3	$18.6	$5.3	18.3%
General and Miscellaneous	$7.1	$7.6	$0.5	3.7%
Environmental	$3.8	$3.8	($0.0)	-0.2%
Sub-Total	**$60.1**	**$71.3**	**$11.3**	**9.0%**
IT Expenses	$11.0	$15.1	$4.1	17.1%
Total	**$71.1**	**$86.5**	**$15.4**	**10.3%**

**May not sum due to rounding.*
***Please note that historical costs for Boardman & Colstrip are excluded for comparison purposes.*

Q. Describe Staff's analysis of non-labor Generation expense.

A. Staff reviewed Company testimony and work papers, as well as historical expenses for calendar years 2020, 2021, and the Base Year. From my review

[51] See PGE/800 Jenkins-Bekkedahl/7 and CONF GRC Production Workpaper 2022-2024 Variance in Exhibit 800. *See also* Staff/1301, PGE response to Staff DR 345 (pdf). See also Table 2 of Exhibit 800.

of historical figures with and without IT expenses (workpaper GRC production work paper 2022-2024) it appears that the increase in Generation (non-labor) expenses can be attributed mostly to Gas-Fired Plants and Major Maintenance Accrual (MMA). It is important to note that the MMA mechanism is addressed in another Staff testimony.

Q. What is Staff's recommendation regarding PGE's generation expenses (non-labor)?

A. Staff finds PGE's Test Year expense is above recent years. See Figure 12 below showing the generation non-labor O&M for gas plants, hydro plants, wind plants, MMA, general & miscellaneous, and environmental.

CONF FIGURE 12. GENERATION NON-LABOR O&M EXPENSES.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does Staff have an adjustment?

A. Staff proposes an adjustment to bring the 2024 forecast more in line with actuals from 2020-2022. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** this is compared to a Base Year value of $71.1 million and a Test Year value of $86.5 million. Staff believes the increase to 2023 is artificially inflated, since it is a 17.82 percent increase and to 2024, there is an increase of 3.22 percent.

Q. What is the amount of Staff's adjustment?

A. Staff proposes to halve the increase proposed by PGE by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Overall, Staff believes costs are not being managed prudently.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Exhibits in Support
Of Opening Testimony

June 13, 2023

March 30, 2023

To: Marc Hellman
Public Utility Commission of
Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 331
Dated March 16, 2023

Request:

Please state what changes are different from the Company's QF pass through proposal in UE 416 to Staff's proposal in UE 402, and B) For each difference, explain the rationale.

Response:

The modifications proposed by PGE to the QF pass-through proposed by Staff in UE 402 are the following:

Staff Proposal in UE 402: In the AUT, "PGE would forecast QF costs using a three-year moving average of historical QF generation while also including new QFs with CODs in the test year."[1]

> **PGE modification:** PGE proposed to calculate the QF forecast based on a rolling average of the most recent full years of QF generation, up to three historical years because there are QFs that do not have three full years of historical results. Using partial years, as it would be needed under Staff's initial proposal, may impact the annual forecast generation profile due to seasonality of generation.

Staff Proposal in UE 402: "In the Power Cost Adjustment Mechanism (PCAM), PGE's actual QF costs would be compared to the forecasted costs, and the resulting surplus or deficit would be passed through as either a charge or a refund to customers based on the day-ahead Mid-C power price for replacement power, or the difference between the Mid-C price and the QF contract price in the event of surplus generation. The price for the Mid-C would include a weighting of the light load and heavy load hours by the respective hours in the day until a better method is identified."[2]

---

[1] UE 402, Staff/500 at 10.
[2] Id.

PGE proposed modification: Amortize collections or refunds through AUT annual filings instead of PCAM. This would ensure any variations are not subjected to the PCAM framework and would avoid additional administrative burden since PGE already uses the annual AUT to amortize deferred amounts from the QF track and true up mechanism.

February 24, 2023

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Standard Data Request
093 Dated March 10, 2015

Request:

For the Test Year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

The breakout between O&M and rate base for all 2024 labor[3] cost is as follows:

40.9% - Capital,
59.1% - O&M.

All labor relates to Oregon retail prices.

[3] The methodology used to split labor between O&M and capital for this data request is consistent with the methodology used for FERC Form 1 pages 354-355 reporting, which does not include contract labor.

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 248
Dated March 13, 2023

Request:

See PGE/500 Mersereau—Neitzke/17, stating "PGE continues to use well established industry and function-based national, regional, and local benchmarks." Please identify each benchmark referred to in this sentence, explain each benchmark in detail, and provide written copies of documents in the Company's possession regarding these benchmarks.

Response:

Please see identification and explanation of each compensation benchmark source and their usage below. The below information is accessed electronically through proprietary third-party online portals on an as needed basis.

WTW Energy Services Middle Management, Professional and Support Survey

- PGE utilizes the results from this survey to establish the non-executive, non-represented hourly and salary pay ranges. This industry specific compensation survey provides market data to an array of benchmark jobs specific to the energy/utility industry as well as jobs that are common to all industries. The compensation survey consists of 65 job functions and more than 540 disciplines. Compensation elements collected and reported on include but not limited to:
  - base salary
  - base salary pay range midpoints
  - actual performance bonus payouts
  - target performance bonus opportunity
  - total annual compensation
  - long-term incentive (LTI) target opportunity
  - actual total direct compensation
  - total direct compensation

WTW Energy Services Executive

- PGE utilizes the results from this survey as an input to determine executive compensation. This industry specific compensation survey provides market data to an array of benchmark jobs specific to the energy/utility industry as well as jobs that are common to all industries.

The compensation survey consists of over 190 executive benchmark jobs in 53 functions. Compensation elements collected and reported on include but not limited to:

- base salary
- base salary pay range midpoints
- actual performance bonus payouts
- target performance bonus opportunity
- total annual compensation
- long-term incentive (LTI) target opportunity
- actual total direct compensation
- total direct compensation

AON U.S. Energy Marketing and Trading Compensation Survey

- PGE utilizes the results from this survey for our energy trading and origination roles. This industry and function specific compensation survey provides market data to an array of benchmark jobs related to energy marketing and trading operations. Compensation elements collected and reported on include but not limited to:
  - base salary
  - base salary pay range midpoints
  - actual performance bonus payouts
  - target performance bonus opportunity
  - total annual compensation
  - long-term incentive (LTI) target opportunity
  - actual total direct compensation
  - total direct compensation

WTW Salary Budget Planning Survey

- PGE utilizes this survey as input into our salary budget planning process. This crossindustry survey is mainly focused on gathering forecasted salary budget, prior year actual salary increases and various other HR compensation practices (i.e., Salary review timing and type). Results for this survey are summarized in aggregate and by industry.

March 27, 2023

To: Marc Hellman
Public Utility Commission of
Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 246
Dated March 13, 2023

Request:

Explain why salaries for 2023 and 2024 are escalated at a faster rate than historical escalations given that the CPI is expected to be 4.2 percent in 2023, 2.5 percent in 2024, and 2.2 percent in 2025.

Response:

PGE does not budget or forecast wage escalations based on the consumer price index (CPI). However, PGE does note that the CPI of 4.2% for 2023 and 2.5% for 2024, coupled with actual CPI of 4.7% for 2021 and 8.0% for 2022 is markedly higher than the 2014-2020 average of 1.5%. As described in PGE Exhibit 500 pgs. 17-18, wage decisions are ultimately driven by the labor market. The current environment of accelerated wage growth is driven by a shortage of labor supply to meet demand. The Oregon Department of Economic Analysis (OEA) forecasts Oregon's nominal wages and salaries to increase by 5.1% and 3.9% for 2023 and 2024, respectively. In fact, PGE's actual wage escalation for 2022 of 7% for bargaining and 6% on average for non-bargaining employees was considerably higher than the 4.0% PGE has included for 2023 and 2024. Additionally, OEA also projects nominal wage growth to increase between 4.7% to 5.8% from 2025 – 2030. If PGE were to increase wages strictly based on CPI and OEA nominal wage forecasts were to come to fruition, PGE would be a great disadvantage in the job market and would likely face a higher level of turnover and difficulties filling key positions, leading to inefficiencies and likely greater costs for customers in the long-term.

February 24, 2023

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Standard Data Request
094 Dated March 10, 2015

Request:

For the Test Year and preceding 4 calendar years, please provide a summary table in the format as shown on Union Salary Information (Attachment 94A) that includes:

a. The union name;
b. All positions represented by a particular union;
c. The number of FTE for each position (excluding FTE created by overtime hours.);
d. The contracted hourly wage or salary for each position as of December 31 of each year; and
e. The percent change from the previous year's hourly wage or salary.

Response:

Attachment 094-A provides a listing of all Local Union No. 125 of International Brotherhood of Electrical Worker positions, rates, and number of employees for the years 2020, 2021, 2022, and February 8, 2023.

Please note: In order to provide the information as requested, Attachment 94-A lists employee counts for each position, rather than full-time equivalent employees (FTEs).

February 24, 2023

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Standard Data Request
095 Dated March 10, 2015

Request:

For each calendar year included above, please provide a copy of the portion of each union's contract that specifies the hourly wages and the percent increase the wages or salaries represent, for each job classification. Please label and organize the copies to mirror the order of the job classifications as shown in the summary table.

Response:

Attachments 095-A provides excerpts of all union contracts that pertain to specific wages for the years included in PGE's response to OPUC Data Request No. 094.

PGE's Response to DR 255 Attachment A is available in electronic spreadsheet format only.

PGE's Response to DR 256 Attachment A is available in electronic spreadsheet format only.

UE 416 PGE Response to OPUC SDR No. 092
Attachment 092-A
Page 1

FTEs, Wages & Salaries 2019-2023

Class	2019 Actuals		2020 Actuals		2021 Actuals		2022 Actuals		2023 Budget	
	FTE Actuals	W&S Actuals	FTE Actuals	W&S Actuals	FTE Actuals	W&S Actuals	FTE Actuals	W&S Actuals	FTE Actuals	PGE Share
Exempt	1,627.4	193,108,287	1,634.6	187,290,392	1,674.6	196,141,176	1,775.2	221,116,961	1,934.3	250,693,133
Hourly	499.5	28,760,085	416.8	24,206,219	404.0	23,765,080	389.0	24,184,834	390.1	25,289,128
Officer	11.9	4,737,159	11.1	4,510,023	10.8	4,793,841	10.2	4,841,318	10.0	5,000,653
Union	707.4	69,529,325	654.7	66,895,465	629.5	67,081,985	641.4	71,950,473	702.0	80,476,790
Total	**2,846**	**296,134,856**	**2,717**	**282,902,099**	**2,719**	**291,782,083**	**2,816**	**322,093,587**	**3,036**	**361,459,704**

Class	2024 FTE	%	Pro Rata Adjustments	2024 FTE Adjusted	2024 W&S Forecast	%	Pro Rata Adjustments	2024 W&S Adjusted
Exempt	1,941.3	62.78%	(61)	1,881	261,000,550	69.14%	(8,118,820)	252,881,730
Hourly	449.2	14.52%	(14)	435	32,894,180	8.71%	(1,023,224)	31,870,957
Officer	10.0			10	5,193,708			5,193,708
Union	702.0	22.70%	(22)	680	83,592,021	22.14%	(2,600,257)	80,991,764
Total	**3,102**	**100.00%**	**(97)**	**3,006**	**382,680,459**	**100.00%**	**(11,742,302)**	**370,938,158**

Incentives by Employee Class 2020-2024

	2020 Actual	2021 Actual	2022 Actual	2023 Budget	2024 Forecast Unadjusted	2024 Forecast Adjustment	2024 Forecast Adjusted
Exempt	23,072,047	32,481,003	30,559,188	37,227,773	38,855,268	(19,427,636)	19,427,632
Hourly	990,113	1,638,690	1,223,445	1,519,340	1,930,448	(965,224)	965,224
Officer	5,512,715	10,215,340	10,606,729	9,137,580	10,678,114	(10,678,114)	
Union	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total	**29,574,875**	44,335,033	42,389,362	47,884,694	51,463,830	(31,070,974)	20,392,856

Overtime by Employee Class 2020-2024

	2020 Actual	2021 Actual	2022 Actual	2023 Budget	2024 Forecast
Hourly	812,674	1,807,636	1,228,398	1,038,912	1,080,944
Union	26,317,950	33,462,764	32,788,520	22,316,477	23,205,000
Exempt	n/a	n/a	n/a	n/a	n/a
Officer	n/a	n/a	n/a	n/a	n/a
Total	27,130,624	35,270,399	34,016,918	23,355,389	24,285,943

April 14, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 416
Dated March 31, 2023

Request:

State whether your incentives for the 2024 forecast were based on 2022 actuals or the 2023 budget. Also explain how you escalated the incentives. Provide an excel document that shows this escalation.

Response:

Non-stock incentives for the 2024 forecast are based directly upon the projected base pay for 2024. Base pay projections for 2024 are based upon the employee population annualized base salary as of Sept. 22, 2022. That total employee population annualized base salary is then escalated by the wage increase assumption for 2023 of 4%. The resulting 2023 wage base assumption then escalated by the annualized 2024 escalation rate of 3.67% (i.e., 4% escalation assuming a February 1st increase for 2024). Finally, with a projected full-year base pay for 2024 PGE then forecasts incentives utilizing the Bonus Target Percent for each position, with the assumption that final payouts will meet that target. Stock incentives for non-officer plan participants are based on employee level at the time stock grants are awarded and the 2024 forecast is based on the expected vesting period.

Confidential Attachment 416-A provides the details of this calculation. Please note that Attachment 416-A includes amounts prior to accounting for co-owned facilities.

Attachment 416-A is protected information and subject to Protective Order No. 23-039.

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 244
Dated March 13, 2023

Request:

Explain PGEs decision to use total forecasts and to not include information on FTE in the written portion of your testimony.

Response:

PGE's testimony focuses on labor costs, rather than full time equivalent employees (FTEs). Focusing on labor dollars, as opposed to FTEs, is consistent with most other elements of PGE's regulatory accounting for operating expenses. Focusing on FTE can often be misleading as FTEs are calculated using straight-time PGE labor hours, whereas PGE relies on a mix straight-time labor, overtime labor, and contract labor throughout the business. At times, even though PGE has budgeted for work to be accomplished using straight-time PGE labor, through turnover and a tight labor market, coupled with the specialized skills required to be successful at PGE, greater than budgeted overtime and/or contract labor may be necessary to ensure the work gets done. PGE's work papers provided with Exhibits 600, 700, 800, and 900 provide account detail by operating unit, department, and accounting work order for all total labor expense requested in PGE's case. These sections of testimony also discuss labor related costs throughout. PGE's aggregate labor costs are discussed in PGE Exhibit 500.

PGE Exhibit 500, pages 15-17 provide additional detail regarding PGE's total labor philosophy.

April 10, 2023

To: Marc Hellman
Public Utility Commission of
Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 363
Dated March 27, 2023

Request:

A) What has been the correlation between total amount spent on salaries and amount of FTE for each of the years from 2014 to 2022? B) What is the projected relationship for FTE and total amount spent for 2023 and 2024? (Spent includes wages, incentives and benefits.)

Response:

A) The total amount spent on salaries and number of FTEs has a correlation coefficient of 0.80 – which is generally considered to be a strong positive correlation.
B) The projected relationship between FTEs and total amount spent in 2023 and 2024 continues this positive correlation.

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 249
Dated March 13, 2023

Request:

See PGE/700 Bekkedahl—Jenkins/21, stating "We spent approximately $10.7 million on grid modernization O&M in 2022. We expect to spend $14.0 million in 2024, which is an increase of $3.4 million. The increase in grid modernization O&M costs is driven by filling positions that were included in the last GRC but have gone unfilled due to a tight labor market for the required skillsets and adding eight new positions." Is Staff correct in their assumption that the cost for these positions were collected in rates but absorbed by the Company in other capacities given that these positions were not filled?

Response:

PGE utilized incremental outside services to help support the above work given the challenges in hiring PGE labor.

April 21, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE *Revised* Response to OPUC Data Request 250
Dated March 10, 2015

Request:

Provide information on the positions that were asked for in the previous four general rate cases and not filled and how that compares with the request for the current rate case. Include information on the number of positions that were requested and the number of positions that were unfilled after each GRC.

Response:

Initial Response (dated March 27, 2023):

PGE objects to this request on the basis that it is unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

Attachment 250-A provides the number of FTE, straight-time labor, overtime labor, and contract labor dollars request for PGE's previous four general rate cases along with the respective actual amounts over the same time period. Note that the general rate case amounts provided are what PGE included within its initial filing and do not include any adjustments made during the proceeding to PGE's initially filed amounts.

Revised Response (dated April 21, 2023):

Labor dollar amounts in Attachment 250-A inadvertently included actual Level III Storm amounts, as well as FERC accounts 417, 418, and 426.

Attachment 250-A *Revised* removes these amounts. Additionally, and in response to OPUC Data Request No. 418, Attachment 250-A *Revised* now provides the following:

- Budget FTE for 2017, 2021, and 2023
- Forecast FTE for 2024
- Total labor budgets for 2017, 2020, 2021, and 2023
- Forecast total labor for the 2024 test year

Please note that PGE does not budget FTE consistent with FTE reported for general rate case purposes outside of rate case filings. As such, there is no 2020 budget of FTE consistent with FTE calculated for general rate case purposes.

PGE’s Response to DR 250 Attachment A is available in electronic spreadsheet format only.

PGE's Response to DR 258 Attachment A is available in electronic spreadsheet format only.

PGE's Response to DR 418 Attachment A is available in electronic spreadsheet format only.

PGE's Response to DR 366 Attachment A is available in electronic spreadsheet format only.

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 345
Dated March 16, 2023

Request:

Regarding the Company's non-labor generation expenses:

a. Please provide a narrative explanation of what specific expenses are included in the Company's non-labor generation expenses.

b. Please specify the value of non-labor generation expenses that the Company is requesting recovery for in this filing in US dollars. Include a reference to where this value is reflected in the Company's work papers and indicate whether and when this value will be updated during the course of this filing.

c. Please provide a breakdown showing the specific expenses included in the Company's non-labor generation expenses in the test year, and the value of each.

d. Please provide a narrative explanation of how non-labor generation expenses are forecasted in the Company's filing.

Response:

PGE objects to this request on the basis that it is overly broad. Notwithstanding its objection, PGE responds as follows:

a. Non-labor Production O&M costs are all costs provided within PGE's Exhibit 800 confidential work paper "GRC Production Workpaper 2022-2024 Variance." These costs include both non-labor and labor-loadings costs. Effectively, these represent all plant and generation-related costs that are not otherwise capitalizable or included within PGE's Net Variable Power Costs as defined within PGE Exhibit 300 and included in MONET. Confidential Attachment 345-A provides a list of PGE cost elements used to categorize non-labor expenses. In addition, PGE follows FERC Uniform System of Accounting guidance for defining generation expense, which can be found here: eCFR :: 18 CFR Part 101 -- Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act.

b. PGE is requesting $86,474,542 for non-labor generation expenses. For the source of this value, please see the workpaper titled "GRC Production Workpaper 2022-2024 Variance," which was filed along with Exhibit 800 – Production. The total can be found on the sheet

"Generation O&M Summary," in the total row for Table 2. PGE does not plan on adjusting this value as it remains our best estimate of the 2024 test year.

c. Confidential Attachment 345-A provides a breakdown of specific expenses and their associated values.
d. PGE forecasts its non-labor generation expenses based on a large number of factors, all in order to ensure energy reliability and safety. Forecasting occurs by department, and is based on department expectation of materials, supplies, and anticipated work. Specifically, PGE power plants will forecast based on the expectation of upcoming maintenance, making forward looking budgets for maintenance items. Certain PGE plants have Long Term Service Agreement (LTSA) obligations that incur costs as plants age and require maintenance work. Similarly, PGE's plants have time-based maintenances that occur based on the age or run time of the plant.

Attachment 345-A contains protected information and is subject to General Protective Order No. 23-039.

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

June 13, 2023

PGE's CONF Response to DR 330 Attachment A is available in electronic spreadsheet format only.

May 2, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 584_CONFIDENTIAL
Dated April 18, 2023

Request:

[BEGIN CONFIDENTIAL] [redacted]

a [redacted]
b [redacted]
c [redacted]

[END CONFIDENTIAL]

Response:

[redacted]

a. [redacted]

b. [redacted]

c. [redacted]

[redacted]

CASE: UE 416
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

Exhibits in Support
Of Opening Testimony

June 13, 2023

Staff's CONF Workpaper UE 416 Exhibit 1303 Wage and Salary Model is available in electronic spreadsheet format only.

CASE: UE 416
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

OPENING TESTIMONY
Advertising and Marketing
Promotional Activities and Concessions

June 13, 2023

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

A. My name is Charles Lockwood. I am a Utility Analyst employed in the Utility Strategy and Integration 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 qualifications statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's 2024 Test Year expense for advertising and marketing, as well as promotional activities and concessions.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1402, PGE Response to Staff DR No. 351 Attach B, Exhibit Staff/1403, PGE confidential Response to Staff DR No. 352A, and Exhibit Staff/1404, PGE Responses to Staff DR Nos. 487-89.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ADVERTISING AND MARKETING

Q. Does the Commission have a standard means of determining how advertising expenses are treated?

A. Yes. OAR 860-026-0022 specifies how advertising expenses are treated in a utility rate case. The rule details five categories (A-E), each with a different standard for inclusion in rates. Category "A" includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[1] Advertising expenses in this category are presumed reasonable when expenses are twelve and one-half hundredths of one percent (0.125 percent) or less of the gross retail operating revenues determined in that proceeding.[2]

Category "B" includes legally-mandated advertising expenses, which are assumed to be reasonable for rate-making purposes.[3] Category "C" includes institutional advertising expenses, promotional advertising expenses, and any other advertising expenses not fitting into Category "A," "B," or "D".[4] Utilities must demonstrate these expenses are just and reasonable for inclusion in rates, as well as separately state the amount of advertising expenses in this category. Category "D" includes political advertising expenses and nonutility advertising expenses, which are presumed to be not just and reasonable for

---

[1] OAR 860-026-0022(2)(a).
[2] OAR 860-026-0022(3)(a).
[3] OAR 860-026-0022(2)(b).
[4] OAR 860-026-0022(2)(c).

ratemaking purposes.[5] Finally, Category "E" includes energy efficiency or conservation advertising expenses that relate to a Commission-approved program. Utilities must show these expenses are reasonable and recoverable in rates. With Commission approval, advertising expenses in Category "E" may be capitalized.[6]

Q. Please describe the Company's Test Year expense for advertising.

A. The Company proposes to include approximately $2.8 million in Category A and $0 in its mandated Category B advertising in the 2024 Test Year as illustrated in Figure 1.[7]

FIGURE 1. TOTAL ADVERTISING IN THE TEST YEAR

Category	FERC Account	Included in Rates?	2024 Expenditures $
A	909	YES	$2,770,128
B	909	YES	$0
C	930.1	NO	$828,929
D	417.1	NO	$12,368
E	182.3	NO	$0
TOTAL			**$3,611,425**

Q. Does PGE include advertising expense for any other category in its Test Year expense?

A. No, although PGE has budgeted for other advertising during 2024. PGE has excluded from the Test Year approximately $800 thousand in Category C

5 OAR 860-026-0022(2)(d).
6 OAR 860-026-0022(2)(e).
7 Staff/1402, Lockwood/1, PGE's Response to Staff DR No. 351 Attach B (electronic spreadsheet).

Institutional/Promotional Advertising (FERC 930.1) budgeted for 2024 as well as approximately $12 thousand in political advertising or Category D (FERC 417.1).[8] PGE has not included any Category E Advertising expenses (FERC 182.3) in its 2024 Test Year. In total, the Company has budgeted approximately $3.6 million for its 2024 advertising budget, with $2.8 million being included as Test Year expense and be added into rate base, as illustrated above.

Q. Please describe your analysis of the Company's proposed advertising expenses.

A. First, Staff analyzed the Company's transactional data shown in the Company's response to Standard Data Request Nos. 57 and 104, which inquired further about PGE's largest advertising expenditures in the base year of 2022. Staff confirmed the advertisements were entirely related to consumer safety, energy efficiency, conservation, and billing assistance. Staff also notes that the Company utilized the same Category A Vendors as in previous years, all of which were audited and reviewed in the Company's previous rate case, UE 394. While this does not guarantee the credibility of the Vendors in future agreements, this provides Staff with a measure of confidence that will be reassessed periodically. The largest Category A Vendors are illustrated below, in Figure 2.[9]

---

8 *Id.*

9 Staff/1403, Lockwood/1, PGE Confidential Response to Staff DR No. 352 Attach A (electronic spreadsheet).

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Due to the scale of PGE's advertising spending with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, Staff analyzed the Company's media purchases. Staff reviewed the various advertisements and the advertisements related to safety and bill assistance for the Company throughout all of 2022.[10]

[BEGIN CONFIDENTIAL]

[redacted]

[10] *Id.*

[END CONFIDENTIAL]

Q. How does the Company's advertising expenses compare to historical spending?

A. PGE's request for approximately $2.7 million budgeted for Category A expenses is a 36 percent increase from the approximately $2 million in Category A expenses approved by the Commission in the Company's last GRC, Docket No. UE 394.[11] This proposed increase is larger than the overall 21 percent increase between the 2022 and 2024 total revenue requirements in this docket and Docket No. UE 394.[12] The requested amount is presumed just and reasonable according to OAR 860-026-0022, as seen in Figure 4. Staff's review found that while PGE's 2024 Test Year Budget for Category A advertising is increasing, there is no evidence to rebut the presumption the amounts spent on Category A advertising are reasonable. .

---

11 Staff/1402, Lockwood/1, PGE Response to Staff DR No. 351 Attach B (electronic spreadsheet).
12 *Id.*

FIGURE 4. 2024 TEST YEAR CATEGORY A ADVERTISING CALCULATION

Q. After Staff's review, does Staff believe the Company has properly categorized its advertising expense?

A. Yes. The Company's budgeted Category A expenses are presumed to be just and reasonable as the expenses are less than twelve and one-half hundredths of 1 percent (.125 percent) of PGE's operating revenues, as seen below.[13] PGE is not seeking to include any expenses in Category B or E, has removed all expenses in Category C from base rates, and has no included Category D expenses in base rates.

Q. What is your recommendation regarding advertising expense?

A. PGE has not exceeded the 0.125 percent limit of Category A Advertising and all expenses appear to be prudent. Therefore, Staff has no adjustment.

Category A Calculations:	
FERC 9090001:	**$2,770,128**
**Less: Legally Mandated Advertising (Cat B):	$0
Net Category A:	$2,770,128
2024 Total Revenue Requirement:	2,671,544,933
*Factor per OAR:	0.125%
Presumed Reasonable (Cat A) Costs:	3,339,431
Difference between Presumed and Proposed:	**$569,304**
*OAR 860-26-022 Rule = 1/8 of 1% of sales is presumed reasonable	
**Legally Mandated Advertising expense occurs as arises, typically less than $5,000/year.	

13 *Id.*

ISSUE 2. PROMOTIONAL ACTIVITIES AND CONCESSIONS

Q. What are promotional activities and concessions?

A. A promotional activity or concession is intended to promote the use of the utility's product or service among present or prospective customers.

ORS 860-026-0010 defines promotional activity as:

> [A]ction by an energy or large telecommunications utility or its affiliate with the objective of increasing or preventing a decrease in the quantity of the energy or large telecommunications utility's service used by present and prospective customers; inducing any person to use an energy utility's service rather than a competing form of energy[.]

OAR 860-026-0015 defines promotional concession as:

> [A]ny consideration offered or granted by an energy or large telecommunications utility or its affiliates to any person with the object, express or implied, of inducing such person to select or use the service or additional service of such utility, or to select or install any appliance of equipment designed to use such utility service.

Examples of promotional concessions include rebates, provision of free goods or services, or providing financing for a natural gas appliance at a lower-than-market interest rate.[14] Utilities are required to file a description of all promotional concession expenses with the Commission before making them.[15] Utilities are also required to file, concurrently with their annual report, a report detailing the previous year's promotional activities and concessions and a statement of the benefits achieved from each.[16]

---

14 OAR 860-026-0015(2).
15 OAR 860-026-0025(1).
16 OAR 860-026-0035(1).

Q. What are the standards for reviewing promotional activities and concessions?

A. Promotional activities and concessions should benefit both the utility and its customers. ORS 860-026-0020 provides the following direction for promotional activities and concessions:

> All promotional activities and concessions shall be just and reasonable, prudent as a business practice, economically feasible and compensatory, and reasonably beneficial both to the energy or large telecommunications utility and its customers. The cost of promotional activities and concessions must not be so large as to impose an undue burden on the energy or large telecommunications utility's customers in general and must be recoverable through related sales stimulation within a reasonable time.[17]

Q. Has the Company filed its annual promotional concessions report with the Commission for the 2024 Test Year?

A. No. In compliance with OAR 860-026-0035, PGE submits the required Reporting of Promotional Concessions and Activities for the prior year on or before May 1 of each year in RE 46. Any information regarding the 2024 Test Year will be available at that time.[18]

Q. Is PGE seeking to include any promotional activities or concessions in the GRC, including but not limited to FERC Accounts 909-913 and 930.1?

A. No. PGE is not seeking any promotional activities or concessions in its UE 416 proposal. The Company stated that if any promotional activities arise, such as

[17] OAR 860-026-0020.
[18] Staff/1404, PGE Non-Confidential Response to Staff DR Nos. 487-489.

PGE's Tool Exchange events,[19] the Company will utilize the budget from FERC Account 930.1, or Category C from Advertising and Marketing.[20] Further, as stated above, PGE has completely excluded the FERC Account 930.1 budget from base rates.

Q. Does Staff propose an adjustment to promotional activities and concessions?

A. No. Staff does not find any adjustment is needed or recommended as there were no promotional activities or concessions included in PGE's UE 416 proposal.

Q. Does that conclude your testimony?

A. Yes.

---

[19] PGE's Tool Exchange Events provide an opportunity for community members to recycle gas-powered lawnmowers, leaf blowers, chainsaws, and trimmers for free and receive a gift card to purchase a new electric tool from Ace Hardware.

[20] *Id*.

CASE: UE 416
WITNESS: Charles Lockwood

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Charles Lockwood
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	University of Florida Bachelor of Science in Environmental Science, 2019 University of Oregon Juris Doctor, 2022 Concentrations in Green Business Law, Environmental and Natural Resources Law
EXPERIENCE:	Oregon Public Utility Commission Administrative Hearings Division Law Clerk, 2021-2022 Oregon Public Utility Commission Utility Analyst, 2022 - Present

CASE: UE 416
WITNESS: Charles Lockwood

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Filed in
Electronic Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Charles Lockwood

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1403
CONFIDENTIAL

Filed in
Electronic Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Charles Lockwood

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1404

Exhibits in Support
Of Opening Testimony

June 13, 2023

April 20, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 487
Dated April 6, 2023

Request:

Is the Company required to submit a promotional report to the Commission? If so, please submit detailed expenses for the items in this report in an excel document.

Response:

Yes. In compliance with OAR-860-026-0035, PGE submits the Reporting of Promotional Concessions and Activities for the prior year on or by May 1st of each year in RE 46. The information requested will be available at that time.

April 20, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 488
Dated April 6, 2023

Request:

Please state and explain the proposed change from previous base years to the current test year for any FERC accounts encompassing promotional activities and concessions, including FERC accounts 909-913.

Response:

There are no actual or forecasted expenses in the base year or current test year for FERC accounts 909-913 and therefore no change. Budget from FERC Account 930.1 are used for promotional activities when the opportunities arise.

April 20, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 489
Dated April 6, 2023

Request:

Please provide:

a. A list of expenditures for promotional activities and concessions projected to be charged to accounts during the test year; and
b. A description of all programs related to sales promotions included in the test year

Response:

a. PGE does not have a detailed test year budget for promotional activities and concessions. When opportunities arise, for example the Tool Exchange events in recent years, budget from FERC Account 930.1 is used for promotional activities and concessions.
b. PGE does not have a test year budget for promotional activities and concessions.

CASE: UE 416
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony

June 13, 2023

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. Please describe your educational background and work experience.

A. My witness qualification statement is found in Staff Exhibit 1501.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Test Year expenses for Customer Services – (Operations and Maintenance (O&M) – Non-Labor)
- Test Year expenses for Customer Service: Information and Sales Expense (Operations and Maintenance Non-Labor)

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please outline your supporting exhibits for this testimony?

A. My testimony is supported by the following exhibits:

- Staff Exhibit 1501: Witness Qualifications
- Staff Exhibit 1502: Exhibits in Support of Opening Testimony

ISSUE 1. CUSTOMER ACCOUNTS EXPENSES (O&M NON-LABOR)

Q. Please describe customer account expenses.

A. Customer account expenses are recorded in FERC Accounts 901, 902, 903, and 905. These accounts track expenses related to supervision, meter reading, customer records and collection, as well as miscellaneous customer accounts. Uncollectibles, Account 904, has been analyzed separately in a Staff testimony 1200.

Q. Please describe the Company's customer account expense in the Test Year.

A. For customer account expense, excluding uncollectibles (FERC Accounts 902, 903, and 905), the Company forecasted a 2024 Test Year total of $15.7 million (non-labor). There were no pre-filing adjustments performed for these accounts. The Company includes no FERC Account 901 expense in its Test Year.

Q. What is the methodology used by the Company to forecast the Test Year?

A. PGE's 2023 budget is the basis of the 2024 Test Year values. The 2023 budget is developed from the 2022 budget with escalations. The 2023 budget is then escalated using non-labor escalation factors to create the 2024 budget along with discrete adjustments to 2024.[1]

Q. How did Staff perform its analysis of the Company's customer account expense?

---

1 Staff 1502. PGE's response to Staff DR 185.

A. Staff reviewed transactional information as well as historic trends. Staff compared the Test Year forecast to the Base Year actuals and to a three-year average of budgeted amounts. Staff analyzed data requests responses for additional details as well.

Q. How does the amount requested in the Test Year differ from historical trends?

A. Staff reviewed historic actuals and budgets in the area of customer accounts. Based on the information provided in discovery, Staff calculated a three-year average using budgeted expenses in 2023, 2022, and 2021.[2] Staff than compared the Test Year expense to the Base Year actuals and the average to get a better idea of the trend.

Figure 1. Customer Service Account Expenses Test Year Comparisons

	Actual	3 yr	Projection	% Change from		$ Change from	
	2022	average	2024	Base year	Average	Base year	Average
902-Meter reading	254,204	-	-	-100%	0%	(254,204)	-
903-Customer Receipts/Collections	13,510,339	12,141,343	15,578,238	15%	28%	2,067,899.79	3,436,895.30
905-Misc. Customer Accounts	94,798	45,005	98,403	4%	119%	3,605.48	53,398.55

While the Test Year amounts represent a 29 percent overall increase from the Company's three-year budgetary average (2021–2023), PGE saw the budget for meter reading (FERC Account 902) expenses disappear completely. In its response to DR 490, PGE stated that the 902 account is used to budget

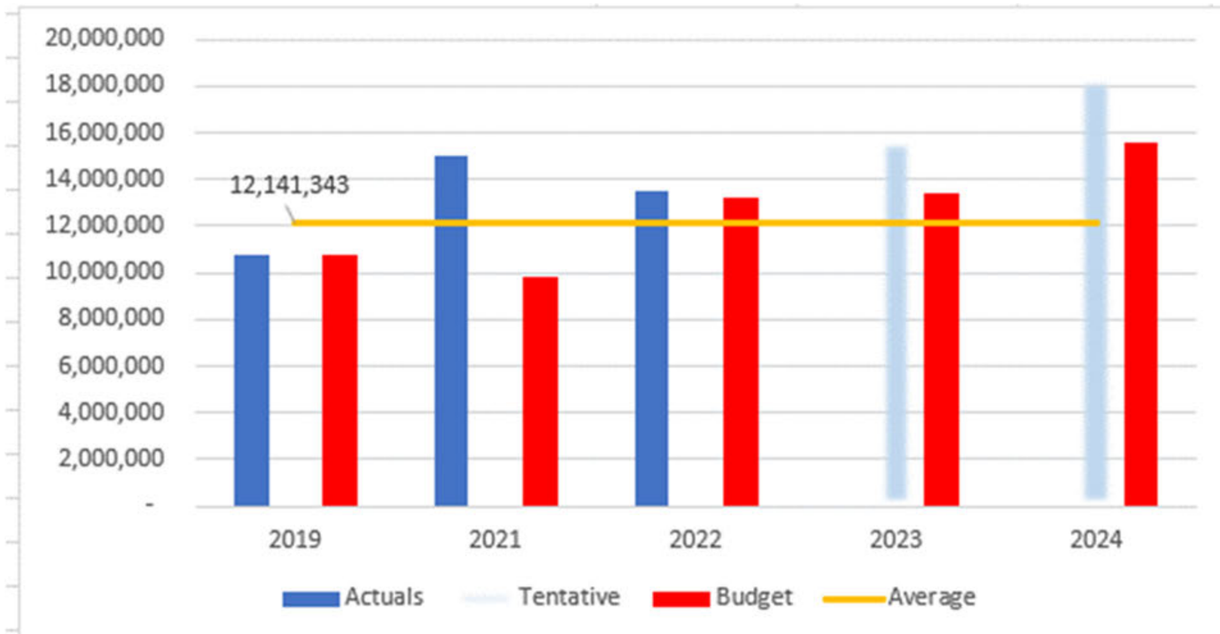
[2] Staff/1502, PGE Response to Staff DR 183, Att A.

known or planned research and development (R&D) projects, none were planned at the time of budget. The actuals in its historical data reflect unplanned projects.

Customer receipts/collections expenses (FERC Account 903) are seeing growth as a result of increased payment processing fee and volume of transactions. The projected increase is also associated with printing and mailing due to postage rate increases,[3] and a net of $1.8 million decrease for miscellaneous accounting adjustment for write-offs of unreconciled cash balances.[4] In comparing with the three-year average budget, the 2024 forecast is 28 percent greater with an increase of $3.4 million. Looking at percentage change between Base Year and average, the increases do not appear unreasonably large, but being that the 903 account makes up 60 percent of the Non-Labor Customer Service O&M Expenses ($26 million), such variances result in large dollar values, as shown in Figure 2.

[3] Staff/1502. PGE's response to DR 184.
[4] Staff/1502. PGE's response to DR 491D.

Figure 2. Customer Receipts/Collections Trends[5]



Miscellaneous customer accounts (FERC Account 905) is seeing a large percentage increase from the three-year average at 119 percent. Although the percentage variances in this account are large, because misc. customer accounts make up less than one percent of the proposed non-labor customer service O&M expenses ($26M), the dollar amounts are small, and the overall effect is nominal. The increases are the result of the reallocation of the VP Customer Solutions to Account 905.

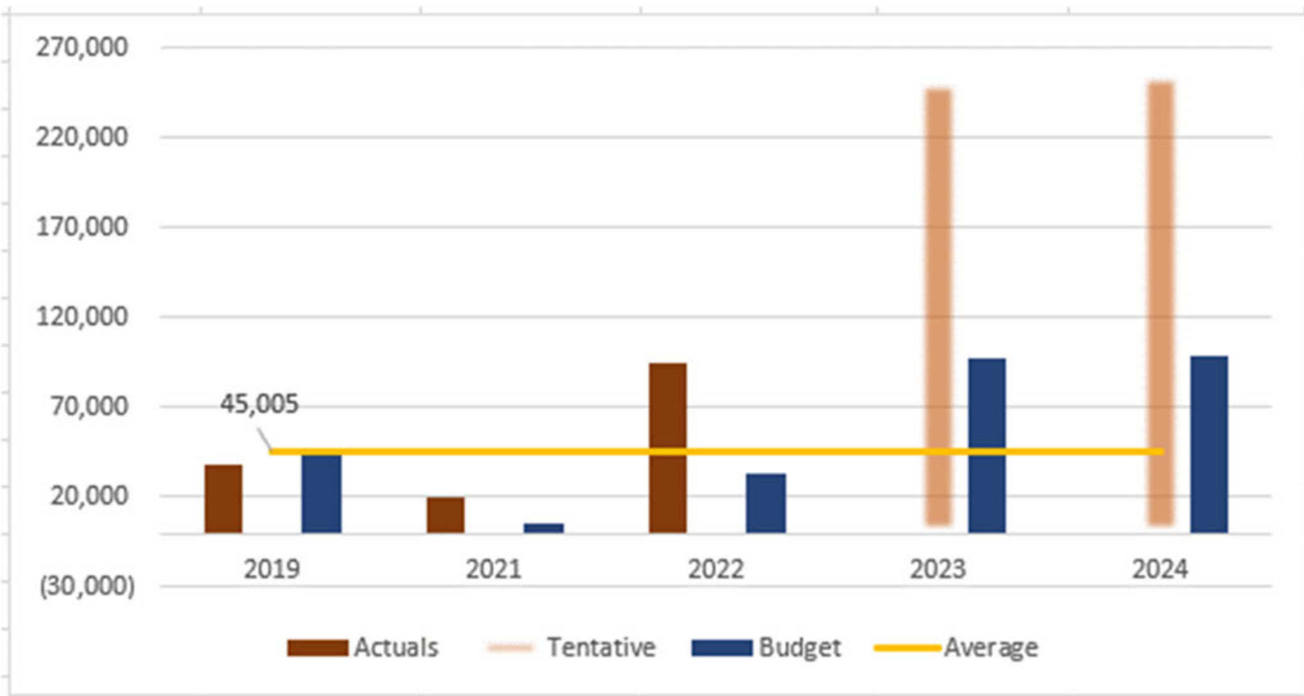
Analysis of PGE's actuals to budget show that the 2023 budget appears to be closer in line with the 2022 actuals. This explains why the percentage change from the Base Year to the Test Year is only four percent. The 2023 budget deviates from the budgeting philosophy given in their response in

---

5 The "Tentative" bars are calculated based on average variances in actuals to budget, from previous years.

DR 185, which states "The 2023 budget is developed from the 2022 budget with escalations."

Figure 3. Misc. Customer Account Trends



Q. Did Staff find any issue with customer account expense in the Company's application?

A. No.

Q. Does this conclude your testimony on customer accounts O&M Non-Labor expense?

A. Yes

ISSUE 2. CUSTOMER ASSISTANCE EXPENSES (O&M NON-LABOR)

Q. What are the customer assistance expenses addressed in this section of your testimony and what amount does PGE include in the 2024 Test Year for customer assistance O&M Non-Labor?

A. Customer assistance expenses are recorded in FERC Account 908, which is for "the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service." The Company has proposed to increase total customer assistance O&M (non-labor) costs for the 2024 Test Year relative to the Company's 2022 actual costs by approximately $26 million. Of this amount, $7.6 million is associated with Customer Assistance Expense O&M Non-Labor. The primary drivers of the increase include the Company's Clean Energy target communication and outreach, as well as support for the Transportation Electrification (TE) of their fleet.

Q. How does the amount requested in the Test Year differ from historical trends?

A. Staff reviewed historical actuals and budgets trends in the area of customer assistance expense. Based on the information provided in discovery, I calculated a three-year average of amounts budgeted for customer assistance in 2023, 2022 and 2021[6]. Staff than compared the Test Year to the Base Year actuals and the average to get a better idea of the trend.

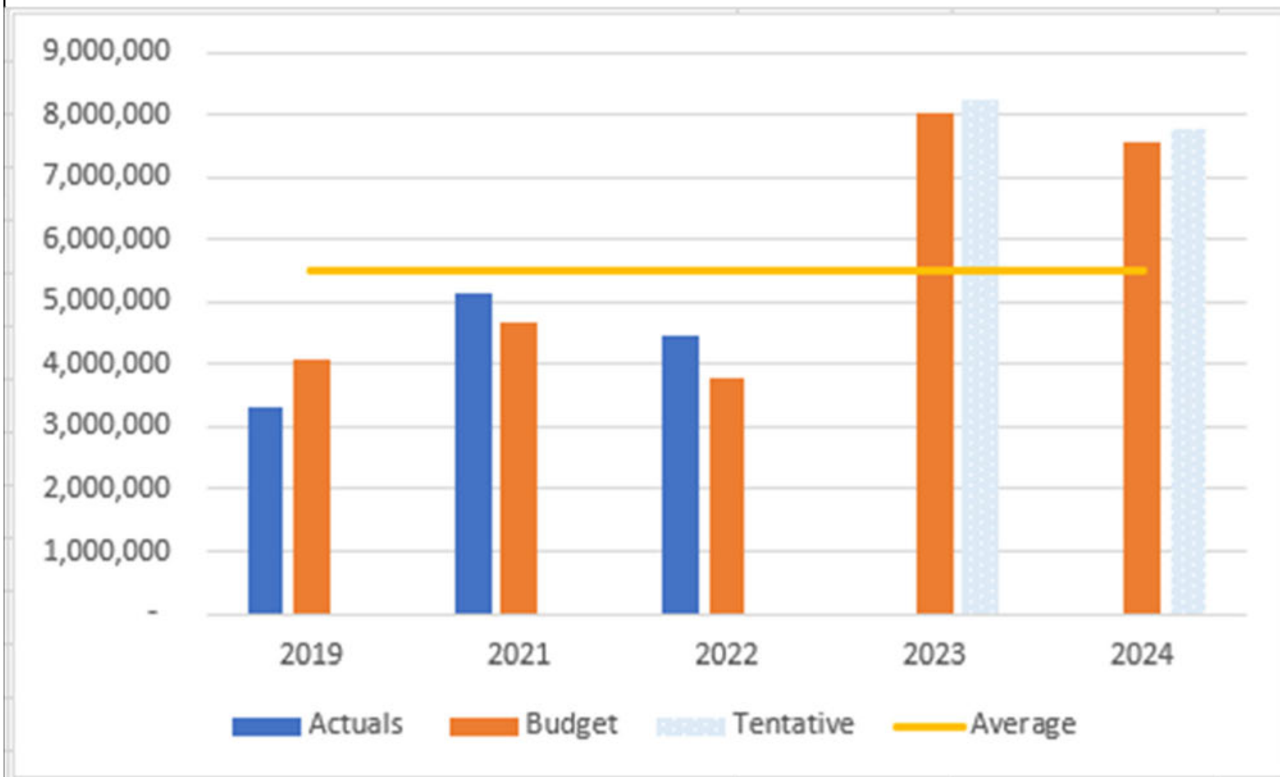
[6] Staff/1502, PGE Response to Staff DR 182, Attachment A.

Figure 1. Customer Assistance Expenses Test Year Comparisons

	Actual	3 YR	Projection	% Change from		$ Change from	
	2022	Average	2024	Base year	Average	Base year	Average
908-CustSvc-Customer Assistance Exp	4,442,177	5,505,483	7,561,358	70%	37%	3,119,181	2,055,875
909-CustSvc-Advertising	922,821	1,263,524	2,770,128	200%	119%	1,847,307	1,506,604

In analyzing budget trends for Account 908, Customer Service Assistance Expense, we see quite a variance from the 2022 to 2023 budget and to 2024 Forecast. There is $4 million increase from 2022 to 2023's budget, which is primarily due to customer communication and outreach marketing in support of the transportation electrification strategy and implementation as well as energy efficiency initiatives. The change from 2022 to 2023 is 112 percent while the 2024 forecast is decreased by six percent. Although we see a decrease in the Test Year forecast from the 2023 budget, this is mainly made up of neutral shifts to other departments. There is, however, a $615,000 increase for Transportation Electrification in PGE's Fleet program. Comparing to the Base Year and the three-year average, the 2024 forecast is considerably more, as seen in Figure 1 above.

Figure 2. Customer Assistance Expenses



Q. Please describe Staff's evaluation of primary cost drivers behind the O&M/NL increase.

A. Staff reviewed the Company's Customer Services work papers and SDRs 57 and 58 to identify and verify allocation of costs as described in PGE's opening testimony. As will be described below, the $1.2 million in non-labor TE program costs were allocated to FERC Account 908. Staff is proposing these costs be reallocated to the appropriate FERC account and subject to adjustments.

The proposed amount in the Test Year for communication and marketing for Clean Energy Targets was also analyzed. PGE proposed $2.56 million increase for the educational campaign "Path to 2030". This will be a multi-year, multi-channel campaign for customers which will include social, digital, video, radio, and community events.[7]

Q. Please elaborate on the increased costs associated with the TE program.

A. In the Company's response to DR 624, PGE indicated that the increase of $615,000 would be used for the customer programs and PGE fleet and workspace charging. Additionally, the Company's 2023 budget contains $1 million to support this program.[8] The Company acknowledges that the TE program more closely aligns with PGE's transportation service provider allocation and in the future will be tracked in the FERC account that aligns with the activity. The funds requested will be used for outside services, maintenance, materials, and tools for supporting PGE's fleet and workplace charging stations.

Q. Please describe the increased costs associated with Path to 2030 communication and outreach.

A. PGE's 2023 budget includes $2.56 million for customer communication and outreach marketing. Two million dollars is being used for 2030 Clean Energy Target communications, while $259,000 will be used in customer research and $250,000 for web-based communications. The Company states that,

> "*[C]ommunications and outreach is included in PGE's customer base rate request because this is an educational and awareness campaign aimed to engage customers and increase their needed participation*

---

[7] Staff/1502. PGE response to DR 623
[8] Staff/1502. PGE response to DR 187

to achieve decarbonization targets. Customer awareness and participation must increase significantly and consistently through the 2040 time horizon. Customer participation in customer-sited actions like demand response, energy efficiency and other programs directly support PGE's efforts to reach is Clean Energy Targets."[9]

Q. Please summarize Staff's proposed adjustment to PGE's customer assistance O&M/NL expense.

A. Staff recommends the Commission decrease the Test Year forecast by $2.1 million to the three-year average of $5.5 million for customer assistance expenses to eliminate expense for activities that are not related to "encourage[ing] safe, efficient and economical use of the utility's service," but rather activities aimed at promotion of PGE.

The budgeted TE program amount will be primarily used to fund O&M costs related to the Company's fleet program and workspace charging stations. PGE has not explained why it is necessary to provide "assistance" to customers regarding electrification of the PGE fleet or why it is appropriate to include expense for materials and supplies related to the program in the customer assistance expense FERC Account. The details of the transformation of PGE's fleet do not count as "instructions or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service."

---

9 Staff/1502. PGE response to DR 623.

Staff also recommends adjusting the 908 expenses to the three-year average of the budgeted expense because the amounts PGE has planned for communications and outreach to customers about the 2030 targets seems excessive in light of the other unavoidable cost pressures that PGE must account for in rates. Staff recommends implementing cost saving strategies.

Q. Does this conclude your testimony on Customer Service O&M/NL expenses?

A. Yes.

CASE: UE 416
WITNESS: Luz Mondragon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Luz Mondragon

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Rates, Safety and Utility Performance Program (RSUP)

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Western Governors University
Bachelors of Science in Accounting

EXPERIENCE: I have been employed with the PUC since March of 2023 as a Senior Finance Analyst tasked primarily with research and analysis of utility company filings, including, affiliated interests and rate case dockets.
I have over 15 years of accounting/finance experience, most recently working for Northern Wasco County PUD as a Finance Analyst. My duties included financial reporting, internal and external, as well as budgeting. I also worked very closely with the Engineering team on work orders, inventory, capital budgets and Plant assets.

CASE: UE 416
WITNESS: Luz Mondragon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1502

Exhibits in Support
Of Opening Testimony

June 13, 2023

“PGE Response to OPUC DR 183 Attachment A”

Is filed in electronic format

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 184
Dated March 10, 2023

Request:

For each subcomponent or subcategory of the account's data, for Customer Account Expenses described in the immediately prior DR, where there is a 5 percent or greater change, year-to-year, in actuals or budgets, please explain the reasons for the variance.

Response:

The reasons for year-over-year variance in actuals greater than 5% are as follows:

For FERC Account 902, 2020 actuals to 2021 actuals had an overall increase of $174K, or 7% related to:

- $200K increase for Corporate R&D (Electric Power Research Institute) for Transmission Planning and DER Integration
- Net amount due to items below scope

For FERC Account 903, 2020 actuals to 2021 actuals had an overall increase of $3,313K, or 28% with key increases related to:

- $2,100K increase for payment processing
- $1,500K increase for customer digital outside services
- $1,200K increase for call center, contracts for Internet Virtual Assistant Interactions
- $400K increase for customer experience and analytics
- $200K increase for printing/mailing (postage/forms)
- $1,800K decrease for miscellaneous accounting adjustment for write-off of 903 balances
- Net amount due to items below scope

For FERC Account 904, 2020 actuals to 2021 actuals had an overall decrease of $1,092K, or 15% related to:

- $1,092K decrease in uncollectible expense reflecting COVID deferral for 9 months (March to December) in 2020 compared to 2021 which had a full year of COVID uncollectible expense (bad debt) deferral above the amount in customer rates.

For FERC Account 905, 2020 actuals to 2021 actuals had an overall decrease of $3.6K, or 15% related to:

- Miscellaneous variances, totaling $3.6K

For FERC Account 902, 2021 actuals to 2022 actuals had an overall increase of $78K, or 45% related to:

- $200K increase due to a meter services data plan expense, which began in 2022
- $125K decrease due to lower R&D expense to FERC account 902 in 2022
- Net other miscellaneous

For FERC Account 903, 2021 actuals to 2022 actuals had an overall decrease of $1,490K, or 10% related to:

- $1,000K increase for payment processing
- $300K increase for call center, Internet Virtual Assistant Interactions
- $200K increase for printing/mailing
- $1,500K decrease for customer digital outside services, due to completion of work from 2021
- $1,300K decrease for lower amortization related to dispatchable standby generation project

For FERC Account 904, 2021 actuals to 2022 actuals had an overall increase of $1,008K, or 17% related to:

- $1,008K related to end of COVID bad-debt deferral in 2022 compared with a full year of bad-debt deferral in 2021

For FERC Account 905, 2021 actuals to 2022 actuals had an overall increase of $ 75K, or 379% related to:

- $55K related to the Response Recognition Program, which was a new program in 2022
- Net amount due to items below scope, escalations

The reasons for year-over-year budget variances greater than 5% are as follows:

For FERC Account 904, comparing the 2020 budget to the 2021 budget there was an overall $470K decrease, or 7% change. The primary reasons for the decrease in 2021 budget were related to:

- Full year of COVID bad debt deferral in 2021, compared with 2020 budget that was created prior to the COVID-19 pandemic

For FERC Account 905, comparing the 2020 budget to the 2021 budget there was an overall $1K decrease, or 22% change. Though this variance is over 5%, the dollar amount is $1K and there is no material discrete cause of this variance.

For FERC Account 905, comparing the 2021 budget to the 2022 budget there was an overall $29K increase, or 593% change. The primary reasons for the decrease in 2021 budget were related to:

- $81K increase for VP Customer Solutions budgeted to FERC 905 due to

- budget reallocation from reorgs and allocation to FERC 905
- $53K decrease related to an offsetting credit out of FERC 905 to offset reallocation and reorgs
- Net amount due to items below scope

For FERC Account 904, comparing the 2022 budget to the 2023 budget there was an overall
$6,297K increase, or 105% change. The primary reasons for the increase in 2023 budget were related to:

- 2022 budget assumed COVID bad-debt deferral for all of 2022 compared with 2023 being the first post-COVID-19 pandemic without bad debt (uncollectible expense) deferral. The increase in 2023 also reflects that uncollectibles is a revenue sensitive item with higher revenues in 2023.

For FERC Account 905, comparing the 2022 budget to the 2023 budget there was an overall $63K increase, or 190% change. The primary reasons for the increase in 2023 budget are related to:

- $53K related to the 2022 budget containing a decrease as an offsetting credit and 2023 budget is “flat” or zero without a credit
- Net amount due to items below scope, escalations

For FERC Account 903, comparing the 2023 budget to the 2024 budget there was an overall
$2,194K increase, or 16% change. The primary reasons for the increase in 2023 budget are related to:

- $2,100K increase in payment and processing due to increased payment processing fees and volume of transactions, net
- $900K increase in printing and mail due to escalations and postage rate increases in 2023 and 2024
- $1,000K decrease due to regulatory amortizations
- Net amount due to items below scope, escalations

For FERC Account 904, comparing the 2023 budget to the 2024 budget there is an overall $1,060K increase, or 9% change. The primary reasons for the increase in 2024 budget is related to:

- $1,060K variance is from the proposed uncollectible expense rate (%) for 2024 and an increase due to being a revenue sensitive item.

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 185
Dated March 10, 2023

Request:

Please provide a narrative explaining the base year values, adjustments and escalation to test year values for each of Customer Accounts Expenses (Non-Labor, Accounts 901-905), expanding on PGE/900 Lynn-Nestel/7-8. Please also point to and attach work papers with highlighted cells referenced in the narrative provided.

Response:

The base year values are 2022 actuals. The 2023 budget is the original basis of the 2024 test year values. The 2023 budget is developed from the 2022 budget with escalations. Please see PGE's response to OPUC DR 184 for the discrete changes from 2022 budget to 2023 budget. The 2023 budget is then escalated using non-labor escalation factors to create the 2024 budget along with discrete adjustments to 2024. The discrete adjustments for 2024 compared to the 2023 budget are
$2,100K for payment processing and $900K for printing and mail (postage) in FERC account 903. FERC account 904 is a revenue sensitive item that is calculated by applying the uncollectibles rate proposed in PGE/900 Lynn-Nestel in the revenue requirement calculation PGE/200 Ferchland- Batzler. No adjustments were made to FERC account 902 or FERC account 905.

"PGE Response to OPUC DR 186 Attachment A"

Is filed in electronic format

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 187
Dated March 10, 2023

Request:

For each subcomponent or subcategory of the account's data, for Customer Account Expenses described in the immediately prior DR, where there is a 5 percent or greater change, year-to-year, in actuals or budgets, please explain the reasons for the variance.

Response:

The reasons for year-over-year variance in actuals greater than 5% are as follows:

For FERC Account 908, 2020 actuals to 2021 actuals had an overall increase of $343K, or 7% related to:

- $547K increase to Distributed Resource Planning preparing for DRP Integrated Resource Plan, partially offset by
- $209K reduction in external digital communication

For FERC Account 908, 2021 actuals to 2022 actuals had an overall $680K reduction, or 15% decrease related to:

- $223K increase to conferences, training and travel, offset by
- $294K reduction to Distributed Resource Planning department related to DRP Integrated Resource Plan timing
- $540K reduction to external professional/outside services usage
- $80K reduction in collections fees

For FERC 909 the 2021 Actual to 2022 Actual change was overall $618K reduction, 67%

- $714K reduction in Category A spending, partially offset by
- $92K increase in community safety communications

The reasons for year-over-year budget variances greater than 5% are as follows:

For FERC Account 908, comparing the 2021 budget to the 2022 budget there was an overall $880K increase, or 19% change. The primary reasons for the increase in 2022 budget were related to:

PGE's Response to OPUC DR 187
March 24, 2023
Page 2

- $431K increase to external marketing
- $289K increase to Distributed Resource Planning
- $200K increase to community battery storage projects

For FERC Account 908, comparing the 2022 budget to the 2023 budget there was an overall
$4,249K increase, or 112% change. The primary reasons for the increase in 2023 budget were related to:

- $2,563K increase to customer communications and outreach marketing
    - o $2,000K was reduced in 2022 to temporarily support increase for transmission and distribution accounts and was restored in 2023 budget for communications to customers about the 2030 Clean Energy Targets and how customers can participate, partially offset by
    - o $259K increase to customer research
    - o $250K increase to web based communications
- $600K increase to support transportation electrification strategy and implementation
- $300K budget transfer from non-customer FERC accounts to support customer related energy efficiency initiatives
- $410K budget transfer from non-customer FERC accounts to support material purchases and equipment rentals for electric vehicle charging installations
- $200K increase to community battery storage projects
- $160K increase to business expense primarily for conferences, training, and travel

For FERC Account 908, comparing the 2023 budget to the 2024 budget there was an overall $483K decrease, or 6% decrease due to escalations offset by miscellaneous decreases all immaterial.

- $615K increase for transportation electrification, due primarily to growth in Fleet program
- $798K decrease for a budget neutral shift in Distribution System Planning from FERC account 908 to a distribution FERC account 588
- $241K decrease for a budget neutral transfer for Transmission and Interconnect from FERC account 908 to a transmission FERC account 560

For FERC Account 909, comparing the 2020 budget to 2021 budget there was an overall decrease of $137K, or a 10% decrease related to:

- $100K reduction in external advertising
- $22K reduction related to software implementation which was completed in 2020

For FERC Account 909, comparing the 2023 budget to 2024 budget there was an overall increase of $1,544K, or a 126% increase related to:

- $1,500K increase related to outreach and education to customer of how the electrical grid is evolving and the decarbonization path to 2030

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 188
Dated March 10, 2023

Request:

Please provide a narrative explaining the base year values, adjustments and escalation to test year values for each of Customer Service & Informational; Sales Expenses (Non-labor, Accounts 906- 917) expanding on PGE/900 Lynn-Nestel/7-8. Please also point to and attach work papers with highlighted cells referenced in the narrative provided.

Response:

The base year values are 2022 actuals. The 2023 budget is the original basis of the 2024 test year values. The 2023 budget is developed from the 2022 budget with escalations. Please see PGE's response to OPUC DR 187 for the discrete changes from 2022 budget to 2023 budget. The 2023 budget is then escalated using non-labor escalation factors to create the 2024 budget along with discrete adjustments to 2024. The discrete adjustments for 2024 compared to the 2023 budget is
$615K in FERC Account 908 related to transportation electrification department, $798K budget neutral shift from Customer FERC account 908 to Distribution FERC account for Distribution System Planning and $241K budget neutral shift from Customer FERC account 908 to Transmission FERC account 560 for Transmission and Interconnection department, and $1,500K increase in FERC Account 909 related to outreach and education to customers on how the electrical grid is evolving and the decarbonization path to 2030.

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 490
Dated April 6, 2023

Request:

Referring to the Company's response to DR 183 with DR 183_Attachment A

a. Please explain the reasoning behind not budgeting for FERC account 902, historical figures show there has been activity in this account.

b. Explain the differences in the 202 budget ($15,761,968) provided at the top of the excel spreadsheet versus the 2021 budget in the "Year-over-Year Change-Budget" section ($18,743,578) at the bottom of the spreadsheet.

Response:

a. FERC 902 is budgeted based on known or planned R&D projects during the budget process. In recent years there have not been planned projects at the time of budget, and historical activity reflects unplanned R&D related projects.

b. This difference is in FERC account 903 related to the inclusion of the CET deferral amortization[1] in 2020 and 2021 in the "Year-over-Year Change-Budget" section, whereas the budget in the top of the excel spreadsheet did not include the CET deferral amortization.

[1] This is the expense amortization from Schedule 112 which recovers the unamortized 2014-2016 deferred costs and the estimated 2017 and 2018 operations and maintenance costs related to PGE's Customer Engagement Transformation (CET) project consistent with OPUC Order No. 17-511.

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 491
Dated April 6, 2023

Request:

Referring to the Company's response to DR 184

a. Regarding the $200K increase in Corporate R&D for Transmission Planning and DER Integration in the account 902, has the company filed for deferrals for this activity?

b. Please expand on the reasoning behind the variances 2020 actuals to 2021 actuals for FERC account 903.

c. For the variances behind FERC account 903 actuals, please identify whether any of the expenses were captured in your covid deferral.

d. Provide more detail behind the miscellaneous accounting adjustment for write-off in the 903 balance for 2020-2021 actuals.

e. Provide all instances where commercial customers paid their bill, all or in part, with a credit card.

f. Provide an explanation for any variances greater than 5% in the "Annual Variance to Budget" section of the DR 183_Attach A provided by the Company.

Response:

a. No, PGE did not file a deferral for the difference in actuals between 2020 and 2021 for the Corporate R&D for Transmission Planning and DER Integration (EPRI) in account 902 as referenced in OPUC DR No. 184.

b. Additional sources of variances for FERC account 903 from 2020 to 2021 actuals are as follows:
   - $2.1M - Credit Card, ACH payment processing, customer payments, remittances
   - $1.2M for Internet Virtual Assistants Interactions (2021 was the first full year of usage)
   - $1.5M Customer Digital for Web and Mobile Outage Map and Reporting functionality changes including display of the outage information to decrease

customer friction in seeing, reporting and getting updates on outages impacting them. Web Start/Stop/Move self-service changes to increase customer success rates online when initiating a request to PGE. Changes within the public Web designed to improve ease of information access by customers to PGE programs, offerings, services such as net metering, as well as PGE's stewardship of community resources such as parks

- $0.4M Customer Experience engagement (Medallia survey platform

c. No, these are not captured in the COVID deferral account and COVID Deferral AWO.

d. This was a write-off of unreconciled cash balance for a multi-year period.

e. PGE objects to this request on the basis that it is unduly burdensome and calls for information not in PGE's possession as each vendor would need to provide transaction by transaction data. Notwithstanding this object PGE answers as follows:

   Attachment 491-A provides the number of instances where commercial customers paid their bill, all or in part, with a credit card, shown by credit card vendor.

f. The explanations for variances greater than 5% for the Annual Variance to Budget are as follows:

<u>2020 Budget Variances:</u>

- FERC account 903 2020 budget variance is due to:
  - $1.8M higher than budget from Write-off of unreconciled Acct 903 cash balances
  - $0.7M higher than budget Payment Processing fees and related expenses
  - $0.1M higher than budget Customer Experience support
  - $0.3M lower than budgeted EV O&M and DSG reimbursement of DEQ fees
  - $0.1M lower than budget Printing & Postage
  - $0.1M lower than budget Automated Outbound Credit call fees

- FERC account 904 2020 budget variance is due to budget being set in 2019 prior to COVID-19 and 2020 COVID-19 pandemic resulting in deferral of uncollectible expense in excess to the amount in customer prices for March 2020 to end of year.

- FERC account 905 2020 budget variance, while this variance is over 5%, the total dollar variance is $17K, as is due primarily due to vehicle allocations.

<u>2021 Budget Variances:</u>

- FERC account 902 2021 budget variance due to Corporate R&D projects related to DER Integration and Transmission Planning

- FERC Account 903 2021 budget variance is due to:

- $1.2M higher than budget for Call Center: Internet Virtual Assistant Interactions (first year using new service)
- $1.7M higher than budget Payment processing costs
- $0.4M higher than budget Project Customer 360
- $1.4M higher than budget Customer Digital for Web and Mobile Outage Map and Reporting functionality changes including display of the outage information to decrease customer friction in seeing, reporting and getting updates on outages impacting them. Web Start/Stop/Move self-service changes to increase customer success rates online when initiating a request to PGE. Changes within the public Web designed to improve ease of information access by customers to PGE programs, offerings, services such as net metering, as well as PGE's stewardship in of community resources such as parks
- $0.5M higher than budget Printing/Postage
- $0.2M higher than budget Customer Analytics project work

- FERC account 905, 2021 budget variance was primarily due to vehicle allocations and language interpreter service.

2022 Budget Variances:

- FERC account 902 2022 budget variance due to Corporate R&D project, OUS Oregon State University and meter services data plan.
- FERC account 905, 2022 budget variance, primarily due to language interpreter service.

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 623
Dated April 24, 2023

Request:

Regarding to your response to DR 187, 2022 to 2023 budget comparison of account 908 (Customer Assistance Expense) please explain

a. Why would the 2030 Clean Energy Targets communication and outreach need to be included in the rate base?

b. Expand on what the $2,563K in customer communications and outreach marketing expenditures would entail in 2023. Provide samples of the communication if available.

Response:

b. PGE assumes Staff's intended question is regarding amounts included in *base rates* and not in rate base. The Path to 2030 communications and outreach is included in PGE's customer base rate request because this is an educational and awareness campaign aimed to engage customers and increase their needed participation to achieve decarbonization targets. Customer awareness and participation must increase significantly and consistently through the 2040 time horizon. Customer participation in customer-sited actions like demand response, energy efficiency and other programs directly support PGE's efforts to reach is Clean Energy Targets. Additionally, these actions have been identified in the preferred CEP/IRP portfolio.

c. The 2023 budget for customer communications and outreach marketing is related to the Path to 2030 educational campaign, which is currently being developed and also related to safety outreach campaigns. In 2023, we have partnered with a strategic communications and creative agency to plan and launch a multi-year, multi-channel campaign for customers including social, digital, video, radio, out of home, and community events for the Path to 2030. Communications will be developed beginning in late Q2-Q3 2023. No samples of communications are available at this time.

Portland General Electric Company
UE 416
PGE Response to OPUC Data
Request 624
Dated April 24, 2023

Request:

Regarding your response to DR 187, 2023 and 2024 budget comparison of account 908, Please explain why Transportation Electrification in your Fleet program would be a major driver? How will the increase of $615K be used?

Response:

The EV Field Operations department O&M is budgeted to FERC account 908 because this department was originally funded through a budget transfer from customer programs when it was created in 2022. The EV Field Operations department supports both customer programs and PGE fleet and workplace charging. However, PGE fleet and workplace charging more closely aligns with PGE's transportation service provider allocation. In the future, budget and actuals will be in the FERC account that aligns with the activity. The increase of $615K will primarily fund outside services for maintenance activities, materials, tools for supporting PGE fleet and workplace charging and training of staff in the new department.

CASE: UE 416
WITNESS: Mitchell Moore

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

OPENINGTESTIMONY
Miscellaneous Operating Revenue,
Non-Fuel Materials and Supplies,
Deferred Debits, and
Affiliated Transactions

June 13, 2023

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

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) n 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 qualifications statement is found in Exhibit Staff/1601.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address PGE's request for Test Year expenses for Miscellaneous Operating Revenue, Non-fuel Materials and Supplies, and Deferred Debits. I also review Affiliated Interest activity since the last General Rate Case.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff 1602, PGE Responses to Staff Data Requests, and Staff/1603, Staff workpaper.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. OTHER OPERATING REVENUE

Q. Please summarize this issue.

A. PGE forecasts revenue for the Test Year in various categories as a component of a general rate case. FERC accounting rules classifies revenue into several different components:

- Retail Sales (accounts 440-446);
- Sales to other entities intended for resale (account 447);
- Intracompany transfers (account 448); and
- Other operating revenues, including miscellaneous service revenues, rents and revenues from the use of transmission and other facilities (accounts 450-456).

In this testimony, I evaluate the Test Year revenues for “other operating revenues,” or the final bullet above. Other Revenue is a substantive component of a rate case in that Other Revenue is an offset to expenses and reduces the overall revenue requirement.

In this case, PGE proposes Test Year Other Revenues of $39.7 million, which is a decrease of ($2.5 million) from the base year actuals.[1] PGE states that the primary sources of Other Revenue are pole attachment rental revenue, third-party transmission revenue, late payment fees, and rent of electric property. PGE arrives at its forecast by using historic revenues to forecast 2024 revenues, and making pro-forma adjustments for deferred items, Green

[11] PGE/200, Batzler-Ferchland/8.

Power Administration revenue, transmission sales to electric service suppliers (ESS) that sell energy directly to customers based on the outcome of its FERC 2021 transmission rate case.

Q. How does PGE explain the reduction in Other Revenue over the base year?

A. PGE identifies 3 major downward adjustments to its 2022 actuals:

1. Removal of transmission intertie reimbursement revenues – ($64,794).
2. Removal of steam sales revenue (due to one-off increase in 2022) – ($2.75 million).
3. Removal of offset to expenses for 3rd party facility access – ($3.9 million).

Q. DOES STAFF AGREE WITH PGE'S TRANSMISSION INTERTIE ADJUSTMENT?

A. Perhaps. Staff believes the removal of such revenues is reasonable given that the costs they are meant to reimburse are not included in power cost rates. However, Staff is still in the process of investigating transmission-related revenues totaling approximately $17.5 million that were included in the base year, and aren't included in either the test year, nor in years previous to the base year.

Q. DOES STAFF AGREE WITH PGE'S STEAM SALES REVENUE ADJUSTMENT?

A. No. Staff believes PGE underestimated its forecast for steam sales revenue. PGE explained that 2022 revenues were abnormally high because one of its large steam customers had a failure in its on-site boiler, which necessitated the customer purchasing more steam than normal. For the Test Year, PGE forecasts steam sales revenue at $2.3 million, an amount lower than received in 2021, $2.56 million. However, looking at historical steam sales revenue for the years 2010-2022, it is clear that steam revenue can vary significantly from year to year.

Q. Does Staff agree with PGE's removal of offset revenues to expenses for 3rd party facility access?

A. As a matter of principle, no. However, in this case PGE has removed the costs of providing the services from the case. Staff reviewed the historical costs and revenues for this category and finds that the positive value of offsetting revenues is consistent, but relatively de minimis. For the years 2020 through 2022, the revenues exceed the costs by an average of $21,757.[2]

Q. Does Staff agree with PGE's overall Test Year forecast for Other Revenues?

A. No. After reviewing PGE's filing, responses to Staff data requests, and historic forecast versus actuals, Staff believes PGE has under-estimated its Test Year forecast for Other Revenues, as it consistently has in each of the last four general rate cases that staff reviewed.

Q. Explain PGE's history of Other Revenue forecast versus actuals?

A. PGE has underestimated its forecast of Other Revenues in each of the last four general rate cases that Staff reviewed. The following table illustrates the differences in forecast Test Years and actual revenues:

[2] Staff/1602, Moore/1 - PGE response to DR No. 210.

Table 1 – Other Revenue, Forecast vs Actuals

	PGE - OTHER REVENUE					
	2016 - UE 294	2017	2018 - UE 335	2019 - UE 319	2020	2022 - UE 394
Other Revenue Actuals	$26,154,793	$25,326,933	$31,644,096	$41,172,048	$32,074,214	$42,155,091
PGE Forecast	$25,100,000		$25,800,000	$25,300,000		$29,300,000
Percentage of underforecast	**4.20%**		**22.65%**	**62.74%**		**43.87%**

Historically, PGE has underestimated its Test Year Other Revenue forecast by an average of 33.37 percent.

It is also notable that Other Revenue actuals have steadily increased every year since 2016, with the exception of a substantive drop in 2020. This was attributed in UE 394 mainly to the decrease in account 4500001 – Forfeited Discounts as a result of the effects of COVID-19 when the Commission suspended utility disconnections and late payment charges.[3]

Q. What does Staff conclude from its review of Other Revenues?

A. Staff concludes that PGE's Other Revenue consistently increases year-over-year, and that PGE consistently underestimates its forecast. It is reasonable to conclude that PGE has underestimated Other Revenue in this case also.

Q. Does Staff recommend an adjustment?

A. Yes. Based on historical performance in underestimating Other Revenue, Staff recommends an adjustment that would increase Other Revenue by $13.24 million. This amount is based on the average percentage of under-forecasted Test Year estimates in UE 294, UE 335, UE 319, and UE 394.

[3] See UE 394 Staff/1300, Zarate/8.

Issue 2. Non-Fuel Materials and Supplies

Q. Please summarize PGE's proposal for non-material fuel and supplies

A. The Company forecasts a year-end balance of $59.7 million in non-fuel material and supplies inventory for 2023. Actual year-end balance for 2022 was 62.8 million.[4]

Q. Please summarize the Commission's historical treatment of non-fuel materials and supplies in rate base.

A. The Commission typically authorizes utilities to include an allowance for non-fuel materials and supplies in rate base.

Q. Please describe staff's analysis of this issue.

A. Staff reviewed historical balances for the years 2020 through 2023 and compared the average of monthly average balances for each year with the year-end forecast for 2023. Staff believes that using an average of monthly averages balance for rate-based items provides a more accurate picture of yearly rate-based components that earn a rate of return.

I took the average of monthly average balances for 2020, 2021, and 2022 and escalated for inflation factor of 6.6 percent to 2023 to arrive at a Test Year forecast 2023 of $58.3 million.[5]

Q. Does Staff propose an adjustment?

A. Yes. Staff believes PGE has overestimated the non-fuel material and supplies by ($1.4 million), and therefore recommends an adjustment of this amount.

[4] PGE/208, Batzler-Ferchland/1.
[5] See Staff/1603, Moore/Workpaper.

Issue 3. Miscellaneous Deferred Debits

Q. Please summarize PGE's proposal with regard to Miscellaneous Deferred Debits.

A. PGE proposes $17.8 million under miscellaneous deferred debits to be included in rate base for the test year. This represents an increase of $6.9 million over the UE 394-approved rate base amount. Of the total, PGE includes $8.2 million for cloud-based software license and hosting fees and $1.3 million in the Major Maintenance Accrual (MMA). These items are addressed by Staff consultant Robert Young in Staff/2100, and Staff consultant QSI in Staff/2700. The remaining miscellaneous deferred debits represent an approximately $1.3 million decrease from the existing rate base.

The individual deferred debit accounts reviewed in this testimony include:

- Glass insulators - $5.8 million
- Dispatchable Standby Generation - $4.2 million
- Wheatridge O&M Start-up costs - $1.4 million

Q. Please describe your review of this issue.

A. For glass insulators, Staff relies on Commission Order No. 10-478 that allowed glass insulators to be classified as capital costs, rather than O&M expense, because their useful life exceeds one year. The rate base amount increases by $369,000, or 6.8 percent. This appears a reasonable increase, given that overall net utility plant increases 14.3 percent over the same period.

For Dispatchable Standby Generation (DSG), Staff issued several data requests to review the costs and the amortization schedule. DSG refers to a program defined in Schedule 200, that provides for 3rd party-owned emergency backup generators that PGE is able to deploy in an emergency. PGE funds some of the costs for upgrades and enhancements to the generators to enable program participation. Staff reviewed the costs and amortization amounts and is satisfied that they match the program guidelines and DSG agreement period of 10 years.

For Wheatridge start-up costs, Staff reviewed Company responses to data requests that asked for the forecast vs actuals of the start-up costs as well as the amortization schedule. Staff is satisfied that the actual costs match the forecast/budgeted amounts, and that the amortization is proceeding as previously approved by the Commission.[6]

Q. Does Staff have a recommended adjustment for this issue?

A. No.

[6] In UE 370, Order No. 20-321 the Commission approved the Wheatridge project and adopted the proposal to capitalize the start-up costs as a regulatory asset included in rate base, to be amortized over 30 years.

Issue 4. Affiliated Interest Transactions

Q. What transactions between PGE and its affiliates are forecasted for the 2024 test year?

A. PGE forecasts Administrative and General (A&G) expenses totaling $5 million to be billed to one of its affiliates in the 2024 Test Year, namely 121 Southwest Salmon Corporation, (121SWS) owner of the World Trade Center (WTC) building where PGE has its headquarters.[7] 121SWS charges PGE rent based on PGE's percentage of occupancy of the rentable space in the WTC.

PGE forecasts that it will be billed $7.64 million for rent by its affiliate 121 Southwest Salmon Corporation. There are no transactions forecasted between PGE and its affiliate Salmon Springs Hospitality Group.[8]

Expenses will be billed between affiliates in accordance with the Company's Cost Allocation Manual, and approved Master Services Agreement.[9]

Q. Does Staff have an adjustment related to Affiliated Transactions?

A. Not at this time. However, there are some outstanding Staff data requests to inquire into variations in rent per square footage costs from 2019 through the 2024 test year that may result in a Staff recommended adjustment in future testimony.

Q. Does this conclude your testimony?

A. Yes.

---

[7] Staff/1602, Moore/2 Company response to Staff DR No. 521 Attachment A.
[8] Ibid.
[9] See June 1, 2023 filing in Docket No RE 64 for PGE's current Cost Allocation Manual.

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. I have provided expert witness testimony on a number of general rate case dockets, including: UE 294, UE 319, UE 335, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, and UG 388.

My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints.

Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 210
Dated March 13, 2023

Request:

Referencing PGE 200, pg 9, lines 4-8, please : a) Provide the amount of revenue recorded to Other Revenue in 2020 – 2022 as offsets to expenses incurred for each year for the referenced project; and b) Provide, for each year in 2020-2022 the amount of expense incurred that the revenue recordings offset.

Response:

The below table provides the 2020-2022 project expense and revenue referenced in PGE Exhibit 200, page 9, lines 4-8.

Account	2020 Actuals	2021 Actuals	2022 Actuals
4560001: Other Electric Revenues	($5,342,471)	($4,515,841)	($3,883,684)
5800001: DistOp-Engineering & Design	$1,159	$0	$0
5800002: DistOp-OpSupv-General Support	$0	$373	$0
5800038: Distribution OPS - Non Alloc	$5,146,336	$3,948,023	$3,334,359
5930001: DistMaint-Overhead Lines	$162,251	$551,253	$532,965
5940001: DistMaint-Underground Lines	$0	$2	$0
Total	**($32,724)**	**($16,189)**	**($16,360)**

April 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 521
Dated April 10, 2023

Request:

Please provide the Company's forecast of payments to its affiliated interests during the 2024 test year. Please provide this information in electronic workbook format with all cells and formulas intact. Further, please:

a. Show payments to each affiliated interest separately.

b. Break the requested data down to show different categories of payments to each affiliated interest separately.

c. Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

d. For each transaction that the Company has indicated as valued at the market price in response to section "c," please provide a narrative explanation of what market price is used by the Company, including reference to specific sources used.

Response:

Attachment 521-A provides all 2024 forecast affiliate amounts billed to and from PGE. All transactions are valued at cost.

Exhibit 1603/workpaper

Is

Filed in electronic format

CASE: UE 416
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700

OPENING TESTIMONY
Depreciation Expense, Amortization Expense, Depreciate Reserve, Amortization Reserve, and Allowance for Funds Used During Construction

June 13, 2023

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 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. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1701.

Q. What is the purpose of your testimony?

A. I discuss my analysis of the depreciation expense and accumulated depreciation, or depreciation reserve, and portions of Portland General Electric's (PGE or Company) revenue requirement for this rate case as documented by the Company witnesses in PGE/200, Batzler – Ferchland, PGE/600, Ajello – Batzler, and PGE/800 Jenkins – Bekkedahl. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualifications statement, I prepared Exhibit Staff/1702, PGE Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. DEPRECIATION EXPENSE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

Q. Why is depreciation important in a revenue requirement?

A. NARUC states that:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[2]

1. From a valuation perspective, depreciation is the loss in service value not restored by current maintenance.
2. From an accounting perspective, depreciation is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept.

---

[1] NARUC, Public Utility Depreciation Practices, p.318 (1996).
[2] NARUC, Public Utility Depreciation Practices, p.195 (1996).

3. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1) states:

> Every public utility shall carry a proper and adequate depreciation account. the public utility commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. the rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. What is the Commission's historical treatment of a depreciation calculation in a revenue requirement?

A. A utility should use the Commission-authorized depreciation parameters and rates to calculate the depreciation and amortization expense and reserve. A Company's Depreciation Expense is determined by (OPUC-Authorized Depreciation Rate) x (Oregon net plant in service) x (allocation factor).

Q. Has PGE complied with the OPUC Order by using the Commission-authorized depreciation rates in the calculation of revenue requirement for the UE 416 general rate case?

A. PGE used the depreciation rates that were authorized in Order No. 21-463, except that PGE updated the depreciation rates for Faraday Hydro Plant after the plant got repowered. The updated depreciation rates for Faraday Plant include the following FERC Accounts:

FARADAY HYDRO PLANT

FERC Account	
331.00	STRUCTURES AND IMPROVEMENTS
332.00	RESERVOIRS, DAMS AND WATERWAYS
333.00	WATER WHEELS, TURBINES AND GENERATORS
334.00	ACCESSORY ELECTRIC EQUIPMENT
335.00	MISCELLANEOUS PLANT EQUIPMENT
336.00	ROADS, RAILROADS, AND BRIDGES

Q. How did you review the depreciation and amortization expenses?

A. I sent Data Request 223 to PGE asking the Company to provide the Test Year depreciation and amortization expenses and reserves in Excel format based on the Commission-authorized depreciation parameters under Order No. 21-463, UM 2152. The calculation links and formulas should all tie to the Revenue Requirement Model. However, in Data Response 223 and Exhibit 200, I did not see that the depreciation parameters and rates used matched the study rates in tab “UM-2152,” and there were no calculation links.

Q. How did PGE calculate the depreciation expenses?

A. According to PGE, the Company used the third party “PowerPlan” software to calculate the depreciation expense based on the OPUC-authorized depreciation rates. PGE explained in an email on April 12, 2023, that “PowerPlan, our software system generates our depreciation expense based on the parameters we enter into it, which are from the UM 2152 study (provided it was part of the study).”

Q. What did you do when you could not verify if the Commission order had been followed?

A. The PowerPlan software does not show the data link and the calculation formula, it only provides the results. Therefore, for the purpose of compliance verification, I had several email exchanges and a meeting with PGE to clarify the depreciation rate application. I asked PGE to use a traceable formular to recalculate the depreciation expense. By using this method, PGE could get identical results of a depreciation expense of $300.4 million each year as of 2021, as the company filed in UE 416. It turns out that PGE recalculated expense matched the filing result. Based on my review, PGE implemented the depreciation rates in UM 2152, Order No. 21-463 in the UE 416 filing. The one exception is that PGE proposed a new life-span and net salvage percent for Faraday Hydro Plant.

Q. What is PGE's new depreciation rate proposal for Faraday Hydro Plant?

A. PGE proposes to extend the depreciable life from June 2055 to June 2085 for the Faraday hydro plant, due to the replacement of a 100-year-old plant with new Faraday Units 7 and 8.

Q. Did you make an adjustment to the PGE-proposed survival curve and net salvage rate for Faraday?

A. No. I did not make an adjustment to Faraday's repowering investment for the following reasons: First, the PGE-proposed survival curves for FERC Account 331-336 are basically the same as the Commission-authorized existing curves. Second, PGE recalculated the net salvage rates by adding in the terminal decommissioning cost for which Staff verified the calculation and finds reasonable. Third, the industry average service life for Account 331-Structures and Improvements is 98 years and the maximum service life is 125 years, so PGE's proposed service life is within the industry range. Fourth, based on the survival curve and updated net salvage rate, Staff considers the new depreciation rate and the extended remaining life are reasonably derived for Faraday hydro plant.

Q. How did you review the decommissioning cost recovery for Faraday Hydro Plant?

A. Decommissioning cost is a terminal retirement in a net salvage rate. A Weighted Average Net Salvage Percent consists of two parts of retirements: Terminal Retirements (i.e., Decommissioning Cost), and Interim Retirements (the retirements that take place before the final retirement of all property). This is because the depreciation rates are derived by two depreciation parameters: Survival Curve[3] and Net Salvage[4] Percentage Rates.

To verify the decommissioning cost for Faraday Plant, I sent Data Request DR No. 484 to PGE. In PGE's Response to OPUC DR 484, the Company provided 1. Calculation Of Terminal and Interim Retirements As A Percent Of Total Retirements, and 2. Decommissioning Costs Related To Generating

[3] "Survivor Curve" is a curve that shows the number of units or cost of a given group which is surviving in service at given ages. The survivor curves were developed by the Engineering Research Institute of Iowa State University. These curves are frequently referred to as "Iowa Curves".

[4] Net Salvage is the gross salvage of the property retired less the cost of removal. This will be negative if the cost of removal exceeds the gross salvage.

Units, and Terminal Net Salvage Percent. After reviewing the new rates, I consider the Company's calculations are detailed enough to support the depreciation rate calculation for Faraday plant in this filing.

Q. How did PGE treat the existing plant depreciation during the 2019-2021 Faraday repowering period?

A. I sent Data Request No. 234 to PGE, and PGE sent its Response on March 13, 2023. The following below clarified the questions:

Staff Request No. 234a:

The existing Faraday Hydro plant was not fully depreciated when the repowering project started. Under FERC Accounts 331-336, the total estimated future capital to be recovered was $59 million and the annual depreciation expense was $1.8 million, as of December 2019. During the re-powering period, how did PGE treat the Faraday's pre-existing depreciation?

a. Did PGE continue to depreciate the unrecovered the cost for all six FERC accounts during the repowering period? If not all 6 accounts, did you continue to depreciate for some of these 6 accounts (see Table below)?

PGE Response No. 234a:

Without acknowledging the accuracy of any statements or information presented in this data request, PGE responds as follows:

a. Yes, PGE continued to depreciate the existing Faraday plant balances in their related FERC Hydraulic Production accounts during the re-powering period.

Staff Request No. 234b:

Did PGE put Faraday repowering cost under the CWIP (Construction Work In Progress) that was not recovered through rate base depreciation?

PGE Response No. 234b:

b. Yes, costs for the re-powering project were accumulated in CWIP during the construction period and were not included in rate base during the construction period.

Staff Request No.234c:

Did PGE treat the repowering cost as a capital addition, and put Faraday repowering cost into the rate base to get recovered from depreciation?

PGE Response No. 234c:

c. Yes, upon achieving commercial operation in January 2023, the cost of the re-powering project was transferred from CWIP to Utility Plant in Service as a capital addition.

Staff Request No.234d:

Did PGE use the same depreciation parameters that were authorized by OPUC? If so, the decommissioning cost is included in the depreciation.

PGE Response No. 234d:

d. No, for test period depreciation expense, PGE has proposed modified depreciation rates for the Faraday Plant. The proposed depreciation rates are based on the assumed extension of the FERC license from 2055 to 2085.

Q. How are hydro licensing fees treated in depreciation?

A. Hydro power license fee revenue enables the hydropower industry to meet federal licensing requirements that protect water quality and also protect, mitigate, and enhance fish, wildlife, and habitat, and therefore, utilities make use of these fees to fund construction, renovation, or real property projects to meet federal requirement. These project costs are normally depreciated through the depreciation schedule in Summary Table 1. For example, the license fees that are used in these projects listed above are included in FERC Account 331-336, specifically in Account 332- Reservoirs, Dams And Waterways - Fish And Wildlife Conservation.

Historically, hydro power licensing fees have been recovered through a "depreciation schedule" under FERC Accounts 331-336 for Faraday, North Fork, Oak Grove, Pelton, River Mill, Round Butte, and Sullivan. These hydro power license fees were included in depreciation expense as tangible assets in UM 2152 and Order No. 21-463.

Q. How does PGE's 2024 total depreciation expense forecast compare to 2022 actuals?

A. PGE estimates $339.6 million in depreciation expense for 2024. The total forecasted depreciation for 2024 reflects a $26.8 million increase over 2022 actuals.

Q. Has PGE explained what the primary drivers are for the increase in depreciation expense?

A. Yes. In its initial filing, PGE explained that the primary drivers of the increase in depreciation expense are:[5]

- $16.2 million for transmission and distribution facilities;
- $4.3 million for Faraday Resiliency and Repowering Project;
- $3.3 million for Beaver plant due to the Beaver modernization project;
- $3.7 million in general plant; and
- $0.1 million in Coyote Springs generation plant.

These increases are partially offset by:

- $0.6 million net reduction in wind and other generation plant.

Q. Do you propose an adjustment to depreciation expense in UE 416?

A. No. After reviewing PGE's work paper for the total depreciation expense and Faraday life-extension calculation, and with my Data Requests being answered, I consider that PGE complied with the Commission Order No. 21-463, and its calculated depreciation expense is reasonable. Therefore, I do not make an adjustment to PGE's depreciation expense in UE 416.

[5] UE 416 / PGE / 200, Batzler - Ferchland / 12.

Q. Please explain if the depreciation expense in this testimony is final.

A. No. If any adjustments are made to Plant-In-Service (which is being reviewed by other Staff witnesses), the Company's final depreciation expense and accumulated depreciation would be changed accordingly.

ISSUE 2. AMORTIZATION EXPENSE

Q. What is Amortization?

A. Amortization is the practice of spreading an intangible asset's cost over that asset's useful life. Amortization and depreciation are two methods of calculating the value for industrial assets over time. The formula for calculating the amortization on an intangible asset is similar to the one used for calculating straight-line depreciation: dividing the initial cost of the intangible asset by the estimated useful life of the intangible asset.

Q. How did you review PGE'S 2024 amortization expense?

A. My review was focused on the assets that are included in FERC Accounts 300s—Detailed Plant Accounts, in *Table 1. Summary Of Estimated Survivor Curves, Net Salvage Percent, Original Cost, Book Depreciation Reserve And Calculated Annual Depreciation Accruals Related To Electric, Gas And Common Plant As Of December 31, 2021.*

Q. What is the PGE-proposed 2024 amortization expense?

A. PGE Exhibit 204 details the total 2024 amortization expense of $82.9 million summarized in Table 3 below.

Table 3
Amortization Expense
($millions)

Category	**2022 Actuals**	**2024 Forecast**
Software Amortization 3-10 years	$56.6	$78.3
Other Intangible Amortization	3.5	3.5
Trojan Decommissioning	1.9	1.9
Regulatory Credits		(0.5)
Retail Allocation		(0.2)
Total Amortization*	$62.0	$82.9

* May not sum due to rounding

Q. What is PGE's proposal for cloud-based software cost recovery?

A. PGE proposes to include the unamortized balance of applicable license and hosting fees associated with prepaid cloud-based solutions with a contract length of three years or greater as a regulatory asset in rate base. The current forecast of this amount as of December 31, 2023 totals approximately $8.2 million.[6]

Q. Does Staff agree that PGE should put the cloud-based software into a rate base and gain a return on this software?

A. No. Staff witness Robert Young addresses this issue in Staff/2100 and recommends disallowance of the $8.2 million.

Q. Does Staff make any other adjustments to amortization?

A. No. FERC states that Account 303 - Miscellaneous Intangible Plant "shall include the cost of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account." Based on FERC guidance, I reviewed amortization in the FERC Account 300s and found that the other amortization calculations are reasonable.

Q. Please explain if the amortization expense in this testimony is final.

A. No. If any adjustments are made to Plant-In-Service (which is being reviewed by other Staff witnesses), the Company's final amortization expense and accumulated amortization would be changed accordingly.

---

[6] UE 416 / PGE / 600, Ajello – Batzler / 21.

ISSUE 3. DEPRECIATION RESERVE

Q. What is Depreciation Reserve?

A. Depreciation Reserve is Accumulated Depreciation at a point in time, which includes the total amount of recorded depreciation, retirements, gross salvage, cost of removal, transfer asset, and other adjustments.

Q. What is the Commission's historical treatment of this issue?

A. Depreciation Reserve is also called Accumulated Depreciation Reserve. In a revenue requirement, as an average depreciation reserve increases, the Rate Base decreases. The Rate Base is the value of property/assets of a utility minus the accumulated depreciation of those assets.

Q. Have you made adjustments to Depreciation Reserve?

A. Not at this time. The depreciation reserves are affected by depreciation expenses, asset retirements, sales, transfers, gross salvage, cost of removal, and other adjustments. If depreciation expense is changed, the accumulated depreciation should be changed accordingly. I did not make an adjustment to depreciation expense, therefore, the accumulated depreciation would not be changed. There is one exception, like I stated in previously: if any adjustments are made to Plant-In-Service (which is being reviewed by other Staff witnesses), the Company's final depreciation expense and accumulated depreciation reserve would be changed accordingly.

ISSUE 4. AMORTIZATION RESERVE

Q. Describe Amortization Reserve.

A. Amortization Reserve is accumulated amortization at a point in time, which includes the total amount of recorded amortization, retirements, gross salvage, cost of removal, transfer asset, and other adjustments.

Q. What is the Commission's historical treatment of this issue?

A. Amortization Reserve is also called Accumulated Amortization Reserve. In a revenue requirement, as an amortization reserve increases, the Rate Base decreases. Rate Base is the value of property/assets of a utility minus accumulated amortization of those assets.

Q. Have you made any adjustments to Amortization Reserve?

A. As noted above, Staff witness Robert Young is proposing an adjustment for cloud-based software. Therefore, the accumulated amortization is changed accordingly.

ISSUE 5. AFUDC

Q. What is AFUDC?

A. Electric (Gas) Plant Instruction No. 3(17) provides a formula for computing rates used to capitalize Allowances for Funds Used During Construction (AFUDC).[7] The formula includes a component for the weighted average cost of long-term debt. The entire issue of the use-restricted long-term debt should be included with other long-term debt used in calculating AFUDC rates. Average balances of the trust or other special funds should be included in the computation of the average balance of Construction Work In Progress (CWIP) used in the formula.

AFUDC assigned to the project should be determined by applying AFUDC rates to the eligible project expenditures and also balances in the trust or special funds. Fund earnings during construction should be credited to the cost of construction of the project facilities.

Q. What is the purpose of the AFUDC review?

A. The purpose of this review is to address whether the Company complied with guidance[8] related to AFUDC and the capitalization of assets based on the regulations of both the Federal Energy Regulatory Commission (FERC) and the Oregon Public Utility Commission (OPUC) in this filing.

Q. Please provide more details regarding AFUDC.

---

7 https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance-funds-used-during-construction.

8 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101.

A. AFUDC is a non-cash item that is included in the cost of Utility Group utility plant and represents the cost of borrowed and equity funds used to finance construction. AFUDC is the cost of both the debt and equity funds used to finance utility plant additions during the construction period for such additions, determined in accordance with Generally Accepted Accounting Principles (GAAP).

FERC has prescribed two formulas for calculating maximum allowable AFUDC rates:[9]

1. DEBT: This formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.
2. COMMON EQUITY: This formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes.

FERC has indicated that if the FERC AFUDC rate is different than the state-approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount capitalized in utility plant would be based on the FERC AFUDC rate. The amount included in the regulatory asset would be the difference between the State AFUDC rate and the FERC AFUDC rate.

The FERC formula and elements for the computation of the allowance for funds used during construction are:[10]

9 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101.
10 FERC 18 C.F.R. Part 101 (17) Allowance for funds used during construction (a), (b): https://www.law.cornell.edu/cfr/text/18/part-101.

***Ai*=*s**(*S*/*W*)+*d**(*D*/*D*+*P*+*C*)*(1-*S*/*W*)** = Gross allowance for borrowed funds used during construction rate

***Ae*=[1-*S*/*W*]*[*p**(*P*/*D*+*P*+*C*)+*c**(*C*/*D*+*P*+*C*)]** = Allowance for <u>other</u> funds used during construction rate

- S=Average short-term debt
- s=Short-term debt interest rate
- D=Long-term debt
- d=Long-term debt interest rate
- P=Preferred stock
- p=Preferred stock cost rate
- C=Common equity
- c=Common equity cost rate
- W= Average balance in construction work in progress, less asset retirement costs related to plant under construction

Q. Did you make any adjustments after the review?

A. No. Staff proposed no adjustment to PGE's original filing for the following reasons:

- <u>Compliant monthly AFUDC rates</u>: The Company's calculation of its monthly AFUDC Rates complies with the FERC AFUDC rate formulas and accounting requirements. The monthly calculation method has been authorized by FERC. Per FERC Order No. 561, on April 8, 1982, PGE was granted FERC approval to calculate AFUDC rates on a monthly basis utilizing balances and applicable cost levels, as of the end of preceding month, for all components of capital, and utilize estimates of construction work in progress balances and short-term debt balances and cost rates in the month that the AFUDC rate is to be used. In general, FERC's approval to calculate AFUDC rates is on a semiannual basis.

- Meets FERC guidelines: Under FERC's AFUDC calculation guide, PGE calculates AFUDC rates in accordance with FERC guidance in 18 C.F.R. pt. 101 Electric Plant Instruction. When construction funding is not met by short-term debt, PGE calculates the maximum allowable AFUDC rates relevant to long-term debt by multiplying the total long-term debt cost rate by the ratio of total long-term debt to total capitalization. The maximum allowable AFUDC rates relevant to other funds (common equity & preferred stock) are calculated by multiplying the current authorized return on equity (ROE) by the ratio of total common equity to total capitalization. Lastly, cost rates for debt and equity sources of financing are each multiplied by one minus the ratio of weighted average short-term debt to CWIP to reflect that short-term debt financing is assumed to be the first source of financing in capital construction.
- Meets OPUC's rate of return: PGE's AFUDC rates are not higher than the authorized rate of return (Weighted Average Cost of Capital - WACC). Its authorized rate of return is 6.81 percent, and PGE's actual AFUDC rate is 6.51 percent (see the table below).

	AFUDC	AFUDC	AFUDC	Authorized	Authorized	Authorized		
Year	Debt	Equity	Total AFUDC	LT Debt	Common Equity	WACC	OPUC	OPUC
	Rate	Rate	Rate	Rate	Rate	Rate	Order #	Docket #
2017	2.46%	4.82%	7.28%	5.20%	9.50%	7.35%	17-511	UE 319
2018	2.52%	4.79%	7.30%	5.10%	9.50%	7.30%	18-467	UE 335
2019	2.40%	4.73%	7.13%	5.10%	9.50%	7.30%	18-467	UE 335
2020	2.30%	4.56%	6.86%	5.10%	9.50%	7.30%	18-467	UE 335
2021	2.28%	4.40%	6.68%	5.10%	9.50%	7.30%	18-467	UE 335
2022	**2.43%**	**4.08%**	**6.51%**	**4.13%**	**9.50%**	**6.81%**	**22-129**	**UE 394**

- The Company's policy for AFUDC complies with the FERC requirement. In the month after it is placed in service, the facility being constructed is excluded from AFUDC base and thus, AFUDC accrual for the facility ceases.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Accounting and Finance Section of the Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION & TRAINING:

M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

400+ credit hours on 30+ training topics in the public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 24 years. My roles include:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

I have testified in various formal state hearings and performed numerous analyses, including economic, financial, statistical, mathematical, marketing, and policy analyses in the public utility industry.

Principal Analyst and Case Manager, Settlement Lead/Negotiator for Depreciation Ratemaking:

I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for the past 15 years. In this role, I've had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed, and calculated energy asset retirement cost and impact, as well as power plant decommissioning cost and impact, on customer rates. I reviewed, calculated, and analyzed fixed asset depreciation and proposed depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigations and analyses on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG; Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a Lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments to the Commission for decision making on Boardman to Hemingway (B2H), a 500-kV transmission power line, which included a cost and benefit list, a pros and cons list, alternatives, and the relevant legal risks. I also provided comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I have been a part of *almost every energy rate case* since I joined the Oregon PUC on January 11, 1999. Historically, my reviews included fuel price forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, and AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications, "Market Competition and Economic Policy Survey Analysis" for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

<u>Mentor in the ICER - International Confederation of Energy Regulators</u>: I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My mentoring topics focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in the U.S.; "Price-Cap Performance Based Regulation" in UK; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UE 416
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1702

Exhibits in Support
Of Opening Testimony

June 13, 2023

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 234
Dated March 13, 2023

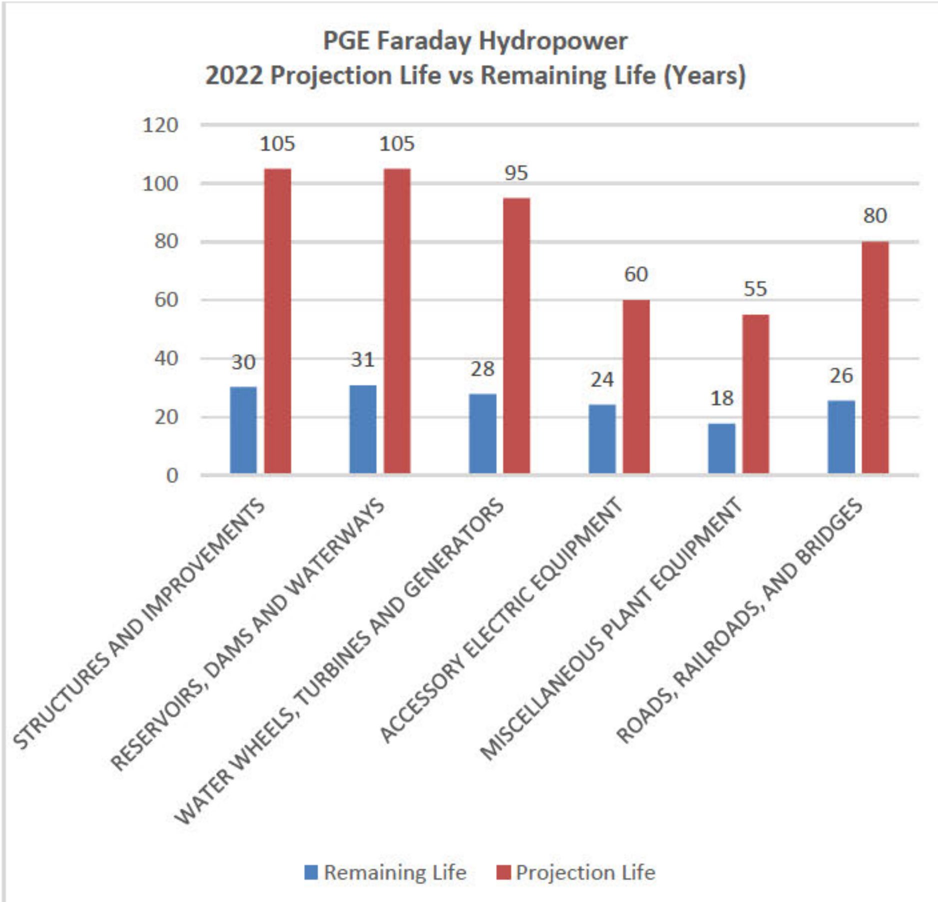
<u>Request:</u>

The existing Faraday Hydro plant was not fully depreciated when the repowering project started. Under FERC Accounts 331-336, the total estimated future capital to be recovered was $59 million and the annual depreciation expense was $1.8 million, as of December 2019. <u>During the re-powering period</u>, how did PGE treat the Faraday's pre-existing depreciation?

a. Did PGE continue to depreciate the unrecovered the cost for all six FERC accounts during the repowering period? If not all 6 accounts, did you continue to depreciate for some of these 6 accounts (see Table below)?
b. Did PGE put Faraday repowering cost under the CWIP that was not recovered through rate base depreciation?
c. Did PGE treat the repowering cost as a capital addition, and put Faraday repowering cost into the rate base to get recovered from depreciation?
d. Did PGE use the same depreciation parameters that were authorized by OPUC? If so, the decommissioning cost is included in the depreciation.

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2019

	ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF 12.31.2019 (5)	NET SALVAGE RATE =N*L/100	BOOK DEPRECIATION RESERVE (6)	Total Capital to be recovered FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRU AMOUNT (8)	Average DEPR. % RATE (9)=(8)/(5	COMPOSITE REMAINING LIFE (10)=(7)/(8)
FERC Account	HYDRAULIC PRODUCTION PLANT										
331.00	STRUCTURES AND IMPROVEMENTS										
	FARADAY	6/30/2055	105 - R2.5 *	-42	14,154,712	(5,944,979)	2,289,524	17,810,167	536,884	3.79	33.2
332.00	RESERVOIRS, DAMS AND WATERWAYS										
	FARADAY	6/30/2055	105 - R3 *	-42	32,440,590	(13,625,048)	16,545,932	29,519,705	872,857	2.69	33.8
333.00	WATER WHEELS, TURBINES AND GENERATORS										
	FARADAY	6/30/2055	95 - S0.5 *	-42	6,752,412	(2,836,013)	2,871,859	6,716,565	218,146	3.23	30.8
334.00	ACCESSORY ELECTRIC EQUIPMENT										
	FARADAY	6/30/2055	60 - R2 *	-42	2,737,870	(1,149,905)	1,527,591	2,360,184	86,631	3.16	27.2
335.00	MISCELLANEOUS PLANT EQUIPMENT										
	FARADAY	6/30/2055	55 - R0.5 *	-42	257,629	(108,204)	147,345	218,489	10,553	4.10	20.7
336.00	ROADS, RAILROADS, AND BRIDGES										
	FARADAY	6/30/2055	80 - R1 *	-42	2,441,325	(1,025,356)	996,114	2,470,567	86,381	3.54	28.6
	TOTAL FARADAY				58,784,537	(24,689,506)	24,378,365	59,095,677	1,811,452	3.08	32.6



Response:

Without acknowledging the accuracy of any statements or information presented in this data request, PGE responds as follows:

a. Yes, PGE continued to depreciate the existing Faraday plant balances in their related FERC Hydraulic Production accounts during the re-powering period.
b. Yes, costs for the re-powering project were accumulated in CWIP during the construction period and were not included in rate base during the construction period.
c. Yes, upon achieving commercial operation in January 2023, the cost of the re-powering project was transferred from CWIP to Utility Plant in Service as a capital addition.
d. No, for test period depreciation expense, PGE has proposed modified depreciation rates for the Faraday Plant. The proposed depreciation rates are based on the assumed extension of the FERC license from 2055 to 2085.

April 19, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 484
Dated April 4, 2023

Request:

With regard to Staff data request 234 d, please provide the following Tables 1-4 with the weighted average net salvage percent PGE used in the depreciation rate calculation, in Excel format:

Table 1. Calculation of Terminal and Interim Retirements as a Percent of Total Retirements

TABLE 1. CALCULATION OF TERMINAL AND INTERIM RETIREMENTS AS A PERCENT OF TOTAL RETIREMENTS

	PROJECTED RETIREMENTS				
LOCATION	TERMINAL	INTERIM	TOTAL OF ALL RETIREMENTS	TERMINAL RETIREMENT %	INTERIM RETIREMENT %
(1)	(2)	(3)	(4)=(2)+(3)	(5)=(2)/(4)	(6)=(3)/(4)

Table 2. Calculation of Weighted Net Salvage Percent

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT

	TERMINAL RETIREMENTS		INTERIM RETIREMENTS		
LOCATION	RETIREMENTS (%)	NET SALVAGE (%)	RETIREMENTS (%)	NET SALVAGE (%)	WEIGHTED AVERAGE NET SALVAGE %
(1)	(2)	(3)	(4)	(5)	(6)=(2)*(3)+(4)*(5)

Table 3. Decommissioning Cost, Terminal Retirement, Terminal Net Salvage

	TERMINAL NET SALVAGE		
LOCATION	DECOMMISSIONING COST	TERMINAL RETIREMENTS	TERMINAL NET SALVAGE %
(1)	(2)	(3)	(4)=(2)/(3)

Table 4. Interim Net Salvage, Original Cost

		INTERIM NET SALVAGE		
ACCOUNT	INTERIM NET SALVAGE (%)	ORIGINAL COST AS OF 12/31/202x	202x ORIGINAL COST AS A PERCENT OF TOTAL	WEIGHTED AVERAGE OF INTERIM NET SALVAGE (%)
(1)	(2)	(3)	(4)	(5)=(2)*(4)

Response:

Attachments 484-A, 484-B, 484-C, and 484-D provide the requested tables demonstrating the development of the weighted net salvage value of (14)% used for the calculation of Faraday depreciation rates.

Attachment 484-A provides Table 1. Calculation of Terminal and Interim Retirements as a Percent of Total Retirements.

Attachment 484-B provides Table 2. Calculation of Weighted Net Salvage Percent.

Attachment 484-C provides Table 3. Decommissioning Cost, Terminal Retirement, Terminal Net Salvage.

Attachment 484-D provides Table 4. Interim Net Salvage, Original Cost.

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

REDACTED

OPENING TESTIMONY

Subject to Modified Protective Order No. 23-039

June 13, 2023

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

A. My name is Rose Pileggi. I am a Senior Utility Analyst employed in the Energy Costs Section of the Rates, Safety and Utility Performance (RSUP) Program 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 qualifications statement is found in Exhibit Staff/1801.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to address the Company's testimony on the Faraday Resiliency and Repowering Project, Capital Structure, and Cost of Long-Term Debt.

Q. Did you prepare any additional exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff/1802, PGE's non-confidential responses to DRs
- Staff/1803, PGE's confidential responses to DRs
- Staff/1804, PGE's highly confidential responses to DRs
- Staff/1805, Staff workpapers
- Staff/1806, PGE's confidential reports to FERC
- Staff/1807, Major Program and Project Monitoring Updates
- Staff/1808, Faraday Repowering Project Updates.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. FARADAY RESILIENCY AND REPOWERING PROJECT

Q. Please provide some background on the Faraday Resiliency and Repowering Project.

A. The Faraday Resiliency and Repowering Project (Faraday, Repowering or Project) replaced the original 1907 Faraday Powerhouse, one of PGE's West Side Hydro plants on the Clackamas River. The Project involved the complete demolition of the original 1907 Faraday Powerhouse, removal of Units 1 through 5, construction of a new reinforced concrete powerhouse and flood protections, and the addition of two new turbines (Units 7 and 8). Faraday Unit 6 was deemed to not require upgrades. Units 7 and 8 were placed in service during January 2023, and the costs related to the Faraday Project were included in PGE's 2024 GRC rate base.[1]

Q. Has the Commission dealt with this issue prior to the current GRC?

A. Yes. The Faraday Repowering Project was included in the Company's Docket No. UE 394 GRC filing and was removed from the rate base due to delays in the Project timeline. The power cost impacts of the Project have been considered in the Company's 2021, 2022 and 2023 AUT filings.[2] The Faraday Project was not addressed in an IRP filing.

---

[1] See PGE/800, Jenkins – Bekkedahl/18.
[2] See Docket Nos. UE 377, UE 391, and UE 402.

Q. What is the total expected cost of the Project?

A. The latest cost estimate of the project, including project cost loadings and allowance for funds used during construction (AFUDC), is $189.7 million.[3] This total cost is comprised of:

- $146.1 million in construction costs
- $1.7 million as cost of removal within PGE's total accumulated depreciation
- $22.6 million in project cost loadings
- $19.3 million in AFUDC

Q. What is the standard by which the Faraday Project is analyzed?

A. Two standards of review are applied, that the plant is used and useful prior to the effective date of rates, and the prudence of the Company's investments. As stated in Staff/1000, Enright, under PGE's previous GRC filing, Docket No. UE 394, "The prudence standard revolves around the question of whether an action is reasonable given the facts that are known and knowable at the time that the decision is made." And, "[f]urther, NARUC stresses that a utility must follow a course of conduct that a capably managed utility would have followed in light of existing and reasonably knowable circumstances. NARUC also presents the following factors that should be considered when determining prudence:

- Utility executives are financial and technical experts;

---

3 See Staff/1802, Pileggi/1-5, PGE Response to Staff DR 358, updating response to Staff DR 963 issued under UE 394.

- Prevailing practice is relevant but not determinative;
- The utility's legal obligation to provide safe, reasonable, and adequate service at lowest cost;
- The initial utility decision and its subsequent utility response to changing circumstances; and
- Prudence analysis is not based on hindsight." [4,5]

Q. Will the Faraday Project be substantially complete and "used and useful" by the rate effective date, January 1, 2024?

A. Yes. Work on the Faraday Project was substantially completed on March 31, 2023. Faraday Units 7 and 8 were placed into service and deemed used and useful on January 31, 2023.[6]

Q. Did the Project face delays that caused the Project to miss the targeted completion date?

A. Yes. The Project faced many challenges that pushed the completion date several times to a date more than two years after the original scheduled completion date. In the Company's Opening Testimony, PGE includes several contributing factors to the delays including:[7]

- "…the added complexities inherent for a hydro project that involves repowering a 100+ year old plant…"[8]

---

4 See Docket No. UE 394 Staff/1000, Enright/12 and Docket No. UE 246, Order No. 12-493.

5 "Management Audits / Prudency," NARUC, 2014. See: https://pubs.naruc.org/pub.cfm?id=537CC901-2354-D714-5154-339AD3909936

6 See Staff/1802, Pileggi/6, PGE's response to Staff DR 358, Attachment A, update to Staff DR 965 issued under UE 394.

7 PGE/800, Jenkins – Bekkedahl/42

8 PGE/800, Jenkins – Bekkedahl/44, lines 6-7.

- Limited in-water work window caused a delay of a few weeks to push the entire project back one year.
- COVID-19 caused loss of qualified personnel, delays in supply chain, and delays in other aspects of construction.
- 2020 Labor Day wildfire causing flooding from loss of power, repairs, cleanup, and loss of access to the site via the wooden bridge.

Q. Have issues with the prudence of the Faraday Resiliency and Repowering Project been identified?

A. Yes. Staff has identified several issues in the prudence of the Project. These issues are discussed later in Staff's testimony, and summarized here:

- PGE has provided little testimony to support the prudence of this project. While various reasons are provided for why the project was undertaken—reductions in greenhouse gas emissions, regional capacity shortages of dispatchable generation, and insufficiency of the powerhouse and difficulties in maintaining Units 1 through 5—the Company dedicates just 20 lines to the economic prudence of undertaking the Faraday Resiliency and Repowering Project.[9]
- The initial analysis grossly overestimated the Net Present Value (NPV) of the Faraday Repowering Project and did not include an analysis of decommissioning. PGE chose to not evaluate decommissioning of Faraday as it was a reduction in resources and would forgo the eligibility

[9] PGE/800, Jenkins – Bekkedahl/29 lines 10-15, Jenkins – Bekkedahl/36 lines 7-19, and Jenkins – Bekkedahl/48

of the Company to earn Production Tax Credits associated with the incremental energy from repowering.[10]

- Mismanagement of the Company's contracting for construction.[11]

Q. Please provide more information on why Staff has indicated that PGE has provided little evidence establishing the prudency of the decision to undergo the Faraday Resiliency and Repowering Project?

A. The issues with the Faraday powerhouse were known for many years prior to the decision to undertake the Project and yet PGE did not include the project in any Integrated Resource Planning (IRP) filing. As already noted, the Company's decision to undergo the Project with its $189.7 million price tag is justified by only 20 lines of PGE testimony. While many pages of the Company's testimony are dedicated to providing reasons to undergo the project, the economic prudency is severely limited.

Q. What is the significance of the Project not being considered in an IRP filing?

A. The significance of the Project not being considered in an IRP was addressed in Staff Opening Testimony in Docket. No. 394. Staff states, "[t]he IRP process helps to identify the lowest practical and least risk cost at which a utility can deliver reliable energy services to its customers. This requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of various resource options. The IRP process also allows the

---

[10] PGE/800, Jenkins – Bekkedahl/29-30.
[11] See Docket No. UE 394, Staff/1000, Enright/22.

Commission, Staff, and other stakeholders to be involved in decisions affecting ratepayers.

By excluding the Repowering from an IRP filing, and conducting an extremely limited analysis of its options, as detailed below, the Company engaged in an expensive project without taking advantage of an IRP review process."[12] The benefit of an IRP analysis is that projects can be evaluated as part of an overall generation mix which allows any synergies and operating complexities to be analyzed.

While it is not required that any specific project be evaluated within an IRP context, it is at least expected that a utility undertake an analysis of the cost/benefits of a multimillion-dollar decision related to a 100-year old resource considering all reasonably available alternatives, including decommissioning.

Q. Why should the Company have considered the NPV of all possible options including decommissioning?

A. Given the scope of the various options, and the capital outlays required to conduct the Repowering, it would have been appropriate for the Company to evaluate all options available. As the Repowering required the complete removal and replacement of the Faraday powerhouse, much of the same work would be involved in the decommissioning of the 1907 Faraday powerhouse, decommissioning should have been evaluated.

Q. General construction costs were [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Is Staff attempting to judge the

[12] Docket No. UE 394, Staff/1000, Enright/15-16

Company in hindsight, rather than what was known or knowable at the time?

A. No. At the time of the Project selection, general construction costs were estimated to total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The general construction costs were revised **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** during the first GC's tenure course of the project, a **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** and ultimately increased to over $150 million after the second GC was contracted.[13] PGE's executives, financial and technical experts, should have been capable of providing a more accurate cost estimate of the general construction costs. Under Staff Opening Testimony in the previous GRC, Staff indicated that it was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As a result, PGE's financial and technical experts committed to fund the project spend while paying insufficient attention to its analysis of the costs and benefits of the project itself."[14]

---

[13] See Staff/1803, Pileggi/4-7, PGE's response to Staff DR 358, providing PGE's response to Staff DR 814 Confidential Attachment A, and Staff/1804, Pileggi/1, PGE's response to DR 963 Highly Confidential Attachment A issued under Docket No. UE 394. Also, see Staff/1803, PGE's response to AWEC's DR 57 Confidential Attachment A, available in electronic format only.

[14] Docket No. 394, Staff/1000, Enright/19-20

Q. The Company states in their testimony that additional economic analysis was performed in April 2019, after actual bids were received. What was the NPV of selecting the Faraday Resiliency and Repowering Project, versus the NPV of maintaining the Status Quo, when PGE conducted this analysis?

A. Construction bids and subsequent total project cost were based on a 90% design. The expected accuracy of such a cost estimate would be consistent with a Class 1 probable cost estimate. Under normal circumstances, a Class 1 probable cost estimate can be expected to vary as much as 10% below or 15% over the cost estimate. The cost estimate of $84 million was used to generate economic analysis.[15] At a cost estimate of $84 million, the NPV analysis of the Repowering Project was calculated to be $8.4 million below that of the status quo.[16] The acceptable cost variances at this level, not accommodating for the risks caused "complexities inherent for a hydro project that involves repowering a 100+ years old plant,"[17] provided a range of NPVs that dipped as low as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Absent any adjustments for these inherent complexities, immediately prior to the start of construction, PGE considered the range of NPVs shown in Confidential Figure 1 to be acceptable:

---

[15] PGE/800, Jenkins – Bekkedahl/36.
[16] Ibid. Also, see Staff/1803, AWEC DR 59, Confidential Attachment A, NPV Analysis – 2019, available in electronic spreadsheet format only.
[17] PGE/800, Jenkins – Bekkedahl/44.

[redacted]

[redacted]

[redacted]

Q. What is Staff's recommendation regarding the adjustment to the Faraday related costs?

A. Staff's recommended adjustment to the Faraday plant is comprised of eight parts. Staff recommends a disallowance **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** on general construction costs paid to the initial general contractor, for a disallowance of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** a disallowance of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, a disallowance of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**, a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] for a total disallowance of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** from rate base. Additionally, Staff recommends that an amount of Project costs included in Rate Base, equal to the balance of the overall **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, be included in Rate Base at the

[18] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[19] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Company's Cost of LT Debt. The overall **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. After Staff's recommended disallowances, the balance is **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**, this is the amount of Project costs included in Rate Base that Staff recommends be recovered at the Company's Cost of LT Debt. Each of these parts of Staff's recommendation are discussed further in the testimony below.

Q. Why does Staff recommend the [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. Staff maintains the disallowance recommended under the prior GRC. The rationale provided for this has not changed. The Company's original contract for construction services **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The outcome of this **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[21]

---

[20] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[21] See Docket No. UE 394, Staff/1000, Enright/22; and Staff/1803, Pileggi/30-33, PGE Confidential responses to Staff DRs 820, 821 and 825 issued under Docket No. UE 394

Q. Was it "known or knowable" at the time that PGE signed the contract to include "critical milestones" in contracts with third parties and that the [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. Yes. The usage of critical milestones in contracting is common and well established. As documented in Staff Opening Testimony under the prior GRC filing, PGE was aware of their usage as early as 2016 and included them in a draft Power Purchase Agreement (PPA) submitted to the Commission in 2016. PGE included critical milestones to ensure that the energy producer would meet a required Guaranteed Commercial Operation Date, imposing damages for non-compliance. This draft PPA is directly equivalent to the contract that PGE signed with its construction contractor for Faraday.[22] **[BEGIN CONFIDENTIAL]** [redacted]

[22] See Docket No. UE 394, Staff/1000, Enright/22; and Docket No. UM 1773, filing dated July 13, 2016, Appendix C, "Wholesale Renewable Power Purchase Agreement Between Portland General Electric Company And [Seller]."

[redacted] **[END CONFIDENTIAL]**.[23]

Q. Did Staff consider the utility's response to the changing circumstances, as recommended by NARUC, in the prior GRC and does Staff maintain this position?

A. Yes. Staff considered the response of PGE to the changing circumstances under the prior GRC, Docket No. UE 394, and Staff maintains the same position. Staff's analysis on this subject, under the prior GRC filing, is presented here:

"Once the Company realized the contractor **[BEGIN CONFIDENTIAL]** [redacted]

---

[23] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. See Staff/1803, Pileggi/34, PGE Confidential response to the Staff DR 908, section (a), issued under Docket No. UE 394; and Staff/1803, Pileggi/4-7, Confidential Attachment C to PGE's response to Staff DR 591, page 8, issued under Docket No. UE 394.

[24] See Staff/1803, Pileggi/30, PGE's Confidential responses to Staff DR 820, issued under the prior GRC, Docket No. UE 394.

[redacted] **[END CONFIDENTIAL]**. Staff's opinion is that PGE should have been capable of correctly contracting from the outset, or at the very least recognized the shortcomings of its abilities, drawing on the help of outside experts at that early stage.[27]

Q. Why does Staff recommend the [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. In PGE's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The breakdown of this budget adjustment was **[BEGIN CONFIDENTIAL]** [redacted]

---

25 Liquidated damages are an estimate of the actual damages that would likely be sustained in the event of a delay.

26 See Staff/1803, Pileggi/31-32, PGE's Confidential responses to Staff DR 821, issued under the prior GRC, Docket No. UE 394.

27 See Docket No. UE 394, Staff/1000, Enright/24.

[redacted] **[END CONFIDENTIAL]**.[28] It was "known or knowable" at this time that the impacts of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Due to the nature of compounding of interest and property taxes, the full impacts are experienced at the end of a project. This disallowance is justified in the same manner as the disallowance of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**—it is an effect experienced by the **[BEGIN CONFIDENTIAL]**

[28] See Staff/1803, Pileggi/8-9, PGE's Confidential response to Staff DR 592, issued under Docket No. UE 394, and reissued under Staff DR 358 of this GRC.

[redacted] [END CONFIDENTIAL].

Q. Why does Staff recommend a [BEGIN HIGHLY CONFIDENTIAL] [redacted] [END HIGHLY CONFIDENTIAL] disallowance on the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to general construction costs paid to the initial general contractor?

A. Staff recommends that the Commission disallow 10% of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in general construction costs, representing approximately **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** in capital costs. This percentage disallowance is maintained from Staff's recommendation under the prior GRC docket. Staff's recommended disallowance is intended to reflect PGE's over-reliance on "known" estimated construction costs, to correct for PGE's financial and technical experts relying upon an NPV calculation **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, greenlighting the project cost estimate change to $84 million while aware that the NPV analysis was now $8.4 million—and under normal circumstances could increase to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[29], and PGE's lack of inclusion of a project of this size in an IRP filing.

---

[29] This number does not account for the knowable risk posed by "complexities inherent" to repowering a hydro plant of this age.

Absent the "unparalleled extreme events," PGE still attributes "the added complexities inherent for a hydro project that involves repowering a 100+ years old plant" as cause for ultimately severely impacting the project schedule and costs.[30] Complexities inherent to a project present a known or knowable risk. The exact complexities faced may vary, but this inherent risk increases the risk to cost overruns. Some complexities faced included site issues "that would not be easily identifiable prior to starting the project." PGE provides an example of such with the mention of additional construction work required because sub-surface geotechnical conditions and the state of the concrete supports were not as expected and required significant modifications to the project design.[31] As an additional complexity given the age, PGE notes in the same section that the project "entailed demolishing the 1907 Faraday Powerhouse concrete structure while ensuring that the adjacent Faraday Units [Sic] 6 was not damaged." Given that the project was undertaken to address seismic instability, poor concrete structural integrity, and with the intent to maintain Unit 6, these site issues present good examples of the "complexities inherent." In PGE's NPV analysis, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Had the Company made an effort to investigate the "knowable," included protections for "knowable" risks, its NPV analysis would have been better

[30] See PGE/800, Jenkins – Bekkedahl/44.
[31] See PGE/800, Jenkins – Bekkedahl/40-41.

informed. Had this analysis been better informed with "known or knowable" risks and costs, it may have resulted in an alternative project at Faraday.

At the time of the 2016 NPV analysis, the NPV of pursuing this project over that of doing nothing was approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** The increases in costs arising from foreseeable risks **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and costs not included in the initial analysis, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, may have significantly changed the NPV of pursuing this project and resulted in undertaking an alternative project at Faraday.

At the time of the 2019 NPV analysis, the NPV of pursuing this project versus that of "Status Quo" option was approximately negative $8.4 million. The increases in costs arising from foreseeable risks, such as "complexities inherent for a hydro project that involves repowering a 100+ years old plant," and evaluating the full range of NPVs considered acceptable at the Class 1 cost estimate—absent these inherent complexities—provided by the contractor who won the bid, an NPV **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, may have significantly changed the NPV of pursuing this project, changed the perception of the NPV, and resulted in undertaking an alternative project at Faraday.

Q. Why does Staff recommend the [BEGIN CONFIDENTIAL] [redacted]

[redacted] **[END CONFIDENTIAL] at the $84 million project cost estimate?**

A. In PGE considered it acceptable to take on the Project and approved the budget at a cost estimate of $84 million, with the knowledge of the 2019 economic analysis. PGE was aware that the cost estimate had a level of variance to project costs up to 15% above the point estimate. PGE's BOD, as technical and financial experts, were also aware that there were inherent complexities that presented abnormal risks beyond those of a typical project. PGE considered it acceptable to conduct the project at a cost to customers, beyond that of the "Status Quo" option, of up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PGE chose to pursue this project that provided a marginal increase of 2.8 MW of capacity beyond the capacity of Units 1-5, 18.8 MW of overall capacity, at a project cost estimate of $84 million and a cost to customers expected to be as high as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PGE pursued this without an IRP filing, and in Staff's opinion, without thoroughly analyzing other options or knowable risks. For reference, PGE's entire West Side Hydro project represents 178 MW of capacity.[32] As justification for this Project, PGE states that Faraday Units 7 and 8 are important to decarbonization, and that PGE expects to procure and integrate at least 3,000 MW of non-emitting capacity by 2030.[33]

---

[32] PGE/800, Jenkins – Bekkedahl/19.
[33] PGE/800, Jenkins – Bekkedahl/49.

PGE considers Faraday particularly valuable in this context as it is a non-emitting capacity resource. Of the 3,000 MW needed by 2030, the new units represent 18.8 MW, or a 2.8 MW increase on the former Units 1-5. The total MW capacity of Units 7 and 8 equates to 0.63% of the total needed, and the increase of 2.8 MW equates to 0.09% of the capacity needed by 2030. This miniscule percentage, greenlit at a considerable cost to customers, is perhaps not as characterized in PGE's testimony stating: "PGE needs resources like Faraday Units 7-8 to achieve significant emissions reductions while maintaining reliable and affordable electric service for customers.[34]

Q. Why does Staff recommend a disallowance of [BEGIN CONFIDENTIAL] [redacted]

A. [redacted]

[34] Ibid.

[redacted] **[END CONFIDENTIAL]**

Q. Please explain Staff's rationale for disallowing [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[35] [redacted] DR No. 61, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[36] Staff/1803, Pileggi/67-68, PGE Response to AWEC DR No. 58, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[redacted] **[END CONFIDENTIAL]** Although PGE cites the complexity of working on a 100+ year old facility and external events (wildfire, ice storm, flooding, and Covid-19) as the causes of the delay, this explanation of the delay is not borne out by discovery. Instead, the documents Staff has reviewed **[BEGIN CONFIDENTIAL]** [redacted]

Q. Please elaborate on Staff's conclusions regarding the delays in the Faraday Project.

A. The first General Contractor (GC) began construction 2019. **[BEGIN CONFIDENTIAL].** [redacted]

[37] Staff/1808, Pileggi/15-20, PGE Response to AWEC DR No. 60, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[redacted]

[38] Id.

[39] Staff/1807, Pileggi/15-20, PGE Response to AWEC DR No. 61, NTIAL] [redacted] [END CONFIDENTIAL].

[redacted]

A. [redacted]

[40] Staff 1808, Pileggi/14, PGE Response to AWEC DR No. 060, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[redacted]

[41] Staff/1806, PGE Response to AWEC DR No. 65, Monthly Report to FERC, April 2020.

[42] Staff/1806, PGE Response to AWEC DR No. 65, Monthly Report to FERC, July 2020.

[43] Staff/1806, PGE Response to AWEC DR No. 65, Monthly Report to FERC, November 20

[44] Staff/1808, Pileggi/14, PGE Response to AWEC DR No. 60, **[BEGIN CONFIDENTIAL]**, [redacted] **[END CONFIDENTIAL].**

Docket No: Staff/1800
Pileggi/28

[redacted]

[redacted]

[45] Staff/1803, Pileggi/47-53, PGE Response to AWEC DR No. 60, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[46] Id.

[47] Id.

[48] Staff/1807, Pileggi/83, PGE Response to AWEC DR No. 61, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[redacted]

Q. PGE asserts in its testimony that the delays in the Project were caused by events beyond its control. If this is true, does that mean a disallowance is not appropriate?

A. No. First, Staff disagrees that most of the delay was due to events beyond PGE's control. However, Staff agrees that delays and unanticipated circumstances were bound to occur. And, as PGE notes, demolishing and rebuilding a 107-year-old has "intrinsic complications." Notwithstanding the complicated nature of the project, PGE's contract with the general contractor had insufficient protections for ratepayers.

---

[49] Staff/1803, Pileggi/40, PGE Response to AWEC DR No. 60, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Furthermore, PGE's assertions regarding, the reasons for delay, particularly for the eleven-month delay for in-water work, are not well supported. PGE asserts,

> [t]he Faraday Resiliency and Repowering Project construction was impacted by multiple extraordinary events that occurred during the 2020 and 2021 timeframe. It began with a flooding event in January 2020, followed by the COVID-19 pandemic, which caused construction delays associated with mobilizing and demobilizing crews for safety reasons when COVID-19 outbreaks occurred. These events were soon followed by the 2020 Labor Day wildfire, which was followed by another flooding event in early 2021, as well as the historic 2021 February ice storm emergency event. These unprecedented and catastrophic events were not foreseeable when PGE entered the original construction contract. Consequently, these events contributed to delays in the anticipated in-service date of the project, which went from the initial completion estimate of Q3 2021, to Q1 2022, to Q4 2022, and the project came online in January 2023.[50]

Review of PGE's quarterly reports to its Board's Finance Committee reflect **[Begin Confidential]** [redacted]

---

[50] PGE/800, Jenkins-Bekkedahl/41.

[51] Staff/1807, Pileggi/2, PGE Response to AWEC DR No. 61, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

[redacted]

[redacted]

[redacted]

[redacted]

Q. Why does Staff recommend that a portion of project costs included in Rate Base, equal to the difference of recommended disallowances and the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL], a dollar value of [BEGIN HIGHLY CONFIDENTIAL] [redacted] [END

---

52 Staff/1807, Pileggi/12, PGE Response to AWEC DR No. 61, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (emphasis added).

53 Staff/1807, Pileggi/69, PGE Response to AWEC DR No. 61, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

54 Staff/1807, Pileggi/22, PGE Response to AWEC DR No. 61, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

HIGHLY CONFIDENTIAL], be recovered at the Company's Cost of LT Debt?

A. Staff finds PGE did not conduct a diligent enough process in decision-making, nor did the Company employ processes like the IRP process to protect ratepayers from unwarranted costs. Staff's proposed adjustment is not new and has been approved by the Commission under similar circumstances, such as in Order No. 20-473, in which PacifiCorp was not allowed to earn a return on the investment, and that PacifiCorp should not be entitled to profit on its investment made. Page 81 of the order states: "Instead of Staff's primary proposal, we adopt a version of Staff's alternative proposal. We will allow the Oregon-allocated remaining book value of the investment into rates, but will not allow PacifiCorp to include a return on equity in its "return on" the investment. Instead, we will limit its return on the investment to its cost of long-term debt, which will apply to the entire remaining investment. We expect the company to approach significant capital investments in a way that thoroughly examines all reasonably available alternatives, incorporates a consideration of risks and changing circumstances, and demonstrates a well-documented commitment to ensure that the investment is in its customers' interests. This remedy is appropriate because PacifiCorp did not diligently enough undertake its decision-making process in order to protect ratepayers from unwarranted costs, and should not be entitled to profit in the typical manner from the investments it made as a result of that process." PGE's decision-making process regarding this project faced shortcomings including:

- Not diligently weigh risks,
- Incorrect contracting,
- Readily greenlit a project that would saddle customers with a significant cost—both the reasonably expected cost based on the project cost estimate in 2019 and the much greater final cost arising, in part, due to unmitigated risks of such a project—for a marginal increase to capacity and marginal portion of PGE's anticipated 2030 non-emitting capacity.

Staff recommends that it is fitting for ratepayers to be protected from such unwarranted costs, and the Company not profit in the typical manner on this investment, by recovering the entirety of this portion of Faraday Rate Base, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**, at the Company's Cost of LT Debt.

ISSUE 2. CAPITAL STRUCTURE

Q. Has the Commission recently considered this issue?

A. Yes. The Commission issued Order No. 22-129 in Docket No. UE 394. In Docket No. UE 394, the Commission adopted a settlement among parties that maintained PGE's regulated capital structure at 50% equity and 50% debt.

Q. What is the Company's proposed regulatory capital structure?

A. PGE proposes that the capital structure be maintained at 50% equity and 50% debt. The Company acknowledges that this is a long-term goal, and the exact equity ratio fluctuates above and below the 50% target "due to the phasing and sizing of debt and equity issuances."[55]

Q. How has the Commission recently treated capital structure for other utilities in Oregon?

A. In Docket No. UE 399, the Commission adopted a settlement among the parties that maintained PacifiCorp's 50% equity capital structure.[56] The adoption of this settlement by the Commission maintained PacifiCorp's existing structure of 50% common stock equity, 49.99% long-term debt, and 0.01% preferred stock equity.

Q. Have there been circumstances that would indicate a change to the existing capital structure of the Company is necessary?

---

[55] PGE/1000, Liddle – Villadsen/73

[56] *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism,* UE 339, Order No. 22-491 (December 16, 2022).

A. No. The Company maintains a long-term capital structure of 50% equity and 50% debt as the Company states that the "…capital structure is important because it represents how PGE finances its cash needs."[57]

Q. What does Staff recommend for capital structure?

A. Staff recommends that the last adopted capital structure of 50% equity and 50% long-term debt be maintained.

[57] PGE/1000, Liddle – Villadsen/73.

ISSUE 3. COST OF LONG-TERM DEBT

Q. What does Staff recommend for the Cost of Long-Term Debt for the Company?

A. Staff recommends a Cost of Long-Term Debt (Cost of LT Debt) for the Company of 4.293 percent. This reflects the cost of servicing outstanding LT Debt as well as the forecasted issuances in October 2023 and January 2024. No other issuances are forecasted through the end of the 2024 Test Year.

Q. How is the Cost of LT Debt determined?

A. The Cost of LT Debt is the cost to an organization to service outstanding debt. This may include costs to call or refinance the debt when advantageous to do so, coupon payments, and embedded costs to debt such as issuance fees, and whether the bonds were sold at par, discount, or a premium.[58] To provide a reasonable Cost of LT Debt, any outstanding issuances that will have a maturity of less than 1 year, at the end of the 2024 Test Year, must be removed from the calculation. One such series, CUSIP 736508N*9, was removed from the outstanding debt before Staff performed analysis.[59] Additionally, a reasonable Cost of LT Debt must be informed with values for forecasted debt issuances. Forecasted debt issuances are reviewed for impacts to maturity profile, and a reasonable expected coupon is calculated for each forecasted issuance date.

[58] The face value of a bond is the lump sum of money the investor receives at the maturity of the bond, generally $1,000. Par is a whole number percentage of price paid relative to the face value of the bond. A bond purchased at face value would have a par value of 100. A bond purchased above face is at a premium, and below face is at a discount.

[59] See Staff/1803, Pileggi/35, PGE Response to Staff DR 360.

Q. How is a reasonable expected coupon on future issuances calculated?

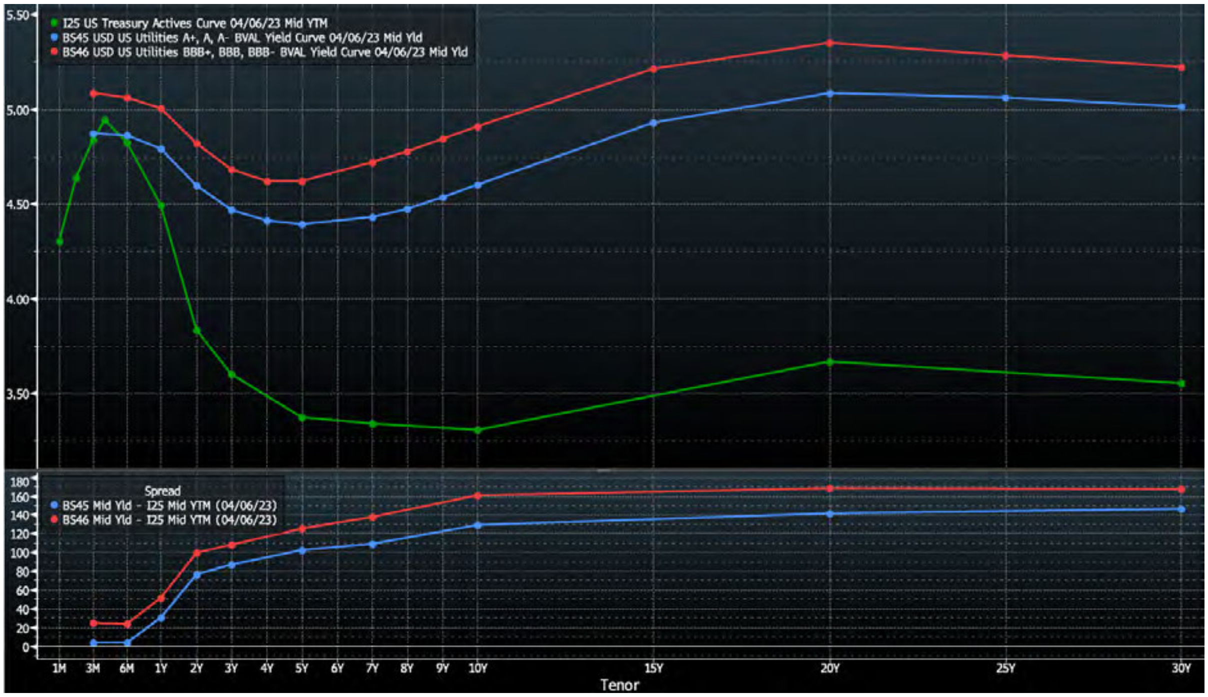
A. To forecast an expected coupon on a future debt issuance, Staff looks at the utility's credit rating, expected risk free rate, and calculates the current credit spread of similarly rated utility bonds over an appropriate risk-free rate.[60] This credit spread is applied to the forecasted risk-free rate to generate a reasonable coupon required by the market at the time of the debt issuance.

Q. Please explain how Staff calculates an appropriate forecasted risk-free rate and credit spread.

A. Staff utilizes a Bloomberg terminal to review forward curves of risk-free rates, at various tenors, and takes a 5-week average of these forecasted rates to provide a well-informed estimate of future rates that is reasonably assumed to be free from exogenous and endogenous shocks that might be captured if the forecasted rates were taken from a single data point. To calculate the current credit spread, Staff uses the Bloomberg terminal to review market indices of utility debt instruments with similar ratings and deducts the current active Treasuries yield. The indices and active Treasuries curves, as well as their spreads, are shown below in Figure 2:

[60] A credit spread is simply the premium required by investors to invest in a given debt instrument instead of in a risk-free alternative, such as a US Treasury instrument.

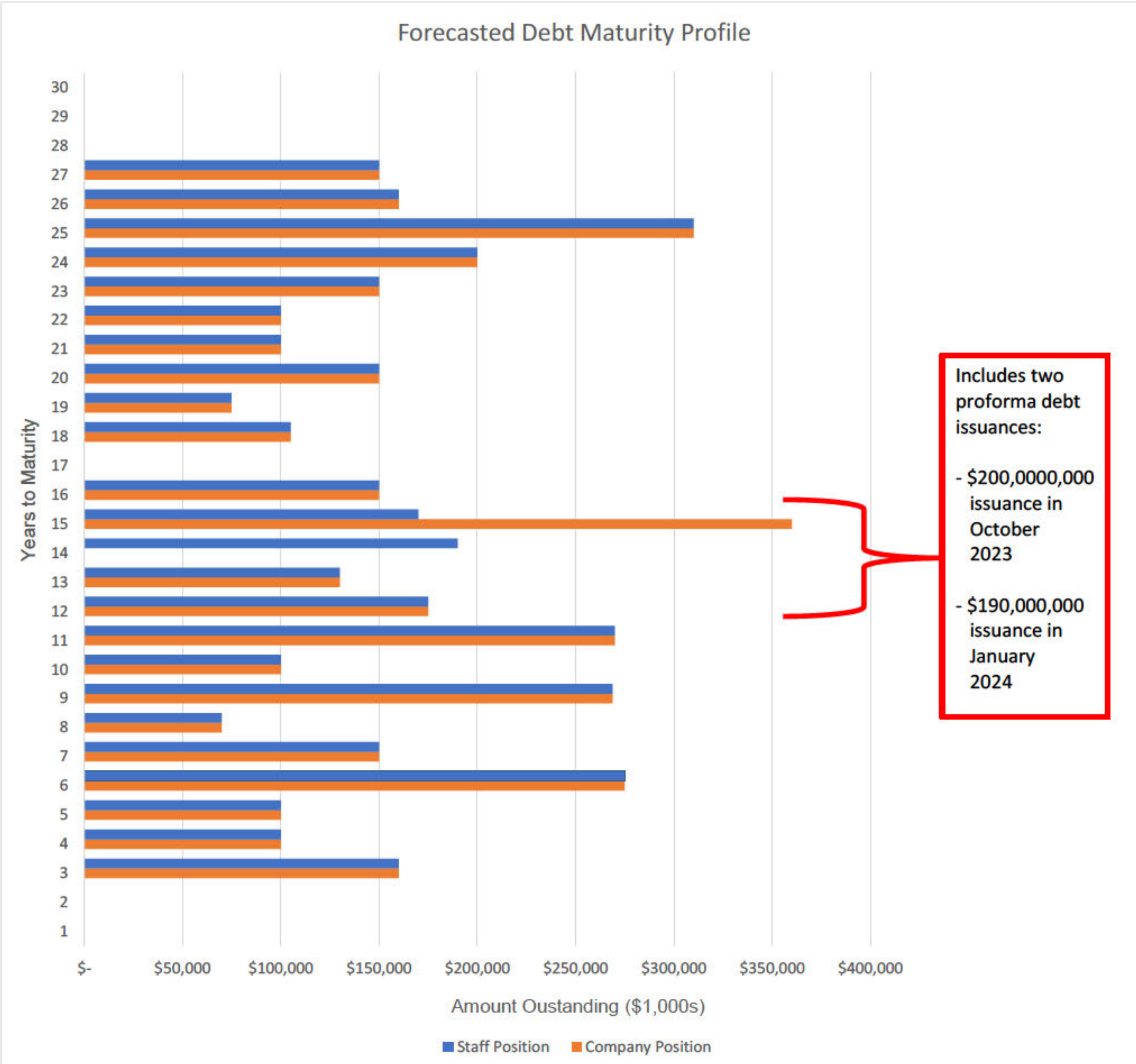
FIGURE 2. UTILITY AND TREASURY CURVES



Q. Did Staff perform other analysis on the forecasted issuances?

A. Yes. Staff also reviewed the outstanding debt profile of the Company and reviewed the forecasted issuances for their fit in the profile. Staff has reviewed the outstanding debt and forecasted issuances and recommends that the Company consider a 14-year maturity for the 2024 forecasted debt issuance, as shown in Table 1.

TABLE 1. PGE DEBT MATURITY PROFILE



Q. Please summarize Staff's recommendation on the Cost of Long-Term Debt.

A. Staff recommends an overall Cost of LT Debt of 4.293%, comprised of a Cost of LT Debt of 4.233% for outstanding LT Debt, and 4.815% for forecasted issuances. This represents a decrease in the Cost of LT Debt of 0.024%, or 24 basis points, from the Company's proposed Cost of LT Debt of 4.317%.[61]

Q. Does this conclude your testimony?

A. Yes.

[61] See PGE/1000, Liddle – Villadsen/20. Also, see Staff/1805, workpaper for cost of long-term debt—available in electronic spreadsheet form only—for the Table 1 and Figure 2. This workpaper incorporates PGE's Confidential Attachment in response to Staff DR 359.

CASE: UE 416
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Rose T. Pileggi

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Costs Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: In 2013, I received a Bachelor of Science in Business Administration from Thomas Edison State University. In 2017, I received a Master of Science in Finance from the University of Portland.

EXPERIENCE: I have been employed by the Commission since July of 2022 analyzing finance, power cost, rate case and affiliated interest dockets.

From July 2021 through June 2022, I worked as an Analyst for the Oregon Judicial Department. Duties included data analysis, ensuring compliance with pertinent statutes and rules to ensure that data was being handled in accordance with requirements and recommending process improvements.

From 2017 to 2021, I worked as an Investment Analyst, Portfolio Manager, and Systems Manager for Northwest Capital Management. My work included analysis of the markets and investments, the management and rebalancing of portfolios, creating reports as required by the SEC, as well as managing software integrations for operational and reporting purposes.

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1802

Exhibits in Support
Of Opening Testimony

June 13, 2023

April 6, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 358
Dated March 23, 2023

Request:

For the DRs 584 through 593, 812 through 826, 908, and 962 through 968 issued by Staff under UE 394, please:

a. Provide the responses to these DRs; and
b. Please provide updates to the Company's responses in a) above where best available information has changed.

Response:

Attachment 358-A provides public responses and attachments to the data requests issued by Staff under UE 394 and within the scope of this data request.

Confidential Attachment 358-B provides confidential responses and attachments to the data requests issued by Staff under UE 394 and within the scope of this data request.

Please note that the responses to data requests that include updated, supplemental, and revised information include the word "UPDATED" in the name of the file.

Confidential Attachments 358-C provides supplemental information in response to OPUC Data Request Nos. 908 and 967, submitted in Docket No. UE 394

Confidential Attachments 358-D and 358-E provide supplemental information in response to OPUC Data Request Nos. 591, 822, and 966, submitted in Docket No. UE 394.

Attachments 358-B, 358-C, 358-D, and 358-E are protected information subject to Protective Order No. 23-039.

February 15, 2022

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 963
Dated February 1, 2022

Request:

With regard to the cost of the Faraday project. Please:

a. Provide the Company's most recent estimate of the total cost of the Faraday project in US dollars.
b. Provide a breakdown of the amount shown in response to section (a).
c. Indicate what amount in US dollars the Company is currently proposing to recover for the Faraday project.
d. Provide a breakdown of the amount shown in response to section (c).
e. Provide a narrative explanation of any difference between the values shown in response to sections (a) and (b).
f. Indicate the total amount that will be paid to the Company's original construction contractor in US dollars. If this amount is offset by liquidated damages or other amounts, please provide the total value, and a breakdown showing each value separately. If the total amount is not yet known, please provide the Company's most recent estimate.
g. Indicate the total amount that will be paid to the Company's new construction contractor in US dollars. If the total amount is not yet known, please provide the Company's most recent estimate.

Original Response in Docket No. UE 394:

a. PGE's most recent estimate for Faraday Repowering Project total construction cost is approximately $98.2 million. Including loadings and allocations, the total project cost as currently budgeted for year 2022 is approximately $124.4 million. The current budget is higher than the $119.4 million amount that PGE originally included in its initial filing of the 2022 general rate case due to increased Allowance for Funds Used During Construction (AFUDC) that reflect the expected in-service date delay.
b. The following is a breakdown of the estimated project cost:

- PGE Labor, Other Contracts and Materials (miscellaneous materials, Geotech surveys, trailer leases, janitorial cleaning, etc.) - $5.6 million
- Design/ Engineering - $5.5 million
- Owner Furnished Equipment/Materials - $13.1 million
- Construction Costs - $71.0 million
- Contingency - $3.0 million
- AFUDC and other allocations and loadings - $26.2 million

c. PGE is proposing to recover all prudently incurred costs associated with the Faraday Repowering Project. While the current estimate is approximately $124.4 million as provided in part a, this is subject to change in accordance with the construction contract executed with the new general contractor and the amendment of that contract which will be executed by the end of February 2022.
d. See PGE's response to part b.
e. Not-applicable.
f. See Attachment 963-A.
g. PGE and the new contractor are currently in active negotiations and expect to execute an amendment to the original contract by the end of February 2022 that will contain a target price for the contract, construction schedule, estimated online date, and other contractual terms. Because PGE is in active negotiations at this time, it will be inappropriate for PGE to create an estimate of the cost.

Attachment 963-A is highly confidential information subject to Modified Protective Order No. 21-237.

<u>Supplemental and Revised Response in Docket No. UE 416:</u>

a. PGE's most recent estimate for Faraday Repowering Project total construction cost is approximately $147.8 million. Of this total amount, $146.1 million represents construction costs and approximately $1.7 million is reflected as cost of removal within PGE's total accumulated depreciation. Additionally, PGE incurred project cost loadings of approximately $22.6 million and Allowance of Funds Used During Construction (AFUDC) of approximately $19.3 million.
b. See PGE's response to AWEC Data Request No. 056, Attachment 056-A.
c. PGE is proposing to recover all prudently incurred costs associated with the Faraday Repowering Project, provided in supplemental responses to parts a and b.
d. See supplemental response to part b.
e. Not-applicable.
f. PGE inadvertently misstated the amount paid to the general contractor in

the original response to the OPUC Data Request No. 963, Attachment 963-A, submitted in Docket No. UE 394. Additionally, PGE considered the original information submitted in Attachment 963-A as highly confidential in Docket No. UE 394. This information is no longer highly confidential but continues to be confidential subject to Protective Order No. 23-039. See PGE's response to AWEC Data Request No. 057 submitted in Docket No. UE 416, Confidential Attachment 057-A for the final amount paid to the original general contractor.

g. See PGE's response to AWEC Data Request No. 057, Confidential Attachment 057-A. Additionally, Confidential Attachment 358-E provides the construction contract with BVCI, including the contract price (see Section C) and costs associated with allowance for other works (Section D).

February 8, 2022

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 965
Dated February 1, 2022

Request:

With regard to the project schedule for the Company's agreement with its new construction contractor, please provide an updated project schedule, equivalent to that provided by PGE in the table in response to Staff DR 817, section (a), part (iii). In this response, please include:

a. All project milestones (i.e. not limited to those with liquidated damages).
b. The scheduled completion date.
c. The Company or contractors most recent estimated completion date.
d. Indicate whether the milestone has associated liquidated damages.
e. Indicate whether the milestone is a critical milestone.

Original Response in Docket No. UE 394:

Attachment 965-A provides PGE's response to this data request. Also, please see PGE's responses to OPUC Data Request Nos. 962 and 964.

Attachment 965-A is protected information subject to Protective Order No. 21-206.

Supplemental Response in Docket No. UE 416:

a. Confidential Attachment 358-E provides the current construction agreement with BVCI, including project schedule.
b. Faraday Units 7 and 8 were placed in service and deemed used and useful on January 31, 2023. The Faraday Resiliency and Repowering Project was substantially completed on March 31, 2023.
c. See part b.
d. See Attachment 965-A.
e. See Attachment 965-A.

Attachment 358-E is protected information subject to Protective Order No. 23-039.

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1803

CONFIDENTIAL

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1804

Highly Confidential Exhibits in Support Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1805

Exhibits in Support
Of Opening Testimony

June 13, 2023

Staff's CONF Workpaper UE 416 Cost of Long-Term Debt is available in electronic spreadsheet format only.

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1806

Confidential Exhibits in Support Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1807

CONFIDENTIAL

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1808

CONFIDENTIAL

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Opening Testimony

June 13, 2023

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

A. My name is Eric Shierman. I am a Senior Utility Analyst employed 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. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1901.

Q. What is the purpose of your testimony?

A. My opening testimony discusses issues associated with transportation electrification (TE) covering PGE's fleet electrification, line extension allowances of TE-related customers, and expenditures in support of transportation electrification.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/1902 – Select PGE Discovery Responses..................... 91 pgs
Exhibit Staff/1903 – PGE's Fleet Benefit/Cost Analysis. .... 18 pgs
Exhibit Staff/1904 – PGE's EV-Related Capital Expenditures .... 1 pg
Exhibit Staff/1905 – Fleet EV Comparison... 9 pgs
Exhibit Staff/1906 – UE 394 Line Extension Allowances .... 27 pgs
Exhibit Staff/1907 – New Line Extension Allowances .... 19 pgs
Exhibit Staff/1908 – UE 395 TE-Related Capital Expenditures.............. 1 pg
Exhibit Staff/1909 – PGE-owned Charging Infrastructure.................... 3 pgs

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF RECOMMENDATIONS

Q. Please summarize the recommendations included in your opening testimony.

A. Staff recommends the Commission:

1. Permanently remove $6.9 million from the rate base for imprudent capital expenditures on charging infrastructure for PGE's fleet that were excluded from rates in UE 394.
2. Permanently remove $2.4 million for imprudent capital expenditures on electric vehicles for PGE's fleet.
3. Permanently remove $9.8 million for imprudent capital expenditures on charging infrastructure for PGE's fleet since the last rate case.
4. Permanently remove $212 thousand from the rate base for imprudent line extension allowances that were excluded from rates in UE 394.
5. Permanently remove $743 thousand for imprudent line extension allowances incurred since the last rate case.
6. Permanently remove $400 thousand from the rate base for above-budget capital expenditures on TE programs that were excluded from rates in UE 394.
7. Permanently remove $1.6 million from the rate base for imprudent capital expenditures on Electric Island that were excluded from rates in UE 394.
8. Permanently remove $125 thousand from the rate base from imprudent capital expenditures on a TE-dedicated database integration.
9. Approve an O&M budget for TE-related operating expenses of $2.2.
10. Remove $1.7 million from the rate base for decommissioned charging infrastructure.

ISSUE 1. UE 394 FLEET ELECTRIFICATION

Q. What is fleet electrification?

A. Fleet electrification is when PGE procures an electric vehicle (EV) for the Company's fleet of motor vehicles and fleet charging infrastructure to refuel Company-owned EVs.

Q. Has the Commission authorized PGE's fleet electrification?

A. No. However, the Company has tried to recover some expenses for fleet electrification in UE 394.

Q. What capital expenditures on fleet electrification did PGE seek to recover in UE 394?

A. PGE sought to recover **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the price of purchasing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** EVs and approximately $6.9 million in capital expenditures for construction of fleet charging infrastructure.

Q. What was Staff's recommendation in UE 394?

A. Staff recommended the Commission permanently remove $6.9 million in capital expenditures on new fleet charging sites from the rate base.

Q. How was this issue ultimately resolved in UE 394?

A. A black-box settlement reduced PGE's proposed revenue requirement by an amount greater than $6.9 million in capital expenditures. Based on the filing in this rate case, it is clear that PGE is treating the black-box adjustment as a one-time event as no permanent rate base adjustment is reflected on PGE's regulatory books.

Q. Does utility investment in fleet electrification without prior Commission approval mean the Commission should automatically deny recovery of these costs?

A. No. PGE purchases vehicles for its fleet on an ongoing basis. Staff's analysis in UE 394 and in this proceeding has looked at whether fleet electrification has been an investment a reasonable person would make. Staff looked for what the Company knew and reasonably should have known at the time these investments were made.

Q. How did Staff evaluate the net benefit of electrifying the Company's fleet?

A. Staff asked PGE to share all research in the Company's possession on EV total cost of ownership (TCO) and all planning workpapers for the procurement of EVs for PGE's fleet.[1] Of the documents PGE shared, two included net assessments of the electrification of the Company's fleet. **[BEGIN CONFIDENTIAL]** [redacted]

---

1 See Docket No. UE 394, OPUC Staff, Staff/1706, October 25, 2021, Shierman/111. See Docket No. UE 394, OPUC Staff, Staff/1705, October 25, 2021, Shierman E32 in the sheet titled "TCO".

2 Staff/1902, Shierman/02 (PGE response to OPUC DR 263).

[redacted] **[END CONFIDENTIAL]**

Q. Are any of PGE's EV purchases expected to give ratepayers net long-term savings?

A. No. The EV models PGE procured for UE 394 could roughly breakeven were the Company to only use existing workplace chargers for refueling, but the construction of dedicated fleet charging ports has led to a net loss. Staff performed a total cost of ownership (TCO) analysis on the EVs PGE purchased in comparison to their equivalent internal combustion engine (ICE) vehicle. Of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** EV purchases, 20 show a slightly favorable TCO if the costs of PGE's fleet charging sites are excluded.

Q. How does UE 394 impact this proceeding?

A. PGE has included the test year 2024 book value of this plant in the amount which remains approximately $6.9 million into the rate base as if this asset had been approved by the Commission in the last rate case. Since PGE

---

[3] Staff/1902, Shierman/15 (PGE response to OPUC DR 263).

[4] Staff/1903, Shierman/S4 in the sheet titled "Assump" (PGE response to OPUC DR 236).

continues to include, in the Company's rate base, amounts that Staff continues to dispute, and the matter was not permanently resolved in UE 394 due to the use of a black-box approach, the Staff analysis conducted in UE 394 must be repeated for this docket since we are dealing with a plant/rate base issue. To do otherwise would mean that capital expenditures Staff found to be imprudent would nevertheless be included in the rate base and the costs for the non-prudent investment would be included in rates charged to customers.

Q. What type of adjustment does Staff recommend for this issue?

A. Staff recommends the Commission make a permanent rate base adjustment and such investments would be removed from the rate base, rather than simply removed for earnings test purposes. The amount of the permanent rate base adjustment is $6.9 million.

ISSUE 2. NEW FLEET ELECTRIFICATION

Q. What new fleet electrification costs does PGE seek to recover in this proceeding?

A. PGE seeks recovery of approximately $12.5 million in capital costs from the procurement of 133 EVs, including internal combustion engine vehicles with electrified Altec Job Energy Management System (JEMS).[5]

PGE seeks recovery of $9.8 million in capital costs from the construction of fleet charging infrastructure.[6] And the Company seeks approximately $1 million in O&M for the expense of maintaining fleet charging infrastructure.[7]

Q. How much would PGE need to recover if the Company were to instead purchase the equivalent vehicles with an internal combustion engine rather than EVs?

A. Approximately $6 million. The capital cost from equivalent vehicles with combustion engines is roughly half what PGE spent, and PGE would not require the added $12.5 million in capital expenditures on fleet charging infrastructure or an annual expense of $1 million maintaining fleet charging infrastructure.[8]

Q. Does Staff recommend the removal of the entire cost premium of EVs from PGE's rate base?

---

5 Staff/1905, Shierman F135 in the sheet titled "EV".

6 Staff/1904, Shierman F33 in the sheet titled "TE Charging Plant Adds UE 416".

7 See Docket No. UE 416, PGE, Response to OPUC DR 751, May 23, 2023, p 1.

8 Staff/1905, Shierman H135 in the sheet titled "EV".

A. No. Staff's analysis in Exhibit 1905 identifies the net cost premium by crediting PGE's rate base with the EVs' fuel savings, maintenance savings, federal subsidies, state subsidies, and Oregon Clean Fuels Program credit revenue. Staff considers the net number to be the more appropriate cost premium figure, representing the remaining excessive cost these vehicles impose on ratepayers after consideration of the total cost of ownership of the internal combustion alternatives.

Q. What is the net cost premium from just comparing the TCO of EVs with their ICE alternatives before considering the added cost of fleet charging infrastructure?

A. The EVs PGE has purchased since the last rate case or is currently purchasing cost approximately $2.4 million more than their ICE alternatives after taking the O&M savings of the EVs into account.[9]

Q. What adjustment does Staff recommend?

A. Staff recommends that $2.4 million be permanently removed from the rate base from the imprudent net EV premium associated with the purchase of EVs, $9.8 million be permanently removed from the rate base for the imprudent construction of fleet charging infrastructure, and that $1 million in operating expenses associated with maintaining the fleet charging infrastructure be removed from the O&M budget.

---

[9] Staff/1605, Shierman O115 in the sheet titled "EV Comparison".

ISSUE 3. UE 394 LINE EXTENSION ALLOWANCES

Q. What is a line extension allowance?

A. When a customer requests service, the Company may be required to add facilities to reach the customer's location.[10] Each utility is authorized to provide customers a line extension allowance that covers a portion of the costs associated with the extension. Costs for new connections that are equal to or less than the line extension allowance are treated as the utility's costs and recovered through general rates. If the line extension allowance does not cover all the costs incurred to add facilities to the customer's location, the remaining portion of the cost is paid for by the customer seeking to connect.

Q. What costs for customer line extensions on TE projects did PGE seek to recover in UE 394?

A. Approximately $605 thousand in capital expenditures.

Q. Were all these expenditures reasonable?

A. No. Staff engaged in analysis and concluded that PGE used unreasonably high load forecasts for some projects in determining the line extension allowance.

Q. What was Staff's recommendation on line extension allowances for TE projects in UE 394?

---

[10] OAR 860-021-0045(1).

A. Staff recommended the Commission permanently remove approximately $212 thousand in capital expenditures on line extension allowances from the rate base.

Q. How did UE 394 resolve this issue?

A. The revenue requirement from the $212 thousand in excess capital expenditures Staff found in reviewing PGE's site load forecasts was excluded from rates.

Q. How has the decision in UE 394 impacted this proceeding?

A. PGE has included these capital expenditures into the rate base as if the full value of these assets had been approved by the Commission in the last rate case.

Q. What adjustment does Staff recommend in this proceeding?

A. Permanently remove $212 thousand from the rate base.

ISSUE 4. NEW LINE EXTENSION ALLOWANCES

Q. What line extension allowance costs from nonresidential TE-related projects does PGE seek to recover in this proceeding?

A. Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[11]

Q. Has PGE's method of forecasting the site load forecasts for line extension allowances changed since the last rate case?

A. Yes. In 2022, PGE performed an empirical review of the Company's assumed demand factors (DF) and made changes to site load forecast assumptions.

Q. What is a DF?

A. A DF is the percentage of maximum potential load (kWh) the customer is expected to use during a certain time.

Q. What DF did PGE find to be appropriate for EV charging sites?

A. 4 percent.[12]

Q. Does Staff find that assumption reasonable?

A. Yes.

Q. How did Staff review PGE's site load forecasts in this proceeding?

A. Staff used PGE's 4 percent.

Q. Did PGE consistently use a 4 percent DF?

A. No.

---

[11] Staff Exhibit 1907, Shierman E20 in the sheet titled "Summary".

[12] Staff Exhibit 1902, Shierman 90-91 (PGE's response to OPUC DR 349).

Q. Where can Staff's review of PGE's site load forecasts be found?

A. Staff Exhibit 1907.

Q. If PGE consistently used a DF of 4 percent, what would the total line extension allowances for nonresidential EV charging sites be?

A. Approximately $261 thousand.

Q. What does Staff recommend?

A. Staff recommends the Commission remove the excess capital expenditures beyond the prudent amount of $261 by permanently removing $743 thousand from the rate base.

ISSUE 5. UE 394 ORDER NO. 19-385 BUDGET VIOLATIONS

Q. What budget did Order No. 19-385 set?

A. Order No. 19-385 established a budget for three TE pilot programs: Outreach and Technical Assistance, TriMet Pilot, and the Electric Avenue Network.[13] The Commission approved a stipulation that set maximum capital expenditures for each program. PGE exceeded the maximum expenditure permitted in Order No. 19-395.

Q. What capital costs did PGE seek to recover in UE 394 for these programs?

A. Approximately $3.4 million.

Q. What was the maximum capital expenditure authorized by Order No. 19-385?

A. Approximately $3 million.

Q. What was Staff's recommendation?

A. Staff recommended the Commission permanently remove the above-budget capital expenditures of $400 thousand from the rate base.

Q. What was the outcome of UE 394?

A. Capital expenditures on TE pilots was included in the "bundled issues" resolved in the $10 million dollar settlement for revenue requirement.

Q. How has the budget for TE pilot programs emerged in this proceeding?

[13] See Docket No. UM 1811, OPUC, Order No. 19-385, November 7, 2019, Appendix A, p 4.

A. PGE has included the full amount of capital expenditures into the rate base as though the full value of these assets had been approved by the Commission in the last rate case.

Q. What adjustment does Staff recommend?

A. Permanently remove $400 thousand from the rate base.

ISSUE 6. UE 394 ELECTRIC ISLAND

Q. What is Electric Island?

A. Electric Island is a joint project between PGE and an EV manufacturer to build a public charging station that can refuel heavy-duty EVs at a charging capacity of more than 1 MW.

Q. Was PGE's capital expenditure on Electric Island authorized under Schedule 53, PGE's Nonresidential Heavy-Duty Electric Vehicle Charging Program?

A No. PGE executed a contract with this manufacturer on September 15, 2020, committing the Company to make these expenditures before the Commission approved Schedule 53 nine months later. Tariffs cannot apply retroactively to a subsidy the utility already made.[14] Therefore, Schedule 53 does not apply to the expenditures PGE made on Electric Island prior to the approval of Schedule 53. Staff recommended the Commission approve Schedule 53 at the June 15, 2021, Public Meeting because the program offers needed support to the heavy-duty charging sites that might follow the Electric Island project. The construction of an established manufacturer's product demonstration site is qualitatively different from any expected future projects ratepayers may help fund through Schedule 53.

Q. How has Staff expected future heavy-duty charging projects to be different than the construction of Electric Island?

[14] ORS 757.210.

A. The manufacturer made the decision to enter the heavy-duty EV market and develop charging at MW speeds before receiving subsidies from PGE.[15] In contrast, the expensive infrastructure needed to fuel heavy-duty EVs is expected to remain a significant barrier to fleet customers building charging stations with 1 MW or more of demand capacity, particularly small and medium sized fleets.[16] Schedule 53 is available to fleet operators that may otherwise choose not to electrify their fleets without such subsidies from PGE. Schedule 53 is also available to other truck manufacturers that might not otherwise choose to site a charging facility in PGE's service territory.[17] Staff recommended the Commission approve Schedule 53 with the expectation that future heavy-duty projects will have less free ridership than subsidizing an established multinational corporation to build a site it already needed to build for the development and marketing of heavy-duty EVs.

Q. What are the prudence implications of providing services without a tariff?

A. It is inherently imprudent. A main tenant of the utility regulatory process in Oregon is that utilities are subject to rate regulation and required to file tariffs and schedules for all services they provide with the Commission.[18] This tenant is a statutory requirement in ORS 757.205(1). The reason that

[15] Rogoway, Mike. *Daimler will convert Portland factory to make electric trucks* The Oregonian, April 24, 2019, p 1.
[16] NREL. *R&D Insights for Extreme Fast Charging of Medium and Heavy-Duty Vehicles* March 2020, p 10.
[17] See Docket No. ADV 1239, PGE, Supplemental Filing, March 4, 2021, Sheet No. 53-1.
[18] See Northwest Climate Conditioning Ass'n v. Lobdell, 79 Or. App. 560 (1986) at p. 565.

the legislature required tariffs to be on file is so all activities by the utility are open to public inspection. This transparency seeks to prohibit public utilities from entering into discriminatory deals and preferential treatment for one customer over another.[19]

PGE did not file a tariff for its investment in Electric Island prior to making capital expenditures that the Company then sought recovery for in UE 394. In a regulated market, it is not prudent for a utility to provide a subsidy, with the intention to recover that investment from ratepayers if that investment does not comply with the applicable rules and laws that the utility must abide by. Therefore, this investment would not be prudent even if the investment benefitted ratepayers.

Q. Beyond the inherent imprudence of providing subsidies without a tariff, how prudent was PGE's capital expenditure on Electric Island from an investment perspective?

A. Staff has found that PGE's subsidy of the construction of Electric Island was not a prudent investment. Staff's prudency analysis on the merit of the investment in UE 394 looked at whether this was an investment a reasonable person would make. A reasonable person would not provide such a large incentive to meet objectives that are expected to occur without the subsidy, especially since this capital expenditure provided no incremental benefit to ratepayers.

Q. Were any of the expenditures PGE made on Electric Island prudent?

[19] See Docket No. ADV 1239, OPUC Staff, Staff Report, March 1, 2021, p 4-7.

A. Yes. PGE provided technical assistance to this project, a previously approved TE activity under the Company's Outreach and Technical Assistance Pilot.[20]

Q. What did Staff recommend in UE 394?

A. Staff recommended the Commission allow PGE to recover, through the Company's UM 1938 deferral, the full **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in operating expenses the Company incurred in 2020 for providing technical assistance to the Electric Island project.[21] The incremental benefits to ratepayers from this project stem from that expenditure. Staff also recommended the approximately $1.6 million in capital expenditures be permanently removed from the rate base because those capital expenditures funded an investment that would be reasonably expected to occur without the ratepayer-funded subsidy.

Q. How has this issue from the prior rate case had an impact on this proceeding?

A. PGE has included its Electric Island investment into the rate base as if this asset had been approved by the Commission in the last rate case.

Q. What adjustment does Staff recommend?

A. Staff recommends that this investment's current value of $1.3 million be permanently removed from the rate base.

---

20 See Docket No. UM 1811, OPUC, Order No. 19-385, November 7, 2019, p 11.

21 See Docket No. UE 394, PGE, response to OPUC DR 419, August 25, 2021, Attachment A, cell C3.

ISSUE 7. TE DATABASE

Q. What is the TE Database?

A. PGE describes this capital investment as the integration of program information, charger maintenance, and usage information into the Company's corporate database.[22]

Q. Has PGE demonstrated this was a reasonable investment?

A. No. PGE was unable to provide workpapers showing this investment will benefit ratepayers.[23] Any need or justification for a capital expenditure to avoid using separate databases for some TE data has never been approved by the Commission or communicated to Staff before the nature of this investment was uncovered through discovery in this proceeding. PGE claims this integration will save labor in TE reporting. However, it takes labor to query data from the Company's corporate data base as well. PGE has not provided evidence that the difference in labor cost is greater than the cost of the capital expenditure.

Q. What does Staff recommend?

A. Staff recommends that $125 thousand be permanently removed from the rate base for insufficient evidence it was prudently incurred.

[22] See Docket No. UE 394, PGE, Response to OPUC DR 579, May 1, 2023, p 1.
[23] See Docket No. UE 394, PGE, Response to OPUC DR 810, June 5, 2023, p 1.

ISSUE 8. TE OPERATING EXPENSES

Q. What operating expenses is PGE seeking to recover in base rates?

A. $5.4 million.

Q. Is this consistent with what the Commission has approved?

A. No. The Commission has only approved approximately $740 thousand of operating expenses for base rate recovery of TE-related O&M in ADV 1239 and ADV 1261.

Q. Does Staff recommend the rest be disallowed?

A. No. Staff supports a greater use of base rates to collect TE-related operating costs. Four years ago, TE O&M was entirely recovered through deferrals. Now that PGE's TE planning and the surrounding TE market have become more mature, base rates have become a more appropriate funding source of TE operating expenses.

Q. What does Staff recommend?

A. Staff recommends the Commission align PGE's TE operating expenses in base rates with PGE's new TE Budget. On June 1, 2023, the Company filed a new draft TE Plan which contains a three-year of $94 million.[24] At a public workshop last year, PGE presented a three-year budget more than three times what PGE has ultimately proposed in UM 2033.[25] PGE's O&M budget for TE in this proceeding appears more designed for the larger expenditures the Company was contemplating last year than what PGE has more recently

24 See Docket No. UM 2033, PGE, Draft TE Plan, June 1, 2023, pp 143-154.
25 PGE. *Draft 2023-2025 Transportation Electrification Roadmap* June 14, 2022, slide 15.

filed. Therefore, Staff recommends the Commission approve a budget for TE O&M in base rates of $2.2 million. Staff's recommended TE O&M budget includes test year deferrals in UM 1938 and UM 2003. Staff also recommends the Commission discontinue the approval of TE deferrals in UM 1938 and UM 2003 for operating expenses that occur after this proceeding's rates go into effect. Staff will bring more detailed budget numbers from PGE's UM 2033 filing into the UE 416 record.

ISSUE 9. STRANDED CHARGING INFRASTRUCTURE

Q. What is the current book value of EV charging infrastructure in PGE's rate base?

A. The current book value of PGE-owned charging infrastructure in the Company's rate base is approximately $20 million.[26]

Q. Have any of these assets been decommissioned?

A. Yes. PGE has decommissioned seven of the ten public charging stations the Company procured from the former EV charging firm ECOtality.[27] PGE has decommissioned private charging infrastructure at the Tualatin Contact Center and the Salem Smart Power Center.[28]

Q. Are these decommissioned assets still included in PGE's rate base?

A. Yes.[29] These assets are found within the current value of UE 335 projects P36276 and P36462.

Q. What is Staff's estimate of the current asset value of these decommissioned capital assets that remain in the rate base?

A. Approximately $1.7 million.[30] Staff applied a reduction in the amount of 70 percent for the public chargers and 33 percent for the private chargers.

Q. What is Staff's recommendation?

---

26 Staff/1909, Shierman D40 in the sheet titled "DR 272 Attach A".
27 Staff/1909, Shierman C135:C141 in the sheet titled "DR 272 Attach C".
28 Staff/1909, Shierman C80:C81 and C89 in the sheet titled "DR 272 Attach C".
29 Staff/1909, Shierman D37 and D39 in the sheet titled "DR 272 Attach C".
30 Staff/1909, Shierman D46.

A. The Commission should permanently remove $1.7 million from the rate base. PGE can record this amount as a regulatory asset and earn the time value of money on any undepreciated balance in this account.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1901

Witness Qualifications Statement

June 13, 2023

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 first as a Utility Analyst and as a Senior Utility Analyst since November 2020. I was previously employed by McCullough Research as a Research Associate for two years.

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1902

Exhibits in Support
Of Opening Testimony

June 13, 2023

Page 1 to Page 85 of this exhibit are confidential

March 27, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 264
Dated March 13, 2023

Request:

Regarding the procurement of vehicles for PGE's fleet that the Company is seeking recovery, please share the:

a. make,
b. model,
c. year,
d. date of purchase,
e. odometer reading at purchase,
f. purchase price of vehicle, and
g. for any electric vehicle please also provide the comparable internal combustion vehicle and the expected price of the comparable internal combustion vehicle.

Response:

PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Notwithstanding this request, PGE responds as follows:

In this rate case, PGE is seeking recovery of approximately $35.0 million in capital costs associated with the procurement of vehicles for our fleet. These costs are specifically tied to the two following projects:

- P36394 – Vintage Vehicle Replacement
  - 2022: $915,000
  - 2023: $18,777,608
- P36412 – Incremental Added Vehicles
  - 2022: $1,596,461
  - 2023: $13,641,776

Confidential Attachments 264-A and 264-B provide the Project Justification Forms for the above projects.

Attachment 264-C provides the requested information for vehicles added to, or ordered for, PGE's fleet from May 2022 and to March 2023. The $35.0 million referenced above consists of vehicles that PGE expects to pay for upon delivery between May 2022 and December 2023, some of which may have been ordered several years prior.

Please note that any information not shown in Attachment 264-C is because the vehicle has been ordered but not yet received, is an older vehicle that was not tracked at the time, or because PGE does not have data on all comparable internal combustion vehicles because electric vehicle offerings (and costs) are not always directly comparable to internal combustion vehicles.

Attachments 264-A and 264-B contain protected information and are subject to General Protective Order No. 23-039.

September 28, 2021

To: Eric Shierman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE *First Supplemental* Response to OPUC Data Request 738
Dated September 14, 2021

Request:

Referencing Attachment A of PGE's response to DR 427, please share the analysis that derived each site's combined factor, and please explain why:

a) M2206760, M2493753, M2514850, M2540673, M2575320, M2592820, M2684298, M2732401, M2733476, M2733478, M2768915, M2886696, M2894003, M2932283, M2957731, and M3001633 have combined factors of 1.
b) M2287965, M2638861, M2865157, M2924449, and M2974826 have combined factors of 0.49.
c) M2330041 has a combined factor of 0.1.
d) M2769397 has a combined factor of 0.5.
e) M2875615 has a combined factor of 0.38.

Original Response in Docket No. UE 394:

PGE used Demand Factors and Combined Factors as shown in the Table 1 below to determine/calculate the estimated annual kWh.
When determining the Adjusted kWh per year we use a combination of Load Summary (Connected load and Demand Factor), Combined Factor and/or Hours/Year of Usage.

Hours per year of usage can either be determined upfront (ex: 1.25 hours per day, 365 days/year = 455 hours per year) or the entire year is entered and then adjusted based on the Demand Factor and/or Combined factor calculations.

The Combined Factor is used based on types of services/businesses to determine estimated operating hours.

Table 1

Load Summary			
Load Type	Connect kw	Demand factors*	Estimated demand
Cooking	0	0.30	0
Lighting	0	0.90	0
Receptacles	0	0.10	0
Water heating	0	0.20	0
Electric heat	0	0.75	0
Air conditioning	0	0.75	0
Refrigeration	0	0.75	0
Motors	0	0.50	0
Computers	0	0.67	0
Welders	0	0.10	0
Elevators	0	0.10	0
Irrigation	0	0.75	0
Miscellaneous	0	0.50	0
Total est connected	0		

Combined Factor	
Public assembly	0.50
Offices	0.52
Food Stores	0.59
Hospitals & health care	0.62
Hotels & Motels	0.61
K-12 Schools	0.38
Medical offices	0.53
Misc commercial	0.49
Restaurants	0.57
Retail stores	0.55
Warehouses	0.56
Hobby Shop	0.10
Home Based Business	0.37

* If none of the above are appropriate, use a reasonable factor based on known operating hours. (Examples: large primary customer, irrigation, lighting, etc.)

PGE is in the process of evaluating our Demand Factors and Combined Factors to determine if adjustments might be needed for any of these values in these tables.

Supplemental Response in Docket No. UE 416:

Prior to 2022, the quantity of dedicated charging stations on the PGE network was fairly small and PGE had not performed the research and analysis to determine a specific combined factor values for vehicle charging stations. As a result of this, the design project managers performing the allowance calculations utilized combined factors at their discretion, without actual load data upon which to base the values. A combined factor of 1.0 was used in many of the work orders referenced, which was a very conservative approach. The value of 0.49 that was utilized in some of the work orders was the default "Other" value that was often utilized if no data was available.

In calendar year 2022, PGE performed a detailed analysis of customer energy utilization and revised the combined factors for all commercial customer groupings. Actual annual Peak KW and annual kWh from 2019 (pre-COVID) for 30,000 commercial customers was utilized to calculate actual Combined Factor values. The revised combined factors were implemented for new customer load requests commencing in the summer of 2022. Confidential attachment UE 416_OPUC DR 349_Supp 1 Response to UE 394 DR 738-A provides the current table of combined factors. Confidential Attachment UE 416_OPUC DR 349_Supp 1 Response to UE 394 DR 738-B provides the data utilized in this analysis for the EV Charging Stations. New customer load requests where allowances were calculated and provided to customers prior to implementation of these new combined factors were not revised.

This analysis resulted in the adoption of a combined factor of 0.04 for electrical vehicle charging installations, based on 8,760 hours per year of operation. The results show a wide variation in actual factors by individual customers. Some of the larger dedicated manufacturer installations can have higher values and the Design Project Managers can utilize actual load data provided by the customer for similar installations.

Attachments UE 416_OPUC DR 349_Supp 1 Response to UE 394 DR 738-A and B are protected information subject to Protective Order No. 23-039.

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1903

Is Confidential And Filed in Electronic Format

Exhibits in Support Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1904

Is Filed in
Electronic
Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1905

Is Confidential
And Filed in Electronic Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1906

Is Confidential
And Filed in Electronic Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1907

Is Confidential And Filed in Electronic Format

Exhibits in Support Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1908

Is Filed in
Electronic
Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: Eric Shierman

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1909

Is Filed in
Electronic
Format

Exhibits in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

Opening Testimony
Load Forecast,
Routine Vegetation Management
Marginal Cost Study, Rate Spread, and
Rate Design

June 13, 2023

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates, Safety, and Utility Performance Program 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/2001.

Q. What is the purpose of your testimony?

A. I discuss and review several issues in Portland General Electric's (PGE) general rate case. This includes PGE's test-year load forecast, budget and accounting for routine vegetation management, marginal cost study and rate spread, and rate design.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/2002, consisting of six pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LOAD FORECAST

Q. How Does PGE's 2024 load forecast compare to the previous general rate case, UE 394?

A. On a total Company basis, the 2024 load forecast is expected to increase by 8.89 percent compared to 2021 using weather normalized loads. This is an increase of 1,803 GWh from 20,281 GWh to 22,084 GWh. For further comparison, the weather normalized load for 2022 at 20,772 GWh. By far the largest forecasted increase by segment was industrial load, which is responsible nearly the entirety of the increase. The industrial load forecast increased by 33.8 percent or 1,799 GWh. This growth in the industrial load is largely related to the expansion of tech companies and data centers. The residential load is expected to increase by 32 GWh or 0.4 percent, while the Commercial segment is expected to decrease by 29 GWh or 0.4 percent.

Q. Please describe the Company's general approach to load forecasting.

A. PGE utilizes a generally accepted standard for forecasting each customer class separately, which are further broken out by dwelling type for residential customers. Residential forecasts are the product of a separate use-per-customer forecast and customer count forecast, while the commercial and small industrial customer load is estimated at a schedule-wide level. Large industrial customer forecasts are based on information gathered from individual customers regarding their expected load in the coming years.

PGE utilizes Autoregressive Integrated Moving Average (ARIMA) models for its residential customer and demand forecasts. ARIMA models are used by all Oregon-regulated utilities. ARIMA models work well for forecasting electricity demand because of their ability to model data with trends. This is because the model can be made to handle non-stationarity through differencing if necessary.

Non-stationarity can be a number of things, but in general it means that the predicted variable does not have constant statistical properties over time. For example, in variables that increase over time such as population, the average value would not remain constant. Regression models attempt to identify constant relationships between variables in order to predict future values; if the relationship of two variables does not remain constant because of a trend, then the result of the regression could be spurious.

Q. What inputs go into the ARIMA model?

A. There are three main choices a modeler must make when estimating an ARIMA model: how many autoregressive lags to include, how many times they difference the data, how many lags of the error term to include. Typically, the different combinations of these choices are compared using model selection criteria such as the Akaike Information Criterion (AIC) and Bayesian Information Criterion (BIC). These metrics help decide how to balance the benefit of additional predictors with the parsimony of the model.

Q. Please describe autoregressive lags in the ARIMA model?

A. First, the modeler must choose the number of autoregressive lags to include in the regression. This accounts for the "AR" portion of ARIMA term. An autoregressive lag assumes that each subsequent observation of the dependent variable is, at least partially, based on the previous observation(s). The simplest analogy of this involves a "stock" variable. For example, if you were to predict the number of residents of a city at the end of each year, it would be fair to characterize the population in any given period as the population in the previous year plus or minus any changes in the current year.

The modeler could then find covariates that effect population such as city-wide macroeconomic conditions and building permits to forecast the following year's population, using the previous year's population as a starting point. The modeler can choose to include multiple lags if they think that periods beyond the most recent have an effect on the current observation as well. In PGE's models, they typically choose to use either one or no autoregressive lag.

Q. Please describe data differencing in the ARIMA model?

A. The modeler must decide how many times, if it all, to difference the data. The "I" in the ARIMA model stands for integration and represents the number of times the data was differenced. Differencing time-series data involves simply subtracting the observation(s) preceding the current data point. Using the city population example, this would mean that the modeler subtracts the city population in the previous year from the city's present population – effectively finding the change in the population from one year to the next. If for example, two differences are used, the yearly change is found, then the change in the yearly changes is found and so on. In PGE's models, they typically choose to use no differences.

Q. Please describe error term lag in the ARIMA model?

A. The modeler must choose whether or not to incorporate a lag of the error term. This parameter accounts for the "MA" portion of the ARIMA term. This concept is slightly more complicated to understand. The error term is the difference between the fitted and actual observation for a dependent variable in any given period. For instance, if the population of Portland was 640,000 in 2021, but your model would have guessed that there were 630,000 people, the error would be 10,000. When including a lag of the error term, the modeler assumes that the error in the previous period(s) influences the realized value in the future. Effectively the modeler would be choosing to include the lagged error term(s) as an independent variable in a regression. In PGE's models, they typically choose to use no moving average term.

Q. Has the general approach to load forecasting changed since UE 394?

A. Yes, in UE 394 PGE estimated many more models in its load forecast. In addition to separating residential customers out by dwelling type, separate regressions were also estimated by heating type. Further, commercial and light industrial customers were separated by one of eighteen North America Industrial Classification System (NAICS) segments. The segmentation of these classes was initially done to allow for heterogeneity within schedules. That is, it was expected that customers in these different segments would respond differently to weather, seasonal trends, and grow at different rates over time.

Q. Why did PGE decide to reduce the number of models in its load forecast?

A. PGE states in its opening testimony that the changes were made as the performance of the models they had used in UE 394 deteriorated. Since each division of the data shrinks the number of customers that comprise the time-series, they are more subject to anomalies in the data. For the residential schedules PGE also recognized that its data on heating type is not reliable as it is rarely tracked. PGE also states that when breaking the data into many groups, regressors that according to basic economic theory, should influence load are being returned as not significant. This issue is not present using its more aggregated models.

Q. Do you generally agree with the logic behind these changes?

A. At this time, Staff does not take issue with these changes. PGE is correct to say that as sample sizes decrease, idiosyncratic shocks have an outsized effect on regression results. These seemingly random fluctuations increase the standard error of regression coefficients and make it difficult to link drivers to outcomes. In turn, this muddies model selection. Grouping non-residential customers by rate schedule is a relatively natural division as customers are divided into rate schedules based on their energy consumption patterns. It also seems reasonable to keep the dwelling-type division for residential customers as customers in different dwelling types have different consumption patterns and will likely grow at different rates. Further, because PGE now has a bifurcated basic charge, internal data about dwelling type is relatively accurate.

Q. Should PGE divide residential customers by any other categories?

A. Yes. At this time, the energy industry is dynamic both in production and consumption. If in the future it becomes clear that different groups consume energy in very different ways and are growing at different rates PGE should consider estimating a different model both for energy consumption and customer growth for this segment. An example of a division that PGE should consider is electric vehicle (EV) and non-EV owners. EV owners consume more energy and have a much different load profile than non-EV owners. Further, the relative share of EV owners in the service territory is projected to increase over time.

This distinction is particularly important if decoupling is not readopted. In the absence of decoupling, PGE will be able to increase its net income by increasing sales beyond what the load forecast predicts. As I discuss in Issue 4 of my testimony, Staff does not support PGE's current vision of decoupling. Staff finds it acceptable for PGE to increase net revenue on the basis of exceeding transportation electrification goals. However, Staff does not find it acceptable for PGE to increase net revenue simply due to poor load forecasts. To properly capture the anticipated trend in EV adoption, PGE must use both accurate historical and unbiased forecast data in order to properly calibrate their models.

Further, the recent market trends have spurred an increased electrification of heating. On top of this, recent extreme heat events have increased air conditioning penetration in the region. PGE claims that their data on heating fuel is inaccurate. Staff strongly recommends that PGE make an effort to improve its customer-level data on heating and cooling in order to better understand and account for these trends in their load forecasts. While Staff understands PGE not using inaccurate heating fuel information in their load forecasts in this rate case, Staff strongly encourages PGE to increase the accuracy of this data so that it can be used in the near future.

Q. How does PGE model the effects of COVID-19?

A. PGE models the effect of COVID-19 pandemic in a few ways. For models forecasting Single-Family (SF) Residential, Multi-Family (MF) Residential, Schedule 38, and Schedule 83 a COVID-19 lockdown indicator variable is estimated. This variable effectively estimates the average change in consumption for a class of customers during the COVID-19 lockdowns (April 2020-October 2020) holding all else constant. In some models, PGE assumes that the effects of the COVID-19 pandemic are persistent beyond the lockdowns. For example, in the SF and MF residential models, PGE includes an interaction term between a COVID-19 pandemic indicator variable and heating and cooling degree days. It is important to note that this indicator variable remains on in perpetuity. This effectively estimates the permanent change in how residential customers respond to temperature in response to the COVID-19 pandemic. This variable was added to the model to account for behavioral changes related to a larger proportion of customers working from home compared to pre-pandemic levels. Lastly, in their model forecasting Schedule 85 energy consumption, PGE includes an indicator variable only for

April of 2020. This assumes that the effect of the pandemic on these industries was short lived and only at the beginning of the pandemic.

Q. Does Staff agree with how PGE models for COVID-19?

A. At this time, Staff has no specific recommendations for how to model the COVID-19 pandemic. Staff sees the current method as a vast improvement over the method that was used in UE 394. UE 394 was filed in the middle of the pandemic. As such, it was difficult to tell what the eventual effects of the COVID-19 pandemic would be. Because of this, strong assumptions were imposed on the data. The current methods, while still somewhat restrictive, do more flexibly control for the effects of the COVID-19 pandemic. There is no "correct" way to model the effects of the COVID-19 pandemic and all methods should be compared to relevant alternatives. Staff is still investigating these alternative modeling techniques and may suggest adjustments in later testimony.

Q. How does PGE model energy efficiency programs (EE) in their load forecast?

A. PGE models EE programs by simply including the estimated amount of savings from Energy Trust of Oregon (ETO) activities as a linear regressor in their model. This data comes from the ETO and reflects the incremental savings estimated in each quarter. PGE than interpolates this data to the monthly level. PGE also uses forecasted data from the ETO in order to estimate its test-year forecast.

Q. Does Staff agree with this approach to modeling the effects of EE programs?

A. Staff sees this method as a vast improvement over the previously used outboard adjustment. The best data to use for estimating the impact of EE programs would be household-level causal estimates of pre- and post-intervention consumption. Collecting these estimates would be extremely difficult and costly - if even possible. Including ETO's estimated level of savings is likely the best proxy for the true level of energy efficiency savings customers experience. Including it as an independent variable in the regression will even account for systematic over- or under-estimation from ETO if the bias from ETO's estimates is consistent over time. It should be noted that the coefficients for the estimated effect of ETO savings should not be interpreted as causal. That is, if the coefficient on ETO's estimated savings is above or below 1, it should not necessarily be interpreted as ETO's estimates being biased, nor is Staff implying that ETO's estimates are biased. Rather, Staff is simply stating that PGE's new method for modeling EE savings would be robust to certain forms of measurement bias.

Q. How does PGE model distributed energy resources (DERs) in their load forecast?

A. PGE accounts for the effect incremental DER adoption by using an out-board adjustment, similar to how they handled EE investment in past rate cases. The DER forecast was developed as part of PGE's Distributed System Planning process. This model is discussed at length in UM 2197.

Q. Why does PGE use an outboard adjustment for forecasting DERs?

A. Currently, DER adoption across PGE's service territory is fairly new and relatively uncommon. As such, little historical data can be used in order to reliability parameterize a regression model. PGE developed a specialized DER forecasting tool in order to provide a forecast given limited data.

Q. Does Staff support the use of this outboard adjustment?

A. Yes, as caveated below, Staff does not object to the use of the outboard adjustment. The DER forecasting tool was reviewed by Staff in UM 2197 and again in this rate case. Staff sees it as a reasonable tool given the lack of historical data. However, Staff does expect PGE to transition to include DER adoption in its regression specifications as an independent variable as more historical actuals can be measured.

Q. How does PGE model outliers in their data?

A. PGE uses indicator variables to control for large short-lived shocks to a schedule's demand. These indicator variables effectively net out the effect of the shock from the model. This essentially has the model ignore the spike in energy consumption when calculating the relationship between usage and other variables.

Q. Does Staff agree with this treatment of outliers?

A. Partially. In some cases this type of modeling can be beneficial if an event is truly random but is correlated with a spike in another covariate. These outliers have high leverage and can be overly influential when estimating the relationship between a dependent variable and an independent variable.

Outliers can also increase the standard deviation of regression coefficients which can make it difficult to identify which variables are important regressors.

That said, if a spike in energy consumption was caused by a regressor, say a large spike in temperature, then not including an indicator variable in the regression may be helpful for understanding the relationship between weather and energy consumption. It is unclear from PGE's testimony and workpapers why each outlier was chosen and if the cause of the spike is known. If for instance, these changes in consumption were related to a relatively large customer entering or leaving the schedule, it would be valid to include these types of controls. Staff may address this issue in upcoming testimony.

Q. Does Staff have any proposals to improve the load forecast?

A. Yes. Staff's primary proposal is to automate the parametrization of the ARIMA models that PGE uses in its load forecast. PGE says in their opening testimony,

> For each forecast group, PGE reviews a variety of alternate model specifications. Model residuals were reviewed, confirming that they appeared uncorrelated and normally distributed. PGE also reviewed regression output statistics, such as the Durbin Watson (DW) statistic, adjusted r squared (R2), and Akaike Information Criterion (AIC). PGE inspected the time series plots to assess model performance and to look for outliers. An evaluation of the autocorrelation for each

series was performed and an autoregressive (AR) term was added when applicable.[1]

To be clear, it seems like PGE is generally following industry standard guidelines for load forecasting. However, some the decisions discussed above involve subjective decision making. With the dissolution of PGE's decoupling mechanism in UE 394, PGE has a financial incentive to lower its load forecast. Staff would prefer to increase the transparency in these types of decisions and automate these decisions, when possible, in order alleviate concerns of PGE suppressing the load forecast. Staff has no reason to believe that PGE is suppressing the load forecast at this time. The suggestion to automate the ARIMA parameterization is purely preemptive.

There are many algorithms which can automate these choices. In Staff's analysis, it first replicated PGE's load forecast in the statistical language R. Staff then used the "auto.arima()" function, which was created by Professor Robin Hyndman, a forecasting expert at Monash University in Australia, and is widely used in forecasting. This function applies the Hyndman-Khandakar algorithm to automatically parameterize ARIMA models. In short, this algorithm iterates over possible variations of ARIMA parameterizations to find the combination of parameters that minimizes the AIC and BIC.[2] Staff re-ran every regression used by PGE to construct their load forecast using this algorithm. In many cases, the algorithm chose different ARIMA parameters than those

[1] PGE/1100, Riter-Greene/13.
[2] Hyndman, R. & Yeasmin, K. (2008). Automatic Time Series Forecasting: The forecast Package for R. *Journal of Statistical Software*, 3(27); https://www.jstatsoft.org/article/view/v027i03

chose by PGE. Table 1 depicts the parameters chosen by PGE and Staff. In each cell is an ordered triple. This is the standard way of listing ARIMA parameters. The first number indicates the number of autoregressive lags, the second number indicates the number of differences, and the third number indicates the number of lags of the error term are included in each regression.

Table 1. Staff vs PGE ARIMA Parameterization

Model	PGE Parameters	Staff Parameters
Single-Family Building Permits	(0,0,0)	(3,0,2)
Multi-Family Building Permits	(1,0,0)	(1,0,1)
Single-Family Housing Connects	(1,0,0)	(1,0,0)
Multi-Family Housing Connects	(0,0,0)	(0,0,0)
Single-Family Usage	(1,0,0)	(0,0,1)
Multi-Family Usage	(1,0,0)	(1,0,1)
Mobile Home Usage	(1,0,0)	(2,0,2)
Other Residential Usage	(1,0,0)	(1,0,1)
Schedule 32 Usage	(1,0,0)	(2,0,2)
Schedule 38 Usage	(0,0,0)	(0,0,0)
Schedule 83 Usage	(1,0,0)	(1,0,1)
Schedule 85 Usage	(1,0,0)	(1,0,1)
Schedule 89 Usage	(0,0,0)	(0,0,0)

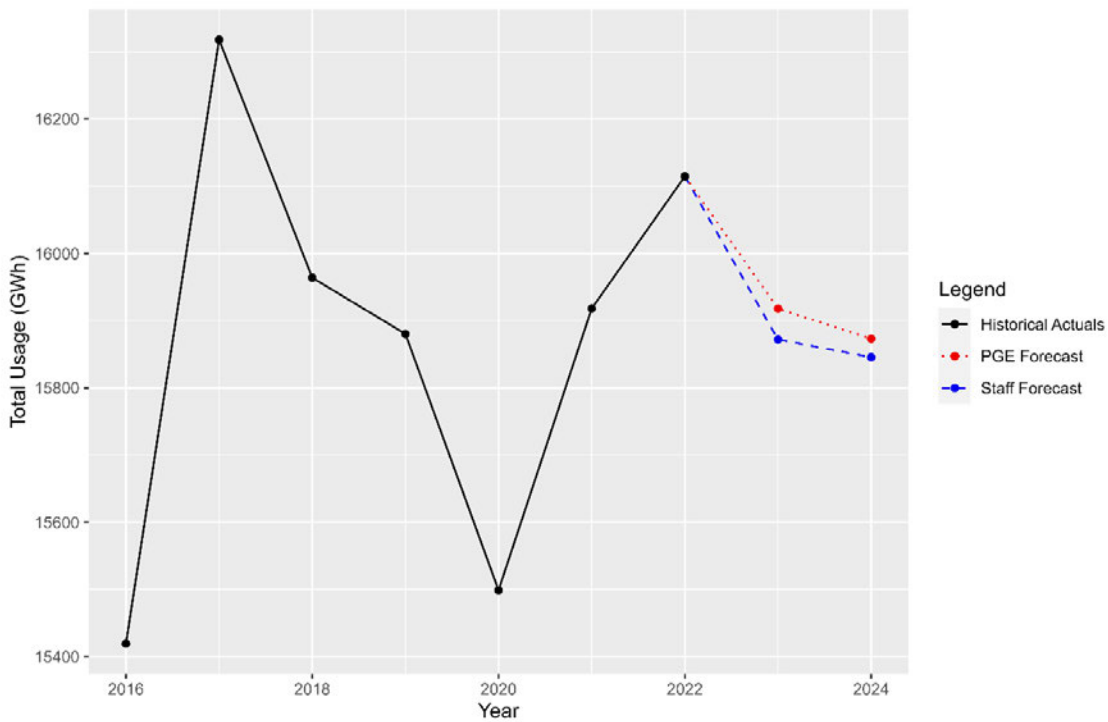
Using this method does mildly affect the base load forecast. Table 2 displays Staff's proposed change in the base forecast for each schedule.[3] Figure 1 depicts the difference between Staff and PGE's forecasts.

[3] Table 2 displays the change in the forecast for customers that do not have individual load forecasts before the outboard adjustment for DER adoption. PGE's base residential forecast is taken from PGE/1101 Riter-Greene/1.

Table 2. Difference in Base Load Forecast by Schedule

Schedule	PGE Forecast	Staff Forecast	Change
Schedule 7	7,891	7,902	0.13%
Schedule 32	1,540	1,520	-1.29%
Schedule 38	27	27	-
Schedule 83	2,867	2,857	-0.35%
Schedule 85	3,161	3,151	-0.32%
Schedule 89	387	387	-
Total	15,873	15,844	-0.18%

Figure 1. Staff vs PGE Load Forecast



Q. Is Staff proposing that PGE strictly follow the Hyndman-Khandakar algorithm when forecasting loads?

A. No. However, Staff does believe that a transparent and automated ARIMA parameterization algorithm should be used as a starting point for any short-term load forecast. Any deviation from this algorithm should be flagged and explained in detail with sufficient justification.

Q. Are there any other decisions in PGE's load forecast methodology that should be automated?

A. Potentially. Staff is also looking into automating outlier identification as that process can also be subjective. Staff has not come to any conclusions on this subject. In general, Staff believes that removing as many subjective decisions as possible from the forecasting process will lead to more trustworthy load forecasts.

Q. Are there any other potential methodological improvements that Staff is investigating?

A. Yes. Staff is also looking into using out-of-sample prediction evaluation methods such as cross-validation to improve model selection.

Q. Is Staff recommending a revenue requirement change based on the analysis presented above?

A. No. Staff is continuing to evaluate load forecast related issues. As such, we are not currently recommending an adjustment to the load forecast.

Q. Please summarize Staff's recommendations regarding PGE's load forecast.

A. Staff recommends that PGE use, in this and future rate cases, the Hyndman-Khandakar algorithm for parameterizing ARIMA models. Any deviations from this algorithm should be flagged and explained in testimony and/or work papers. For future rate cases, Staff recommends that PGE collect better data on household-level heating fuel, A/C adoption, and EV ownership. These data should be used to either estimate separate models or used as control variables to account for trends in electrification. Staff also expects that as DER adoption matures, that PGE will move away from an outboard adjustment and use actuals to parameterize its regression models.

ISSUE 2. ROUTINE VEGETATION MANAGEMENT

Q. Please explain PGE's proposal regarding routine vegetation management.

A. PGE is requesting an incremental increase to its vegetation management budget of $23.6 million.[4] This is an 89 percent increase over their current budget, bringing their total projected spend on routine vegetation management (RVM) to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[7] No wildfire mitigation (WM) costs will be handled through this rate case, but instead in the recently created Schedule 151.

Q. Does this proposal represent a departure from how vegetation management was handled in past rate cases?

A. Yes. In all previous rate cases any funds for WMVM were grouped in with all other RVM costs. In UE 412, these costs were disaggregated, and costs associated with compliance with the Wildfire Mitigation Plan (WMP) are now handled through Schedule 151. RVM are more traditional utility vegetation

[4] Bekkedahl-Jenkins/11
[5] Bekkedahl-Jenkins/12
[6] Bekkedahl-Jenkins/13
[7] Bekkedahl-Jenkins/15

management costs. While vegetation may still pose a contact risk outside of the HRFZs, the focus of this type of work is system reliability.

Q. Please describe PGE's cost forecast for RVM.

A. **[BEGIN CONFIENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** Staff is continuing to look into to the cost drivers behind this budget increase.

Q. Please explain PGE's methodology for estimating the price of [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL].**

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Does Staff agree with the proposed budget for RVM?

A. While extremely high, Staff does not have any adjustments to the proposed budget at this time. Staff is currently looking into whether certain aspects of PGE's outside labor budget are appropriately parameterized. If Staff finds any discrepancies, it will be addressed in future testimony. Given the increased demand for tree trimmers across their system and the region as a whole, Staff generally understands why there is a cost increase. Since 2022 PGE has begun implementing its annual WMPs. These plans require a significant amount of funds to implement and draw from the same pool of labor resources as RVM, so a temporary increased reliance on outsource crews is somewhat expected.

Q. Does Staff have any additional recommendations or adjustments?

A. Yes. Staff recommends that a balancing account be established for RVM costs, a performance based ratemaking mechanism be established for RVM costs, a performance based ratemaking mechanism be established for system performance, and suggests a managerial disallowance.

Q. Please explain Staff's balancing account proposal.

A. Staff is proposing that any incremental or decremental costs compared to PGE's RVM budget in base rates be amortized in the following year. PGE would submit their yearly actual RVM costs to Staff. Incremental costs would be subject to a prudence review and the account would accrue interest at the Commissions Modified Blended Treasury Rate. The prudence review would ensure that any costs beyond what is set in base rates is truly incremental to the RVM program and not related to any other functions of the Company.

Q. Why is a balancing account appropriate for RVM expenditures?

A. First, the future costs of the RVM program are relatively uncertain. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** If the labor market for tree trimmers adjusts to the increased demand and higher wages, setting this budget in stone could allow PGE to profit from a short-term market fluctuation.

More importantly, Staff is concerned about cost-shifting incentives created by the new WMVM mechanism. In UE 412, PGE, Staff, and AWEC entered into, and the Commission adopted, a stipulation which creates a cost recovery mechanism for PGE's WM costs. This mechanism, among other things, tracks PGE's spending on WMVM O&M in a balancing account and allows for full cost recovery on prudently incurred costs. This new mechanism has interactions with PGE's current method for RVM cost recovery as the labor pools and type of work done with RVM and WMVM funds are similar. Given the current cost recovery mechanism for RVM and the proposed cost recovery mechanism in UE 412, PGE has an incentive to shift costs and responsibilities from RVM to WMVM responsibilities between rate cases.

Since the WMVM mechanism allows for full recovery of prudent costs and is evaluated in isolation of RVM costs, PGE may be able to attribute more costs to its WMVM program while "cutting" costs in its RVM program in order to increase earnings. For instance, if PGE prioritizes lower cost crews to work on RVM assignments, while utilizing more higher cost crews for WMVM assignments, costs may exceed forecasts in the WMVM mechanism while being below forecasts for their RVM work. PGE would then be allowed to recover the excess costs in the WMVM budget and retain the underspent dollars in the RVM budget.

Of course, the recovery of O&M costs in the WMVM are subject to a prudence review by Staff. However, it will be difficult for Staff to effectively do a prudence review both for the WMVM and RVM simultaneously to ensure that no double recovery is taking place. Further, in their yearly Wildfire Mitigation Plans (WMP) PGE proposes changes to their WM strategy including which areas are covered by their Advanced Wildfire Risk Reduction (AWRR) program. Between rate cases, if their High Fire Risk Zones (HFRZ) increase in size or change their boundaries, then RVM costs in newly encapsulated areas would decrease while WMVM costs would increase. This would also allow PGE to save on RVM costs and collect unearned gains.

A balancing account will fully alleviate both of these issues as PGE will have reduced incentives to cost shift between programs and if labor prices fall this will be captured and returned to ratepayers. On the other hand, if RVM costs increase, these costs will also be borne onto ratepayers. Staff believes that the benefit of the balancing account will outweigh this potential risk.

Q. Please explain Staff's performance-based ratemaking (PBR) proposal for RVM.

A. Staff is proposing to implement a PBR mechanism that applies to PGE's RVM expenditures. This proposal is coupled with Staff's proposal for a balancing account. However, Staff's balancing account proposal is not dependent on the RVM PBR mechanism. Even if the Commission does not adopt the RVM PBR mechanism, Staff has a strong preference towards the movement to a balancing account for RVM spend.

Staff's proposed PBR mechanism would impose an earnings test on the first $6 million of incremental RVM expenditure beyond what is included base rates. The amount of prudently incurred costs subject to amortization would be based on OPUC vegetation management violations. The purpose of this PBR mechanism is to ensure that PGE's expenditure in RVM is well spent and equally benefitting customers.

The earnings threshold varies based on the number of vegetation management violations identified by Commission Staff. As a starting point, Staff suggests simply using the violations thresholds applied to PacifiCorp in Order No. 22-491. Table 3 below displays the basis point reductions from the Commission authorized return on equity that would apply to any earnings review for the first $6 million in incremental WMVM O&M expenses subject to this proposed mechanism. As is consistent with Order No. 22-491, any amount beyond $6 million would not be subject to an earnings test.

Table 3. Proposed RVM PBR Thresholds

Level	Threshold	Penalty
Level I	150	100 bps
Level II	225	150 bps
Level III	325	200 bps

Staff proposes this mechanism on an initial trial basis for three years (2024-2027), to be amended or revised by the Commission as appropriate for purposes of the ongoing mechanism. However, Staff supports keeping the balancing account discussed above beyond this point even if the PBR is dissolved.

Q. Please explain Staff's rationale for proposing a PBR Mechanism for RVM expenditures.

A. Staff is proposing this PBR mechanism to increase PGE's accountability when it comes to RVM. As it stands, if PGE's RVM performance is not acceptable, there will be significant regulatory lag in imposing any sort of incentive for the Company to respond. Staff believes that a PBR mechanism that is focused on vegetation violations will act as a quick and efficient way of incentivizing PGE to improve its performance if it declines.

Q. Has Staff proposed a PBR mechanism for PGE's vegetation management in the past?

A. Yes. In UE 394 Staff also proposed a PBR for PGE's WMVM and RVM expenditures. In UE 394 the Commission adopted neither Staff or PGE's proposals relating to WMVM and RVM.

Q. Is this mechanism similar to the mechanism proposed in UE 394?

A. Somewhat. The mechanism that was proposed in UE 394 would have encapsulated all of PGE's spend both for RVM and WMVM. The proposal that Staff presents here only applies to PGE's RVM expenditure. The stipulation that was adopted in UE 412 explicitly forebode any PBR in relation to WM costs for at least three years. Further, the intention of the PBR in UE 394 was to decrease vegetation contacts that pose a risk of ignition. This PBR is not focused on wildfires but instead is purely focused on safety, reliability, and program performance. This is why Staff has reintroduced the concept with a narrower focus.

Q. Why does Staff propose that tree contacts should be used as a performance metric?

A. Staff chose tree contacts the preferred performance metric for two reasons. First, the point of RVM is to reduce vegetation contacts. As such, vegetation violations are a natural metric for performance. Second, probable violations and the OPUC's safety audit program for vegetation management performance has been in place for some time and are already in use in PacifiCorp's WMVM mechanism. Staff has experience applying this metric and the Commission has already expressed some support for the metric as a reasonable proxy for VM success.

Q. Please explain Staff's performance-based ratemaking (PBR) proposal for system performance.

A. Staff is proposing, in addition to a Routine Vegetation Management Performance Mechanism, to implement a PBR mechanism that applies to PGE's non-RVM distribution revenue requirement (DRR). Performance standards would be set based on array of holistic Service Quality Measures (SQMs). Potential SQMs and their importance for system reliability and safety are discussed in Staff/2500. Table 4 displays Staff's proposed SQMs for this mechanism.

Table 4. Proposed System Performance PBR SQMs

SQM	Description
At Fault Customer Complaints	Number of "At Fault" customer complaints as defined by current OPUC Customer Service Division practices.
SAIDI	Sustained Average Interruption Duration Index as defined and calculated by IEEE standards.
SAIFI	Sustained Average Interruption Frequency Index as defined and calculated by IEEE standards.
MAIFI	Momentary Average Interruption Frequency Index as defined and calculated by IEEE standards.
CAIDI	Customer Average Interruption Duration Index as defined and calculated by IEEE standards.
Inspection & Repairs Performance	Yearly review of utility repair times by OPUC Safety Staff. Revenue requirement reduction would be based on Staff recommendation within set range.
Major Safety Violations	Achievement of zero patterns of noncompliance as defined in Division 24.

Two tiers of performance metrics would be created for each of these metrics, except the Pattern of Noncompliance measure. The first tier would be associated with a relatively small reduction in DRR, while the second tier would represent a more severe violation and in turn have a larger reduction in DRR. The sum of these reductions would be accumulated in a deferral and the balance would be used in a way that is decided by the Commission.

The purpose of this PBR mechanism is to ensure that PGE's expenditure and investment in its distribution network is well spent and equally benefitting customers. Rates are set based on an expected level of system service quality and network integrity. If PGE does not meet these expectations or has deteriorating service, rates should decrease to reflect the lower quality service customers are receiving. Staff proposes this mechanism on an initial trial basis for three years (2024-2027), to be amended or revised by the Commission as appropriate for purposes of the ongoing mechanism.

Q. Please explain Staff's rationale for proposing a PBR Mechanism for system performance.

A. Similar to the RVM PBR mechanism above, Staff is proposing this PBR to increase PGE's accountability when it comes to the entirety of service quality. As it stands, if PGE fails to achieve each of the SQM goals, there will be significant regulatory lag in imposing any sort of incentive for the Company to respond. As discussed in Staff/2500, Staff has relatively limited insight into PGE's performance as they do not regularly report on all of the metrics Staff is proposing for this PBR mechanism.

Q. Is Staff proposing particular targets for its proposed PBR mechanism in Opening Testimony?

A. No. Staff is currently evaluating PGE data in order to propose a set of SQM thresholds. Staff plans to suggest specific threshold recommendations in a future round of testimony. Staff welcomes threshold recommendations from PGE and interveners.

Q. Is Staff open to other performance metrics?

A. Yes. Staff is open to and actively exploring other potential metrics. Specifically, Staff is looking into the application of regionally disaggregated metrics. For example, evaluating PGE's reliability performance at the regional or circuit level. This would ensure that all customers across PGE's service territory are receiving adequate service quality and that neglected regions are not masked by system averages. Staff would like to work with PGE and other interveners in a collaborative way for establishing which SQM's and also ensure proper application of major events in this mechanism.

Q. Is this proposal based on a degradation of PGE's service quality?

A. No. While Staff would like to see improvements in PGE's service quality, Staff is not necessarily recommending this PBR mechanism in response to a precipitous drop in service quality. Although, as mentioned above, Staff currently has a limited view of PGE's network integrity. Staff does not believe that the implementation of a PBR must be reactionary. A PBR mechanism is a form of sound proactive regulation and is meant to be preventative and provide adequate incentives to improve or maintain service quality. Second, since there is an embedded expectation of system reliability and integrity built into customer rates, it is reasonable to lower prices if service quality deteriorates. Lastly, the Commission has a set a precedent of crafting proactive performance metrics. Staff believes that a mechanism that clearly outlines SQM targets and penalties for breaking those targets will benefit PGE, Staff, and ratepayers. Staff is looking forward to comments from PGE and interveners on this proposal.

Q. What is Staff's proposed managerial disallowance?

A. Staff is proposing a managerial disallowance of [**BEGIN CONFIDENTIAL]** [redacted] [**END CONFIDENTIAL]** for annual RVM costs.

Q. Does PGE's large forecasted RVM budget play a role in Staff's decision to recommend this disallowance?

A. Yes. As discussed above, RVM costs have exploded over the past two rate cases. In 2022 PGE spent $28.2 million in RVM. This represents a 96 percent, or $13.8 million, increase compared to actuals in 2014. Most of that increase happened within the 5-year span leading up to 2022. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This is an unprecedented increase in costs. Figure 2 depicts this rise. The black line depicts PGE's actual RVM spend in the years 2014-2022 while the red line depicts its forecasted costs in 2024. **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. Does Staff believe that this price increase could have been tempered by better management by PGE?

A. Yes. As stated above, roughly half of this forecasted cost increase is coming from PGE's increasing reliance on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In its testimony the Company states:[8]

> **[BEGIN CONFIDENTIAL]** [redacted]

[8] PGE/700, Bekkedahl-Jenkins/15

[redacted] **[END CONFIDENTIAL]**

In OPUC DR 508, Staff asked **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** PGE is projecting to double its RVM budget over a 5-year period. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** In a response to Bench Request 7 in UE 394, PGE discussed its difficulties finding local skilled workers. PGE also stated that this shortage was because of the influx of new work due to new WM and extreme storms. Based on PGE's testimony and response to DR where Staff explicitly asked **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff believes that there was much more PGE could have done to deflate these prices. Further, WMVM work will continue into at least the medium term – and may even expand. Since the number of crews needed will likely not decrease, PGE should be doing everything in its power **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and decrease costs in the future.

It is impossible to know **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** if PGE had given this issue the attention it deserved. However, Staff contends that there was more PGE could have done. As such, Staff is proposing a disallowance equal to the forecasted incremental cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. By recommending this disallowance, we are recognizing that PGE has not done everything in its power to lower RVM costs and that more emphasis needs to be focused on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

ISSUE 3. MARGINAL COST STUDY & RATE SPREAD

Q. Please describe PGE's proposed rate spread.

A. Table 5 displays PGE's proposed rate spread at its proposed revenue requirement.[9]

Table 5. PGE's Proposed Rate Spread

Schedule	CoS Rate Base Impacts w/ Schedules 122, 125, and 146
Schedule 7 – Residential	15.7%
Schedule 32 – Small Non-Residential	15.9%
Schedule 83 – 31-200 kW	12.5%
Schedule 85 – 201-4,000 kW	14.1%
Schedule 89 – over 4,000 kW	10.0%
Schedule 90 – over 30 MWa	10.8%
CoS & DA Overall	14%

Q. Please briefly review how PGE calculated this rate spread.

A. Since 1974, the Commission has used marginal costs as one of the principal factors for spreading revenue requirement among customer classes. PGE explains that its marginal study results in "unit costs, expressed as costs per customer, costs per kilowatt (kW) of demand, or costs, per kilowatt hour (kWh) are then used to allocate the functional revenue requirement."[10] The marginal cost methodology is needed because book values do not have a comparable basis of depreciation and differ from replacement costs – thus book values would not clearly indicate which schedules are more costly to serve. In 1998, the Commission adopted a stipulation under which the marginal costs and revenue requirement should be separated into

[9] PGE/1300, Macfarlane-Pleasant/2.
[10] PGE/1200, Macfarlane-Keene/1.

generation, transmission, and distribution components and then reconciled on a functional basis to calculate class revenue requirement responsibility. Accordingly, PGE computes the incremental cost of replacing each major category of its system.

Q. Schedule 89 and Schedule 90 are seeing a smaller increase than other schedules. Does this necessarily imply that other schedules are subsidizing Schedule 89 and Schedule 90?

A. In general, no. Often Schedule 89 and Schedule 90 will see smaller increases compared to other schedules. This is largely a product of how these customers consume energy. These are large industrial customers and have relatively “flat” loads. This means that they consume roughly the same amount of energy throughout the year as their consumption is related to production as opposed to heating and cooling.

In the marginal cost study, costs that are related to capacity, transmission, and distribution are spread across all customers based on how much they contribute to peak demand throughout the year. This is done to represent the fact that many of the costs PGE incurs to build or upgrade transmission and distribution infrastructure are done in order to meet capacity needs. Since these larger customers have relatively flat loads, their contribution to these peaks is relatively less, and as such they are attributed less of these costs compared to “peaky” schedules. As a result, large industrial schedules will often see lower price increases, but this is often because they contribute less to system costs. However, as I discuss later, Staff does have some concerns about misallocation of costs for these schedules in this case.

Q. Have there been any changes made to PGE's marginal cost study since UE 394?

A. Yes. The primary change in the marginal cost study is in the generation marginal cost study. In UE 394, PGE calculated capacity marginal costs using a simple-cycle combustion turbine natural gas plant as the proxy capacity resource and a weighted average of a combined-cycle combustion turbine natural gas and a wind turbine for its marginal cost of energy. In UE 394, Staff suggested using a generation marginal cost study using only non-emitting resources to be in line with mandates from HB 2021. PGE was not able to implement this change in UE 394 but has made this change in this rate case.

In its new generation marginal cost study, PGE is using a stand-alone four-hour battery storage as its proxy capacity resource and wind turbines as its proxy energy resource. To calibrate its energy model, PGE is using its recently awarded bid for the Clearwater wind facility. For its capacity model, PGE is currently using its results from its draft Integrated Resource Plan (IRP).[11]

Q. Besides the generation marginal cost study, were there any other significant changes made to PGE's marginal cost study?

[11] PGE's Draft IRP can be found here: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf

A. No. The rest of the marginal cost study is largely the same as what was used in UE 394.

Q. Does Staff have any concerns about the generation marginal cost study?

A. Not at this time. Staff agrees with the use of the Clearwater wind plant bid as a relevant proxy for wind. Staff also tentatively agrees with the parameters used to parameterize the capacity cost study but may suggest alterations as the IRP process continues.

Staff also notes its appreciation that PGE produced a marginal cost study that did not include any fossil-fueled resource. Given Oregon's statutory framework, it is unclear whether any new fossil-fueled generation resource would be a resource of choice in an IRP.

Q. Does Staff have any other concerns about the transmission marginal cost study?

A. Yes. In the PGE's transmission marginal cost study and Near-Term Local Transmission Plan, Staff noticed that that roughly 70 percent of transmission upgrade dollars from 2020-2024 were or are planned to be spent in the Hillsboro area to meet increased load. These transmission projects also included significant upgrades to the local distribution system.

In DR 477 Staff asked for the energy usage for each Schedule for the Hillsboro area. Staff found that the recent load growth in the Hillsboro area was significant, a roughly 80 percent increase from 2015-2022, but was concentrated in a few schedules. Table 6 below displays the share of the load growth by rate schedule.

Table 6. Hillsboro Load Growth by Schedule

Schedule	Load Growth 2015-2022
Schedule 7	1.77%
Schedule 32	0.05%
Schedule 83	0.4%
Schedule 85	-1.75%
Schedule 485	3.55%
Schedule 89	15.68%
Schedule 489	13.81%
Schedule 90	66.78%

The vast majority of this load growth came from very large industrial customers. These schedules with the largest growth, Schedule 89, Schedule 489, and Schedule 90 have a total of 22 accounts. It is likely that some of these accounts are owned by the same company, meaning the total number of customers is likely less. Staff questions the logic that the costs of these transmission and distribution upgrades should be spread to all customers, since they are necessary to handle the growth of so few customers.

Q. Do you have any adjustments to the marginal cost study?

A. Not at this time.

Q. Do you have any adjustments to rate spread?

A. Yes. Staff proposes that the transmission and distribution revenue requirement related to the Hillsboro Reliability Project and the Horizon-Keeler #2 230kV line be removed from all schedules excluding Schedules

89, 489, and 90. The costs of these projects would then be spread between these two schedules by 12-CP for revenue requirement related transmission and 4-CP for revenue requirement related to distribution. Staff believes that it is unjust to place the costs of these system upgrades on all customers when the costs were very directly costs by a handful of large customers. Staff has an outstanding DR that will allow for the calculation of the rate spread impact. The result of this adjustment will be to spread a relatively larger amount of the transmission and distribution revenue requirement to Schedules 89, 489, and 90. Staff also has outstanding DRs looking into other T&D projects and may discuss them in future testimony.

ISSUE 4. RATE DESIGN

Q. Please describe the changes PGE is proposing to make to its tariffs.

A. PGE proposes the following changes:

Residential Basic Charge Increase: PGE proposes to increase the single-family (SF) and multi-family (MF) residential basic charges by $2. Currently the basic charges for SF and MF customers are $8.00 and $11.00, respectively.

Flattening residential rates: PGE proposes to fully eliminate the increasing block design of Schedule 7. Currently the differential between the tariff rate applicable to the first 1,000 kWh per month and all other kWh is 0.36 cents per kWh or 5 percent.

Elimination of Schedule 7 Legacy Time-of-Use (TOU): PGE proposes to close this option to new enrollment by the effective date of this rate case then retire the option entirely on December 31, 2024.

Schedule 7 Time-of-Day (TOD) Peak Hours Change: PGE proposes to adjust the peak hours of its new TOD offering such that the transition from on-peak to mid-peak is at 4 p.m. Currently, the transition is at 5 p.m. This would expand the on-peak window by one hour and reduce the mid-peak window by one hour.

Schedule 32 and Schedule 83 Basic Charge Increase: PGE proposes to increase the Schedule 32 basic charge for both single and three-phase customers by $2. Currently the basic charge is at $20 for single-phase and $29 for three-phase customers. PGE is proposing to increase the

Schedule 83 basic charge for both single and three-phase customers by $5. Currently the basic charge is at $35 for single-phase and $45 for three-phase customers.

Schedule 83 and 85 Generation Demand Charge Increase: PGE is proposing to increase the generation demand charge for both Schedule 83 and Schedule 85 to $3.80 and $4.28 per kW of monthly on-peak demand, respectively. This represents roughly an 80 percent increase in the demand charge for both schedules. However, other rates applicable to those customers are adjusted accordingly.

Decoupling: PGE proposes a decoupling mechanism that is contingent on the Commission approving PGE's proposed revisions to the PCAM rate mechanism. This proposal is similar to the decoupling mechanism that was in place prior to UE 394. The primary differences are that this new mechanism would have a symmetric 3 percent limiter that carries forward into the subsequent year as opposed to the asymmetric 2 percent limiter that was in place prior to UE 394.

Rules and Regulations Changes: PGE proposes changing the language around certain Rules and Regulations undergrounding line extensions for resiliency.

Q. Please summarize PGE's argument for increasing the residential basic charge.

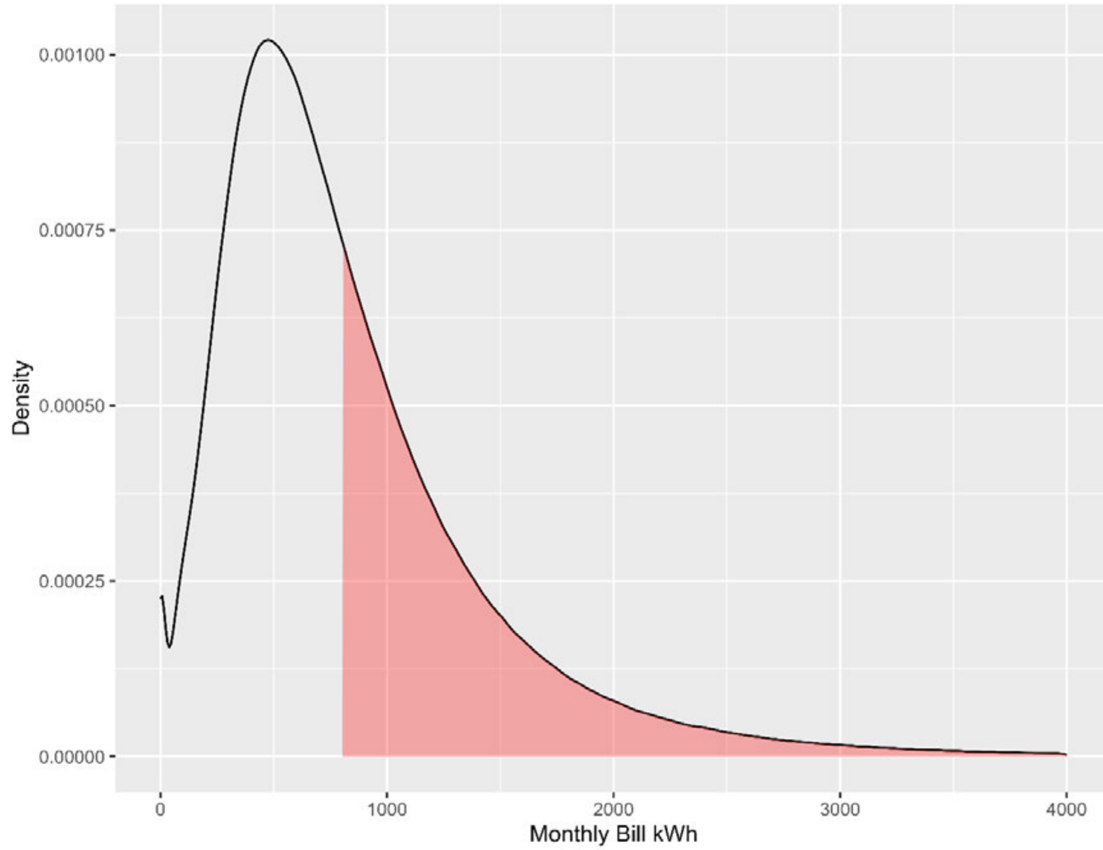
A. PGE is proposing to raise the residential basic charge such that the share of the average customer's bill that is recovered through the basic charge remains constant. Since PGE proposes increasing the revenue requirements that make up the volumetric portions the Schedule 7 bill, the volumetric charge has also increased. Without increasing the basic charge, the relative weight of the basic charge would decrease.

Q. Does this mean that the amount recovered by customers will increase as a result of raising the basic charge?

A. No. The projected amount of revenue raised by any class is set at the revenue requirement allocated to that class. Increases/decreases to the basic charge are offset by decreases/increases to the distribution charge. The effect of changing the relative weight of the basic charge is that it changes the size of a customer's bill given how much they consume. Lower basic charges result in lower bills for customers who use less than average, but higher bills for customers who use more than average. If the basic charge remains unchanged, customers who consume less than roughly 800 kWhs a month would see a lower bill relative to PGE's proposal. The opposite is true for customers that consume more than 800 kWhs a month. Figure 3 depicts the monthly average billing distribution. Customers whose average consumption is in the shaded region will see a lower bill because of this change, while customers whose average consumption is in the unshaded region will see a higher bill on average because of this change.[12]

[12] Figure 3 is derived from customer billing data supplied by PGE in DR 325. The data was truncated to only include customers who consumed less than 4,000 kWh per month for ease of reading. This represents the 99.9th percentile of consumption.

Figure 3. Effect of Basic Charge Increase by Monthly Usage



Q. Is the price of the residential basic charge set by cost causation principles?

A. To some extent. The “embedded basic charge” for the entire residential class is calculated by PGE to be roughly $30.[13] The residential embedded basic charge represents the average amount that all residential customers would pay to recover the costs related to distribution infrastructure and other customer related costs if each customer was charged the same amount. As noted in Staff testimony in UE 335, this does not represent the marginal cost of each

[13] PGE/1300, Macfarlane-Pleasant/14.

additional customer, but instead the average cost of each customer including shared costs. The current basic charges are roughly 65-75 percent below this amount. In the past, Staff has argued that the basic charge should be set to represent the marginal cost of each customer as opposed to the average. So that shared costs are recovered more by customers that consume more.

Q. Are there equity concerns regarding a higher basic charge?

A. Yes. Economics identifies electricity use as a normal good, meaning that income and energy consumption are positively correlated. There are many papers in the economic literature which find, in absolute terms, that lower income customers consume less on average that higher income customers. The cause of this relationship is often linked to lower-income customers having smaller dwelling sizes, less electric appliances, and stricter budgets.

A lower basic charge allows these customers to better manage their bill and makes essential energy more affordable.[14] However, given PGE's claims in its opening testimony, this link between income and consumption may not be as strong as previously thought. This does cast doubt on the assumption that lower basic charges are beneficial for low-income customers as a whole and indicates that the story may be more nuanced. Staff is currently investigating these claims and more rigorous analysis will have to be done before suggesting a break from precedent.

Q. Does Staff oppose this increase?

[14] See also Staff/600.

A. Currently, Staff does not oppose this proposal. However, Staff may change this stance if research into customer billing data shows a different charge may be preferable on equity grounds. Staff would like to point out that if the revenue requirement increase to the residential class is materially less than PGE proposes, that would translate into reduced increases in the basic charge rate.

Q. Please describe PGE's current energy blocking structure.

A. For many years PGE has had an inverted tiered energy rate. This means that the price charged for a kWh of energy increases at specified levels of kWh monthly-billing usage. PGE currently charges 5 percent less per kWh for the first 1,000 kWh a customer consumes in a month compared to all subsequent kWhs consumed in the same billing cycle. As stated in PGE's opening testimony, this was originally done to encourage conservation and to ensure that customers could purchase the minimum amount of energy needed to participate in modern life at a relatively low rate. The idea was that the marginal cost of supplying electricity was above average cost and therefore to charge prices closer to marginal cost, an inverted rate design was necessary.

Q. Have there been any recent changes to PGE's Schedule 7 increasing block structure?

A. Yes. In UE 335, the cutoff for the residential exchange credit at 1000 kWh a month, provided for in Schedule 102, was eliminated. Instead, the residential exchange credit, which provides the benefit of the federal Columbia hydro-electric system provided by the Bonneville Power Administration was provided to all residential kWh use regardless of how many kWhs a customer might use. Further, in UE 394 the increasing block differential was roughly cut in half.

Q. Please summarize PGE's argument for flattening residential rates.

A. PGE cites three main reasons for wanting to flatten residential rates. First, they cite equity concerns claiming that low-income households are disproportionately negatively affected by the increasing block structure. Using customers who participate in the Income Qualified Bill Discount (IQBD) program as a proxy for low-income customers, PGE finds that low-income customers have monthly bills in which the average usage is above 1,000 kWh at a higher proportion than non low-income customers.

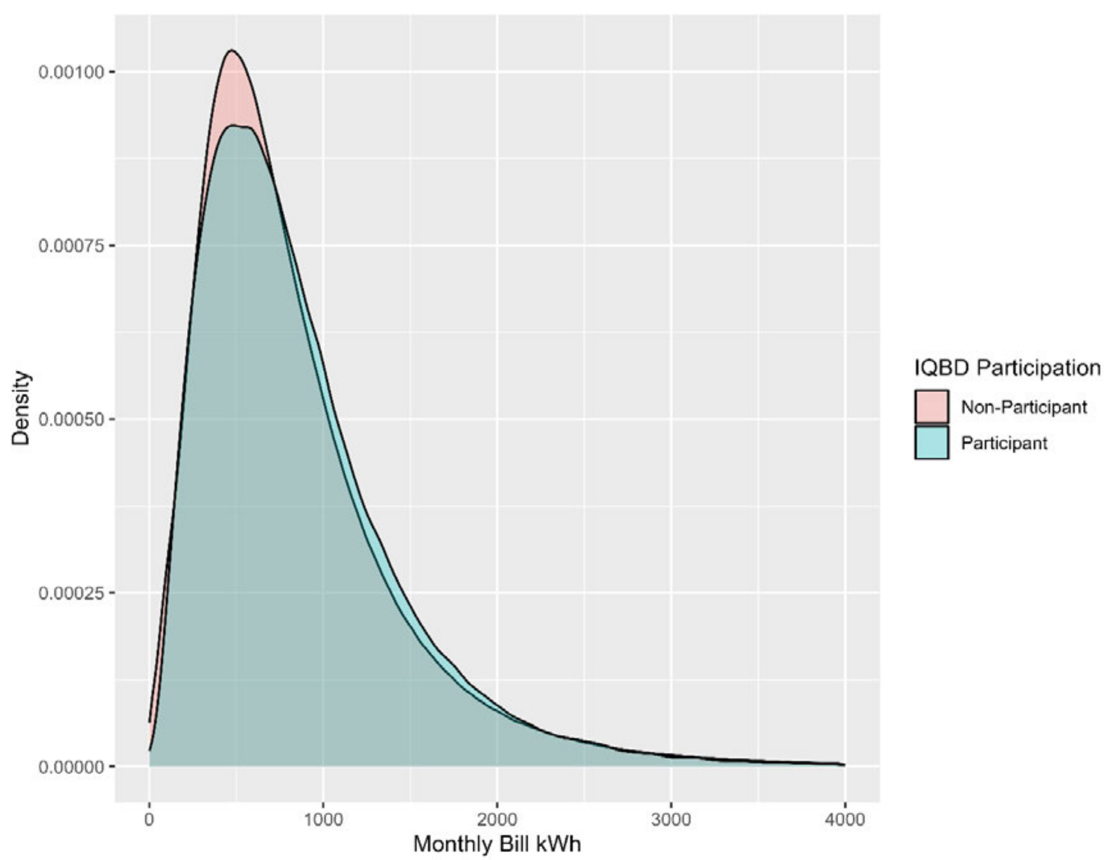
PGE's second argument for flattening rates is that the increasing block is detrimental to customers who own EVs and charge at home. Since both the default and TOD rate are subject to the increasing block, this may make EVs look less desirable to customers.

Lastly, PGE argues that the price signal that the increasing block sends to customers encouraging them to conserve is muted by the TOD rate. They claim that by including the increasing block in the TOD option, the TOD rate becomes burdensomely complicated for customers.

Q. Do you agree with these arguments?

A. No. I will begin with the equity argument. In its analysis, PGE uses IQBD program participants as a proxy for low-income customers as a whole. This has an inherent bias. Customers enrolled in the IQBD program are required to have an income at or below 60 percent of State Median Income meaning that it is likely true that all customers in the IQBD are in fact low-income. However, this does not mean that all low-income customers are enrolled in the program. The IQBD program is still in its infancy and growing rapidly. Staff was able to independently verify using customer billing data obtained in OPUC DR 325 that IQBD participants did generally consume more than non-IQBD participants. A graph of the monthly consumption data can be seen below in Figure 4.

Figure 4. Bill Distribution by IQBD Participation



One reason that IQBD participants may consume more at this stage in the program is that current participants are early adopters. This likely introduces selection bias into PGE's analysis because the higher the bill the more likely a low-income customer is likely to seek out help through support payments. While the program is free, there is still a cost to enrolling – time and effort. This is not to say that enrollment is difficult, but it does take customers taking time out of their day to enroll. The customers most likely to do this are customers who have the most to gain from enrollment. Since the program reduces a customer's bill by a certain percentage based on income, customers with higher average bills will save more by enrolling than customers who have lower bills. As such, customers with higher average bills have a larger incentive to enroll. Therefore, looking at the consumption patterns of program participants early in the program's maturity will make it seem as if low-income customers consume more than they actually do.

To be clear, Staff does not have direct evidence that this sample selection issue is at play because data that provides the usage characteristics for *all* low-income customers has not been provided to Staff. Further, effectively all academic studies looking at the issue find a positive relationship between income and energy consumption. If PGE's claim is true, then the PGE service territory would be a national outlier in this respect. Staff believes that the IQBD program needs more time to mature before participation will become a valid proxy for the low-income population as a whole. Staff intends to continue its investigation into the equity impacts of rate flattening as the rate case proceeds.

The consumption issue is at the heart of the equity discussion as the primary beneficiaries of rate flattening will be customers who consume more energy. Staff finds that customers who consume more than 1,200 kWhs a month will have lower average bills as a result of this change.

Q. Do you agree with PGE's argument about the increasing block discouraging EV adoption?

A. No. Assuming that EV owners have monthly bills above 1,200 kWh a month, an increasing block would make home charging more expensive. However, if a household has a monthly bill below 1,200 kWh per month, an increasing block would make charging relatively cheaper. Flattening rates will likely have a mixed effect on EV adoption given a household's characteristics.

For example, the median SF household in PGE's service territory consumes roughly 750 kWh per month according to billing data provided by PGE. A 2021 Chevy Bolt has an EPA fuel efficiency of 29 kWh per 100 miles.[15] According to the Oregon Metro the average person in Portland drove roughly 18.5 miles per day or roughly 560 miles per month in the years directly before the pandemic.[16] This implies that if this representative Chevy Bolt owner charged exclusively at home their monthly consumption would increase by 163 kWhs per month. This hypothetical EV customer would be better off under the current increasing block regime than under flat rates.

While this example is not perfect, it does illustrate an important point. This hypothetical Chevy Bolt owner would have to drive roughly 51 miles per day and charge exclusively at home in order for the flattened rate to be

---

[15] The EPA's fuel rating for the 2021 Chevy Bolt can be found here.
[16] Report can be found here.

beneficial for them. For a more energy intensive 2022 Rivian R1T pick-up truck, this number becomes roughly 30 miles per day.[17] While the exact billing distribution of current EV owners isn't well known, it seems reasonable to assume that flattening rates will not unequivocally improve EV adoption. For flattening to encourage adoption, a customer would have to already consume a relatively large amount of energy, purchase a relatively inefficient EV, and/or drive a relatively large amount.

Q. Do you agree with PGE's argument about the increasing block's price signal is muddled by the TOD rate's price signal?

A. Perhaps. In UM 1708, the independent evaluator that analyzed PGE's first TOD pilot program found that simpler TOD offerings had similar outcomes than more complex rates and as such were preferable. Staff does also see a benefit to simpler rates as they may help encourage adoption.

However, Staff does not necessarily agree that the price signals are muddled. The increasing block and TOD rates send different price signals and do not counteract each other. The TOD rate sends the price signal related to capacity costs while the increasing block sends price signals related to energy costs. Both are valid price signals to send and achieve different goals.

Q. Are flattened residential rates more closely aligned with cost causation principles?

A. There are two aspects to this issue. First, we should look to see if marginal cost is above average cost. If the revenue requirement at marginal cost is

---

[17] The EPA's fuel rating for the 2022 Rivian R1T can be found here.

higher than the total revenue requirement, it would suggest that the marginal cost of generating unit is increasing, thus providing justification for the inverted block rates. Using PGE's marginal cost study, I find that the revenue requirement at marginal cost for residential customers is approximately $1,250 million. PGE's full residential revenue requirement is $1,378 million and they are proposing to recover roughly $120 million from the residential basic charge. This means that the portion of PGE's residential revenue requirement that is recovered through variable charges is roughly $1,257 million. This shows that the PGE's marginal cost are roughly equivalent to its average cost. This analysis supports PGE's proposal for flattening rates.

The second aspect of this issue is whether there is a cost differential per kWh of serving small versus large residential users. Staff is still investigating this issue. To answer this question we can ask, "are customers that consume more energy, regardless of when, more costly to serve?" If the answer to this question is yes, then increasing block rates are justified under cost causation principles.

One way to investigate this is to look at the month-to-month variability of consumption for customers across the consumption spectrum. The Figure 5 plots the customer-level yearly variance against average monthly consumption.[18]

[18] The billing data in Figure 5 has been truncated at the 95th percentile of customer usage and 2000 kWh of average monthly usage for ease of interpretation.

Figure 5. Monthly Customer Variance on Average Customer Usage

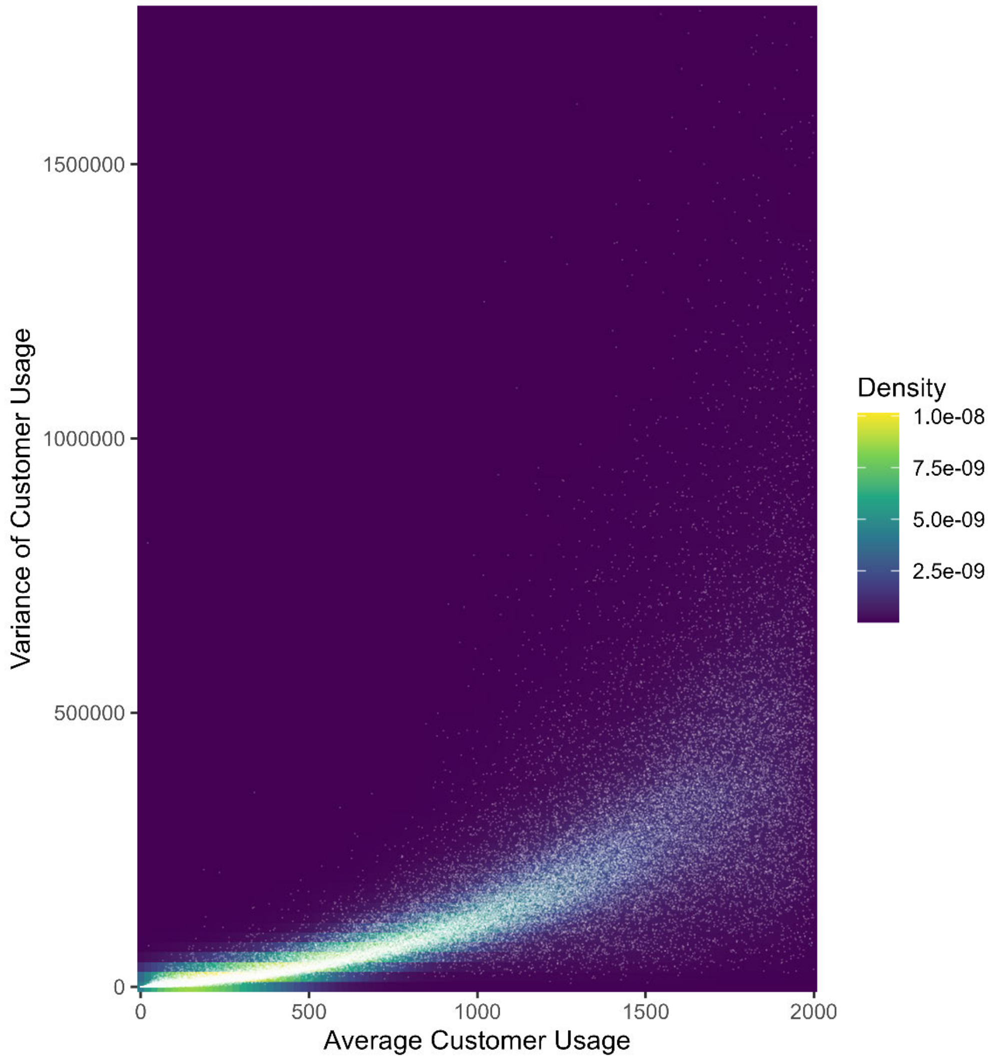


Figure 5 shows that as customers consume more energy per month, their monthly variance increases. This means that month-to-month consumption is more volatile as average monthly consumption grows. Customers with volatile consumption are more costly to serve. Because of their occasionally large demand, distribution upgrades may be necessary sooner to accommodate their load as well as additional generation capacity to serve a kWh of use due to a lower load factor for higher usage customers.

Further, in the months where their load decreases, they will be paying less towards those distribution upgrades due to the volumetric nature of the cost recovery for those costs. Customers who consume less per month have fairly consistent levels of consumption, are easy to plan for, and are less likely to have large drops in consumption. Together, this indicates that customers with large loads regardless of the time of day they are consuming may be more costly to serve than customers with small average loads. Staff is continuing to look into this issue and this investigation is not final.

Q. Do you agree with PGE's proposal to flatten residential rates?

A. Likely not, however Staff has not come to a definite conclusion on this issue and is planning on continuing its investigation into the cost causation issues associated with flattening rates. Staff is looking forward to PGE's future testimony.

Q. Please summarize PGE's argument for retiring the Legacy TOU option for Schedule 7 customers.

A. PGE argues that the schedule is complicated and unappealing to customers, which has led to low uptake over its 20-year history.

Q. Do you support the retirement of the Legacy TOU option?

A. Staff does not have reservations about ending new enrollment in the Legacy TOU option. It has had ample time to mature, and the vast majority of customers have chosen not to enroll. PGE has made an effort to calibrate its new TOD option and it is fair to assume that it will be the natural successor to the Legacy TOU option.

That said, many of the Legacy TOU customers have been on the schedule for a long period of time. Further, the current subscribers have had the opportunity to switch to the new TOD option. These customers have revealed their preference to stay on this option compared to their alternatives. Ending new enrollment would reduce the costs associated with educating customers on the nuances between the schedules, while allowing customers who prefer the Legacy TOU option to remain on it. Staff is interested to see if PGE can demonstrate a need to fully retire the Legacy TOU.

Q. Please describe PGE's argument for modifying the TOD on-peak window.

A. PGE argues that by increasing the size of the peak window, they will be able to temper the price increase for peak hours.

Q. Do you support extending the on-peak window?

A. No. The philosophy behind TOD rates is that it allows retail rates faced by customers to better mirror the system prices faced by the utility at a more granular level. This incentivizes customers to behave in ways that lower overall system costs by lowering power costs and delaying investment in new plant.

PGE is requesting to change the structure of the TOD rate to smooth a price increase. PGE does not offer any evidence that this change will send more clear price signals to customers or that there has been any structural change in the hourly power costs faced by the Company. Staff believes that these are the only two valid reasons for changing the structure of the TOD rate.

PGE also stresses the importance of simplicity and education about TOD rates in its testimony. Changing what is arguably the most important aspect of a TOD rate to communicate, the on-peak window, to temper a price change seems to run counter to PGE's stated goals for the TOD rate. PGE should strive for consistency in the structure of the program and only make structural changes to the TOD rate when there are structural changes to PGE's costs.

Staff sent DRs asking for information about PGE's hourly system costs and loads. A copy of the PGE responses to these data requests is attached as Staff/2002. Staff is currently analyzing this data. If Staff finds, or PGE can provide, sound evidence that this change will better align retail costs with system costs, then Staff may support this change.

Q. Are there any additional impacts from the proposal to change the on-peak hours?

A. Yes. PGE has requested that the allowable event hours within the Peak Time Rebate (PTR) align with its proposed changes to the TOD on-peak window. Staff agrees that the PTR hours and the on-peak window hours should be aligned with or without PGE's proposed change to the TOD on-peak window.

Q. Please describe PGE's argument for increasing the basic charges for Schedule 32 and Schedule 83.

A. PGE provides a similar argument for increasing these basic charges as it does for increasing the residential basic charge. For Schedule 32, PGE states that the last time that the basic charge was changed was in UE 335. At that time, the basic charge made up 14 percent of the average Schedule 32 customer's bill. With this proposed change, the average bill would account for roughly 12 percent of the average customer's bill. PGE claims that by increasing the Schedule 83 basic charge by $5, they will recover the same proportion of the average bill from the basic charge as was done in UE 335. Again, if the overall rate increase for these schedules is less than what PGE requested, the amount of increase to the basic charges should be revisited to ensure proportionality.

Q. Do you support increasing the basic charge for Schedule 32 and Schedule 83?

A. Staff does not object to these changes at this time. Staff is also currently looking into whether a higher basic charge, and conversely lower volumetric charge, is a more just rate design.

Q. Does Staff have any concerns about the way that the current basic charge is set for Schedule 32 and Schedule 83?

A. Yes. Currently the basic charge for both Schedule 32 and Schedule 83 are set well below the embedded basic charge calculated by PGE. Table 7 depicts this discrepancy.

Table 7. Commercial Basic Charges

Schedule	Proposed Basic Charge	Embedded Basic Charge	% Under
32 (Single Phase)	$22	$45	51%
32 (Three Phase)	$31	$55	44%
83 (Single Phase)	$40	$161	75%
83 (Three Phase)	$50	$242	79%

Schedule 32 and Schedule 83 generally encompass small commercial customers. Electricity for these companies is an input into the product that they create, whether that be a service or good. By depressing the basic charge for these customers, PGE is implicitly lowering the cost of this input for companies where energy is a less intensive input and raising the cost for companies that rely more on electricity for their product. To be clear, the marginal unit cost of electricity for these different types of businesses is the same, but the lower basic charge explicitly benefits companies who use less energy at the expense of companies who use more.

While this status quo may be justified if customers who use more total energy cost the system more to serve, the equity justifications for the lower basic charge for residential customers do not hold for these commercial businesses as there is not as strong of a link between profitability and energy use. Staff has issued DRs on this issue and is continuing to investigate as the case proceeds. Staff welcomes PGE to conduct its own analysis of this issue and discuss in future rounds of testimony.

Q. Please briefly review PGE's history with decoupling.

A. In UE 197 the Commission adopted a decoupling mechanism for PGE. This included the Sales Normalization Adjustment (SNA) for Schedule 7 and Schedule 32 customers and the Lost Revenue Recovery Adjustment (LRRA) for some nonresidential customers. This mechanism in included an asymmetric 2 percent cap on collections from customers but no cap on refunds.

In UE 335 and UE 394, PGE proposed to modify the cap such that any amount of collections that would exceed the 2 percent cap would be rolled over into the next year in a balancing account. This would create full, although delayed, pass through of fixed costs. The Commission denied this request in UE 335 and in UE 394 a stipulation was submitted which proposed to terminate the decoupling mechanism. The dissolution of the decoupling mechanism was opposed by the Natural Resources Defense Council (NRDC) and Northwest Energy Coalition (NWEC), although the Commission ultimately adopted the stipulation. Since the termination of the decoupling mechanism was not thoroughly discussed in testimony, the Commission, in Order No. 22-129, requested that PGE discuss decoupling in this rate case.

Q. What is PGE's proposal regarding decoupling?

A. PGE is not technically proposing a new decoupling mechanism. PGE does, however, describe a decoupling mechanism that they would be willing to accept. The acceptance of which hinges on the Commission accepting PGE's PCAM proposal. The hypothetical decoupling mechanism PGE describes has a 3 percent symmetric annual limit on refunds and collections that roll over from year to year. This mechanism is largely similar to what was proposed by the Company and rejected by parties in UE 394. In UE 394, PGE proposed a 2 percent rolling limiter to collections and no cap on refunds.

Q. What is decoupling?

A. Put simply, decoupling is a mechanism that divorces volumetric utility sales and revenue. There is not a monolithic method for applying decoupling as a concept, but a revenue per customer decoupling mechanism is the norm. There are many examples of variations of decoupling mechanisms across and even within states. The issue that decoupling attempts to solve stems from how most energy rates are set. As noted above, the volumetric charge in Oregon does not simply include costs related to net variable power costs (NVPC). PGE also recovers costs related to grid maintenance and customer service through its variable charge. This variable charge is set to allow PGE recovery of its approved revenue requirement given an accurate load forecast. If the load forecast used to set rates is lower than is actually observed, PGE will over-recover its revenue requirement leading to excess profits and vice versa. This provides an incentive to increase sales between rate cases – which may run counter to conservation goals.

Q. What were the arguments for a decoupling mechanism in UE 394?

A. The NRDC and NWEC had three main arguments. First, they argued that investments in energy efficiency would decrease – even though public energy efficiency programs are not administered by PGE. Second, they argued that decoupling actually increases utility support for electrification and distributed energy resources. Lastly, they claimed that eliminating decoupling would decrease PGE's profits if electric vehicles become more energy efficient.

Q. Do you agree with the general idea that getting rid of decoupling will hinder environmental goals?

A. No. While Staff agrees that eliminating decoupling PGE will have an incentive to sell more electricity, this sale of electricity can be to enhance environmental goals - not hinder them. Transportation electrification is one example of this. The main benefit to Staff of removing decoupling is that general economic risk will be returned to PGE as it was before the decoupling mechanisms were adopted. Staff believes that shielding investors from this risk and pushing it onto customers runs counter to the contract between a customer and business.

Q. Do you agree with the argument that removing decoupling will decrease energy efficiency and DER investments?

A. Staff disagrees with the argument that removing decoupling will decrease energy efficiency investments in PGE's service territory. The ETO serves as an unbiased manager of public investment in energy efficiency. This differs from many other states who rely on utilities to run and fund energy efficiency programs. In those states, Staff would agree that removing decoupling would serve as a major disincentive for utilities to properly administer energy efficiency programs. NRDC and NWEC argue that this is not a sufficient barrier, and that PGE will be able to dissuade customers from investing in energy efficiency. We disagree as there is no evidence on this point that Staff has seen.

By all accounts, dissolving the decoupling mechanism in UE 394 has had little to no effect on energy investments in PGE's service territory. Interest in publicly funded energy efficiency has not faltered due to the diminished incentive for PGE to advertise ETO programs. The ETO actually exceeded its conservation goals in PGE's service territory in 2022. Further, a private customer's investment to invest in energy efficiency is largely driven by the volumetric price of energy as opposed to PGE's net income. The recent spike in western power prices have translated to higher power costs and have driven up volumetric rates. This makes energy efficiency investments more enticing to private customers as well. This logic also extends to DERs. A customer's decision to invest in a distributed solar resource, for instance, will largely depend on the benefit received form net metering. The larger the volumetric charge from PGE, the more enticing DER investments will become.

Q. Do you agree with the argument that decoupling will increase utility support for transportation electrification and DERs?

A. Staff agrees with NRDC and NWEC that PGE has incentive, through the language of SB 1547, to invest in electrification even with a decoupling mechanism in place. However, by removing decoupling PGE is incentivized to further exceed the anticipated growth of transportation electrification as it may be able to increase its net income – within bounds. That said, Staff agrees that any gains from transportation electrification should not be earned through sub-par load forecasting. In my testimony above, I stress the importance of further collection of historic EV ownership and heating data to use in PGE's load forecasting models. Given this data, we can help to ensure that any profits stemming from increased transportation electrification come from increased efforts by PGE and not through poor forecasting of previously anticipated trends.

Q. Do you agree with the argument that decoupling will increase utility support for transportation electrification and DERs?

A. Staff disagrees that PGE's incentives will change if EVs become more efficient. First, PGE has little to no control over the efficiency of mass produced EVs. Second, in the absence of decoupling PGE has an incentive to increase sales. Whether this comes from an efficient compact or inefficient truck, PGE will be better off. Staff also does not believe that PGE has undue influence on consumer's preferences for vehicles. Customer's choices will largely depend on their personal preferences, what is available on the market, and the cost to purchase and charge the vehicle.

Q. What is Staff's recommendation regarding decoupling?

A. Staff does not support restoring the decoupling mechanism. Further, Staff does not support PGE's PCAM proposal, which PGE states is prerequisite for its decoupling mechanism. Staff also believes that there are sufficient guard rails to ensure continued investment in energy efficiency in the absence of decoupling and believes that this policy will further transportation electrification goals. Staff believes that when UE 394 shifted the business risk from customers to the utility, that result is largely beneficial to consumers.

Staff also recognizes that by not reinstating decoupling, increased scrutiny must by placed on PGE's load forecast. Absent of decoupling, PGE has an incentive to decrease its load forecast. Staff will continue to make an effort to make PGE's load forecast more transparent and accurate in this and future rate cases.

Q. Please summarize PGE's proposal regarding Rule I Section 3A.2, Applicability of 1 Special Conditions for Underground Line Extensions.

A. PGE is proposing that a change be made to Rule I Section 3A.2 which would include resiliency as a reason to mandate the undergrounding of a line extension.

Q. Does Staff believe that this rate case is the appropriate venue for this topic?

A. No. Addressing this now is premature. Staff believes that this topic should be discussed in more detail within the context of the Wildfire Mitigation Plan Review. Undergrounding new line extensions can be costly and capital intensive. This decision should have careful review both by safety staff and Staff's independent evaluator to ensure that the proper guard rails are placed on this power.

Q. Does Staff have any additional proposals on rate design?

A. Yes. Staff has proposals regarding Schedules 7, 83, 85, 89, 90, and 102.

Q. Please describe Schedule 102.

A. Schedule 102 provides to residential and small farm customers the benefits of the Residential Exchange Program (REP) administered by the Bonneville Power Administration (BPA). The REP allows Oregon customers to have their bills reduced as a reflection of the low-cost power generated by the federally owned dams whose power is marketed by BPA.

Q. Please describe Schedule 102's recent history.

A. In UE 335, Schedule 102 was modified to apply to all kWhs consumed by customers as opposed to being capped at the first 1,000 kWhs. This was done as PGE's first step to flattening residential rates.

Q. What is Staff's proposal regarding Schedule 102?

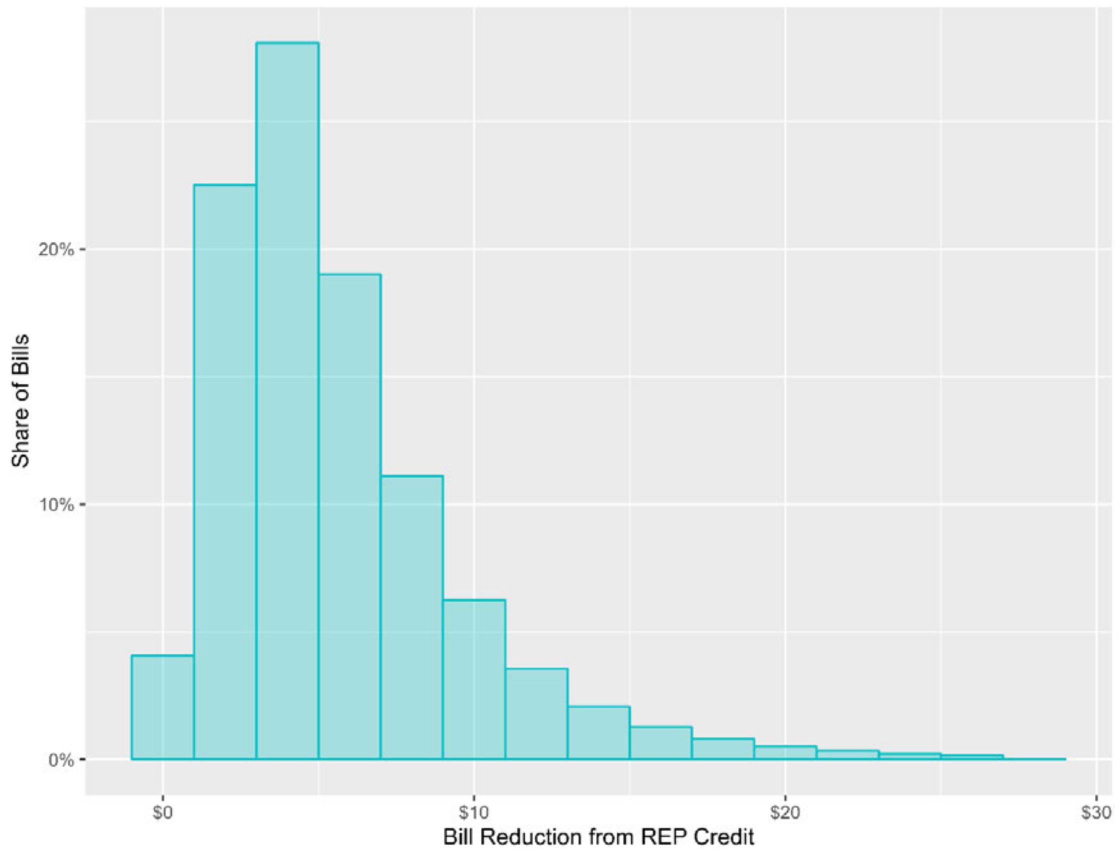
A. Staff is proposing that the REP credit be distributed to customers on a per-customer basis as opposed to a per-kWh basis. Staff believes this to be a more equitable distribution of the credit as currently large users recover unequal portion of the credit. The amount of funds distributed by the BPA to each qualifying investor-owned utility is fixed per year. As such, the credit itself is not truly a per kWh discount on energy, but a transfer from the BPA to each participating utility. While it is true, that the share of the fixed amount each utility receives is partially determined by each utility's load, it only determines PGE's share of the pie, while the size of the pie remains fixed.

As Staff argued in UE 397 and UE 399, it is more equitable have some limit to the amount of funds an individual customer may receive. As a result of UE 399, a cap 2,000 kWh was placed on REP credits given to customers in PacifiCorp's service territory. Staff could support a similar outcome in this rate case. However, as mentioned above, Staff believes that the most equitable outcome would be to apply the BPA credit on a per-customer basis. Staff believes that this better reflects the fixed nature of the credit and would likely lead to smaller yearly deltas rolled over in the balancing account.

Q. What would be the impact of this proposal?

A. The impact of a per-customer distribution of the REP credit would be twofold. First, it would ensure that each customer received the same amount of monthly benefit from the REP credit. The median bill discount from the REP credit is roughly $4.60. Figure 6 below depicts the share of customers who receive a certain amount of benefit from the REP program.[19]

Figure 6. Distribution of REP Credit



There are a handful of extreme cases where customers consume an extremely large amount of energy and as a result receive a large benefit from the REP credit. The maximum amount of REP benefits seen by any one customer was about $288. Under a per-customer regime, each customer would receive the same amount of bill reduction each month.

[19] The billing data in Figure 6 has been truncated at the 99.9th percentile of customer usage for ease of interpretation.

This would also effectively lower the residential basic charge. The net effect would be a decrease in the basic charge by roughly $5.50. This would also result in an analogous increase of 0.676 cents per kWh. Given all other adjustments proposed by PGE, this would lower bills for all customers who consume less than 800 kWhs per month on average. This represents roughly 56 percent of all PGE residential customers and 50 percent of customers currently enrolled in the IQBD program.

Q. Is Staff only amenable to a per-customer credit?

A. No. While Staff does prefer a per-customer credit, a cap similar to that adopted in UE 399 is also acceptable.

Q. Please describe PGE's current TOD structure for Schedule 83, Schedule 85, Schedule 89, and Schedule 90.

A. These schedules, which Staff will collectively call "industrial schedules" for the purpose of this testimony, all have a mandatory TOD rate. The structure for these schedules is simple in comparison to the residential TOD rate. The on-peak window is from 6:00am until 10:00pm Monday through Saturday. The off-peak window encompasses all other hours within the week. This effectively amounts to a "day and night" on- and off-peak breakdown. Some of these schedules have an additional increasing block structure to their energy charge.

Q. What is Staff's proposal for regarding Schedules 83, 85, 89, and 90?

A. Staff is proposing that the on- and off-peak windows for these schedules be restructured to better reflect system costs. The result of the large on-peak window is that the price of the on-peak period is diluted. It becomes a weighted mix of the relatively low system costs associated with the morning hours and the relatively high system costs associated with the evening hours. On net, the on-peak price signal is diluted and ultimately does not send the appropriate price signals to these large consumers.

Shortening this window, and potentially adding an additional mid-peak window to mirror the residential TOD rate, would send stronger price signals to these customers and induce more conservation in hours when the system is expensive to serve. This is particularly important as these schedules contain a small number of very large users. Together, they are projected to contribute roughly 44 percent of the 12 Coincident Peak (CP).

Staff has not had sufficient time to analyze system cost and tightness data recently received via DR 778 in order to propose an exact schedule. Staff welcomes PGE to offer its own analysis of the issue and potential schedule in its future testimony.

Q. What guiding principles did Staff use to create the recommendations regarding rate design?

A. For rate design, Staff is always trying to provide recommendations to the Commission that will attribute costs to cost causers and not be overly burdensome to customers both from an equity and rate shock perspective. Cost causation principles are important to follow as they provide price signals to customers that will incentivize them to consume in a manner that lowers overall system costs. Without these price signals, customers may consume energy in ways that are personally beneficial in the short run, but detrimental to the system as a whole and therefore, harm other customers.

HB 2021 directed the Commission to consider equity in rate making. Staff also recognizes that energy is an essential part of modern life and should be affordable for all customers. It is important to ensure that all customers have access to healthy home environment and fully participate in society.

Q. Are the means for achieving these goals always aligned?

A. No, as is extensively discussed in Staff Exhibit 600/Scala, these goals are often in conflict with each other. There are policies that would align rate design more closely with cost causation principles that would also increase energy burden for energy insecure customers. This is particularly true when the residential class is treated as a homogenous group of customers. As such, many aspects of PGE's current rate design are effectively a compromise between cost causation and equity principles. This creates muddled price signals to customers and encourages inefficient consumption for customers who are adaptable while also allowing for slightly more affordability for energy insecure customers. Another issue Staff faces is understanding magnitude of these conflicts. Given the limited personal customer data available to both Staff and the utilities it is difficult to discern the magnitude of a policy decision for a particular group.

Q. Can you provide an example of a rate design issue that is affected by this conflict?

A. Yes. TOD pricing is a relevant example. TOD pricing objectively sends better price signals to customers to reduce consumption in peak hours, which in turn reduces system costs related to capacity expansion and expensive market purchases during hours where the system is tight. However, many of the tools that allow customers to seamlessly load shift like updated dishwashers and laundry machines are potentially too expensive for energy insecure customers to purchase. Further, customers in well insulated houses may be able to pre-cool or heat their houses during times of extreme temperatures whereas customers who live in areas with older housing stock have less-insulated houses may not have this ability. There are many potential socioeconomic factors that may inhibit a customer's ability to respond to these price signals. This leads energy insecure customers to have to make decisions between high bills or potential negative health outcomes.

Staff is interested in pursuing an opt-out TOD rate for PGE customers as opposed to the opt-in option that is offered now. However, given the potential negative equity impacts Staff has some reservations. One potential solution for these types of conflicts is the creation of an entirely separate equity minded tariff. This would allow for a more targeted approach to rate design which would both allow for energy to be more affordable for energy insecure customers while also sending stronger price signals to more adaptable customers.

Staff does not have an explicit plan regarding how to implement this new tariff at this time. We wanted to give PGE and interveners an opportunity to respond in future testimony and let the Commission decide how to ultimately respond - if at all.

Q. Do you have any additional thoughts?

A. Staff would like to thank PGE for its effort and willingness to provide large and detailed datasets to Staff with relatively small turnaround times. We understand that these take a considerable amount of time to compile and want to recognize this effort.

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff has three primary suggestions regarding PGE's load forecast. If possible, Staff recommends that PGE estimate separate load forecasts for EV and non-EV owners. If this is not possible given current data, Staff encourages PGE to develop this data set along with more accurate household-level data regarding heating fuel and A/C adoption. Second, Staff suggests that PGE use the Hyndman-Khandakar algorithm to automatically parameterize ARIMA models. Lastly, Staff suggests that as DER adoption matures, the DER data be integrated into PGE's regression specifications as opposed to the continued use of an outboard adjustment.

For routine vegetation management, Staff has four primary suggestions. First, Staff suggests that a balancing account be created to track routine vegetation management costs. Second, Staff suggests that a RVM PBR mechanism be put in place to incentivize consistent vegetation management performance. Third, Staff suggests that a system performance PBR mechanism be established to incentivize consistent service quality and network resilience. Lastly, Staff recommends a managerial disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** be imposed.

Staff does not have direct recommendations regarding the marginal cost study at this time. However, Staff does recommend an adjustment to rate spread that would shift the cost for certain transmission and distribution projects to the schedules that necessitated the investments.

For rate design, Staff has several recommendations. Responding to PGE's proposals: Staff suggests that the Legacy TOU schedule not be fully retired, the peak hours for residential TOD not be changed, decoupling not be reimposed as suggested by PGE. Staff also recommends that the RAP credit be applied on a per-customer basis, the on-peak window for Schedules 83, 85, 89, and 90 be modified to better reflect system costs, and that the potential for an equity focused rate schedule and an opt-out TOD schedule be discussed. These, and all other stances, may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2001

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Bret Stevens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Rates, Safety, and Utility Performance

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Ph.D., Agricultural & Resource Economics
University of California, Davis

M.S., Agricultural & Resource Economics
University of California, Davis

B.A., Economics/Environmental Studies
Western Washington University

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since September of 2022. My primary responsibilities revolve around providing research and analysis on rate spread and rate design. I have been a staff witness in UE 407, UE 410, UE 412, and UE 414. Prior to working for the Commission, I was employed by the University of California, Davis as a graduate student researcher, associate instructor, and teaching assistant. I taught courses on econometrics, finance, and microeconomics.

CASE: UE 416
WITNESS: Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2002

Non-Confidential Responses to Staff Data Requests

June 13, 2023

OPUC Data Request 325

Please provide raw anonymized household-level billing data for all Schedule 7 customers for the calendar year 2022. Please provide this in an MS Excel file. If necessary, multiple Excel files can be used. Please include any bill for which the billing period or due date starts or ends in calendar year 2022. An example as to how the data should generally be structured is shown in Attachment 1 of this DR. If PGE does not track any of these data elements, please indicate this in your response and return the rest of the data elements. If you have any questions about this request, please reach out to the Staff Initiator, Bret Stevens, as soon as possible. Please include the following data elements – the preferred data type are in parentheses:

a) Anonymized customer account ID (string or numeric)
    i) Anonymized site ID (string or numeric)
    ii) Please ensure that the anonymized customer ID and anonymized site ID are persistent across different bills.
    iii) Please ensure that the key linking the anonymous account and site IDs to their respective accounts and sites are retained by the company after anonymization.
b) Bill start date (string or data variable in excel)
c) Bill end date (string or data variable in excel)
d) Bill total (numeric)
e) Energy consumption for billing period (numeric)
f) Customer payments made for billing period (numeric)
g) Affected by any PSPS? (binary or string)
    i) If yes, start date of PSPS event (date or string)
    ii) If yes, end date of PSPS event (date or string)
    iii) If yes, duration of PSPS event (numeric)
h) ZIP code (numeric or string)
i) City (string)
j) Heating fuel type (binary or string)
k) Cooking fuel type (binary or string)
l) EV ownership (binary or string)
m) Multi family or single family (binary variable or string)
n) Enrolled in income qualified bill discount program? (binary or string)
o) Enrolled in bill assistance program? (binary or string)
p) Customer has been previously disconnected (binary or string)
q) Customer account has received LIHEAP (binary or string)
r) Customer arrears balance for billing period (numeric)
s) Participate in net metering? (binary or string)

PGE Response to OPUC Data Request 325

PGE objects to this request on the basis that it is overly broad, unduly burdensome and calls for speculation. Subject to and without waiving said objections, PGE responds as follows:

Attachment 325-A provides the raw anonymized household-level billing data for all Schedule 7 customers for the calendar year 2022. Per a phone conversation with OPUC Staff on March 27, 2023, PGE is providing data files in a CSV format. Data on customer EV ownership status was not available for inclusion at this time and will be supplied upon approval that sharing this data, even anonymously, is permitted under any applicable limitations on sharing such information imposed by law, regulation or agreement between PGE and the Oregon Department of Transportation. Data on cooking fuel is not tracked by PGE. This data has not been prepared for analytic use and may contain anomalies.

OPUC Data Request 477

The description of the Horizon-Keeler BPA #2 230 kV Project in the 2023 Near-Term Local Transmission Plan states, "Significant load growth in the Hillsboro area has accelerated the need for another 230 kV source in the Near-Term Planning Horizon". Please provide data showing the load growth in the Hillsboro area for each year of the past 10 years by schedule. Please also provide an average customer count in the area for each year and schedule.

PGE Response to OPUC Data Request 477

Attachment 477-A includes a summary of kWh and year-end customer count for service addresses in Hillsboro for the last 10 years by rate schedule. Some schedules have been consolidated to protect customer confidentiality; these consolidations are clearly marked with two rate schedules (ex. 585/589). The summary shows energy deliveries growth of 115% over 10 years, or a compound annual growth rate of 8.0%.

OPUC Data Request 496

Please provide all relevant workpapers used to derive PGE's routine vegetation management forecasted test year budget.

PGE Response to OPUC Data Request 496

Confidential Attachment 496-A provides the requested information.

Attachment 496-A contains protected information and is subject to General Protective Order No. 23-039.

OPUC Data Request 778

Please provide the average monthly generation capacity cost, energy cost, and probability of loss of load for each hour of the day for each month over the past 5 years. For reference, the final product should look similar to the "12x24 Blocks" tab of the workpaper titled "UM 1912 PGE Compliance Filing to Update RVOS Values_Distributed Workbook_12.11.2020.xlsx" that was submitted in UM 1912.

PGE Response to OPUC Data Request 778

PGE does not have historical datasets with the requested metrics: generation capacity cost, energy cost, and loss of load probabilities by month and hour of day. Per a conversation with OPUC Staff on May 17, 2023, PGE's understanding is that the OPUC Staff would like the detailed data used in allocating revenue from an average residential bill to the three TOD time periods.

The revenue allocation across TOD's on-peak, mid-peak and off-peak windows is based on a mix of the forecasted loss of load probability modeled for 2026, as an indication of relative capacity value, and average residential load between 2019-2021, as an indication of relative energy value. Confidential Attachment 778-A provides the 2026 loss of load probability matrix by month, weekday/weekend and hour of day.[1] Residential load profiles for 2019-2021 are provided in PGE's response to OPUC DR 783.

Staff also indicated they would like to see historical data on the cost to serve by month and hour. PGE determined that this would require significant new analysis and was outside the scope of a data request.

Attachment 778-A contains protected information and is subject to General Protective Order No. 23-039.

OPUC Data Request 779

Please provide raw anonymized customer-level billing data for all Schedule 83, Schedule 85, and Schedule 89 customers for the calendar year 2022. Please provide this in an .csv file. If necessary, multiple Excel files can be used. Please include any bill for which the billing period or due date starts or ends in calendar year 2022. Please format this data similarly to the response to DR 325. Please provide the data for the data elements listed below. If PGE does not track any of these data elements, please indicate this in your response and return the rest of the data elements. If you have any questions about this request, please reach out to Staff Initiator, Bret Stevens, as soon as possible. Please include the following data elements – the preferred data type are in parentheses:

a) Anonymized customer account ID (string or numeric)
   i) Anonymized site ID (string or numeric)
   ii) Please ensure that the anonymized customer ID and anonymized site ID are persistent across different bills.
   iii) Please ensure that the key linking the anonymous account and site IDs to their respective accounts and sites are retained by the company after anonymization.

[1] The 2026 loss-of-load probability matrix is from draft IRP analysis done in December 2022. The final matrix in the IRP may differ slightly (for example, winter 2026 capacity need in this analysis is 429 MW, whereas it is 430 MW in the final IRP runs).

b) Bill start date (string or data variable in excel)
c) Bill end date (string or data variable in excel)
d) Bill total (numeric)
e) Energy consumption for billing period (numeric)
   i) On-peak consumption
   ii) Off-peak consumption
f) Demand (Highest metered kW reading for a 30-minute period)
   i) On-peak
   ii) Off-peak
   iii) Average of the two greatest monthly demands within a 12-month period g. NAICS Code

PGE Response to OPUC Data Request 779

Confidential Attachment 779-A provides the requested anonymized customer data for 2022, as well as fields indicating rate schedule and service delivery level (class). Regarding, part (g), PGE notes that NAICS classification accuracy is inconsistent and recommends this field be used with caution.

Attachment 779-A contains protected information and is subject to General Protective Order No. 23-039.

OPUC Data Request 781

Please provide the residential Schedule 7 hourly loads for a representative subset of customers for each month from January 2021 through December 2021. Please stratify the data such that a sufficient number of customers from each of the following groups are represented:

a) Solar
b) ZIP Code
c) IQBD and EA Participants
d) Legacy TOU
e) TOD
f) Customers with an average monthly usage of less than 300 kWhs
g) Customers with an average monthly usage approximately the median usage level
h) Customers with an average monthly usage approximately 2000 kWhs
i) Customers with an average monthly usage of more than 15,000 kWhs
j) Customers who are likely EV owners

PGE Response to OPUC Data Request 781

PGE objects to this request on the basis that it requires new analysis and is unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

Following a discussion with OPUC Staff on May 17, 2023, this request was adjusted from 2021 “hourly loads for a representative subset of customers” for each residential subgroup to 2022 hourly statistics that show the distribution of load among each subgroup. The profiles provided in response to this request reflect new analysis summarizing raw interval load data for the full population of customers within each subgroup. They are not based on curated samples and could include data anomalies.

Attachment 781-A contains data points (a) and (c)-(j). Attachment 781-B contains data point (b).

For each subgroup of residential customers identified in items (a) through (j), the following data fields are provided:

DATE	2022 date
HOUR	Hour of the day where hour=0 represents 12 a.m. to 1 a.m.
CUST COUNT	Total number of distinct customers represented in the hourly statistic
DEMAND_AVE	Average kWh per hour
DEMAND_10	10th percentile kWh per hour
DEMAND_50	50th percentile kWh per hour
DEMAND_90	90th percentile kWh per hour

The following assumptions and adjustments were made when developing aggregate hourly profiles:

a) Solar: the solar profile reflects net-metered customers and excludes the small number of residential customers on PGE’s Solar Payment Option tariff.
b) ZIP Code: zip codes with fewer than 5 Service Points were excluded.
c) IQBD and EA Participants: Energy Assistance participants have been auto enrolled in PGE’s IQBD program and are thus included in the aggregate profile for IQBD participants. Statistics are calculated from historical usage data for current IQBD participants with the assumption that the income status of these customers was relatively consistent between early 2022 and now. Actual IQBD enrollment numbers were provided in PGE’s response to CUB DR 65.
d) Median usage level: customers with annual usage within +/-10% of the 2022 median residential usage (700 kWh) are included in the aggregate profile.
e) 2,000 kWh usage level: customers with annual usage within +/-10% of 2,000 kWh are included in the aggregate profile.

OPUC Data Request 783

By industrial schedule, please provide the load for each hour of 2022.

PGE Response to OPUC Data Request 783

Per a conversation with OPUC Staff on May 17, 2023, this data request was revised to include historical hourly profiles for years 2019-2021 for the following rate schedules: 7, 32, 83, 85 and 89. This data is included in Attachment 783-A.

CASE: UE 416
WITNESSES: Robert Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

OPENING TESTIMONY
Cloud-Related IT Expenses

June 13, 2023

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

A. My name is Robert Young. I am a Managing Director of Economists.com of Portland, LLC, a consulting firm based in Portland, Oregon. My business address is 7380 SW Kable Lane, Portland, Oregon 97224.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/2101.

Q. What is the purpose of your testimony?

A. I present Staff's analysis and recommendation regarding PGE's proposal to include in rate base certain cloud computing-related expenses as well as review PGE's proposed rate base projects relating to transmission and distribution.

Q. Did you prepare any exhibits for this docket?

A. In addition to my witness qualifications statement, I prepared the following exhibits:

Exhibit Staff/2101. .... Resume of Robert Young
Exhibit Staff/2102. .... Representative Staff DRs
Exhibit Staff/2103. .... Representative PGE DR Responses
Exhibit Staff/2104. .... Response to Staff DR No. 586-OH FITNES Dist.
Exhibit Staff/2105. ....Response to Staff DR 586-Brookwood Substation
Exhibit Staff/2106. ....Response to Staff DR 792-Brookwood Substation
Exhibit Staff/2107. ....Response to Staff DR 586-Orenco Substation
Exhibit Staff/2108. ....Response to Staff DR 590-Helvetia Substation
Exhibit Staff/2109. .... Response to Staff DR 586-Helvetia Substation
Exhibit Staff/2110. .... Response to Staff DR 586- OH FITNES Trans.
Exhibit Staff/2111. .... Response to Staff DR 789- OH FITNES Trans
Exhibit Staff/2112. .... Response to Staff DR 586-Downtown Core
Exhibit Staff/2113. .... Response to Staff DR 586-Blue Lake Phase II
Exhibit Staff/2114. .... Response to Staff DR 586-Memorial Substation
Exhibit Staff/2115. PGE's March 2023 OH FITNES Program Health Report

Q. Please present a summary of your testimony and adjustments.

A. I find that PGE's recommendation to rate base certain cloud costs is not necessary and should not be adopted by the Commission. With respect to transmission and distribution plant, I find that PGE has significantly increased its spending on plant and does not seem to consider the impact of such spending on rates and the energy burden of customers. Further, significant dollars are being built ahead of need and that the explosive growth in OH FITNES capital expenditures are the result of revised inspection criteria that Staff believes results in excessive amounts of OH FITNES equipment classified prematurely as non-compliant.

A table showing a summary of my adjustments appears below.

Table A
Summary of Adjustments in Staff 2100
($millions)

Category	Additions
Cloud Expenses in Rate Base	8.3
OH FITNES Distribution	27.7
OH FITNES Transmission	1.5
Project Sample Based Adjustment	23.9
T&D Gross Plant Additions	**61.4**

ISSUE 1. RETURN ON CLOUD-BASED IT EXPENSES

Q. Please explain PGE's proposal to include certain cloud-based IT expenses in rate base.

A. PGE proposes to include the unamortized balance of applicable license and hosting fees associated with prepaid cloud-based solutions with a contract length of three years or greater as a regulatory asset in rate base. The current forecast of this amount as of December 31, 2023, totals approximately $8.2 million.[1]

Q. What are the four components of cloud computing solutions?

A. Cloud based solution costs can be broken down into four basic components:

Implementation Costs, which under current accounting guidelines can be capitalized;

License Fees; which can be capitalized under certain conditions,

Hosting Fees; which are an O&M expense; and

Maintenance/Support, also an O&M expense.

Q. What arguments did PGE provide to support inclusion of certain cloud-based costs in rate base.

A. PGE's primary argument in support of their proposal to include certain cloud-based costs in rate base is that accounting guidelines have not kept pace with the technological advancements in cloud computing that make it the preferred solution when compared to on premises solutions. PGE states:[2]

---

1 PGE/600, Ajello-Batzler/21.
2 *Id*. at 20

> Because accounting guidelines have failed to keep pace with this changing technology environment, there is an inherent disincentive for utilities to invest in superior cloud-based solutions.

And further states:

> Our proposal also provides the proper incentive for us to engage in pre-paid contracts for cost-effective cloud-based solutions, which are the better option for PGE and our customers as opposed to more costly monthly or annual payments for cloud-based solutions that do not result in any savings.

PGE testifies that several other state regulatory commissions permit utilities to include certain cloud-based costs in rate base and that two California utilities recently requested rate base treatment for pre-paid license fees.[3] In addition, PGE stated that NARUC advocated for:

> …utilities to not only invest in cloud-based solutions, but for regulators to allow O&M expenses, such as license fees, associated with these cloud-based solutions to be rate based.[4]

Review of the NARUC resolution indicates that it does not advocate for rate base treatment of cloud expenses, it simple suggests that regulatory commissions consider rate base treatment of cloud expenses as shown below:

> **RESOLVED**, That NARUC encourages state regulators to consider whether cloud computing and on-premise solutions should receive similar regulatory accounting treatment, in that both would be eligible to earn a rate of return and would be paid for out of a utility's capital budget.[5]

---

3 *Id.* at 24.
4 *Id.* at 21.
5 See NARUC November 16, 2016 "Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements," available at: https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476

Q. What are the benefits identified by PGE of cost-effective cloud computing as compared to on premises computing?

A. Cloud computing is less expensive, more secure, provides greater reliability, is able to scale much faster when demands for computer processing increase significantly, can be and is updated more frequently at lower cost, provides built in redundancy in the event of natural disasters, and is more energy efficient.[6]

Q. Does Staff think it is necessary or appropriate to adopt rules that grant special accounting treatment for certain cloud-computing costs as proposed by PGE?

A. No. It is clear from PGE's own testimony that cloud computing is a superior and lower cost alternative to on premises computing, so no special incentive is required for PGE to invest in cloud computing. PGE's argument that they need an additional incentive to migrate to cloud computing because of a capital bias or that they need to "level the playing field" conflicts with the regulatory compact that a utility's duty is to manage their costs in a reasonable, business like and just manner. Utilities that fail to utilize modern and efficient services would be failing to operate reasonably irrespective of profit to shareholders. Staff does not think PGE's shareholders should be provided an additional return for making the correct economic decision to migrate their IT operations to the cloud, with the added return paid for by PGE's customers. PGE appears

---

[6] PGE/600, Ajello-Batzler/19; PGE/605.

to be embracing migration to the cloud and they do not need any additional incentive to continue the migration.

Q. Please summarize Staff's position on PGE's proposal to rate base certain cloud-related expenses.

A. Staff believes that PGE does not need additional incentives to continue its migration to cloud computing. PGE's testimony states clearly that cloud computing is a far superior product and is a lower cost alternative than on premises solutions. PGE's proposal should be rejected.

My recommendations may change based on further review and as informed by the testimonies offered by other parties.

Account 182.3 Other regulatory assets. ($000)	**-$8,277**

ISSUE 2. OVERVIEW OF PGE'S INVESTMENT IN TRANSMISSION AND DISTRIBUTION PLANT

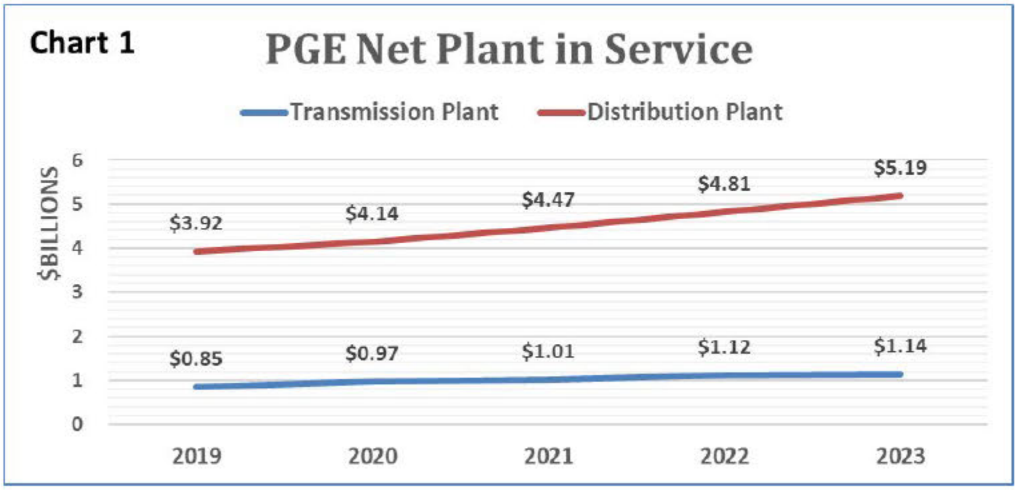
Q. Please provide an overview of PGE's investment in transmission and distribution plant in this Docket.

A. Between May 1, 2022 and December 31, 2023, PGE projects $754.8 million in new transmission and distribution plant, net of plant for wildfire mitigation. The investment categories are shown in Table 1 below:

Table 1.
PGE Transmission and Distribution Capital Additions Net of WM ($millions)

Category	Additions
Poles and Wires	481.2
Substation	200.1
Grid Modernization	68.2
Other	5.3
T&D Gross Plant Additions	**$754.8**

This is a significant increase in capital additions and continues the recent rapid growth in PGE's grid investment over the past five years. Transmission net plant in service increased by 34.3 percent, from $849 million in 2019 to an estimated $1.14 billion by 2023. Distribution net plant in service increased by 32.4 percent, from $3.92 billion in 2019 to an estimated $5.19 billion by 2023. This growth is shown in Chart 1 below:



Q. Did PGE provide a list of the new T&D projects in their testimony or exhibits?

A. No. After some back and forth in discovery, Staff ascertained through discovery a list identifying all new T&D projects in excess of $3 million that PGE proposes to be included in rate base in this general rate filing. The list includes 38 projects over $3 million comprised of eight transmission projects that total $72.1 million, and 30 distribution projects that total $561.8 million, for a total of $633.9 million, as shown in Table 2 below.

Table 2.
PGE Transmission and Distribution Capital Additions Net of WM Greater than $3 million

Category	# of Proj.	Additions
Transmission	8	$72,099,908
Distribution	30	$561,785,712
Total Transmission and Distribution	**38**	**$633,885,620**

Q. Please discuss your review of PGE's T&D projects in this docket.

A. Staff asked a series of data requests for information on project need, benefit to PGE customers, management briefings, NERC compliance requirements, method used to forecast project need, resource loaded project management reports, load/transmission service request studies, T&D risk assessment and risk reduction reports, project justification reports, economic analysis that supports project need, project line item budgets, monthly status reports and project post completion reports, among other documents. A representative list of T&D related data requests is attached as Staff Exhibit 2102.

Initially, Staff sought information on all T&D projects over $1 million but soon realized that for practicality purposes of review the project size was increased to $3 million.

Q. Was Staff able to obtain detailed cost information on the 38 T&D projects at various points of the project to determine in the project was managed prudently?

A. Staff DRs 788 through 790 asked for detailed line-item budgets for all projects (including generation and general plant) with a projected cost of over $3 million (at the date the project was approved), and the quarterly and monthly project status reports from the project start date through project completion, or the most recent month available for projects still in construction. PGE responded via email that:

> Given that there are 81 capital projects greater than $3M not currently in rate base and included in UE 416, this is a large and time-consuming request. We would like to work with you to provide information in a way that provides useful and timely information to you in a less burdensome manner. We would

> like to suggest that we provide the requested information for a sampling of 10-15 projects. If you find this agreeable, would you please provide the project numbers for the selected 10-15 projects?

Staff agreed, identified 15 projects, and asked PGE to send the requested information. The responses were provided on June 6, 2023. Staff has not yet had time to review all of the information and may revise this testimony based on PGE's response.

Q. Please discuss Staff's efforts to obtain information related to the progression and cost of projects to determine whether they were reasonably managed.

A. Staff asked for resource loaded project management schedules for all new completed and in progress T&D capital projects that PGE plans to include in rate base in this docket.

Q. What is a resource loaded project management schedule?

A. A resource loaded project schedule is a tool to help companies manage large construction projects. A resource loaded project schedule includes the cost of, labor, equipment and supplies assigned to each task in the project plan, which results in a project schedule with resource allocation and workload information and provides a detailed view of the project status and relationship to budget at any point in time. Resource loaded project schedules help management allocate resources, identify resource or schedule conflicts, allow accurate estimates of project costs, and provide accurate budget variance information over the duration of the project. Other benefits include workload balancing and the ability to make informed decisions to minimize schedule conflicts.

Q. Does PGE prepare resource loaded project schedules for its T&D capital projects?

A. Based on PGE's response to Staff DR 590, they do not:

> PGE currently does not resource or cost load its schedules due to lack of system integration capabilities and labor constraints. Instead, PGE utilizes a project schedule to manage discrete capital projects for projects within its Generation, Transmission, and Distribution Project Management Organization (PMO) Department. PGE does not utilize project schedules for repeated, programmatic work. Confidential Attachment 590-B provides the project schedules for the applicable capital projects at the beginning of the project, at the midpoint of the project, and at the end of the project.

Q. Did the information provided in response to Confidential 590-B provide any useful information?

A. No. PGE's response to Staff DR 590 contained well over one hundred pages of truncated, color coded Gannt Charts, without any cost information.[7] Staff could have requested the project schedules as computer files in Oracle Primavera or the program used to prepare the schedules, but since they did not contain cost information, Staff saw little value in pursuing this line of inquiry.

<u>Analysis of Individual T&D Projects</u>

Q. What Individual T&D projects did Staff review?

---

7 See e.g., Staff/2103, Representative PGE Response to Staff DR 590.

A. Staff performed a more detailed review of seven T&D projects; three transmission projects totaling $42.8 million, and four distribution projects totaling $255.6 million. Because of the small size of the sample, there are 35 T&D projects in excess of $3 million, and the diversity of the projects, which include substation construction/upgrades, ongoing facility replacement and purchase of equipment such as meters and transformers, the sample was based on informed judgement of projects from ongoing facility replacement, and substation upgrades. Routine equipment purchases were excluded. The total cost of projects reviewed by Staff was $298.5 million.

Reviews were based on information contained in PGE's Projects Justification Forms (PJF) supplied in response Staff DR 586, detailed line-item budgets in response to Staff DR 788, Monthly Project Status Reports in response to Staff DR 789, truncated project schedules in response to Staff DR 590, Attach-B, cash flow net present value analyses in response to Staff DR 787 (except for Memorial substation where one was not prepared), and a Post Completion Review for the Brookwood Substation in response to Staff DR 792 and PGE's March 2023 OH FITNES Program Health Report to the OPUC. None of the cash flow net present value analysis for the projects reviewed by Staff contained any information on the project benefits when completed and placed in service.

While this absence of information about project benefits is understandable for projects such as meter, transformer and other equipment purchases, it is surprising in the case of new substations built to serve load growth, particularly when a substation is built or expanded for a customer that signs a minimum load agreement. The list of the reviewed T&D project names, number, plant category and cost are shown in Table 3 below.[8]

Table 3 Staff Reviewed T&D Projects			
Project Name	**Proj. #**	**Area**	**Cost**
OH FITNES Distribution	**P37218**	**Distribution**	**$173,079,692**
Brookwood Substation Conversion	**P36680**	**Distribution**	**$61,196,673**
Orenco Substation 115kV Rebuild	**P36679**	**Transmission**	**$29,671,871**
Helvetia Substation Phase 2	**P37160**	**Distribution**	**$10,879,955**
OH FITNES Transmission	**P37061**	**Transmission**	**$9,228,514**
Downtown UG Core Cable Replacement	**P35995**	**Distribution**	**$6,709,540**
Blue Lake Phase II	**P36373**	**Transmission**	**$3,925,092**
Memorial Substation Build	**P36953**	**Distribution**	**$3,763,187**

Q. Please discuss the results of your review of sample projects.

A. Staff believes that the proposed investment OH FITNES Transmission and OF FITNES Distribution are excessive and based on a recent change in OH Pole and equipment hardware criteria that results in far more out of compliance reviews. This results in plant being replaced prematurely. We made a separate adjustment for those projects and based our disallowance on the cost of the sample projects, $298.4 million, less OH FITNES Transmission and OH FITNES Distribution, for a net reviewed plant amount of $116.1 million. Our review of the Helvetia Substation Phase 2 (Helvetia) resulted in a $4.352 million adjustment because a portion of it was built in advance of need. The

8 PGE response to OPUC DR 588 Attach A.

ratio of the Helvetia adjustment to the net reviewed plant is 3.747 percent. Staff will apply this ratio to the UE 416 Total T&D plant additions, $754.8 million, less OH FITNES Transmission and Distribution, $182.3 million, for net T&D plant additions of $638.2 million. The resulting sample-based adjustment to total T&D capital additions less OH FITNES T&D is $23.9 million.

Transmission and Distribution Plant ($000)	**-$23,913**

Q. Please discuss your review of the OH Fitness Distribution project.

A. The OH Fitness Distribution project in an ongoing program, with $173.1 million proposed for inclusion in UE 416 rate base. PGE testifies the project,

> is designed to meet the requirements of OAR 860-024-00ll(l)(b). FITNES results in the detailed inspection of 10 percent of PGE's poles and related overhead facilities each year, 100 percent of poles and facilities every 10 years. FITNES inspectors use a detailed visual inspection of structure and support systems (poles, crossarms, insulators, guys, anchors, etc.), grounding, conductor clearances and conditions, etc., as well as hammer sounding or actual measurement of remaining pole shell from grade to six feet above grade. Poles older than five years also receive remedial internal treatment The FITNES inspection is performed by contract inspection personnel who annually walk PGE's overhead electric supply lines.[9]

The project includes tasks such as pole, cross-arm and bollard replacements, which are performed by a mix of internal and external resources. The OH Fitness Distribution Project Justification Form is attached as Confidential Exhibit Staff/2104, it is only six pages of tables and provides little probative

[9] PGE/810, Bekkedahl-Jenkins/36.

information. The “Justification” consists of statements of the amount to spent on capital and O&M at 3-month intervals through November of 2022.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

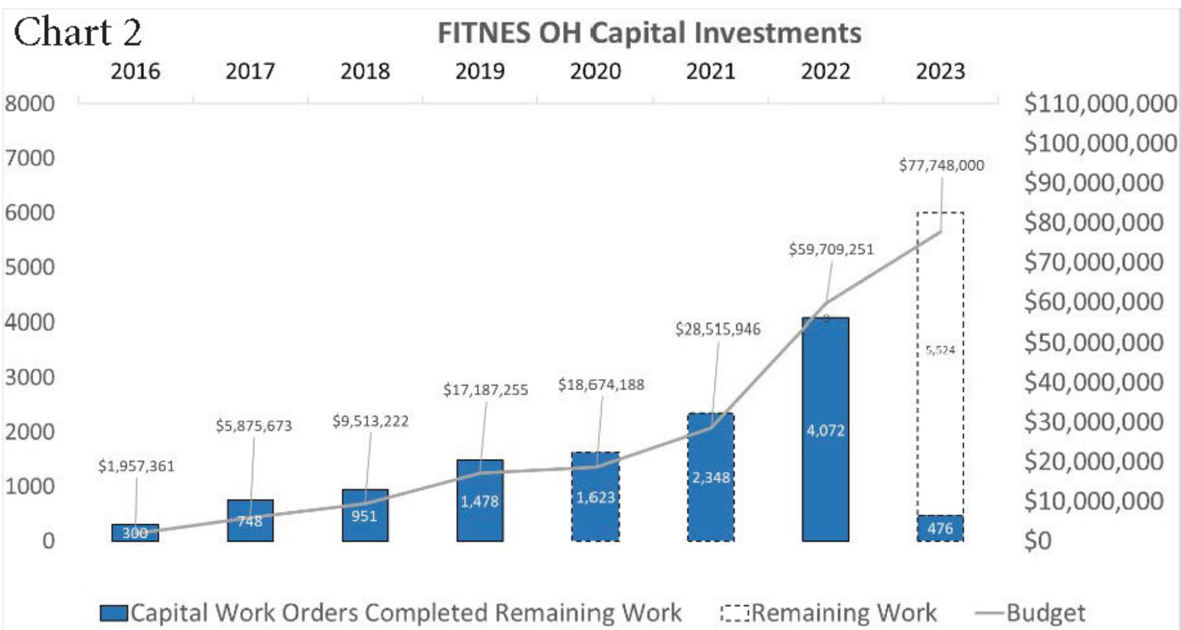
Staff is waiting on a response from PGE to a data request to reconcile the budget amounts include in the PJF to the amount included in the rate case. The OH FITNES Monthly Project Status Reports (MPSR) provide additional information and it appears from the Project Description on page one of all of the OH FITNES MPSRs is:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The OH FITNESS Distribution program is the largest single category of capital spending in UE 416 and the documentation and support for the spending is limited and PGE did not explain in sufficient detail the need for such a significant investment in this program, which is close to the cost of a small wind generation facility. Staff reviewed the March 2023 FITNES Program Health report to the Oregon PUC, attached as Exhibit Staff 2115. It provides six years of OH FITNES capital investments from 2016 through 2022, plus projected capital expenditures for 2023, as shown in the Chart 2 below:



The information in Chart 2 raises three significant issues. First, the total OH FITNES capital expenditures for 2022 and 2023 are $137.5 million, yet the UE 416 proposed rate base values are $182.3 million. Staff requested a reconciliation of the OH FITNES capital expenditures shown in the table above, with the UE 416 proposed T&D OH FITNES amounts. The second concern is the dramatic increase in OH FITNES capital expenditures beginning in 2021 when OH FITNES capital expenditures increased 52 percent over the 2020 capital expenditures. Staff's third concern is that there was likely a change recently in the criteria for pole and overhead equipment inspection, which may be a driver of the explosive in OH FITNES investment. Staff sent a series of data requests to PGE requesting information and rationale on changes in pole inspection criteria and more detailed information on work order completion and the number of out of compliance pole and overhead equipment.

Staff believes that the recent explosive growth in OH FITNES capital expenditure is the result of changes in inspection criteria and needs to review the information. Staff used the annual 2016 through 2020 OH FITNES capital expenditures from Chart 2 to develop a forecast for the 2022 and 2023 OF FITNES capital expenditures. The forecast values for 2022 and 2023 OH FITNES capital expenditures are shown in Table 4 below:

Table 4
Forecast Values of OH FITNES

	OH FITNES Capital Expenditures ($)	
Year	Actual	Forecast
2016	1,857,361	
2017	5,875,673	
2018	9,513,222	
2019	17,187,255	
2020	18,674,188	
2021	28,515,946	25,779,954
2022	59,709,251	30,123,719
2023	77,748,000	35,580,907

The T&D OH total capital expenditures for 2022 and 2023 are $65.7 million, versus the UE 416 proposed values for T&D capital expenditures of $182.3 million. Staff believes that the forecast values are a more accurate representation of what OH FITNES capital expenditures should be based on historic data. As a result, Staff believes that there are excess expenditures of $116.6 million included in the UE 416 T&D portion of rate base. Using the ratio of OH FITNES Distribution and OH FITNES Transmission to Total OH FITNES, the OH FITNES Distribution is $110.7 million. Because the plant appears to be replaced prematurely, Staff's adjustment is to have a permanent rate base adjustment equal to 25 percent of the total amount representing the time value of replacing plant ahead of need. Therefore the adjustment amount is $27.7 million. Staff reserves the right to adjust this amount based on responses to Staff data requests. The OH Fitness Distribution Project Justification Form is attached as Confidential Exhibit Staff/2104.

Distribution Plant ($000)	**-$27,675**

Q. Please discuss your review of the Brookwood Substation Conversion Project.

A. The Brookwood Substation Conversion Project (Brookwood) is a proposed $61.2 million increase to rate base and is a component of PGE's Hillsboro Reliability Project. The Brookwood Substation supports industrial, manufacturing and data center load growth and was placed in service in

December 2022.[10] The PJF for this project contains 39 pages of tables dating back to June 2021.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Staff reserves judgment on the reasonableness of costs until it completes a review of responses to Staff data requests. The Brookwood Project Justification Form is attached as Confidential Exhibit Staff/2105. The Brookwood Post Completion Review is attached as Confidential Exhibit Staff/2106.

Q. Please discuss your review of the Orenco Substation 115 kV Rebuild.

A. The Orenco Substation 115 kV Rebuild is a $29.7 million project and is also a part of PGE's Hillsboro Reliability Project. PGE states the Orenco Substation is designed to improve T&D reliability, alleviate existing heavily loaded equipment, provide operational flexibility and addresses a potential NERC

---

[10] PGE/200, Bekkedahl-Jenkins/7.

compliance issue.[11] The PJF contained 40 pages of tables dating from January of 2019 and contains the following description of the project:

[BEGIN CONFIDENTIAL]

[redacted]

[redacted][12]

[END CONFIDENTIAL]

The narrative in the Orenco PJF identified several instances of both relatively minor positive and negative variances from the original estimates, which were reasonable considering the size and complexity of this project.

Based on review of the documentation provided by PGE, the costs of the Orenco project are reasonable. The Orenco Substation 115 kV Rebuild Project Justification Form is attached as Confidential Exhibit Staff/2107.

Q. Please discuss your review of the Helvetia Substation Phase 2.

---

[11] *Id.* at 7.
[12] Staff/2106, PGE Confidential Response 586_A, page 2 of 9.

A. The Helvetia Substation Phase 2 (Helvetia) is a $10.9 million project intended to serve additional load to a large customer under a Minimum Load Agreement. The project will add a third and fourth 50 MVA transformer at the Helvetia substation.[13] The project was placed in service in 2023. The PJF contained 15 pages of tables dating from May of 2021 and contains the following description of the project:

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

---

[13] PGE/200, Bekkedahl-Jenkins/8.
[14] Exhibit Staff/2108, page 3.
[15] Exhibit Staff/2109, page 3.

Because the MLA agreement shows that the 2024 customer load is well below the additional capacity installed at Helvetia, Staff believes that only 60 percent of the Helvetia substation capacity is need to serve 2024 customer loads. It will adjust Helvetia Substation rate base by 40 percent, or $4.352 million, which will be used to calculate the sample-based adjustment to total T&D capital additions discussed above. Staff reserves the right to modify this adjustment based on review of DR from PGE. The Helvetia PJF for this project is attached as Highly Confidential Exhibit Staff/2108. The Helvetia MLA is attached as Highly Confidential Exhibit Staff/2109.

Q. Please discuss your review of the OH FITNES Transmission.

A. The OH FITNES Transmission is a proposed $9.2 million ongoing project and is the transmission equivalent of the OH FITNES Distribution project discussed above. The PJF for this project contains 12 pages of tables.

[BEGIN CONFIDENTIAL]

[redacted]

[16] Exhibit Staff/2110, Page 8.

[redacted]

[END CONFIDENTIAL]

Based on the discussion in OH FITNES Distribution above, Staff believes As a result, Staff believes that there are excess expenditures of $5,902 million to OH FITNES Transmission include in UE 416 rate base. Again, taking 25 percent of the value for premature replacement results in a permanent rate base reduction of $1.5 million. This is a permanent rate base adjustment. Staff may adjust this amount based on responses to Staff data requests. The OH FITNESS Transmission PJF is attached as Confidential Staff Exhibit 2110. The OH FITNES Transmission Project Status Reports are attached as Confidential Exhibit Staff 2111.

Transmission Plant ($000)	**-$1,475**

[17] Exhibit Staff/2111, Pages 2, 5, 8, 11, 14.
[18] *Id.,* Page 3.

Q. Please discuss your review of the Downtown Core UG Cable Replacement.

A. The Downtown Core UG Cable Replacement (Downtown Cable) is a proposed $6.7 million ongoing project that began in 2013. The fifteen-page PJF describes the history of the project:

[BEGIN CONFIDENTIAL]

[redacted]

The PJF indicates that there are no alternatives to this project:

[redacted]

[redacted]

[redacted] [redacted]2112, Young/3

[20] *Id.* Page 3.

[redacted]

[END CONFIDENTIAL]

Based on review of the PJF and the MPSRs the costs of the Downtown Cable project are reasonable.

The Downtown Core UG Cable Replacement PJF is attached as Confidential Exhibit Staff/2112.

Q. Please discuss your review of the Blue Lake Phase II.

[BEGIN CONFIDENTIAL]

A. [redacted]

[END CONFIDENTIAL]

---

21 *Id.* Page 4

22 *Id.*, Page 4

The project was completed in 2022. There also is a distribution component to this project that will be completed in 2024 that is not included in this docket. The PJF was descriptive and provided a good overview of project. The costs of the projects appeared reasonable. The 21-page Blue Lake Phase II PJF is attached as Confidential Exhibit Staff/2113.

Q. Please discuss your review of the Memorial Substation Build.

A. The Memorial Substation Build (Memorial) is a proposed $3.8 million project to build a new substation in Wilsonville to support area load growth and

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

---

23 Staff Exhibit 2114/5, Potential Project Consequences, Justification 1.
24 *Id.*, Page 8
25 *Id.*, Page 13
26 *Id.*, Page 13

[redacted]

[END HIGHLY CONFIDENTIAL]

After review of the responses to Staff data requests, Staff believes the project is reasonable. The Memorial Substation 14-page PJF is attached as Highly Confidential Staff Exhibit Staff/2114.

Q. Does this conclude your review of PGE's T&D Projects?

A. Yes. My recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2101

Resume of Robert Young

June 13, 2024

RESUME OF ROBERT E. YOUNG

ROBERT E. YOUNG **Managing Director**
Economists.com **Portland, Oregon**

***"Innovative Solutions for
21st Century Infrastructure Industries"***

SUMMARY:

Mr. Young has extensive experience in economic, regulatory and financial and information technology consulting for the utility industry. Mr. Young advises several Pacific Island Electric utilities on diesel and solar generation, integrated resource planning, cost of service and rate design, and fuel adjustment clause design. He served recently as Staff of the Guam Public Utility Commission on water and wastewater regulation.

As part of the Glarus Group Team, Mr. Young used the AURORAxmp electric market forecasting and resource planning model to estimate the benefits of increased power sales between the **Mountain West Transmission Group** (MWTG) and the **Southwest Power Pool** (SPP).

Mr. Young worked as part of the Modern Grid Solutions team which advised **Puget Sound Energy** on the redesign of the distribution grid in preparation for high penetration of distributed energy resources such as roof-top solar, electric vehicles, and energy storage. Projects included development of ADMS business case, integration of distribution planning into an integrated resource plan, prepared a feeder level forecasting whitepaper, distributed energy resource (DER) vision and strategy and preparation of IRP chapter in integration of distribution planning,

He served recently as Staff of the Guam Public Utility Commission on water and wastewater regulation. Prepared expert testimony in regulatory proceedings filed by Guam Waterworks Authority, Guam Public Utility Commission Docket 19-08, Phase 1 and Phase 2.

Mr. Young serves on the Advisory Board of Digital Iron Network, a startup that plans to build a global network of Nvidia DGX-H100 supercomputers.

Mr. Young worked with Intel on a high-performance computing initiative to improve the performance of computer models used to prepare Integrated Resource Plans. He consulted with electric utilities concerning entry into the telecommunications business and developed a fiber optic strategy for Bonneville Power Administration. In addition, he developed a financial model of the fiber program for BPA and provided litigation support for a dispute with a telecom company that leased some of BPA's fiber.

Mr. Young has provided expert testimony on cost allocation and rate design before the Oregon Public Utility Commission, the Washington Utilities and Transportation Commission (WUTC), Guam Public Utilities Commission, Commonwealth Public Utilities Commission of the US Commonwealth of the Northern Marianas Islands, the Bonneville Power Administration (BPA), and the U.S. Department of Commerce.

Robert Young served as the lead damages witness for Isolux, a large multi-national construction company that built over $800 million of transmission plant for an independent transmission company as part of the $7 billion Texas Competitive Renewable Energy Zone project, designed to integrate wind generation from west Texas into central Texas, the location of most of the state's electric load.

Assisted Rio Tinto in the $38 billion acquisition of Alcan Aluminum in 2007. Working directly for CFO, Mr. Young provided a valuation of Alcan's over 4,100 MW of hydro generation and other merger related issues.

Mr. Young prepared an expert report and reply report in a contract dispute between two aluminum companies before the International Chamber of Commerce, International Court of Arbitration.

Developed an information systems architecture plan for the Transmission Business Line (TBL). Mr. Young advised TBL on the development of new transmission billing, metering, scheduling, and contracts systems. He has also provided strategic consulting to US Generating Co. and PacifiCorp. Mr. Young has assisted large high-tech manufacturing companies with negotiating open access electric power sales agreements and advised a large independent power producer on electric power pricing issues for a proposed new aluminum smelter.

Mr. Young taught a variety of classes on engineering economics, regulatory economics and accounting, rate of return, cost allocation and rate design, and economic and financial analysis at numerous utilities in the US and in small Pacific Island utilities. He enjoys teaching classes to the next generation of electric utility industry leaders throughout the world and has in excess of 500 in-class hours of electric utility training experience.

Represented the **Oregon Department of Corrections** (DOC) in contract negotiations and mediation of rates for fire service at the Snake River Correctional Institution (SRCI). Worked with DOC management and Oregon Department of Justice attorneys to research comparable rates for SRCI fire service and developed a financial model of the Ontario Fire Department to determine their cost of fire service for SRCI.

Developed a comprehensive capital budgeting methodology for the transmission group of **Saudi Electricity Company**.

Represented **Energy Northwest** (then Washington Public Power Supply System, **Portland General Electric**, **and Xcel Energy** (then Public Service of Colorado) on setting rates for disposal of low-level-radioactive waste before the Washington Utilities and Transportation Commission.

Mr. Young taught a variety of classes on engineering economics, regulatory economics and accounting, rate of return, cost allocation and rate design, and economic and financial analysis at numerous utilities in the US and small Pacific Island utilities. He enjoys teaching classes to the next generation of electric utility industry leaders throughout the world and has more than 500 in-class hours of electric utility training experience.

Mr. Young received a B.S. and a M.S. in Economics from Southern Illinois University.

PROFESSIONAL EXPERIENCE

ECONOMISTS.COM **Portland, Oregon**

Managing Director

- Analyzed engineering, economic, and regulatory issues related to competitive alternatives to **Commonwealth Utilities Corporation** (CUC) energy services to its customers, including solar, wind, liquefied natural gas, and new diesel generation. Provided estimates of the costs to customers of alternative energy supplies, and assisted CUC with the development of their first integrated resource plan. Testified in Commonwealth Public Utility Commission Dockets 13-01, 15-01 and 16-01

- Assisted **Commonwealth Utilities Corporation** with analysis of responses to a fuel supply contract. Served on CUC's Source Selection Committee that awarded a new six-year fuel supply contract that represents almost 70% of CUC's annual operating expense.
- Provides rate design, financial strategy, resource planning, fuel supply, and other services to the **Guam Power Authority**, **Commonwealth Utilities Corporation, American Samoa Power Authority**, **Electric Power Corporation of Samoa, and the Palau Public Utilities Corporation.**
- Developed a comprehensive information systems strategic plan for **Bonneville Power Administration Transmission Business Line**. Elements included business imperatives for change, assessment of existing technology, new information technology architecture, data governance, and data stewardship, and implementation plan.
- Advised **Bonneville Power Administration** on the development of new transmission billing, metering, scheduling, and contracts systems.
- Assisted in the development of an IT strategic plan for **Guam Power Authority**. Reviewed existing IT governance processes, operations, software and data architecture, networks, hardware assets, and controls. Compared to industry best practices for similar utilities. Recommended changes in IT funding levels and priorities. Assisted in resolving network performance issues.
- Assisted **Bonneville Power Administration** with the development and implementation of the 2008 Average System Cost Methodology (ASCM). Researched accounting issues and prepared issue papers related to the use of the FERC Form 1 as the basis for the new ASCM. Appeared as an expert witness in WP-07S and WP-10 BPA Rate Cases on ASC technical and policy issues. Identified regulatory and financial concerns of participating public and private utilities, and analyzed economic, legal, and political factors. Reviewed transfer pricing arrangements between PacifiCorp and its mining subsidiaries. Addressed customer and party concerns in resolving complex program issues. Reviewed and analyzed over 60 ASCM filings by participating utilities.
- Provided a variety of energy management services for **Nordstrom**. Reviewed electric and gas commodity contracts, assessed performance vs. regulated tariffs, and recommended a revised portfolio strategy. Prepared annual electricity budget and quarterly variance report for over 200 Nordstrom facilities nationwide. The electricity budget for kWh sales and revenue were consistently within 1% on kWh sales and 2% on cost. Defined requirements for a new energy information management system and processing of energy bills, identified viable vendors and assisted in vendor selection.
- Reviewed energy risk management policies and practices at **Snohomish PUD**. Identified board objectives for risk management and clarified risk preferences, reviewed risk management manual and formalized practices, and tested risk metrics and analytical methods. Reviewed governance structure, controls, trading book documentation, and trading processes

for both physical and derivative transactions. Recommended appropriate risk management improvements, and outlined methods for integrating risk management and resource planning more effectively.

- Provided litigation support for **Snohomish PUD** in litigation before the FERC. Litigation focused on alleged overcharges, unreasonable contractual terms, and exercise of market power by certain power marketers during the Western power crisis of 2000-2001. Quantified economic impacts on clients, identified bounds for just and reasonable terms based on competitive market fundamentals, and accepted industry practices demonstrated compelling public interest to justify contract modification, and outlined proposed remedies. Supported client counsel in case strategy, discovery, and briefing.
- Developed North American market strategy for **Alstom's** Energy Management and Markets business unit. EMM is a leading vendor of critical operations control and telecommunication systems for electricity and gas companies. Identified critical business issues facing Alstom's customers, assessed profitability and attractiveness of available segments of the customer value chain, analyzed competing vendors and recommended break-out growth strategy. Developed business case tool and assisted in the rollout of the sales campaign. Drove a major strategic alliance with a global electronics manufacturer
- Served as an expert witness in an arbitration proceeding for **Kaiser Aluminum** against Rio Tinto/Comalco before the International Chamber of Commerce, International Court of Arbitration concerning legal disputes related to the enforceability of commodity supply contracts in unusual market conditions during the West Coast electricity crisis. Identified key issues to be addressed, used electric industry market data and personal expertise to compile the documentary record, analyzed market fundamentals and related price behavior, and drafted initial and reply reports. Considered issues related to client bankruptcy filings. Coordinated with outside and inside counsel in case strategy, discovery, depositions, hearings, and briefs.
- Provided acquisition integration assistance to the President of **US Generating Co**. for the transformation of the Boston, MA. office of the former J. Makowski & Associates into US Generating's first major regional office. Defined overall organizational structure for the regional office, integrated and refined strategic direction and intent of the consolidated organization, and communicated results to Boston office staff.
- Successfully represented **Norsk Hydro Canada, Inc.,** (NHCI) owner of the largest magnesium plant in North America, in defense of a counter-veiling duty petition filed by a U.S. Magnesium producer. The petition argued that the variable rate power contract between NHCI and Hydro Quebec constituted a government subsidy. Prepared a report and briefed U.S. Commerce Department staff on utility rate design and cost allocation for large industrial customers and the worldwide development and use of variable rate power contracts for large, nonferrous metal smelters. Presented Oral Argument before the US Department of Commerce during the hearings phase of this dispute.
- Reviewed energy risk management policies and practices at **Snohomish PUD**. Identified board objectives for risk management and clarified risk preferences, reviewed risk management manual and formalized practices, tested risk metrics and analytical methods. Reviewed governance structure, controls, trading book documentation, and trading processes for both physical and derivative transactions. Recommended appropriate risk management

improvements, and outlined methods for integrating risk management and resource planning more effectively.

- Provided litigation support for **Snohomish PUD** in litigation before the FERC. Litigation focused on alleged overcharges, unreasonable contractual terms, and exercise of market power by certain power marketers during the Western power crisis of 2000-2001. Quantified economic impacts on clients, identified bounds for just and reasonable terms based on competitive market fundamentals and accepted industry practices, demonstrated compelling public interest to justify contract modification, and outlined proposed remedies. Supported client counsel in case strategy, discovery, and briefing.
- Assisted the **City of Portland** with determining the effects of electric utility restructuring on franchise fee revenues after Oregon Senate Bill 1149 was signed into law. Analyzed the effect of a volumetric approach to franchise fee collection on revenues and customer classes for SB 1149. Prepared report for the City of Portland analyzing various volumetric franchise fee scenarios consistent with the provisions of SB 1149.
- Assisted an Independent Power Producer in preparation of responses to utility resource RFPs. Reviewed and analyzed responses to public utility resources RFPs. Assisted in the development and sale of a proposed wood-fuel resource in British Columbia.
- Assisted **PacifiCorp** in the development of their least-cost plan, Resource and Market Planning Program-3.
- Negotiated open market electric power sales contracts under PGE's Customer Choice Pilot Program for **Komatsu Silicon America** and **Integrated Device Technology**. Assisted **NEC America** with contract negotiations and analysis for an open market electric power sales contract.
- Represented the **Port of Morrow**, an Oregon port district in economic, financial, and regulatory matters for the construction of two 220 MW cogeneration units.
- Reviewed cable TV rate filings for a variety of cities across the US. Analyzed rate design, cost allocation, and rate of return for compliance with FCC regulations.
- Assisted **BPA** in preparation of its Business Plan Environmental Impact Statement (BPEIS). Faced with continuous radical changes in the electric utility industry, BPA engaged in an intensive and thorough review of its business strategy. The result was BPA's Business Plan and the associated BPEIS, which were published in 1995. The BPEIS was used as the basis for several BPA Record of Decisions including new transmission agreements for BPA's large industrial customers (DSIs). These new contracts were challenged at the 9th Circuit Court of Appeals by a group of BPA customers and others. The 9th Circuit affirmed BPA's right to offer new transmission agreements and the validity of the BPEIS.
- Advised major European energy company on West-coast electric market economics and performed feasibility analysis on location of new generating capacity in the Pacific Northwest.
- Reviewed and external benchmarking study for Portland General Electric.

DELOITTE & TOUCHE CONSULTING **Portland, Oregon**

Manager

- Managed consulting team of over 15 financial analysts, auditors, and economists to assist **Bonneville Power Administration** in administering the Average System Cost rate equalization program. This program distributes over $150 million annually to Northwest utilities for equalizing residential electric rates. Identified regulatory and financial issues relating to participating public and private utilities, and analyzed economic, legal, and political factors. Incorporated customer and party concerns in successfully resolving complex issues facing the program. Reviewed and analyzed over 75 cost allocation and rate design studies for compliance with Average System Cost Methodology procedures.
- Assisted **Bonneville Power Administration**'s Transmission Business Line with the development of a revenue forecasting system. Specified business objectives and functional requirements for actual and forecasted revenue by product, customer, and contract. Evaluated software and hardware options, and developed high-level system design. Planned package modification, programming, testing, and roll-out of the completed system.
- Conducted a study for **Bonneville Power Administration** comparing transmission operations and maintenance practices and management at five large North American utilities. Conducted on-site visits, developed engineering and accounting information consistently across utilities, analyzed system characteristics, and compared key practices and performance measures.
- Directed a team of consultants which developed a comprehensive model of the resource plans, finances, and rates of over sixty Northwest utilities **for Bonneville Power Administration**. Developed load/resource balance models, reviewed and revised load forecasts, developed resource stacks ordered by cost-effectiveness, projected long-term resource additions and financial impacts, and analyzed key sensitivities.
- Directed **Bonneville Power Administration** team in analysis and position development in utility merger regulatory proceedings before state PUCs and FERC. Determined operational and financial effects of the PP&L/UP&L merger, reviewed transfer pricing arrangements between PacifiCorp and Utah Power and Light and their coal mining subsidiaries, reviewed filings, and drafted testimony. Assessed competitive implications.
- Managed the development of the Financial Strategy for **Bonneville Power Administration**. This strategy was used as the basis for the development of BPA's long-term financial plan, resulting in positive Net Revenues (retained earnings) for the first time in over 10 years.
- Directed an analysis to determine the price for the sale of long-term transmission rights for **Bonneville Power Administration**. Identified highest-value transactions over the line, determined net benefits, evaluated private opportunity costs, considered market constraints on pricing, assessed regulatory and technological risks, and developed positions on financing and contractual issues.

DIRECT SERVICE INDUSTRIES, INC. Portland, Oregon
Director of Rates and Technical Issues

- Responsible for the coordination of policy analysis on all energy issues affecting member companies of Direct Service Industries, Inc., a trade association consisting of 11 members with 15 energy-intensive plants whose annual electric energy cost exceeded $700 million per year and purchased over 3,200 AvMW of electricity at full production.
- Participated in the development of a detailed production-costing model of the Pacific Northwest aluminum industry. The model forecasts aluminum industry electricity loads and revenues.

Portland General Electric Company Portland, Oregon
Rate Analyst

- Developed a 20-year generation-expansion model to determine the need for future generating resources.
- Designed electric rates and prepared cost-of-service studies.

Professional Memberships (and Offices Held)

Western Energy Institute Executive Committee, Board of Directors 2016

Western Energy Institute Board of Directors 2003 – 2006, 2013 – 2016

American Nuclear Society

Civic/Charitable Organizations (*selected, and offices held*)

Ainsworth Public School Foundation

Co-Chair Board of Directors 2003 - 2005

Board of Directors, 2002 - 2005

Oregon Ballet Theatre

Treasurer, Board of Directors, 1992 - 1993

Board of Directors, 1989 - 2002

Pacific Ballet Theatre

Vice-President, Board of Directors, 1986-1988

Treasurer, Board of Directors, 1985-1986

Board of Directors, 1984-1988

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2102

OPUC Staff representative Transmission and Distribution Data Requests

June 13, 2024

April 19, 2023

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND, OR 97204
pge.opuc.filings@pgn.com

RE:

Docket No.	OPUC Request Nos.	Response Due By
UE 416	PGE UE_416 OPUC DR 586-593	May 3, 2023

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with all cell references and formulae intact.

Topics or Keywords: Project Management, T&D Capital Projects
Contains Standing Data Requests

586. Please provide any briefings to PGE management on the status of all capital transmission and distribution projects in excess of $1 million that PGE proposes to be included in UE 416 rate base that reflects capitalized plant not included in current rates.

587. Please provide a list of project management software programs used by PGE to manage capital projects. If there is more than one project management software program used, please explain the factors that influence which project software is chosen to be used for capital projects.

588. For all capital transmission and distribution projects in excess of $1 million that are included in UE 416 rate base please provide the following information:

    a. Project number and description including why it was necessary and how ratepayers will benefit;

    b. Date the project was placed into service or is expected to be placed into service;

    c. Final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service;

d. FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General);

e. Capital spending by month;

f. Date and amounts of transfers to plant;

g. Documents associated with project approval, including approval of any substantial changes (such as project justification forms);

h. One-line diagrams, as applicable; and

i. Reference the Company's direct testimony and exhibits in this case if applicable.

589. For each capital transmission and distribution project included in UE 416 rate base where the Company determined a project was needed to meet NERC compliance requirements, please provide the following information:

a. A narrative description of how the need to meet NERC compliance requirements factored into decision-making for the project;

b. Any analysis associated with meeting NERC compliance requirements for the project; and

c. A narrative description of any unresolved NERC compliance requirements, and future projects which may result.

590. For all capital transmission and distribution projects in excess of $1 million constructed by PGE that that are included in UE 416 rate base:

a. A narrative explanation of how the Company forecasted growing need or load for each particular project.

b. All applicable distribution or transmission planning documents, such as load service request/transmission service request studies or Minimum Load Agreements, demonstrating forecasted load growth.

c. Please provide a copy of a resource loaded schedule for all completed capital projects at the beginning of the project, at the midpoint of the project and at the end of the project.

d. Please provide a copy of a resource loaded schedule for all in-progress capital projects at the beginning of the project, at the midpoint of the project and the most recent version of the resource-loaded schedule.

591. For all capital transmission and distribution projects constructed by other companies for PGE in excess of $1 million that PGE proposes to be included in UE 416 rate base that reflects capitalized plant not included in current rates:

a. A narrative explanation of how the Company forecasted growing need or load for each particular project.

b. All applicable distribution or transmission planning documents, such as load service request/transmission service request studies or Minimum Load Agreements, demonstrating forecasted load growth.

c. Please provide copies of all sections of the contract between PGE and the companies constructing the project that pertain to project management.

d. Please provide a copy of a resource loaded schedule for all completed capital projects at the beginning of the project, at the midpoint of the project and at the end of the project.

e. Please provide a copy of a resource loaded schedule for all in-progress capital projects in excess of $10 million at the beginning of the project, at the midpoint of the project and the most recent version of the resource-loaded schedule.

592. Please provide the Strategic Asset Management department's annual T&D risk assessment, and the associated portfolio of recommended risk reduction projects for 2021, 2022 and 2023 (indicating if projected or actuals).

593. For all capital transmission and distribution projects in excess of $1 million that are included in UE 416 rate base please provide the following information: **This is a Standing Data Request to be supplemented with any new reporting as that is available.**

a. Project Justification Report;

b. Any Change Orders; and

c. Any Project Post Completion Report.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

May 11, 2023

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND, OR 97204
pge.opuc.filings@pgn.com

RE:

Docket No.	OPUC Request Nos.	Response Due By
UE 416	PGE UE_416 OPUC DR 784	May 25, 2023

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with all cell references and formulae intact.

Topics or Keywords: Project Management, Information Technology Capital Projects

784. Please provide PGE's 2023 projected Transmission and Distribution plant balances by FERC Account based on the format of the attached Excel File UE 416_OPUC DR 784 Attachment A.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

May 15, 2023

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND, OR 97204
pge.opuc.filings@pgn.com

RE:

Docket No.	OPUC Request Nos.	Response Due By
UE 416	PGE UE_416 OPUC DR 787-793	May 29, 2023

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell references and formulae intact.

Overall Topic or Keyword: Capital Projects
Testimony Reference: PGE/700; Bekkadahl, Jenkins, Section II Capital Projects Since UE 394 and PGE/800; Bekkadahl, Jenkins, Section II PGE's Generation Resources

Topic or Keyword: *Capital Projects*

787. For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, please provide all economic analysis used to prepare the Project Justification Forms produced in response to OPUC Request Nos. 586 and 628.

788. For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, please provide a detailed line-item budget from the date the project was approved.

789. For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, please provide the Monthly Project Status Report quarterly, from the date the project was started until it was placed in service.

790. For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, that is still under

construction, please provide the Monthly Project Status Report quarterly, from the date the project was started until the most recent report available.

791. See the excerpt below from UE 416_OPUC DR 626_Attach A, projects in FERC Form 1 CWIP at 12/31/2022 and the two highlighted columns referencing Project Total amounts from PGE's New Construction Budget Report for the 2023 calendar year filed with the OPUC on April 3, 2023.

Line No.	FP Description (PP)	Funding Project	CWIP @ 12/31/2022	In-Service Date(s)	Final Project Cost	New Construction Budget Report 2023 (filed 4/3/2023)	New Construction Budget Report Project Total Greater (Less) Than Final Project Cost	FERC account category	Reference to PGE's direct testimony, as applicable
1	FY: Repower Faraday Units 1-5	P36167	168,332,602	March 2017 January 2023	188,067,480	173,838,281	(14,229,199)	Hydro Production	PGE Exhibit 800, Section V
2	powERPlay	P37346	22,953,607	August 2023	37,595,820	33,142,867	(4,452,953)	Intangible Plant	PGE Exhibit 600, Section III.B
5	Hydro Control System Upgrade	P36134	13,928,197	December 2018-October 2024	35,224,139	36,260,289	1,036,150	Hydro Production	Not explicitly referenced
6	Build Evergreen Substation	P36666/P36422	22,236,911	May 2024	116,595,680	34,903,843	(81,691,837)	Transmission Plant	Not included in UE 416
10	Facilities Upgrades-EV Readiness	P37017	8,314,688	December 2022 February 2023 June 2023 August 2023 June 2024 February 2025 December 2025	16,137,739	19,619,074	3,481,335	General Plant	Not explicitly referenced
12	Substation Communication Upgrade	P36101	7,794,354	November-December 2020 July 2021 December 2026	47,011,909	55,283,032	8,271,123	General Plant	PGE Exhibit 700, Section IV, discussed generally on pages 21-27
13	RB: Replace Turbine Shut-off Valves	P36838	7,716,735	January 2023 December 2023 January 2025	35,130,724	10,553,110	(24,577,614)	Hydro Production	Not explicitly referenced
18	South Milliken Line Rebuild	P36617	4,524,716	November 2023 - June 2027	11,660,623	14,093,496	2,432,873	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
21	BR: Beaver Modernization	P36836	3,897,887	July 2022 August 2023 April-December 2024 May-December 2025 January 2026	122,585,726	57,406,880	(65,178,846)	Other Production	PGE Exhibit 800, Section II, "PGE's Generation Resources" on pages 2-3.
25	PW2: Top End Engine Parts and Insta	P37417	3,206,684	December 2024	12,578,000	10,615,088	(1,962,912)	Other Production	Not included in UE 416

Provide the following information concerning the above table.

a. Explain why all projects listed in PGE's New Construction Budget Report for the 2023 calendar year with start dates of 2023 or earlier are not included in CWIP at 12/31/2022 if the project is not yet completed or is ongoing?

b. Explain what the Final Project Cost amount in UE 416_OPUC DR 626_Attach A represents.

c. Explain what the Project Total amount in PGE's New Construction Budget Report for the 2023 calendar year represents.

d. Explain what the variances between Final Project Cost and Project Total represent.

e. For each project listed in Schedule B: Electric Company New Construction Budget (System) in PGE's New Construction Budget Report for the 2023 calendar year, explain why the Total amount reflecting the sum of actual to date and all current and future budget years is different from the Project Total amount in the Project Narrative section of the report for those projects where a variance exists.

792. Referring to PGE's response to UE 416 OPUC DR 706, part (e), provide post completion reports for all capital projects in excess of $3 million other than transmission and distribution in the UE 416 rate base.

793. Referring to PGE's response to UE 416 OPUC DR 706, part (h), explain the following excerpts in more detail in PGE's statement in the second sentence of the response and provide relevant sections of PGE's accounting manual that describes the asset unitization process.

a. "After a reasonable trailing charge period,…"

b. "…PGE will unitize the related assets to their final utility accounts, units of property (retirement units), and asset locations."

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.
You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to
puc.datarequests@puc.oregon.gov

May 17, 2023

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND, OR 97204
pge.opuc.filings@pgn.com

RE:

Docket No.	OPUC Request Nos.	Response Due By
UE 416	PGE UE_416 OPUC DR 796-801	May 31, 2023

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell references and formulae intact.

Overall Topic or Keyword: Capital Projects – 2023 Forecasted Plant Additions
Testimony Reference: PGE/700; Bekkadahl, Jenkins, Section II Capital Projects Since UE 394 and PGE/800; Bekkadahl, Jenkins, Section II PGE's Generation Resources

Topic or Keyword: *Capital Projects*

796. Explain how 2023 forecasted capital additions by project greater than $3 million provided in UE 416_OPUC DR 627_Attach A can be traced to PGE's listing of all 2023 forecasted capital additions in UE 416_AWEC DR 039_Attach A, tab "2023 FCST Plant Activity – Adds".
797. Provide a reconciliation of 2023 forecasted plant additions for each project listed in UE 416_OPUC DR 627_Attach A to the relevant line items that comprise each project in UE 416_AWEC DR 039_Attach A, tab "2023 FCST Plant Activity – Adds" and explain all differences in 2023 forecasted plant additions by project.
798. Referring to UE 416_OPUC DR 588_Attach A, confirm whether all transmission and distribution capital projects in excess of $3 million included in the UE 416 rate base were initiated in 2023.
    a. If the answer is no, explain why each of these projects are not included in the Construction Work in Progress project listings for the years 2021 and/or 2022 in UE 416_OPUC DR 626_Attach A.

b. If the answer is yes, confirm whether each of these projects should be included in the 2023 plant additions listing in UD 416_OPUC DR 627_Attach A. If not, explain why not.

799. Referring to UE 416_OPUC DR 626_Attach A, explain whether the Final Project Cost amounts in column (b)

800. Referring to UE 416 OPUC DR 586, Confidential Attachment 593-A, explain why PGE provided a post completion report for only one project, P36439. PGE's response should include an explanation of how soon a post completion report is issued once a project is ready to be transferred to plant-in-service.

801. Referring to PGE's Project Justification Forms produced in response to UE 416 OPUC DR 586 and 628, explain which amount or amounts in the Revision Summary section of each form should be used to compare to (1) PGE's Final Project Cost amounts in UE 416_OPUC DR 626_Attach A for projects in 2021 and 2022 Construction Work in Progress and (2) PGE's proposed 2023 Forecasted Plant Additions in UE 416_OPUC DR 627_Attach A to identify whether a project's actual expenditures exceeded or are less than the approved funding.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.
You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

May 22, 2023

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND, OR 97204
pge.opuc.filings@pgn.com

RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 416	PGE UE_416 OPUC DR 807-809	June 5, 2023

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with all cell references and formulae intact.

Overall Topic or Keyword: Capital Projects – 2023 Forecasted Plant Additions
Testimony Reference: PGE/700; Bekkadahl, Jenkins, Section II Capital Projects Since UE 394 and PGE/800; Bekkadahl, Jenkins, Section II PGE's Generation Resources

Topic or Keyword: *Capital Projects*

807. Referring to UE 394_OPUC DR 311_Attach A, provide a schedule of all UE 416 plant additions by project number from April 30, 2022 through December 31, 2023. Additions should be broken out in the same manner as UE 394_OPUC DR 311_Attach A such as Table 1 Grouping fields, By Function fields, and In Service Dates.

808. Refer to PGE's response to UE 416 OPUC DR 628, Confidential Attachment A, containing Project Justification Forms for capital projects other than transmission and distribution greater than $3 million. Produce the Project Justification Forms for the following projects listed in PGE's response to UE 416 OPUC DR 626, Attachment A, that were not produced in response to UE 416 OPUC DR 628.

    a. P36101 – Substation Communication Upgrade;

    b. P36838 – RB: Replace Turbine Shut-Off Valves; and

c. P37477 – Zero Trust

809. Refer to PGE's response to UE 416 OPUC DR 628, Confidential Attachment A, containing Project Justification Forms for capital projects other than transmission and distribution greater than $3 million. Also, refer to the Attachment A workbooks produced in response to UE 416 OPUC DRs 626 and 627. Confirm whether each project listed below has an amount representing the cost being included in the UE 416 rate base that was part of either 2021 CWIP, 2022 CWIP, or 2023 Forecasted Capital Additions in UE 416 OPUC DRs 626 and 627. If the answer is yes, provide the amount. If the answer is no, explain why not.

a. P23528 - Clackamas PME - Recreation, Aesthet.pdf;

b. P35172 - PSES - Generation Fitness Fund.pdf;

c. P36116 - Wind Generation Fitness Program.pdf;

d. P36394 - Vintage Vehicle Replacement II.pdf;

e. P36449 - PRB Upgrade Governors & Exciters.pdf;

f. P36501 - Integrated Operations Center - IOC.pdf;

g. P37162 - Bill Redesign.pdf;

h. P37176 - Eastern Gen Admin Building-Carty.pdf;

i. P37251-PACS 2.0.pdf;

j. P37314 - Project 360 Bundle 1_Redacted.pdf;

k. P37336 - Operational Technology Visibility_Redacted.pdf;

l. P37347 - Risk Technology Optimization.pdf;

m. P37376-CS Rewind Unit 1 CTG & STG.pdf;

n. P37509 - Biglow I Wind Enhancement Program.pdf; and

o. P37533-2022 Microsoft Enterprise Agreement_Redacted.pdf

May 23, 2023

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND, OR 97204
pge.opuc.filings@pgn.com

RE:	Docket No.	OPUC Request Nos.	Response Due By
	UE 416	PGE UE_416 OPUC DR 813-817	June 6, 2023

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with all cell references and formulae intact.

Overall Topic or Keyword: Capital Projects – 2023 Forecasted Plant Additions and Rate Base
Testimony Reference: PGE/700, Bekkadahl, Jenkins, Section II Capital Projects Since UE 394; PGE/800, Bekkadahl, Jenkins, Section II PGE's Generation Resources; and PGE/200, Batzler, Ferchland, Section IV Rate Base

Topic or Keyword: *Rate Base*

813. Referring to *UE 416-21-23 Exhibit Support_2024_Errata.xlsx*, Ex 208 Rate Base Delta, provide the following linked Microsoft Excel workbooks referenced on this sheet:

   a. *Integrated PGE RevReq_4-25-22_Final Order_net Colstrip.xlsx* referenced in cells C9-C11, C16, and C20.

   b. Exhibit Support 2022_Errata.xlsx referenced in cells C19-C20, C22-C23, and C26-C30.

814. Referring to *UE 416-21-23 Exhibit Support_2024_Errata.xlsx*, Ex 208 Rate Base Delta, provide a reconciliation between the amounts in column UE 394 Approved Order No. 22-129, Lines 1-27 and the amounts in the stipulated integrated revenue requirement schedule for rate base in UE 394 Order No. 22-129,

Appendix C, Stipulating Parties/302/2. Provide all of the reasons for the differences.

815. Provide a breakout of the UE 394 Approved Order No. 22-129 Plant in Service amounts by FERC account category similar to *UE 416_AWEC DR 039_Attach A.xlsx*, tab Unbundling Source Data.

816. Refer to *UE 416_AWEC DR 039_Attach A.xlsx*, tabs Unbundling Source Data, Net Plant Recon Detailed and CPR Controls. Explain why PGE used its general ledger balances as of December 31, 2022, instead of the balances reflecting the rate effective date of May 1, 2022 from UE 394 as the beginning balance of these reconciliations.

817. Refer to *UE 416_AWEC DR 039_Attach A.xlsx*, tabs Unbundling Source Data, Net Plant Recon Detailed and CPR Controls. Revise these schedules to add PGE's plant balances as of May 1, 2022 by the same FERC account categories as the starting point and then showing actual additions, retirements, and other adjustments to get to the actual December 31, 2022 plant balances that currently serve as the starting point for each schedule.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.
You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@puc.oregon.gov

/s/ Marc Hellman
Administrator

Staff Initiator:	Warren Fischer	wfischer@gsiconsulting.com	1 (303) 883-9014
	Robert Young	robert@economists.com	1 (503) 816-5103

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF
EXHIBIT 2103

Representative PGE response to Staff DR 590 Shute Capacity Addition P36866, as of November 2020

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF
EXHIBIT 2104

PGE response to Staff DR 586
P37218 OH FITNES - Distribution

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION OF OREGON

CONFIDENTIAL STAFF EXHIBIT 2105

PGE response to Staff DR 586
P36680 Brookwood Substation Conversion

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF
EXHIBIT 2106

PGE response to Staff DR 792
P36680 Brookwood Substation Conversion

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF
EXHIBIT 2107

PGE response to Staff DR 586
P36679 Orenco Substation 115 kW Rebuild

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

HIGHLY CONFIDENTIAL
STAFF EXHIBIT 2108

PGE response to Staff DR 590
P37160 Helvetia Substation Phase 2

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION OF OREGON

HIGHLY CONFIDENTIAL STAFF EXHIBIT 2109

PGE response to Staff DR 590 P3716 Helvetia Substation Phase II

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION OF OREGON

CONFIDENTIAL STAFF EXHIBIT 2110

PGE response to Staff DR 586
P367061 OH FITNES Transmission

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF
EXHIBIT 2111

PGE response to Staff DR 789
P37061 OH FITNES Transmission

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF
EXHIBIT 2112

PGE response to Staff DR 586
P35995 Downtown Core Cable Replacement

June 13, 2024

[redacted]

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION OF OREGON

CONFIDENTIAL STAFF EXHIBIT 2113

PGE response to Staff DR 586 P36373 Blue Lake Phase II

June 13, 2024

[redacted]

[redacted]

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION OF OREGON

CONFIDENTIAL STAFF EXHIBIT 2114

PGE response to Staff DR 586
P36953 Memorial Substation Build

June 13, 2024

CASE: UE 416
WITNESS: Young

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2115

PGE March 2023 OH FITNES Program Health Report to OPUC

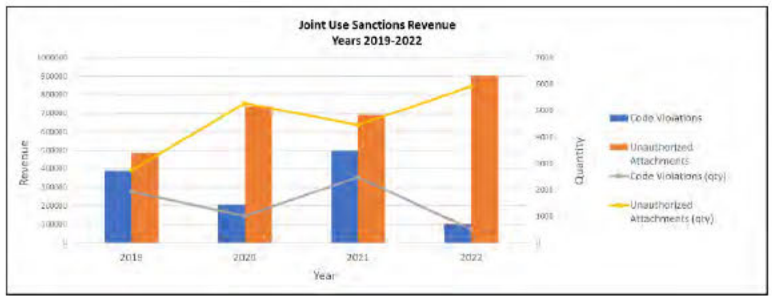
June 13, 2024

Utility Asset Management: FITNES Program
March 2023: Program Health

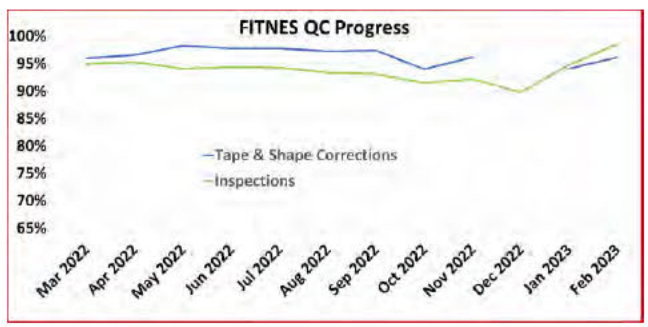
Program Updates

- **Continuous Improvement:**
  - GIS Technology
    - Transition from ArcGIS Online Field Maps to IQGeo

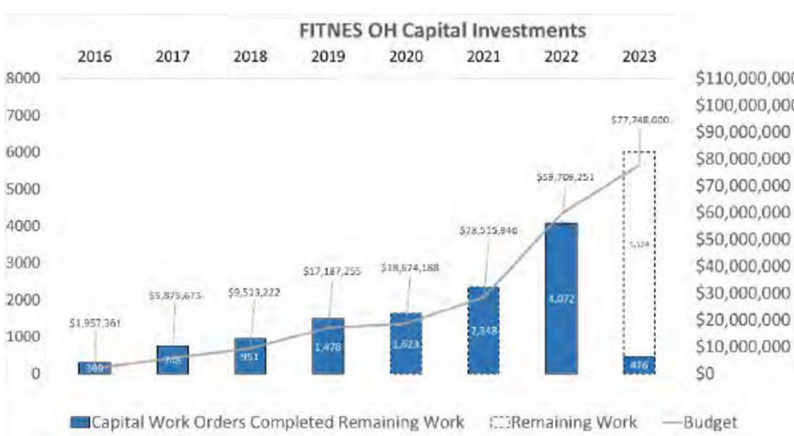
- **Joint Use:**
  - On average, pole occupant violations comprise 40-50% of FITNES-identified violations
  - Enforcement mechanism to address non-compliance
    - Sanctions for safety violations
    - Penalties for unauthorized attachments
    - Assessment of the non-compliant rental rate
  - Joint Inspection Program
    - PGE Poles and ILEC poles, including communications only poles
    - Participants include: Ziply; Lumen; Level 3; Comcast; and Wave Broadband



- **Heightened Quality Control (QC):**
  - PGE continues to implement weekly, systematic QC activities of Tape & Shape work and inspection work, with an accuracy rate trending above 95-percent.



- **PGE Correction Work Tracking and Throughput:**
  - Monthly cross-departmental stand-ups (FITNES; Project Management Office; Line Design and Crew Coordination).
  - Enhanced work order status visibility and accountably using work queue dashboard software.
  - Accelerated FITNES Capital Investments



* Year 2023 represents both a forecasted budget and capital work order quantity

CASE: UE 416
WITNESSES: Curtis Dlouhy, Matt Muldoon,
Michelle Scala and Bret Stevens

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2200

OPENING TESTIMONY
Automatic Adjustment Clauses (AAC)
Role in Regulation, and
Need for Deferrals with AACs

June 13, 2023

Q. Please introduce yourselves.

A. I, Dr. Curtis Dlouhy introduce myself in Exhibit Staff/300 and provide my witness qualifications in Exhibit Staff/301.

I, Matt Muldoon introduce myself in Exhibit Staff/400 and provide my witness qualifications in Exhibit Staff/401.

I, Michelle Scala introduce myself in Exhibit Staff/600 and provide my witness qualifications in Exhibit Staff/601.

I, Dr. Bret Stevens introduce myself in Exhibit Staff/2000 and provide my witness qualifications in Exhibit Staff/2001.

Q. What is the purpose of this testimony?

A. This testimony examines two policy issues regarding Automatic Adjustment Clauses (AAC), namely the role of AACs in utility regulation and the need for deferrals with AACs.

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared the following exhibits:

- Exhibit Staff/2201, Responses to Data Requests used in Support of Testimony,

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. THE ROLE OF AACS IN UTILITY REGULATION

Q. What is an AAC?

A. According to ORS 757.210(1)(b):

> "[A]utomatic adjustment clause" means a provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility and that is subject to review by the commission at least once every two years.

Put differently, an AAC allows a utility to periodically update rates for certain cost categories without going through the typical, more rigorous ratemaking process where overall costs are considered.

Q. Does Staff believe that AACs and single-issue ratemaking are a useful tool in ratemaking?

A. Yes, Staff believes that AACs and single-issue ratemaking can be useful tools in ratemaking in some contexts. One example is pilot programs. The costs associated with pilot programs can be hard to forecast, as enrollment, asset rollout, and success of these programs is uncertain. In this context, an AAC is a useful way to ensure costs associated with these programs are fairly collected and any lessons learned from the pilot aren't obfuscated by potential funding issues.

Another instance where AACs and single-issue ratemaking are useful is a program that involves a pass-through of costs or benefits of State-imposed programs. One such example is Schedule 137, which is the Company's Customer-owned Solar Payment Cost Recovery Mechanism. This program was implemented under ORS 757.365, which requires utilities to pay "incentive rates" for solar energy produced by customers and that "prudently incurred costs associated with compliance with this section are recoverable in the rates of an electric company."

A benefit of AACs in that they may have led to a reduction in general rate case (GRC) filings. This can be good when utility earnings have not exceeded authorized levels as utilities may have made a GRC filing absent the AAC. An AAC allows for yearly changes in rates where the utility rate filing does not allow other parties to make a collateral attack on revenue requirement for other costs, or at least minimizes the opportunity for such collateral attacks.

The AACs appear to be increasing one or several per year, so it has been a gradual increase. However, the current volume of AACs now rises to a level that merits Commission attention.

Q. Why are you bringing up AACs in this the context of this rate case?

A. Stakeholders have recently brought up concerns that utilities are overusing deferrals and AACs for ratemaking, citing concerns that the use of these two mechanisms unfairly shifts the cost recovery risk to customers from shareholders. In particular, the Oregon Citizens' Utility Board (CUB) highlighted this concern during the Commission's deliberation on ADV 1453, the Advice Filing for PGE Schedule 153, Community Benefits and Impact Advisory Group Cost Recovery Mechanism, at the regular public meeting on

March 7, 2023. While also decrying the sheer volume of single-issue ratemaking proposals brought forth by PGE, CUB recommended that the Commission open an investigation into ADV 1453 and apply an earnings test to the AAC and balancing account related to ADV 1453.[1]

Ultimately, the Commission chose to approve ADV 1453 in Order No. 23-088 and also stated:

> We note that the automatic adjustment clause at issue in this filing is one of many such mechanisms, and we urge parties to Portland General Electric Company's open rate proceeding, docket UE 416, to review the prevalence of these mechanisms and welcome discussion of the issues associated with that prevalence in that docket.[2]

Q. When you address AACs, are you also addressing the Company's AACs associated with Net Variable Power Costs (NVPC)?

A. No. While the Company does technically have AACs associated its NVPC forecast and true-up, Staff views these as separate issues from the issues of AACs and deferrals considered "single-issue ratemaking." Staff's concern in this testimony series is just single-issue ratemaking issues.

---

1 See CUB's March 3, 2023, comments on ADV 1453 here.

2 *In the Matter of Portland General Electric Company, Advice No. 22-36 (ADV 1453), Establishes Schedule 153, Community Benefits and Impact Advisory Group Cost Recovery Mechanism*, Order No. 23-088 (March 14, 2023).

Q. How has the prevalence of AACs changed in the Company's overall ratemaking?

A. Based on Staff's analysis of the Company's tariffs and the Company's response to Staff DR 328, the Company only had four schedules associated with AACs in 2010.[3] After the approval of ADV 1453, this number has risen to thirteen included in its revenue requirement forecast according to the Company's response Staff DR 328.[4]

Q. Are there reasons external to the Commission that the number of AACs has risen so dramatically?

A. Yes. There are many examples of recent legislation that has been passed in Oregon that mandate that the Commission establish a method for contemporaneous recovery for certain initiatives that the legislature cares about. HB 2021 establishes Oregon's mandate to decarbonize the electricity sector by 2040 and states:

> The commission shall establish a process for an electric company to contemporaneously recover the costs associated with the development of biennial reports and the costs associated with compensation or reimbursement for time and travel of members of a Community Benefits and Impacts Advisory Group.

---

[3] These were Schedules, 105, 109, 110, 126.

[4] These are Schedules 103, 105, 106, 110, 118, 125, 135, 136, 137, 138, 150, 151, and 153. PGE does not include Schedule 126, which is the PCAM, because PGE seeks to eliminate this AAC. When it is included, there are fourteen AACs.

This language was used to create the AAC that was the subject of CUB's comments in ADV 1453. The language of HB 2021 does not directly use the term "automatic adjustment clause," but many other recently enrolled laws use the term more directly, such as SB 1547, which establishes the Renewable Resources Automatic Adjustment Clause (RAC) used to recover investment costs associated with Renewable Portfolio Standards (RPS) compliance, and SB 762, which mandates that the Commission establish an automatic adjustment clause or similar mechanism to recover costs associated with developing a wildfire mitigation plan.

Q. Does the language in these bills necessarily mandate that the Commission needs to use an AAC in lieu of some other cost recovery method.

A. No. The language of these laws discusses contemporaneous cost recovery broadly or explicitly say that the Commission could establish "another method for timely recovery of costs."

Q. What are some alternatives to AACS or modifications of AACs that you believe would still satisfy the requirements and spirit of these laws?

A. Staff holds the position that "timely" or "contemporaneous" cost recovery does not necessarily mean "risk-free" cost recovery. As such, methods that allow the utility to recover the costs for these programs over the same period that they are incurred but allow some deviations in the recovery of these costs due to acceptable business risk would still satisfy this legislative language. Two possible ways to accomplish this are to either move some of these costs into base rates or apply earnings tests to the deferrals associated with these AACs.

Q. Do you believe that the role of AACs is sub-optimal as they are currently being used.

A. Yes, for a few reasons:

1. The increasing number of AACs makes it difficult for Staff and stakeholders to keep track of the filings and view them as a part of holistic ratemaking. Exhibit No. Staff/2201 provides a list of AACs.
2. The dollars recovered by AACs have increased far more quickly than the Company's overall revenue requirement.
3. AACs now comprise a non-trivial portion of customers' bills and rarely contain an earnings test, fundamentally shifting the traditional allocation of risk between the Company's shareholders and customers in manner that Staff believes to be unfair.

Q. Regarding your first point, why do you believe that the volume of AACs makes it difficult for Staff and stakeholders to view them in the context of holistic ratemaking?

A. Although the AACs allow "automatic adjustments," utilities must make an annual advice filing to make the automatic adjustment. Further, the majority of these AACs have an associated deferral or deferrals to track expenses and potentially offset them with any over- or under-earning from a previous year that also needs to be approved. Both of these processes require a public meeting, meaning that PGE's current array of AACs requires at least 26 separate Staff Reports in addition to any other public engagement associated with the docket. In the few instances where a deferral has an earnings review, Staff and potentially stakeholders also need to inspect the Company's earnings to determine whether to advocate for a refund or additional collection of costs, further adding to the Staff's and stakeholders' burden to evaluate rate holistically.

On top of that, many of these schedules with AACs are tied to planning initiatives or pilot programs where the forward-looking budgets that get rolled into the final rate are evaluated. All told, this means that the current setup of 13 separate AACs can potentially involve a budget forecast, a deferral approval or reauthorization, an earnings review, a prudence review, and an advice filing. While many of these are necessary parts of the regulatory process that merit their own process, many of them can be consolidated to lessen the regulatory burden on Staff and stakeholders while also lessening the filing requirements for utilities.

Q. What parts of the process does Staff believe could be consolidated?

A. Staff believes that related AACs can easily be consolidated into one schedule where appropriate. In Staff's view, this accomplishes two things. First, it makes the Company's filed tariffs far easier to read. Rather than searching for every AAC on a single topic, someone can instead read through one document that succinctly summarizes multiple AACs. There is precedent for this already, as PacifiCorp's Schedule 291 consolidates the AACs for four separate programs into a single tariff. In addition, because AACs can have different timing within a year, there would need to be revisions to achieve similar timing.

Second, this would make an application of an earnings test far easier for Staff and stakeholders if multiple AACs with earnings tests are handled together when it comes to the ratemaking phase. In this scenario, the collective over- or under-recovery of funds for various AACs could offset each other, and an earnings test would only need to be assessed once rather than a multitude of times.

Q. Is Staff concerned that this may provide fewer opportunities for intervenors to engage in a particular program, pilot, or proceeding they may care about?

A. No. As we stated previously, most of these AACs have associated planning phases where budgets are presented and approved, and overall project goals are discussed. Staff believes that these should be separated and does not believe that collecting AACs together into a single schedule hinders a stakeholder's ability to participate on the planning side. As an additional benefit, if a stakeholder sees concerns in multiple planning proceedings associated with an AAC, then the stakeholder could potentially bring these concerns up in a single ratemaking proceeding rather than having to engage in multiple proceedings. Combining into a single schedule will not change the amount of deferral applications required, or prudence evaluation, but it will consolidate the timing of review into a single timeframe and make it less likely any party would "miss" a filing because it may have been distracted due to other pressing workload or activities.

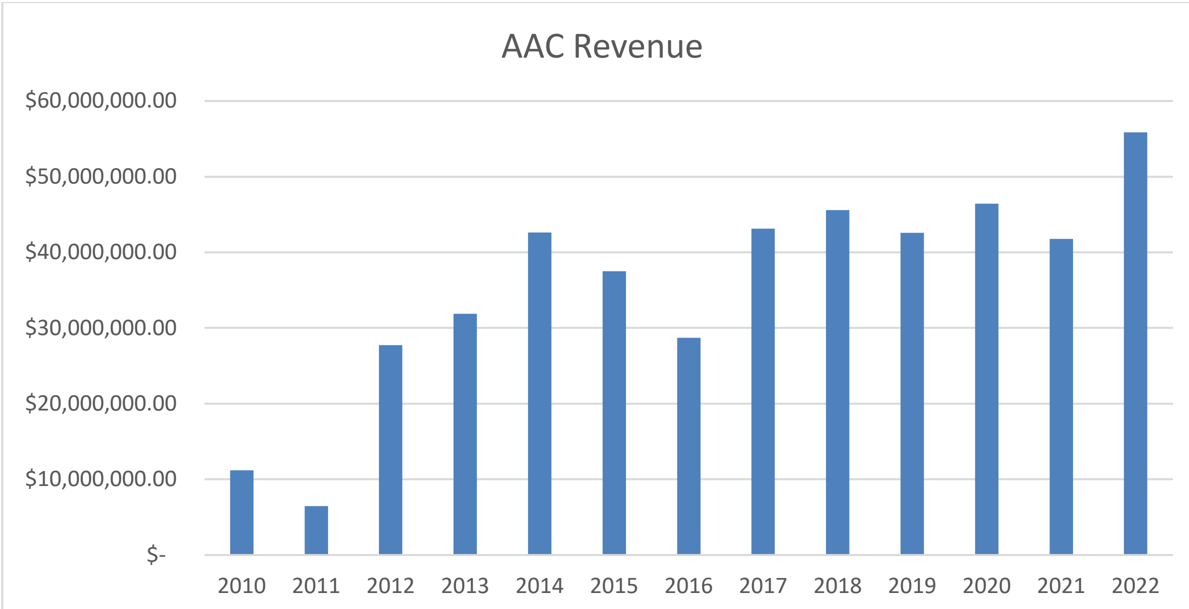
Q. Regarding your second point, excluding the power cost related AAC, how much has forecasted revenue collected through AACs changed recently?

A. Figure 1 shows annual forecast of AAC revenue for each year since 2021. Staff Witness Michelle Scala presents a similar chart showing overall rate pressure from all sources in her testimony contained in Staff Exhibit 600. The data for this figure were compiled using the Company's response to Staff DR 328. Staff chose to focus on the forecasted amount of each of these rather than actual collected amount for two reasons.

First, the Company explained to Staff that collecting the required data on actual revenue collected to create this figure would be exceptionally burdensome.

Second, rates are set on a forward-looking basis, so the forecasted revenues give at least as good of an approximation of bill impacts as actual revenue collected.

Figure 1

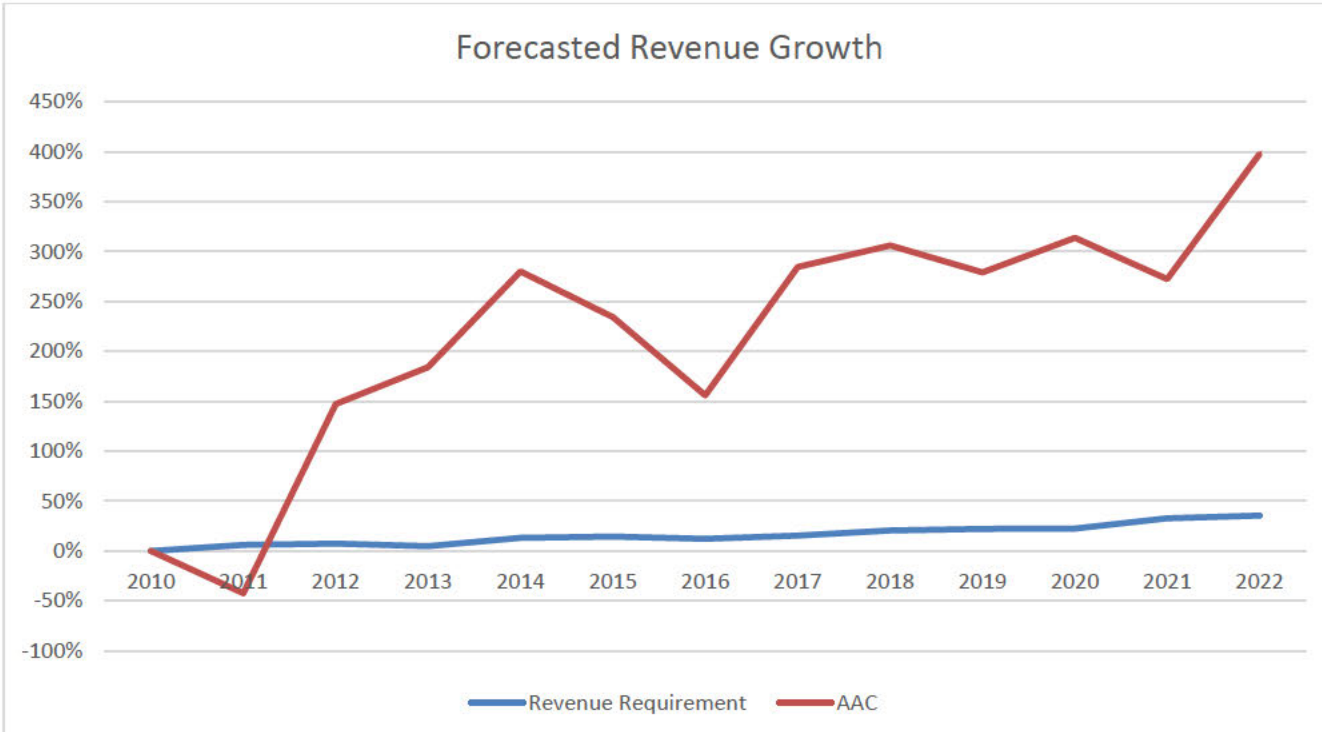


Over this time, forecasted AAC revenue has risen from just over $10 million in 2010 to over $50 million in 2022 for non-power cost AACs.

Q. How much has the dollars recovered through AACs increased relative to the overall revenue requirement, without including power costs and purchase gas adjustments (PGA)?

A. Figure 2 was also created using the Company's response to Staff DR 328 and shows the percent change in overall forecasted revenue requirement and forecasted revenue collected through AACs from the residential customer class from 2010 through 2022.

Figure 2

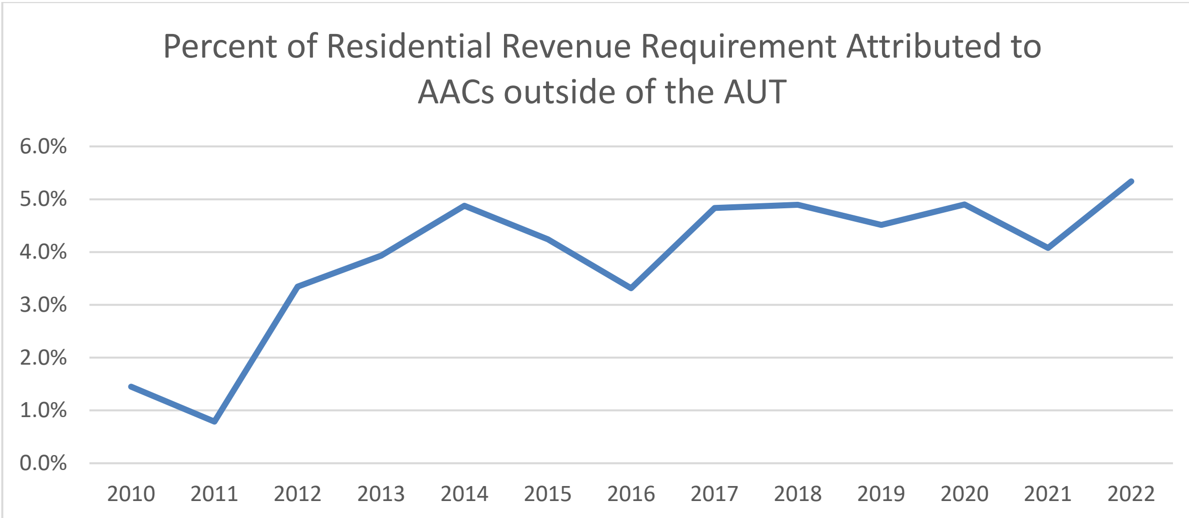


In Figure 2, it can be clearly seen that the growth rate of forecasted revenue collected through AACs dwarfs the growth rate of overall forecasted revenue requirement. While overall forecasted annual revenue requirement has only risen 35 percent over this period, the forecasted AAC revenue has grown a shocking 398 percent.

Q. How has this change affected the makeup of residential customers' bills?

A. Figure 3 shows the annual portion of forecasted revenue requirement that can be attributed to AACs. This was also compiled from the Company's response to Staff DR 328.

Figure 3



This figure shows that AACs covered less than two percent of residential customer bills in 2010, but over five percent of customer bills in 2022. While in itself not significant now, this demonstrates that not only has the overall amount collected through AACs increased non-trivially both when it comes to total amount and growth rate, AACs are also responsible much larger portion of a customer's bill. Given that many of the existing AACs do not contain any form of earnings test, this guarantees that a much larger portion of the Company's overall collection from customers is essentially risk free.

Q. Regarding your third point, why does the prevalence of AACs unfairly shift the allocation of risk from shareholders to customers given the Company's current and requested Return on Equity (ROE)?

A. The ROE and overall rate of return (ROR) are set to allow the Company to attract investment by allowing them the opportunity to earn a fair return on the assets they currently hold and may pursue in the future. Any ROR or ROE that is above the risk-free rate, which is often assumed to be the U.S. Treasury (UST) yield on 10-year note (about 3.5 percent) or 30-year bond (about 3.8 percent) and is far below the Company's current ROE of 9.5 percent and PGE's requested ROE of 9.8 percent,[5] is chosen assuming that there is some risk associated with cost recovery. Relying more heavily on AACs that rarely have earnings tests shifts this risk away from shareholders, which should result in a lower ROE if the same fairness is to hold. Instead, the Company that has largely maintained the same ROE while increasing its AAC collection, is requesting a higher ROE, and is proposing to further mitigate cost recovery risk through its PCAM proposal discussed in Staff Exhibit 2300.

Table 1 identifies which AACs identified in Staff DR 328 have and do not have earnings tests and how many dollars are associated with these. While we focus only on single-issue ratemaking in this testimony, it is worth noting that power costs and Purchase Gas Agreements (PGAs) have earnings tests on the backward looks.

---

5 See Exhibit PGE/100, Pope-Sims/19 at line 11.

Table 1[6]

Tariff	Deferral Docket(s)	2022 Forecast (000)	Earnings Test
Schedule 105	UM 1103, 2046, 1301	-1096	Yes
Schedule 106	UM 1986		No
Schedule 109		76642	
Schedule 110	UM 2039	1082	No
Schedule 112	N/A	3010	No
Schedule 135	UM 1294, 1514, 1827, 2234	10093	Yes, in part
Schedule 136	UM 1977	1180	No
Schedule 137	UM 1482	743	No
Schedule 138	UM 2078, 2113	697	No
Schedule 145	N/A	0	No
Schedule 150	UM 2218	7751	No
Schedule 153	UM 2249	N/A	No

Q. Given that all these changes seem to shift cost recovery risk away from shareholders and onto customers, what does Staff recommend the Commission do regarding the Company's use of AACs?

A. Staff has not opposed establishing AACs to date but now recommends that the Commission broadly do three things:

1. Consider moving more mature pilots into base rates.
2. Consolidate current schedules associated with AACs into fewer schedules based on topic matter to improve efficiency and readability.
3. Increase the number of deferrals and AACs that have earnings tests on the retroactive ratemaking portion.[7]

Staff notes that the first recommendation is done largely for efficiency and to make it easier for stakeholders to engage in the ratemaking process. The

---

6 Earnings Test information compiled from the Company's responses to Staff DRs 540 and 806 contained in Staff Exhibit 2201.

7 We identify which AACs should have an earnings test later on in this testimony.

latter two recommendations are done to maintain a fair allocation of risk between shareholders and ratepayers.

Q. Which existing schedules does Staff believe can be consolidated into a single tariff?

A. As a first step, Staff recommends that existing tariffs that recover costs from the same customer groups be consolidated into a single tariff. This is not unlike what PacifiCorp has done with its System Benefits Charge in Schedule 291. The following tariffs recover costs from all schedules except Schedule 76R and 576R:

- Schedule 137 – Customer-Owned Solar Payment Option Cost Recovery Mechanism
- Schedule 136 – Oregon Community Solar Program Start-Up Cost Recovery Mechanism
- Schedule 150 – Transportation Electrification Cost Recovery
- Schedule 153 – Community Benefits and Impacts Advisory Group (CBIAG) Cost Recovery Mechanism

The following tariffs also have identical customer group exceptions and could be grouped together:

- Schedule 135 – Demand Response Cost Recovery Mechanism
- Schedule 138 – Energy Storage Cost Recovery Mechanism

Combining the first group of five schedules into a single tariff and the second group of two into a single tariff would reduce confusion and administrative burden without having any impact on the recovery of costs.

Q. How would a new program added to a consolidated tariff, or a defunct program be removed?

A. Not unlike PacifiCorp's Schedule 291, a new program could be easily added in the annual tariff update that already happens with AACs. As an example, PacifiCorp seamlessly integrated the CBIAG funding that was required by HB 2021 into an existing tariff in ADV 1490 with next to no duplicated work.[8]

Q. Would this make it any harder to review the budgets associated with pilots or programs that have an AAC?

A. No. As previously discussed, these pilots and legislatively mandated programs have their own planning dockets where budgets and program updates are proposed. Consolidating these into a single tariff would have minimal if any effect on these planning dockets.

Q. Which AACs do you think should have an earnings test on their retroactive portions?

A. Staff recommends that, unless prohibited by specific statutory language, all legislatively mandated AACs or AAC-adjacent mechanisms have an earnings test on their respective deferral portions. Further, any AAC and deferral associated with capital investments should also have an earnings test.

As a reminder, Staff interpretation of this language is that the requirement for contemporaneous cost recovery does not necessarily also mean risk-free recovery. As such, Staff believes that a utility that under-recovers (over-recovers) the costs for a legislatively mandated or authorized program but has

[8] Commission Order No. 23-004.

adequate (inadequate) overall earnings should not be able to recover (refund) the differences in forecasted and actual program costs.

Q. Using this logic, which tariffs does Staff believe should have an earnings test?

A. The following existing tariffs are associated with legislatively mandated contemporaneous cost recovery and thus should be subject to an earnings test:

- Schedule 150 – Transportation Electrification Cost Recovery
- Schedule 153 – CBIAG Cost Recovery Mechanism

While two such examples may not seem a big problem now, it could be easier for the Commission to consider best practices before this number grows.

Q. Moving forward, how do you think the Commission should determine whether an emerging program should be left as an AAC or be moved to base rates?

A. As discussed previously, Staff believes that programs whose costs can be projected somewhat accurately and that do not have large variance year-to-year are good candidates for base rate items. This could be an AAC to collect an annual tax or for a program that has legislatively mandated requirement for contemporaneous cost recovery or a pilot program that has reached maturity. In any event, Staff recommends that Staff and Stakeholders discuss whether a program's costs are becoming consistent enough to move to base rates in each program's respective planning or reporting docket. Staff also proposes that any new pilot have a maximum three-year term at which it either ceases through the tariff sunsetting or is folded into base rates.

ISSUE 2. DEFERRALS AND AUTOMATIC ADJUSTMENT CLAUSES

Q. What is PGE's claim with respect to deferrals for AACs?

A. PGE testifies that the current process by which Staff requires PGE to file deferral applications to support an established automatic adjustment clause (AAC) is administratively burdensome and unnecessarily duplicative. PGE testifies that "Staff has taken the position that a deferral is needed for any AAC and balancing account usage." PGE testifies that AACs and deferrals are separate and distinct mechanisms and should not be used together."[9]

Q. What is Staff's position on this issue?

A. PGE is incorrect that Staff "requires" PGE to file deferral applications for all AACs. First, the requirement is statutory, not imposed by Staff. Second, Staff does not assert a deferral application must be filed for every AAC. Instead, Staff believes a deferral is required for AACs that have a retroactive component that would violate the prohibition against retroactive ratemaking if a deferral, which is an exception to that prohibition, is not used.

The issue presented by PGE is one of statutory interpretation and we are not attorneys. Accordingly, we will not attempt to make legal arguments but will attempt to describe the types of AACs or balancing accounts for which Staff believes deferrals are required and those for which Staff believes deferrals are not required and explain the difference.

---

[9] PGE/1400, Ferchland-Batzler/1-2.

Q. What is the difference between an AAC with a retroactive component and one without?

A. A good example of the dichotomy between AACs with a retroactive component and those without are the AACs PGE uses to recover net variable power costs, the Automatic Update Tariff (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126). Other than the recently adopted pass-through for a subset of costs for new Qualifying Facilities scheduled to come on-line during the forecasted Test Year, the AUT is "forward-looking," or as PGE would describe, allows contemporaneous recovery for costs. Under the AUT, PGE recovers revenue for its power cost as it is incurring power costs. Other than to implement the true-up of a small subset of costs of new QFs in the Test Year, Staff has never suggested PGE must file a request to defer in connection with the AUT.

In contrast, PGE's PCAM is a backward-looking mechanism that is not contemporaneously recovering costs as they are being incurred. Instead, the PCAM tracks the variance between the NVPC collected under Schedule 125 and actual NVPC in a calendar year for recovery or refund to customer rates in a subsequent calendar year. This is "retroactive ratemaking."[10]

Q. What is the significance of retroactive ratemaking?

A. The Commission has determined that it is "generally prohibited from adjusting rates retroactively to address deviations between forecast and actual

---

[10] *In re Portland General Electric Company,* UE 47, Order No. 87-1017 (September 30, 1987) ("Rates lawfully in effect are not revisited or "trued-up" to match actual costs incurred. Such true-up is retroactive ratemaking[.]").

costs."[11] The Commission has also concluded that ORS 757.259(2)(e) creates a statutory exception to the rule against retroactive ratemaking by authorizing this Commission to allow "utilities to track identifiable expenses or revenues through the use of 'deferred accounting' for possible inclusion in a future rate proceeding."[12]

With respect to AACs, the Commission has previously concluded that it is necessary for a utility obtain deferral authority under ORS 757.259 when implementing an automatic adjustment clause mechanism with a true-up component.[13]

Q. Does ORS 757.210 also provide statutory authority for retroactive ratemaking?

A. It is our understanding that it does not. Staff counsel will address this point in legal briefs.

Q. PGE states that AACs and deferrals are not the same thing and serve different purposes. Does Staff agree?

A. Yes. That is why in certain circumstances, both are necessary. When the AAC has a retroactive component, i.e., a true-up mechanism, a deferral is a necessary tool/step to implement the AAC. This is because the statute that authorizes the Commission to implement AACs, ORS 757.210, does not by

---

11 *In the Matter of Oregon Public Utility Commission, Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, UM 1909, Order No. 20-147, p. 2 (April 30, 2020).

12 Id. p. 3.

13 *In the Matter of Idaho Power Company*, UE 195, Order No. 08-491 (October 6, 2008) (Commission rejecting Idaho Power's argument that Idaho Power's PCAM is not retroactive ratemaking and requiring that Idaho Power defer costs under ORS 757.259 to implement PCAM).

itself, authorize retroactive ratemaking. Instead, that authority is found in ORS 757.259. Accordingly, a utility seeking to implement an AAC with a retroactive component under ORS 757.210 must also receive separate authority under ORS 757.259. As noted above, this is not the case when the AAC does not have a retroactive component.

Q. PGE complains that the requirement to obtain deferral authority with AACs is administratively burdensome. Does Staff agree?

A. Staff understands PGE feeling burdened by the statutory obligation to procure annual deferral authority for each of its AACs with a retroactive component. PGE lists multiple dockets for which it must request deferral authority to support recovery of incurred costs. However, Staff disagrees the burden is caused by fulfilling the statutory requirement for a deferral. Instead, the burden is due to the proliferation of deferral requests and AACs.

Q. PGE provides a list including sixteen "Deferral + AAC" combinations[14] in which it files an annual deferral request to support an AAC and asks the Commission to conclude a deferral is not necessary to implement these AACs. What is Staff's response?

A. First, the list should have included an additional "Deferral + AAC." PGE's list indicates that PGE's PCAM is a deferral only. It is not. It is a "Deferral + AAC." Second, Staff's response to PGE's claim that deferrals are not needed to implement the AACs varies, depending on the AAC.

---

[14] See PGE/1401, Ferchland – Batzler/1 (PGE List of Anticipated 2023 Deferrals).

Q. Please elaborate.

A. Whether an AAC must be supported by a deferral depends on whether the AAC has a retroactive component. Almost all the AACs included in PGE's list have a retroactive component. Accordingly, PGE must file a request to defer to implement the AACs. One of the listed "Deferrals + AACs" may not actually have a retroactive component. To the extent it does not, Staff agrees it is not necessary for PGE to ask for a deferral to support the AAC.

Q. Please identify the AACs for which PGE believes deferrals are not necessary

A. The list of sixteen "Deferral + AAC" combinations provided by PGE includes thirteen different AACs. There are only thirteen is because one of the AACs is supported by three deferrals and another is supported by two deferrals. With the addition of PGE's PCAM, there are fourteen different AACs at issue: **Schedule 103** – Metro Supportive Housing Services Business Income Tax Recovery (UM 2132); **Schedule 105** – Regulatory Adjustments (UM 1991); **Schedule 106** – MCBIT Recovery (UM 1986); **Schedule 110** – Energy Efficiency Customer Service (UM 2039); **Schedule 118** – Bill Adjustment Cost Recovery Mechanism (UM 2119); **Schedule 125** – Annual Power Cost Update (UM 1988); **Schedule 126** – Power Cost Adjustment Mechanism; **Schedule 135** –Demand Response Cost Recovery Mechanism (UM 1827, UM 1514, and UM 2234); **Schedule 136** – Community Solar Program Start-Up Cost Recovery Mechanism (UM 1977); **Schedule 137** – Owned Solar Payment Option Cost Recovery Mechanism (UM 1482); **Schedule 138** – Energy

Storage Cost Recovery Mechanism (UM 2078 and UM 2113); **Schedule 150** – Transportation Electrification Cost Recovery Mechanism (UM 2218); **Schedule 151** – Wildfire Mitigation Cost Recovery (UM 2019); and **Schedule 153** – CBIAG Cost Recovery Mechanism (UM 2249).[15]

Q. Please explain your position that deferrals are necessary for most of these AACs.

A. Schedules **135**, **136**, **137**, **150**, **151,** and **153** are AACs with both a forward-looking rate based on a forecasted revenue requirement and a retroactive component that allows PGE to track the variance between PGE's actual costs and those forecasted in the forward-looking rate and amortize that variance in customer rates. A deferral is not necessary for the forward-looking component of these six AACs, but for the reasons discussed above, PGE must defer the variances to make previously incurred costs or previously received revenues eligible for **future** recovery or refund.

As discussed above, **Schedule 125** is a forward-looking AAC that does not, for the most part, require a deferral. The exception is the pass-through of the variance between the previous year's forecast and actuals for certain QF costs. Again, a deferral is necessary to support this one retroactive element that allows PGE to include in future rates actual costs or revenues incurred or received in the past.

Schedules **103**, **106**, and **118** are worded differently than the schedules discussed above, but the effects are the same. These three schedules have a

[15] Some of the deferrals support the same AAC so there are only 13 AACs for the 16 deferrals.

forecasted rate and the variances between actual costs and costs in forecasted rates are tracked. In these three schedules, however, the variance is not specifically amortized but is subtracted or added to the forecasted revenue requirement when the forward-looking rate is re-set. Rolling the variance balance forward for collection or refund in a future rate period is, as a practical matter, the same as amortizing the balance though a rate schedule dedicated to that purpose. In either case, PGE is refunding or charging customers for revenues and costs incurred in a past period.

Schedule 126, PGE's PCAM, is a purely retroactive AAC. Under the PCAM, PGE changes rates every year to recover or refund incremental costs or revenues in a previous year. To implement this retroactive AAC, the Commission must rely on its authority under ORS 757.259 and a deferral is necessary.

The remaining AACs and deferrals in PGE's list are **Schedule 105** – Regulatory Adjustments and UM 1991, **Schedule 110** – Energy Efficiency Customer Service and UM 2039, and **Schedule 138 –** Energy Storage Cost Recovery Mechanism and UM 2113 and UM 2078**.**

Schedule 105 has a retroactive component. Schedule 105 states it "will be trued up annually as necessary to recover nonrecurring Regulatory Adjustments." The associated deferral identified in PGE's list, UM 1991, captures the variance between the amounts in revenue requirement for R&D credits and actual R&D credits received by the Company for later true-up. It is unclear to Staff how a true up for a past variance between costs in rates and actual costs could be accomplished without a deferral. Accordingly, Staff disagrees with PGE's claim the AAC for R&D Tax Credits could be accomplished without a deferral.

Schedule 138 is used for two purposes, to allow PGE to amortize the deferred costs of demand response pilot programs and to allow PGE to track the variance between costs recovered under the schedule and actual costs in a balancing account. Unlike almost all the schedules discussed above, Schedule 138 does not appear to have a forward-looking component. Instead, it is used to amortize costs to start-up and implement pilot programs that PGE has deferred under Docket Nos. UM 2078 and UM 2113. PGE's claim that it can track its costs to implement demand response pilots for later recovery in rates, without a deferral, is incorrect.

Given that Schedule 138 is a backward-looking AC, it is unclear what the second component, the balancing account, is for. Since Schedule 138 is written to collect costs that have already been incurred, the variance between PGE's actual costs and what PGE collects in rates will be due to the unpredictability of PGE's actual revenues, not the accuracy of the revenue requirement used to establish the rate.

In any event, it is Staff's reading of Schedule 138 that Schedule 138 does not allow PGE to amortize the Schedule 138 balancing account into rates. In this case, PGE need not seek a deferral to place the variance between the amounts collected under Schedule 138 and PGE's actual costs in a balancing account. And, in fact, PGE has not sought to defer the variance between actual costs and amounts collected under Schedule 138. PGE's deferral applications related to Schedule 138 seek only to defer PGE's actual costs for later amortization under Schedule 138 and make no mention of deferring the variance between amounts collected under Schedule 138 and actual costs.[16]

The fourteenth AAC on PGE's list of "Deferrals + AACs, **Schedule 110,** is a forward looking AAC that collects costs to fund Company activities associated with enabling customers to achieve energy efficiency. Schedule 110 also specifies that PGE will track the variance between amounts collected under Schedule 110 and actual costs. Schedule 110 does not specify that the balancing account will be amortized.

On its face, it appears that PGE does not need a deferral to support the AAC in Schedule 110 because there is no retroactive component. The rate is a forward-looking rate and the amounts in the balancing account do not appear to be subject to amortization through a rate adjustment.

Q. Why did PGE ask to defer the variance for the Schedule 110 balancing account.

A. Staff notes that there may have been a misunderstanding between Staff and PGE when PGE filed its first request to defer the variance under Schedule 110. In PGE's 2018 application to defer the variance between amounts collected

[16] See UM 2113 PGE's Application to Reauthorize Deferred Accounting of Costs Associated with the Energy Storage Pilots (August 31, 2022); and UM 2078 PGE's Application to Reauthorize Deferred Accounting of Costs Associated with the Residential Battery Energy Storage Pilot (April 24, 2023).

under Schedule 110 and actual costs, PGE stated that it did not believe there was a need for a deferral because PGE did not intend to amortize the variance, but also described the accounting treatment as follows:

> EE Customer Service accounting treatment: the balancing account is recorded in either FERC 182.3 (Regulatory Assets), when qualified expenses incurred exceed revenue collected from customers, or FERC Account 254 (Regulatory Liabilities) when qualified expenses incurred are less than revenue collected from customers. **PGE amortizes the balancing account based on the rate collected from customers through Schedule 110, adjusted by revenue sensitive costs.**[17]

In Staff's first public meeting memorandum recommending approval of PGE's request, Staff noted that it had asked utilities with balancing accounts used to incorporate past costs and revenues into future rates, to file deferrals for those balancing accounts. Staff further noted PGE had filed the Schedule 110 in response to Staff's position "on balancing accounts **used to set rates** with carry-forward balances."[18] Based on this history, it appears Staff may have believed that PGE would actually amortize the variance between amounts collected under Schedule 210 and actual costs rather than allowing the over-collections and under-collections to balance out over time. But, if PGE does not amortize the variance between amounts collected under Schedule 110's

[17] UM 1986 PGE's Application for Deferral of Costs to Support PGE's Use of Balancing Accounts, p. 5 (December 7, 2018) (emphasis added). PGE included this language in the three subsequent requests to defer the variance between Schedule 110 amounts and actual costs. *See* UM 2039 PGE's Amended Application for Reauthorization to Defer Costs to Support PGE's Use of the Balancing Account Associated with the Energy Efficiency Customer Service, p. 3 (December 10, 2019); UM 2039 Application for Deferral Reauthorization to Support the Use of a Balancing Account Associated with the Energy Efficiency Customer Service, p. 2 (December 6, 2021); and UM 2039 Application for Reauthorization to Defer Costs to Support Use of Balancing Account Associated with the Energy Efficiency Customer Service, p. 3 (December 6, 2022).

[18] *In the Matter of Portland General Electric Company, Application for Deferral of Costs to Support the Use of Balancing Accounts*, UM 1986, Order No. 09-020, Att., p. 2 (emphasis added).

forward-looking rate and actual costs, Staff does not think PGE needs to support the AAC in Schedule 110 with a deferral request.

Q. Please summarize your testimony on the issue of deferrals and AACs.

A. As PGE testifies, deferrals and AACs are two separate mechanisms with different purposes.[19] ORS 757.210, the statute that authorizes the Commission to establish AACs, does not authorize the Commission to create AACs with a retroactive component. Instead, this authority is found in ORS 757.259, under which the Commission can authorize a utility to defer costs or revenues for later amortization in rates. Accordingly, AACs with a retroactive component must be supported by a deferral. To the extent the AAC does not have a retroactive component a deferral is not necessary.

[19] PGE/100, Pope – Sims /20.

SUMMARY. STAFF RECOMMENDATIONS

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff makes the following recommendations

1. Consolidation of AAC Schedules:

   Staff recommends that the existing schedules associated with AACs be consolidated into fewer schedules where the tariffs recover costs from the same customer groups. Staff has identified the following schedules as eligible for consolidation under this proposal: schedules like 137, 136, 150, and 153 as a single tariff, and separately, schedules 135 and 138 as a single tariff. This consolidation would bring greater efficiency and readability to stakeholders and streamline the ratemaking process.

2. Increased Earnings Tests:

   Staff recommends requiring earnings tests of deferred balances for all legislatively mandated AACs or AAC-adjacent mechanisms and any AAC and deferral associated with capital investments. This recommendation aims to align the Company's ROE with the associated level of risk in cost recovery.

3. Moving Pilots into Base Rates:

   Staff recommends the Commission consider shifting mature pilot programs from separate AACs into base rates, making the associated costs subject to the regular ratemaking process. By incorporating these costs into the base rates, a comprehensive evaluation of overall costs and fairness in cost recovery can be achieved.

Together, these measures aim to address concerns regarding the proliferation of deferrals and AACs, as well as the potential imbalanced transfer of cost recovery risk from customers to shareholders.

Q. What is your recommendation regarding the need for deferrals with AACs?

A. Given that this is essentially a legal issue, it will be addressed in brief. It is Staff's view that AACs with a backward-looking aspect that can result in the change in rate, require a deferral.

Our recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: CURTIS DLOUHY, MATT MULDOON,
MICHELLE SCALA, BRET STEVENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2201

Responses to Data Requests used in Support of Opening Testimony

June 13, 2023

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 328
Dated March 16, 2023

Request:

From 2010 to 2022, please provide the total annual revenue generated from rates charged to each customer class broken down base rates, power cost cases, non-power cost AACs, other deferral amortizations, and any other mechanisms not identified.

Response:

PGE objects to this request as being overly broad and unduly burdensome in that it requires the development of new information. Without waiving said objections, PGE states the following:

On March 20, 2023, PGE and Staff discussed this DR in a phone call, and Staff agreed due to time limitations that PGE could provide forecasted annual revenue.

Attachments 328-A through 328-N provide the forecasted annual revenue from 2010 to 2022 generated from rates charged to each customer class broken down by base rates, power costs, non-power cost AACs, other deferral amortizations, and other mechanisms.

PGE is providing two files for 2022. Attachment 328-M contains the forecasted revenues effective January 1, 2022. The revenues are calculated using the 2022 load forecast and present a full 12 months of revenue, but are only in effect until May 8, 2022. Attachment 328-N contains the forecasted revenues effective May 9, 2022 when the rates from UE 394 became effective. The revenues in Attachment 328-N also present a full 12 months of revenue.

Tariff	Last Approved Deferral Docket	Last Approved Tariff Filing	Has an Earnings Test?
Schedule 103-Metro Supportive Housing Services Business Income Tax	UM 2131 - 3/11/2022	ADV 1442	No
Schedule 106-Multnomah Counting Business Tax Recovery	UM 1986 - 2/10/2022	ADV 1444	No
Schedule 110 Energy Efficiency Customer Service	UM 2039 - 1/10/2023	ADV 1448	No
Schedule 118-Bill Adjustment	UM 2219 - 12/30/2022	ADV 1447	No
Schedule 122-Renewable Resources AAC	UM 1724 - 10/2/2015 UM 1988 - 11/18/2022	UE 394/ADV 22-08	No
Schedule 125-Annual Power Cost Update	UM 2263 - pending	ADV 1439	No
Schedule 126 PCAM*	UM 1294 - 2/10/2022 UM 1514 - 12/14/2022 UM 1827 - 9/23/2022	ADV 1460	Yes
Schedule 135-Demand Response	UM 2234 - 4/2/2022	ADV 1460	No
Schedule 136-Community Solar Program Start-Up Costs	UM 1977 - 12/2/2021	ADV 1454	No
Schedule 137-Customer Owned Solar Payment Option	UM 1482 - 11/18/2022 UM 2078 - 6/2/2022	ADV 1343	No
Schedule 138-Energy Storage Cost Recovery	UM 2113 - 12/14/2022	ADV 1441	No
Schedule 145-Boardman Decommissioning	N/A - no associated deferral	ADV 1328	No
Schedule 146-Colstrip	N/A - no associated deferral	ADV 1440	No
Schedule 150-Transportation Electrification Cost Recovery	UM 2218 - 6/2/2022	ADV 1459	No
Schedule 153-Community Benefits and Impacts Advisory Group	UM 2249 - 9/8/2022	ADV 1453	No

* As previously stated in this docket, Schedule 126 - PCAM is named an AAC, however, PGE does not agree that it operates or functions as an AAC.

June 2, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 806
Dated May 18, 2023

Request:

Refer to Attachment N to the Company's response to Staff DR No 328. For each Schedule identified as "Deferral" or "AAC + Deferral", please identify the docket number where the deferral was last approved and indicate whether an earnings test was a condition of approval.

Response:

See PGE's response to Staff data request No. 540 for the requested information for AAC + Deferral. The following table contains the requested information related to deferrals without an AAC.

Tariff	**Last Approved Deferral Docket**	**Has an Earnings Test?**
Schedule 105 - Regulatory Adjustments	UM 1103, UM 2046, UM 1301	Yes
Schedule 112 - Customer Engagement Transformation Adjustment	Not applicable, subject to an accounting order established in Order No. 17-511	N/A
Schedule 123 - Decoupling	UM 1417	No

CASE: UE 416
WITNESSES: ISHRAQ AHMED,
CURTIS DLOUHY,
JULIE JENT,
ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2300

Opening Testimony

June 13, 2023

Q. Please state your names, occupations, and business address.

A. My name is Dr. Ishraq Ahmed, Ph.D. I am a Senior Utility Analyst in the Energy Costs section of the Rates, Safety and Utility Performance (RSUP) Program at the Oregon Public Utility Commission (OPUC).

My name is Dr. Curtis Dlouhy, Ph.D. I am an Economist and Senior Utility Analyst employed in the Strategy and Integration Division at the OPUC.

My name is Julie Jent. I am a Senior Economist in the Energy Costs section of the RSUP Program of the OPUC.

My name is Rose Pileggi. I am a Senior Utility Analyst at the OPUC in the Energy Costs section of the RSUP Program at the OPUC.

All of the above Staff have the same business address, which is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your each of your expertise and educational backgrounds.

A. Our witness qualifications statements can be found in Exhibits Staff/101, Staff/201, Staff/301, and Staff/1801.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the Company's testimony on the Power Cost Adjustment Mechanism (PCAM).

Q. Did you prepare any exhibits for this testimony?

A. Yes. Staff prepared Exhibit 2301 for PGE's response to non-confidential DRs, 2302 for PGE's response to confidential DRs, and Exhibit 2303 for Staff workpapers.

Q. How is your testimony organized?

A. Our testimony is organized as follows:

ISSUE 1. PROPOSED UPDATES TO THE PCAM PRINCIPLES

Q. When were the PCAM and its governing principles established?

A. In 2005, the Commission established a set of principles that were designed to ensure an appropriate balance of power cost forecast risk between PGE and customers. Initially, the Commission stated four principles in Order No. 05-1261[1] addressing PGE's request for a Hydro Generation Power Cost Adjustment and reiterated these principles when it adopted the original PCAM in Order No. 07-015.[2] The Commission subsequently added an additional principle when it established a PCAM for PacifiCorp in Order No. 12-493.[3] In its current form, the five existing PCAM principles are:

1. The PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk.
2. There should be no adjustment if the utility's overall earnings are reasonable.
3. The PCAM's application should result in revenue neutrality.
4. The PCAM should operate in the long-term to balance the interest of the utility's shareholders and ratepayers.

---

1 *In the Matter of Portland General Electric Company, Application for a Hydro Generation Power Cost Adjustment Mechanism*, UE 165, Order No. 05-1261 (December 21, 2005).

2 *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 180, Order No. 07-015 (January 12, 2007).

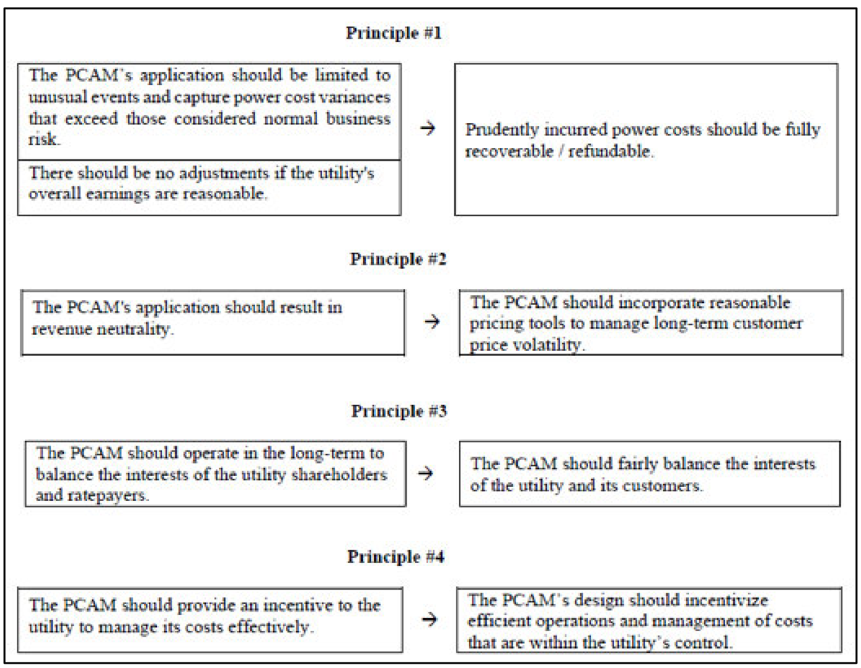
3 *In the Matter of PacifiCorp, dba, Pacific Power, Request for a General Rate Revision*, UE 246, Order No. 12-493 (December 20, 2012).

5. The PCAM should provide an incentive to the utility to manage its costs effectively.

Q. Please describe the Company's proposed changes to the PCAM principles.

A. The Company's proposed changes are shown in Figure 1.[4] In short, the Company's proposal includes language that would allow the Company to pass through more risks, and likely more costs, to customers than the existing PCAM principles.

<u>FIGURE 1. SUMMARIZED PROPOSED CHANGES TO PCAM PRINCIPLES</u>



Q. What reasoning does the Company give to update the PCAM?

A. The Company cites the following reasons as to why the PCAM mechanism needs to be updated and the principles need to be changed:

---

4 *See* PGE/400, Sims—Outama/27, Section III. PGE's Proposal.

1. Regional diversity provides new advantages,
2. Climate change is leading to more severe weather and load events,
3. The Company's and the general western region's portfolio are changing as variable energy resources (VER) are being integrated,
4. The Company's resource mix is changing to accommodate more VER,
5. Wholesale market dynamics are changing, with large price spikes becoming more common, and
6. The policy landscape is changing with the passage of House Bill (HB) 2021.[5]

Q. Does Staff agree with the Company's stance that an increase in severe weather and load events supports changing to a mechanism that allows all NVPC to passed through to customers with no Company assumption of costs related to normal business risk?

A. No. First, the PCAM was created in the 2000s to capture exceptional deviations in NVPC. Accordingly, to the extent changing weather leads to increases in costs beyond the utility's normal business risk, the current mechanism allows PGE to recover those costs, subject to sharing.

Second, the Company's statement that it is facing a current and future state of increased weather and load events in which PGE will be expected to absorb power cost variability that goes beyond normal business risk in not well supported. The Company cites the upward trend in the number of days with highs of 90 degrees or greater since 1980 in the Portland metro area to support

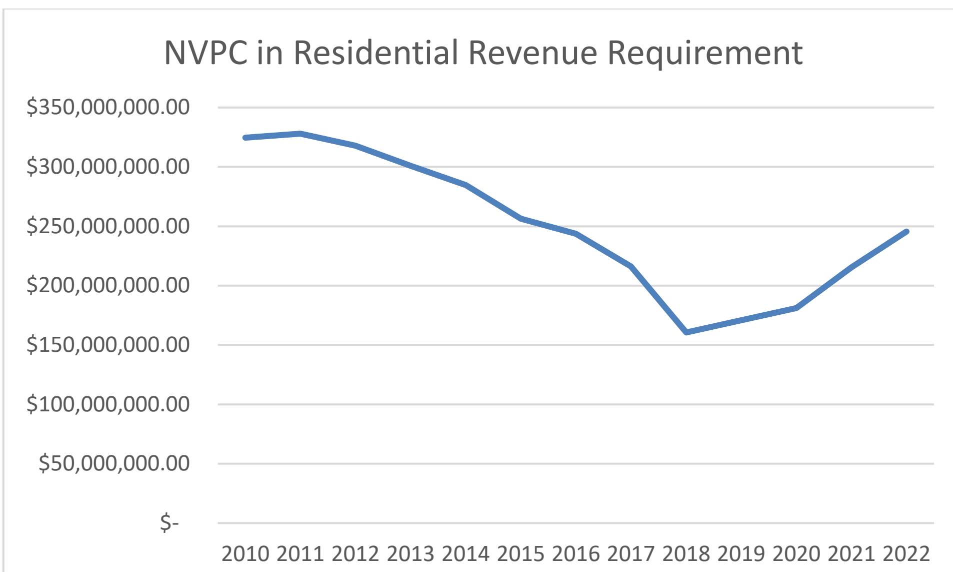
[5] PGE/400, Sims—Outama/2.

its point regarding increasing power costs.[6] PGE has not established a correlation between the count of 90+ degree days in the Portland metropolitan area and increased power costs, particularly given that the Company's total Net Variable Power Cost (NVPC) has drastically fallen in the last decade.

Q. How has the Company's overall NVPC forecast changed recently?

A. Figure 2 shows the Company's NVPC forecast that was used to set residential rates. A similar trend can be seen for all customer classes. As can be seen in Figure 2, the Company's forecasted NVPC has fallen by over $50 million since 2010. While there is an upward trend beginning in 2018, overall, even with this uptick power costs are still over $100 million lower than they were in 2010.

<u>FIGURE 2. NVPC IN RESIDENTIAL REVENUE REQUIREMENT</u>

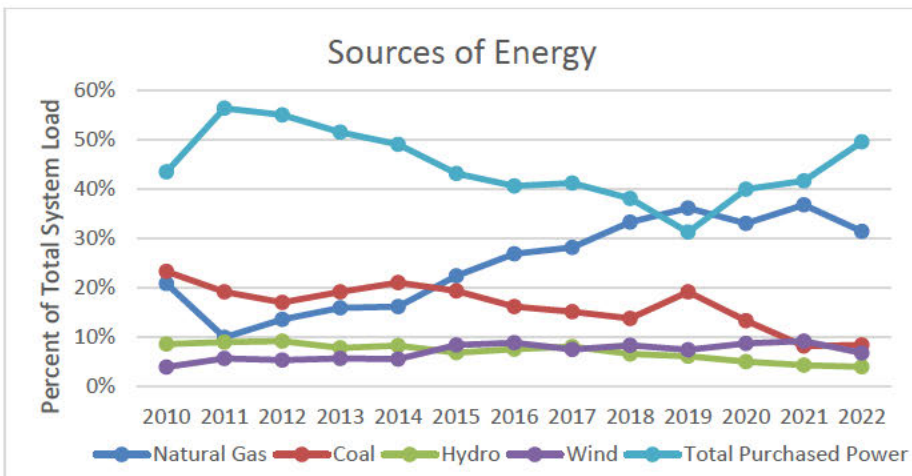


[6] PGE/400, Sims—Outama/16.

Q. Does Staff agree with PGE's stance that there has been a transition in its resource portfolio?

A. Staff does not believe PGE has established this point. PGE shows Northwest Power Pool (NWPP) and California Independent System Operator (CAISO) generation but fails to provide their own.[7] Figure 3, based on information provided in discovery, shows that PGE's resource mix has remained relatively stable and does not evidence conditions that would support the Company's PCAM proposals, even with the inclusion of many renewable power purchase agreements (PPAs).

FIGURE 3. SOURCES OF ENERGY AS A PERCENT OF LOAD[8]



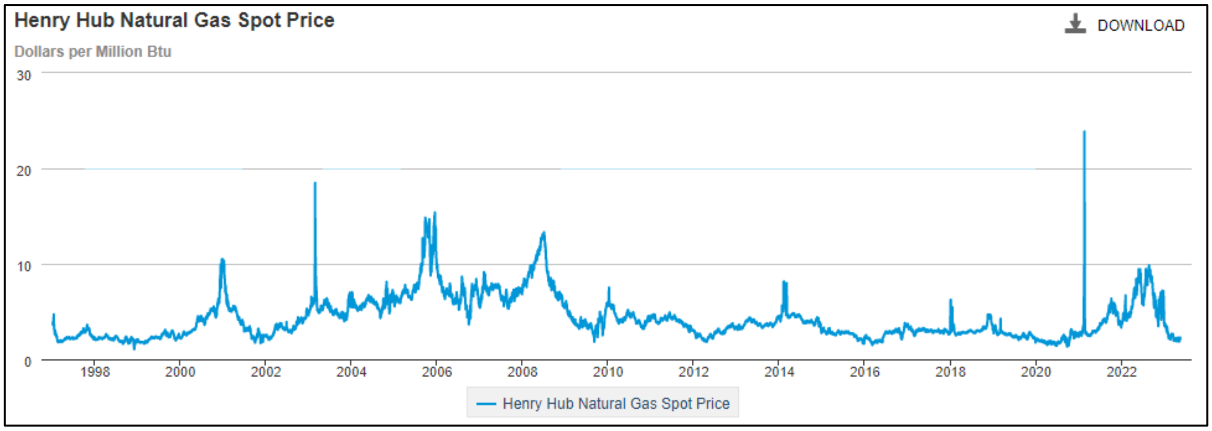
7 PGE/400, Sims—Outama /14.
8 See Staff/2302, which is filed electronically.

Q. Does Staff agree with PGE's stance that there have been changing wholesale market dynamics?

A. Wholesale market dynamics have indeed changed, but this does not entirely capture the Company's power costs related to external entities. Regarding changing wholesale market dynamics, the Company depicts the on-peak coefficient of variance for Mid-C and Sumas to support its point and also details scarcity pricing events. In its opening testimony, the Company fails to detail the implementation of Energy Day Ahead Market (EDAM), Western Energy Imbalance Market (WEIM), and other methods that are meant to protect against volatility. At the time the PCAM was adopted in 2007, there was also a great degree of market volatility. Figure 4 displays the Henry Hub natural gas spot prices between 1997 and 2023 and reveals the volatility during 2007, which was associated with tension in the Middle East and higher demand from transportation and other industries. In addition, "[t]he 2008 financial crisis and the Great Recession that followed had a pronounced negative impact on the oil and gas sector. These events led to steep declines in oil and gas prices and a contraction in credit. The decline in prices resulted in falling revenues for oil and gas companies."[9]

[9] https://www.investopedia.com/ask/answers/052715/how-did-financial-crisis-affect-oil-and-gas-sector.asp.

FIGURE 4. NATURAL GAS PRICES[10]



Q. Does Staff agree with the Company's stance that there have been policy landscape changes leading to the need for a changing resource mix?

A. The policy landscape has indeed changed, but the impact to the Company's resource mix is likely overstated. Regarding policy landscape changes and the changing resource mix, the Company points to Senate Bill (SB) 838, SB 1547, and HB 2021, which establish renewable portfolio standards (RPS) and call for reductions in Green House Gas (GHG) emissions. However, as PGE points out, HB 2021 is technology neutral. SB 1547 specifies that by 2035, customers cannot be served by coal, and the renewable portion of PGE's resource portfolio must reach 50 percent for 2040 and beyond. This deadline allows for time for continued progress and supports the move to renewables, including PPAs. Finally, as discussed in Staff witness Dr. Dlouhy's Exhibit 800 testimony, PGE is well ahead of the benchmarks in the RPS and does not need to make resource decisions in the near future in order meet its compliance obligations.

---

10 https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm.

Q. Are there circumstances that have changed that are directly pertinent to whether it is appropriate to eliminate the PCAM?

A. Yes. What PGE fails to discuss is the extent to which the financial heft of the Company has grown since implementation of the PCAM, and with it, its ability to absorb greater risk. For example, in 2007, the deadband[11] was +150/-70 basis points[12] (bps) of ROE, yet the upper deadband of $30 million has not increased since that time, despite a dramatic increase in rate base.[13]

Q. Does Staff support PGE's proposed revisions to the principles guiding the PCAM, and the changes to the PCAM itself?

A. No. None of the four principles proposed by the Company is consistent with Staff's recommendations in the remaining sections of this testimony. In short, the Company's proposed changes to the PCAM are entirely out of step with current principles governing the PCAM. Staff is not opposed to updating the PCAM principles when there is good reason. That said, Staff does not agree with the reasons the Company has put forth to justify its proposed updates to the PCAM principles, nor does Staff agree with the changes themselves.

---

11 In this context "deadband" refers to a level of cost recovery variance, including levels of under-recoveries and over-recoveries to be borne by the utility.

12 Basis points are a unit of measure used to describe the percentage change in value. One basis point is equivalent to 0.01 percent or 0.0001.

13 See Staff/2301, Ahmed – Dlouhy – Jent – Pileggi/1-4, Attachment A to PGE's Response to Staff DR 181, and Attachment B to PGE's Response to Staff DR 182. The latter two of these are filed electronically.

Q. Please remind us how the Company proposes to change the existing PCAM Principles 1 and 2.

A.

Principle #1

The PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk.	→	Prudently incurred power costs should be fully recoverable / refundable.
There should be no adjustments if the utility's overall earnings are reasonable.		

Q. Does the original purpose underlying Principle 1 still apply?

A. Yes. Principle 1 is still relevant since the PCAM was designed to capture power cost variations that exceed those considered part of normal business risk. Prior to the PCAM, the Commission has, in prior cases, examined whether the event impacted the utility's earnings beyond a reasonable range to determine whether an event is extraordinary and had a substantial financial impact. The intent of this principle was to memorialize that practice. Staff still believes that this framework is a valid way to share risk between shareholders and customers.

Q. Why does Staff disagree with the proposed change to the original Principle 1?

A. We acknowledge that business risks are constantly changing. We recognize this change by supporting inclusion of Reliability Contingency Events (RCEs)-related costs associated with new business risk and other measures of volatility on the front end, in PGE's Annual Update Tariff (AUT). In summary, we account for new business risks with ratemaking treatment that categorizes them as normal business risks.

The current deadband is small (-/+ 15M and 30M) relative to the Company's earnings. Any extraordinary event will likely fall outside of this deadband and be captured (ex. wildfires and ice storm, which resulted in huge deferrals). A move to completely remove the deadband could bring us away from this principle and is addressed more in Issue 2. Further, as stated in the recent order in UE 412 regarding PGE's request for an automatic adjustment mechanism for wildfire mitigation costs:

> [The Commission] appreciates [the Oregon Citizens' Utility Board's (CUB)] position that a utility's rates continue to be just and reasonable if, overall, they allow the utility to cover its expenses and investment costs while earning a rate of return consistent with that authorized in its last rate case. However, it is also well established that there is not one just and reasonable rate but rather a range of just and reasonable rates. Therefore, [the Commission] do[es] not think an earnings test is mandatory in this case. The record does not show that PGE or PacifiCorp are likely to over-recover without one such that their rates will become inherently unjust and unreasonable.[14]

Staff views this text to mean that there is a range of returns that support the notion of just and reasonable rates that result directly from a range of reasonable rates. This notion applies to power cost mechanisms as well. With the presence of a deadband, where costs or benefits are absorbed by the

[14] *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Advice No. 22-18, New Schedule 151, Wildfire Mitigation Cost Recovery*, UE 412, Order 23-173, page 5 (May 10, 2023).

Company, resulting changes in earnings still result in just and reasonable rates.

Q. What is the purpose of the original Principle 2 and does it still apply?

A. Principle 2, adopted in Order No. 07-015, is that there should be no adjustments if the utility's overall earnings are reasonable. The purpose of this principle is essentially what it says. The Commission designed the PCAM so that a utility would not be allowed to collect excess NVPC in a particular year if its earnings within that year were in a reasonable range. Similarly, a utility would not be required to refund an overcollection of NVPC if its overall earnings are below the reasonable range. This principle reflects that single-issue ratemaking is generally disfavored in Oregon. In a 2012 order, the Commission explained why single-issue ratemaking is disfavored:

> Concerns about single-issue ratemaking are grounded in the idea that the ratemaking formula is designed to determine a company's revenue requirement based on the aggregate costs and demands of the utility. Except in limited circumstances, it is improper to consider changes to components of the revenue requirement in isolation. As Staff notes, a change to one item of the revenue requirement is often offset by a corresponding change in another item. If rates are increased based solely on the fact that one type of expense is higher than expected, without considering changes to other elements of revenue requirement, the company's reasonable revenue requirement could be overstated. [15]

[15] *In the Matter of Northwest Natural Gas Company, Request for a General Rate Revision*, UG 221, Order No. 12-437, p. 26 (November 16, 2012).

Q. Why does Staff disagree with the proposed change to the original Principle 2?

A. PGE's proposed change to Principle 2 speaks to its proposal to remove the earnings test. By removing the earnings test, this allows the Company to raise rates to collect additional power costs even if its overall earnings are abnormally high. Similarly, removing the earnings test would allow the Company to pass back to customers large cost savings even if the utility is significantly underearning its cost of capital. The proposal to remove any earnings tests associated with NVPC while also touting the rollout of low-income rate design[16] and DEI initiatives[17] is utterly inconsistent and shifts risk of unexpected power costs and resulting rate changes to the same customers the Company claims to be protecting. Staff supports the concept that risk should reside with the party that is most empowered to manage the risk. That is the Company, as PGE is able to manage risk through power sales contracts, building resources, promoting demand-side management, and entering hedges. Customers on the other hand have no such ability unless they choose direct access and find an Electric Service Supplier (ESS) that is willing to offer fixed priced power long-term.

It is true that some customers may install conservation and/or choose to consume less or more electricity. However, as noted above, many customers may not be able to exercise those choices due to lack of information or ability

[16] PGE/1300 Macfarlane – Pleasant/15.
[17] See Staff/600.

to react to that information in a speedy manner. There is an asymmetry of information between the Company and its customers with the Company having more information and better access and timeliness to that information. Still, regardless of the information available, there will still be some customers who do not have the means to access energy conservation installations or inflexible loads. Therefore, any impacts to the residential customer class that hits affordability in any way will have disproportionate impacts on low-income and marginalized communities. That is why the Company is better enabled to manage the power cost risk. Having a direct passthrough, via removing earnings tests and deadbands, inappropriately shifts risks from the Company to its customers.

Staff also notes that power cost risk may be a diversifiable risk by shareholders, and hence even the market is better able to manage the risk than customers. For example, if one region experiences higher power costs and another region lower power costs due to weather events, that might imply there is some diversification ability with respect to power cost risks and therefore keeping the risk with the utility does not imply a higher cost of equity is required.

Q. Please restate the proposed change to original Principle 3.[18]

A.

Principle #2

The PCAM's application should result in revenue neutrality.	→	The PCAM should incorporate reasonable pricing tools to manage long-term customer price volatility.

Q. What is the purpose of original Principle 3 and does it still apply?

A. The purpose of Principle 3 is to ensure that any refunds or collection due to power cost variance are fair to both shareholders and customers. This still should apply today. In the original Commission Order No. 07-015, the Commissioners was persuaded by CUB's arguments that an asymmetric deadband and sharing bands would be necessary in order to ensure that the PCAM is revenue neutral, therefore establishing Principle 2.[19]

Q. Why does Staff disagree with the Company's second proposed principle, which would replace original Principle 3?

A. The Company's proposal says nothing about revenue neutrality, which was a key feature of the PCAM. Further, the Company's proposal to manage "long-term customer price volatility" assumes that power cost variance is driving changes in customer prices. In reality, revenue requirement is being increasingly driven by rate base, meaning that the power cost price volatility is not as relevant. Figure 4 shows the breakdown of residential revenue requirement by source as compiled from the Company's response to Staff DR

---

[18] It is important to note that revenue neutrality is not defined explicitly in any of the earlier testimonies or orders.

[19] See UE 165/UM 1187, Order No. 05-1261, 10.

328. This is further discussed in the testimony of Staff Witness Michelle Scala. It should be noted that in this figure it appears that some years result in a percent of the residential revenue requirement less than 100 percent; this is driven by deferrals that result in net refunds to customers.

FIGURE 5. PERCENTAGE OF RESIDENTIAL REVENUE REQUIREMENT

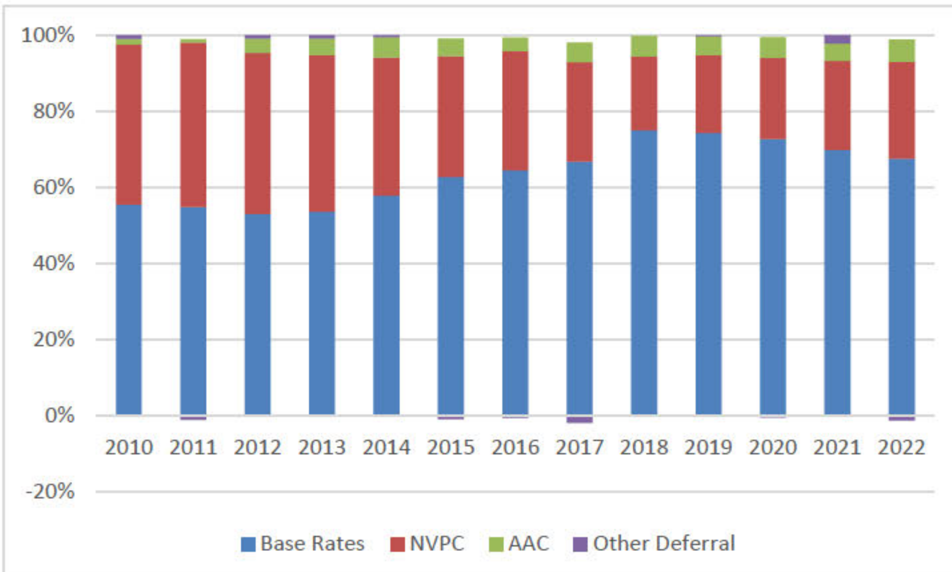


Figure 5 demonstrates that power costs have been a decreasing share of overall revenue requirement and customer rates.

Q. Please restate the proposed change to original Principle 4.

A.

Principle #3

The PCAM should operate in the long-term to balance the interests of the utility shareholders and ratepayers.	→	The PCAM should fairly balance the interests of the utility and its customers.

Q. What is the purpose of original Principle 4 and does it still apply?

A. Principle 4 recognizes that the interests of the Company's shareholders and its customers need to be balanced over the long-term. This should still apply today. Staff recognizes that both shareholders and customers interests are important in the operation of a successful utility.

Q. Why does Staff disagree with the Company's third proposed principle, which would replace the original principle 4?

A. While the spirit of PGE's proposal appears similar to that of the original principle, on the surface, the Company omits a couple key phrases. The Company's proposed principle is vague and could be interpreted in different ways. The proposal also fails to take into account the long-term financial viability of PGE or the health of its customers. In particular, the removal of the word "long-term" could allow the Company to recover costs from a single bad period that would saddle customers with overly burdensome rates for an extended period of time. This would also continue to shift the business risk away from the Company and onto customers. Staff will discuss how this relates to the Company's proposal for a 2.5 percent rolling cap later in this testimony.

Q. Please restate the proposed change to original Principle 5.

A.

Principle #4

The PCAM should provide an incentive to the utility to manage its costs effectively.	→	The PCAM's design should incentivize efficient operations and management of costs that are within the utility's control.

Q. What is the purpose of original Principle 5 and does it still apply?

A. Principle 5 ensures responsibility and accountability for costs by establishing that the Company should be making cost-effective decisions to operate efficiently to keep costs down for customers. This should still apply today. Staff believes that the utility's earnings should be viewed holistically. Therefore, the recovery or refunding of power costs variations are and should be impacted by the performance of other operational areas.

In its current form, 90 percent of prudently incurred power cost variation outside the deadband is eligible for collection from or refund to customers and PGE will bare 10 percent of adjustment. The sharing mechanism provides PGE with an incentive to manage costs effectively.

Q. Why does Staff disagree with the Company's fourth proposed principle?

A. The intent of the Company's fourth principle appears to be to allow the Company to recover abnormal costs beyond its control even if the structure of the PCAM would not otherwise allow the recovery of these costs. As stated before, Staff believes that power costs and the Company's overall earnings should be viewed holistically, which is inconsistent with the Company's fourth proposed principle. Staff will discuss how this principle relates to the Company's detailed PCAM proposal later in this testimony. Further, it is somewhat ambiguous as to what is beyond the Company's control. Are high market prices beyond the Company's control? Perhaps not in the sense that exposure to high market prices can be reduced through hedges and resource acquisition such that the utility is not as reliant on the market. The utility would also be motivated to recommend market monitoring take place in the case of wholesale market manipulation, assuming of course the utility was not the party manipulating the market.

Q. Does Staff believe that any changes should be made to the existing five PCAM principles?

A. No. While Staff is open to reasonable changes to the existing five PCAM principles, Staff does not find the Company's proposed changes to be an improvement to the existing principles or even reasonable.

Q. What is your recommendation regarding the five existing PCAM principles?

A. Staff proposes the Commission keep the existing PCAM principles as they are. If the Commission is inclined to modify the principles, then Staff would add a principle that leaves the price and market risk with the party best able to manage the risk. For the remainder of this testimony, Staff will discuss how the Company's proposed updates to the PCAM align with the existing PCAM principles.

ISSUE 2. PROPOSED REMOVAL OF PCAM DEADBANDS

Q. Please summarize PGE's proposal to remove the PCAM deadbands.

A. In PGE's filing, the Company proposes to remove the deadbands, arguing, "[t]he existence of the deadband construct motivates parties to act in their own self-interest and not consistent with a key objective of the AUT process: to as accurately as possible predict power needs for the coming year and to include in rates the forecasted costs for reliably serving customers."[20] In lieu of the deadbands, the Company proposes a 90/10 sharing mechanism between customers (90 percent) and PGE (10 percent) to allow recovery or refund of all prudently incurred NVPC above or below those recovered in base rates.[21]

Q. How does this proposal align with the current PCAM principles?

A. The existing first and second PCAM principles are:

1. The PCAM's application should be limited to unusual events and capture power cost variances that exceed those considered normal business risk.
2. There should be no adjustments if the utility's overall earnings are reasonable.

These two principles allow utilities to recover costs associated with circumstances outside of normal business risk while also taking into consideration the Company's earnings. The new proposal does not align with these two PCAM principles in that it is designed to recover all prudently incurred power costs, subject to the sharing mechanism, without regard to

[20] See PGE / 400, Sims—Outama/8.
[21] See PGE / 400, Sims—Outama/30.

earnings and places the normal business risks that investors are compensated for via Return on Equity (ROE) onto customers.[22]

Q. Does Staff agree with the Company's proposed change?

A. No. Normal business risks are not meant to be captured under the existing framework. As normal business risk represents the basis for a return on investment at a rate higher than that of the risk-free rate, recovery of such risks would warrant lowering the Company's ROE to keep customers from providing a hedge that benefits investors only.

Q. What was the original deadband construct when it was created in 2007 and when it was revised in 2011?

A. Under UE 180, the initial deadband was an asymmetric -75/+150 bps[23] of ROE. In 2011, the upper end of the deadband was set at $30 million, which represented 116 bps of ROE.

Q. What would be the dollar value if the same basis points of ROE were applied to the 2024 proposed rate base?

A. Applying the same 150 bps to the proposed rate base for the 2024 test year would result in an upper bound of over $64 million, more than double the current limit. Application of the 116 bps upper limit adopted in 2011 on the 2024 test year would result in a dollar value of roughly $50 million.[24]

---

22 Investors in a company are compensated for the normal business risk a company incurs via a return on equity. The return on equity provides an incentive for an individual to invest in a company rather than in a risk-free asset such as treasury bills. Utilities are regulated and their allowed ROEs are set by PUCs.

23 One basis point is one hundredth of 1 percent, or 0.01%.

24 See Staff/2301, Ahmed – Dlouhy – Jent – Pileggi/4 and Attachment A to PGE's response to Staff DR 182 which is filed electronically.

Q. Explain why the basis points of ROE is an important standard for evaluation of the deadband.

A. The deadband construct, in accordance with the current PCAM principles, only allows for sharing when the earnings are no longer reasonable, and the variance is outside that which was determined to be normal business risk. In 2007, under Docket No. UE 180, normal business risk was set at +150/-75 bps of ROE. Under Docket No. UE 215, the deadband was set to a dollar value of +$30/-$15 million, or roughly +116/-58 bps. This normal business risk has not been adjusted for the size of the Company and the deadbands represent less than half of the risk that they were created to capture in 2007.

Q. Does the Company's proposed change cause additional administrative burden?

A. Yes. The current deadband construct results in Staff and Intervenors performing analysis on the prudently incurred NVPC variances when those exceed the deadband amounts, which has happened once in the last seven years.[25] Removal, or even a significant decrease to the deadband amounts, as PGE has proposed, would require Staff and Intervenors to analyze for prudence in the NVPC variance at each annual filing.

Q. How does the 90/10 sharing and deadband construct impact NVPC hedges?

A. The 90/10 sharing structure and deadband construct places the benefit of any hedges on the parties in an uneven fashion. Any hedges upon NVPC

---

25 See Staff/2301, PGE response to DR 181 Attachment B which is filed electronically.

variances should reflect the sharing arrangements set by the Company between customers and the Company.

Q. What is Staff's recommendation?

A. Staff does not support removing the deadbands and the splitting of all refunds or incremental recovery 90/10 between customers and stakeholders, as PGE proposed. Instead, Staff has two options to recommend:

- Option One: Maintain the existing deadband construct in its current form; or
- Option Two: Adopt a multi-tiered sharing construct, including applying an earnings test, as follows:
  - Tier 1:

    A symmetrical $60 million tier shared at a 30/70 ratio between customers and PGE.
  - Tier 2:

    Sharing of any variances beyond Tier 1 at an 80/20 ratio between customers and PGE.

Staff only recommends Option Two if it is paired with a sharing of hedging costs between customers and the Company at the same rate as the Tier 1 sharing and the existing 100 basis point earnings test is maintained.

Q. Why has Staff proposed the first option?

A. Staff has proposed Option One to maintain the current deadband construct, as it is the NVPC variance method last approved by the Commission. As PGE indicated, the current deadband construct is outdated. The deadband has sat at a static fixed dollar amount for over a decade. Option One is Staff's less favored recommendation, as it has not been adjusted for the growth the Company has experienced, causing customers to start assuming risks on an ROE adjusted basis sooner than the Commission originally intended. The current deadband construct is now causing customers to assume normal business risks rather than sharing the risks of abnormal events.

Q. Why has Staff proposed an additional second option?

A. Staff has proposed Option Two, a two-tiered sharing structure, as a solution that acknowledges the decreasing amounts of overall business risks represented by the current construct and the increased volatility in NVPC variances over recent years. The impacts of the current deadband structure, PGE's proposal, and Staff's recommended Option 2 NVPC variance sharing structure, on the variances in the last seven PCAM filings—years 2015 through 2021, can be found in Staff Exhibit 2303 and are summarized in Table 1.[26]

TABLE 1. AVERAGE ANNUAL SHARING OF NVPC VARIANCES

	Current Method	PGE Proposal	Staff Proposal
Customer Share	$ 4,056,910	$ 6,805,476	$ 2,379,474
PGE Share	$ 3,504,731	$ 756,164	$ 5,182,167
$ Change in Customer Burden Relative to Current	$ -	$ 2,748,567	$ (1,677,436)
% Change in Customer Burden Relative to Current	0%	68%	-41%

[26] See Staff/2303 Workpaper (UE 416 Deadband Analysis and Historical Values), which is available in electronic format only. This workpaper incorporates PCAM variances provided by PGE in response to Staff DR 181 Attachment B, and deadband values as bps of ROE under UE 180 and UE 215, as provided by PGE in response to Staff DR 182 Attachment A.

In designing the multi-tiered approach, Staff considered previous deadband structures. On a bps of ROE basis, if the deadband had been adjusted at the 2007 GRC (UE 180) or 2011 GRC (UE 215) rates for the growth of the company, it would appear as shown in Table 2 below (current $30M/-$15M deadband bounds are shown for comparison).

TABLE 2. DEADBAND VALUES ON PROPOSED 2024 TEST YEAR

	Upper Bound bps	Upper Bound $	Lower Bound bps	Lower Bound $
At Current Deadband bps of ROE	69.7	$30.0 M	-34.8	-$15.0 M
At UE 180, 2007 GRC, bps of ROE	150.0	$64.6 M	-75.0	-$32.3 M
At UE 215, 2011 GRC, bps of ROE	116.0	$50.0 M	-58.0	-$25.0 M

Staff believes that the first tier of the two tiered approach is reasonable at $60 million, rather than either $50 million or $64.6 million, for the reasons that: the first tier contains sharing that would not exist under the deadband construct; and, this split, paired with the sharing ratios of the two tiers, finds a mid-ground between customer interests and Company interests. That said, Staff only recommends Option Two if it is paired with a sharing of hedging costs between customers and the Company at the same rate as the Tier 1 sharing. Staff belives that the existing earnings test must be maintained to ensure that the power cost variance sharing arrangement does not cause customers to compensate PGE stakeholders when earnings

Q. How did Staff develop the tier one threshold for Option Two?

A. In Option Two, Staff sought to balance the concerns raised by the Company, and the impacts to the Company that would be caused by increasing the deadband to capture a similar amount of risk as it did under previous rate cases. Staff evaluated the impacts of many tier thresholds and sharing ratios. The $60 million symmetric threshold for the first tier was selected for reasons including:

- The threshold is inside the range created by applying the bps of ROE from the 2007 GRC and 2011 GRC to the 2024 Test Year proposed rate base.
- The first tier is anticipated to capture the majority of NVPC variances so that normal business risks would not be born primarily by customers.
- The symmetric structure and early sharing provide an equal incentive to forecast NVPCs while limiting the volatility of variances born by customers.

Q. Why are the sharing ratios and the tier one threshold of Option Two Reasonable?

A. The sharing ratios were developed to provide a balance between PGE and customer interests. Staff believes it has achieved this balance via a multi-tiered sharing structure, with the threshold between the two tiers described above. Sharing ratios in this recommendation were optimized in tandem with the threshold. Staff evaluated many options before settling on the recommended structure provided in Table 3 below.

TABLE 3. STAFF PROPOSED NVPC VARIANCE SHARING STRUCTURE

Tier 1 Threshold	Upper Bound $60,000,000	Lower Bound $ (60,000,000)
Sharing Party	Customers	PGE
Tier 1 Sharing	30%	70%
Tier 2 Sharing	80%	20%

PGE's previous sharing, outside of the deadband, was a 90/10 ratio between customers and the Company, respectively. Staff has set Tier 1 of our recommended variance sharing structure to a 30/70 ratio between customers and the Company. This was done in order to minimize the shock to PGE of adjusting the NVPC variance sharing to reflect the growth of the Company, minimize the volatility experienced by customers of shared NVPC variances, and allow for earlier sharing without shifting business risk onto customers. As customers are sharing in NVPC variances throughout the entire first tier, Staff has set the sharing ratio outside of Tier 1 at an 80/20 ratio between customers and the Company, respectively.

Staff also notes that the split shown above may not be the ultimate split under regulation as the Company may apply, and the Commission may approve, deferrals for extraordinary events. To the extent that occurs, the likely result will be that the deferrals will be for above-normal costs; and, therefore, the amount of costs being recovered from customers will be greater than 80 percent.

ISSUE 3. PROPOSED REMOVAL OF THE EARNINGS TEST

Q. Summarize the purpose of the earnings test.

A. The Commission applies an earnings test to determine whether the utility is earning an acceptable rate of return in various proceedings including the PCAM, but also allows for deferrals. An earnings test serves to protect customers from paying for higher-than-expected power costs or deferred amounts when the utility's earnings are reasonable. The earnings test also protects the Company from refunding power cost savings or deferred amounts when it is underearning. For the purposes of the PCAM, the Commission established an earnings deadband (discussed above) of ± 100 basis points around the company's allowed ROE. Under this structure, if the Company's earnings fall more than 100 basis points below its authorized ROE, it will have the opportunity to recover excess power costs. This recovery is subject to the application of the deadband in the described 90/10 sharing structure and will be limited to an earnings level that is 100 basis points less than the authorized ROE.

Q. Please summarize the Company's proposal to remove the earnings test in the PCAM.

A. The Company proposes that power costs prudently incurred and necessary to provide service to customers be recoverable and not subject to an earnings test.

Q. Why does the Company believe that it should recover or refund all prudently incurred PCV without an application of an earnings test?

A. PGE dedicates a considerable amount of testimony to the argument that changes to its resource mix, changes to state policies relating to emissions, the introduction of the EIM market, and even climate change have changed the business risk that it faces, and that they are "…expected to absorb power cost variability that goes far beyond the Commission's original notions of normal utility business risk".[27] They also give the following additional reasons: PGE has decreasing ability to influence expenditures, the expenditures offer no return for risks incurred, there is extreme market volatility and prices, and the power cost risk is now inequitably balanced and unfairly borne by PGE."[28]

Q. How does the Company's proposal and logic align with the current five PCAM principles?

A. Its proposal is at odds with the current five PCAM principles and even the condensed principles that PGE proposed. Specifically, existing Principle 2 states that there should be no adjustments if the utility's overall earnings are reasonable. Removing the earnings test is inconsistent with this principle because the Company would be able to pass through almost all of its power costs to ratepayers no matter its overall earnings.

Principle 3 is concerned with the long-term interests of shareholders and ratepayers, in which there is a delicate balance between. By proposing to

---

[27] PGE/400, Sims – Outama/2 and 8.
[28] PGE400, Sims – Outama/32.

recover all costs every year, there could be shocks to the system that could have disproportionate impacts to ratepayers negatively in the short and long-term.[29]

Principle 4 states that the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer. The recovery of refunding of power costs variations are impacted by the performance of other operational areas.

Lastly, it is unclear how this fourth principle would be reconciled with the first principle that it proposes in which PGE says prudently incurred power costs should be fully recoverable/refundable. In short, they are contradictory.

Q. What evidence has the Company presented that removing the earnings test associated with the PCAM is warranted?

A. The Company provides narrative arguments in their opening testimony, which is exemplified by four quotes below.

1. "PGE is facing a current and future state where we are expected to absorb power cost variability that goes far beyond the Commission's original notions of normal utility business risk."[30]
2. PGE goes on to say, "This level of uncertainty exceeds the normal utility business risk contemplated when the PCAM was originally developed and implemented."[31]

---

29 See Staff/600 for a more thorough discussion on these disproportionate impacts.
30 PGE/400, Sims – Outama/8.
31 PGE/400, Sims – Outama/2.

3. PGE also states that, "The earnings test under the PCAM is not an appropriate tool because it allows the recovery or refunding of power cost variations (positive and negative) to be unreasonably impacted by the performance of other operational areas. If PGE does not perform effectively in other areas, our earnings would be reduced, and hence, we would earn a lower ROE."
4. PGE concludes by stating:

> …an earnings test in any PCAM construct does not promote overall efficiency and is not the appropriate tool to fairly balance cost and risk while also ensuring reasonable utility earnings... These are expenditures over which PGE will have decreasing ability to influence due to changing external factors and evolving market structures; they are also expenditures that offer no return for risks incurred. Moreover, we are exposed to increasingly extreme market volatility and prices, thus, increased power cost risk that is now inequitably balanced and unfairly borne by PGE.[32]

In essence, the Company believes that the elimination of the earnings test better aligns interests, appropriately balances risks and benefits, and incentivizes operational efficiency and effective management of controllable costs. This structure would allow for potential power cost refunds to be retained by PGE and effectively offset poorer performing operations elsewhere. Similarly, should PGE overperform in other operational areas and earn a higher ROE, it could result in a reduced recovery of prudently incurred power costs necessary to serve customers.

[32] PGE/400, Sims – Outama /32.

Q. Does Staff agree with PGE's proposal?

A. No. PGE's proposal effectively removes the holistic nature of rates by segmenting off power costs from other utility operations. This is not appropriate. PGE is a vertically-integrated utility and has chosen to be a vertically integrated utility through its continued purchasing and building generation resources. Staff does not view it as appropriate to have customers absorb additional, unexpected power costs when other parts of utility operation result in above normal returns. Customers pay for utility services and the rates that they pay should be just and reasonable. PGE's proposal would result in rates no longer being assured as just and reasonable.

Further, as discussed previously, the Company has much smaller net variable power costs and higher rate base, creating greater overall financial heft that is less reliant on power cost. Financial heft of the company should be considered then versus now and ability to absorb risk.

Q. Why does Staff support keeping the earnings test?

A. The earnings test ensures rates are just and reasonable, as basic tenet of regulatory law. As such, the earnings test precludes raises rates when the Company is earning excessive profits; and the earnings test allows the utility to recover prudently incurred excess power costs in the event that overall earnings are low. Keeping the earnings test also ensures transparency and accountability by requiring that overall Company health is considered in more targeted Company actions.

In addition, Staff does not have a valid counterfactual of what power costs would have been if there had been no earnings test from the PCAM's inception. Therefore, Staff cannot assume that power costs would have only allowed for recovery by PGE in one of the last seven years.

Q. Why does Staff not support the Company's proposal to remove the earnings test?

A. The mechanism is working as intended and was designed to "exclude normal variation from triggering the mechanism." It has consistently worked as intended, including through the 2023 PCAM, discussed below. The PCAM was not designed to fully mitigate the power cost risk to the Company but instead to incentivize the Company to manage its costs while providing balanced protections. As stated in the deadband discussion, the financial heft of the Company should be considered then versus now.

Q. Do you have additional comments on PGEs testimony regarding the PCAM and their proposal to remove the earnings test?

A. Staff is not compelled by the Company's assertion that it faces greater uncertainty under current market conditions. The various risks referred to by PGE are a part of normal business risk of operating as a utility in 2023. With a requested rate base of $6.3 billion[33] and a greater ratio of overall costs recovered through base rates, the Company has significantly higher capacity to absorb variation in power costs. Finally, PGE's narrative assumes that the AUT filing will not be improved by the many modeling changes proposed in its

[33] PGE/100, Pope—Sims/19.

2023 AUT, which drive a large increase in NVPC in 2023. By ignoring these changes, the Company implies that the elimination of ratepayer protections that exist in the PCAM are preferential to resolving the recognized issues of its NVPC forecast.

Staff addresses a trend of utilities trying to offload power cost risk through the removal of deadbands and earnings tests here, NVPC modeling updates in the UE 416 NVPC testimony, and the proliferation of deferrals and AACs in Staff Exhibit 220.

Q. What is your recommendation regarding the Company's proposal to remove the earnings test associated with the PCAM?

A. Staff does not support the Company's proposal and recommends the Commission maintain an earnings test in the PCAM.

ISSUE 4. PROPOSED RCE PASS THROUGH

Q. Please summarize the Company's proposal regarding the treatment of Reliability Contingency Events (RCEs) in the PCAM.

A. The Company proposes to collect or refund 100 percent of all incremental or decremental power costs associated with RCEs outside the PCAM.[34]

Q. Why does the Company believe that it is appropriate to collect or refund any incremental/decremental NVPC prudently incurred during qualifying RCEs outside the PCAM?

A. The Company provides various reasons to support this proposal. First, the Company notes that its resource mix has changed since the PCAM was first introduced in the mid-2000s with the addition of various Variable Energy Resources (VERs) that address renewable portfolio standard (RPS) legislation.[35]

Second, PGE states the number of extreme weather events that are associated with RCEs are increasing due to climate change.[36]

Third, the Company states that the emergence of VERs has led to changing wholesale market dynamics, including a large increase in the market heat rate that makes the heat rate of PGE's historic peaker plants often lower than market heat rate,[37] and an increase in scarcity pricing events that lead to

[34] PGE/400, Sims – Outama/4.
[35] PGE/400, Sims – Outama/12.
[36] PGE/400, Sims – Outama/15.
[37] PGE/400, Sims – Outama/17.

higher market price volatility.[38] Based on these factors, the Company claims that there is no longer any "normal" business risk, particularly during RCEs.[39]

Q. How has the emergence of VERs changed power costs and power operations?

A. The Company's net variable power costs have decreased since RPS legislation mandated the use of renewables. According to PGE's confidential response to Staff DR 279B, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Do you believe the Company's claim that climate change is increasing the number of extreme weather events?

A. Yes. Staff does not dispute this claim and in fact supports the inclusion of a forecast of costs associated with RCEs in PGE's NVPC forecast. The increased presence of extreme weather events, however, does not necessarily fundamentally change how to fairly allocate risk between shareholders and customers.

Q. Do you believe the Company's claim that the emergence of VERs changes wholesale market dynamics?

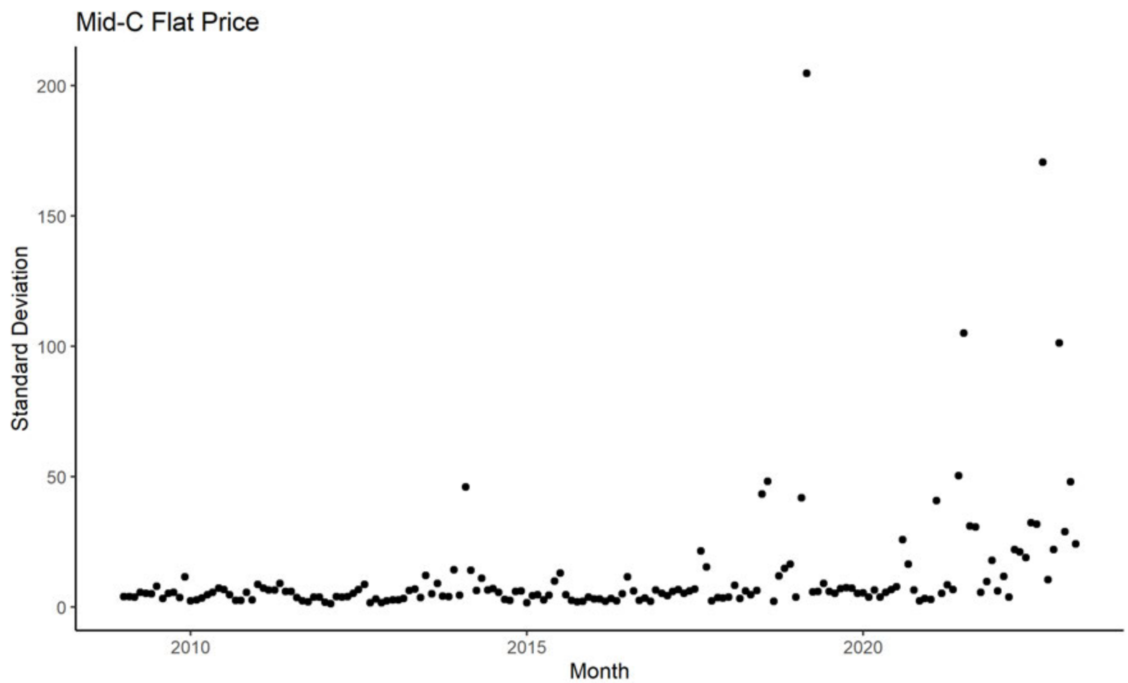
A. Yes. Staff analyzed the change of the within-month standard deviation of both the flat and on-peak Mid-C price. Figure 6 contains the within-month estimate

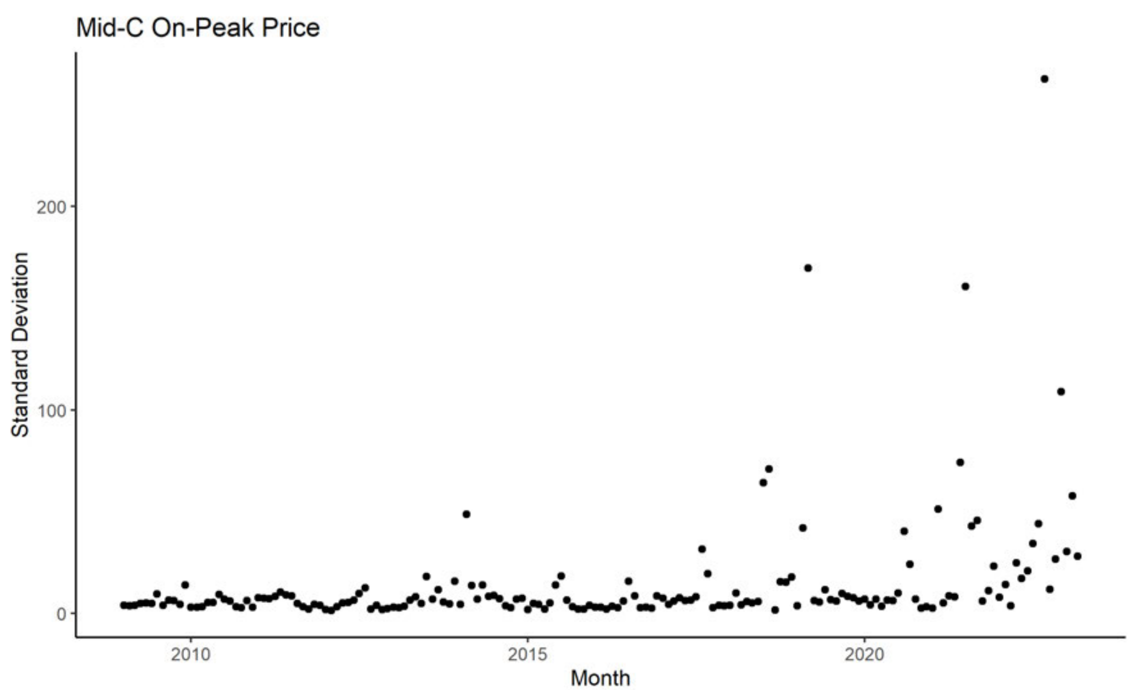
---

38 PGE/400, Sims – Outama/19.
39 PGE/400, Sims – Outama/25.

of the standard deviations of both these prices. It is apparent from these figures that the price variability has substantially risen in the last few years.

FIGURE 6. MONTHLY WHOLESALE PRICE VARIABILITY





Q. Does this increased wholesale price volatility necessarily mean that the Company is experienced greater wholesale price exposure during extreme weather events?

A. No. As Staff Witness Curtis Dlouhy discusses in his UE 416 power cost testimony in Staff Exhibit/300, the Company is committed to joining the Western Resource Adequacy Program (WRAP), which has a forward showing program meant to ensure that its members are planning sufficiently for these extreme weather events and an operational program that forces WRAP participants to share some amount of excess capacity with other WRAP participants, thus mitigating the Company's need to transact at wholesale trading hubs. Additionally, the Company is exploring membership in the Extended Day-Ahead Market, which would further insulate them from wholesale price exposure related to RCEs.

Q. Do you agree with the Company's claim that the above factors mean that there is no longer any "normal" business risk?

A. No. The Company's testimony indicates that the costs of doing business are increasing due to the increased price volatility and increased frequency of extreme weather. Staff is supportive of including a fair forecast of these increased costs of doing business that are not easily modeled, as evidenced by Staff Witness Dr. Dlouhy's power cost testimony on the Company's proposed RCE forecast. It may also be the case that the cost associated with RCEs are more volatile than other line items associated with the overall NVPC estimate. However, allowing a forecast of RCE costs in PGE's NVPC forecast effectively turns this abnormal business risk into a normal business risk that is fungible with the rest of the NVPC forecast. As previously discussed in this testimony, base rates now comprise a much larger portion of revenue requirement than NVPC than in the early days of the PCAM.

Further, Staff does not agree that the RCEs are risky enough that they should be considered as an entirely separate line item from all other NVPC items. As discussed in Staff's evaluation of the PCAM principles, Staff views overall NVPC as something that should be considered holistically. Staff believes that the NVPC associated with an RCE need not be recovered if the overall NVPC is otherwise reasonable.

Q. How does the Company propose to define and implement their proposal to collect or refund 100 percent of RCE NVPC?

A. The Company proposes at least two of the three following conditions must be met for an event to be called an RCE and thus eligible for full refund or collection:

1. The day-ahead Mid-Columbia index prices must exceed $150/MWh.
2. PGE is eligible to request or acquire resource adequacy (RA) assistance through a regional RA program in which it participates.
3. A neighboring Balancing Area Authority (BAA) has declared an event that indicates impending or realized RA constraints.[40]

[40] PGE/400, Sims – Outama/33-34.

The Company states that it can foresee an instance in which two of the conditions are met but the Company does not declare the event to be an RCE.[41]

Q. How would allowing perfect pass-through of RCE costs align with the PCAM principals proposed by Staff earlier in this testimony?

A. In short, it would not. PGE's proposed RCE pass-through appears to directly violate many of the existing PCAM principles. Allowing perfect pass-through of RCE costs violates the following PCAM principles created by the Commission:

- Principle 1: The PCAM's application should be limited to unusual events and capture the power cost variance that exceed those considered normal business risk.
- Principle 2: There should be no adjustments if the utility's overall earnings are reasonable.
- Principle 5: The PCAM should provide an incentive to the utility to manage its costs effectively.

Q. Why do you believe that PGE's proposal violates the first PCAM principle?

A. While RCEs can be associated with high market prices, Staff's proposal to allow a forecast of RCEs in the NVPC forecast essentially makes this a normal business risk that can be quantified in a NVPC line item that can have expected deviations just like any other NVPC line item. Further, PGE's

[41] PGE/400, Sims – Outama/34.

proposed criteria gives them discretion to call an RCE regardless of how much it actually adds to its costs.

Staff is not persuaded by the Company's claim that it may choose to not declare an RCE. In the event that actual overall NVPC is significantly higher than forecasted NVPC and this is due to RCEs, then the current PCAM structure provides a framework for the Company to recover these abnormal costs. In addition, the RCE is one-sided. PGE has not proposed a similar proposal for when power costs are exceptionally low, which presumably could occur in the instance of very low natural gas prices, reduced loads and high hydroelectric availability. Therefore, PGE's proposal is not balanced.

Q. Why do you believe that PGE's proposal violates the second PCAM principle?

A. As Staff has mentioned before in this testimony, Staff views RCEs to be a fungible portion of the Company's overall NVPC forecast. Allowing the recovery of RCE costs during an otherwise banner year could potentially lead to the Company charging customers for RCE costs while it is already overearning.

Q. Why do you believe that PGE's proposal violates the third PCAM principle?

A. Perfect pass-through of RCE costs removes incentives for the Company to prudently manage costs during an RCE. Although the Company's proposal specifies that it would only request the recovery or refund of prudently incurred costs, Staff struggles to picture a scenario in which the Company would claim that it incurred costs imprudently during an RCE.

Q. Based on this, what is your recommendation regarding the Company's proposal to allow perfect pass-through of all prudently incurred costs associated with RCEs?

A. Staff recommends that the Commission reject the Company's proposal to refund or recover all decremental or incremental costs associated with RCEs outside of the PCAM.

ISSUE 5. PROPOSED PCAM ROLLING CAP

Q. Please describe the rolling cap structure in the Company's PCAM proposal.

A. PGE believes its PCAM proposal allows for a better balancing of risks and rewards associated with power cost variations while allowing it to compete for capital more effectively and providing incentives for them to operate and manage power operations efficiently. One of the four proposed adjustments to the PCAM includes the establishment of a +/-2.5 percent rolling cap on customer price changes year over year. Amounts beyond the cap that will roll over to the next year will be subject to either continued amortization in customer prices or netted against future PCAM credits.[42]

Q. Why does the Company believe that this +/- 2.5 percent rolling cap is appropriate?

A. PGE's rationale for this cap is to smooth impacts and mitigate against large single-year customer price changes due to power costs. Any amounts that would result in price impacts greater than 2.5 percent will be deferred until the following year. PGE indicates that power costs incurred can be amortized over a longer period to provide customer price stability if the need arises. PGE's proposed rolling cap was set at +/- 2.5 percent since from their standpoint, it strikes a balance between amortizing as soon as practicable after the year costs are incurred and maintaining customer price stability. To that end, PGE

---

[42] PGE/400 Sims-Outama/30.

based the +/- 2.5 percent on the 10-year average all-urban inflation rate observed at the time of filing (i.e., 2013-2022), which was 2.5 percent.[43]

Q. How does the rolling cap interplay, if at all, with any overall statutory rate cap for amortizations?

A. The statutory cap limits the amortization of deferred amounts under the PCAM in any year to 6 percent of PGE's revenues for the preceding calendar year (ORS 757.259). PGE's proposed price cap does not interplay with ORS 757.259 as Schedule 126 would be an automatic adjustment clause pursuant to ORS 757.210.[44] In effect, this means that the total cap of amortization would rise to 8.5 percent.

Q. How does this align with the current PCAM principles?

A. PGE's rolling cap proposal violates Principle 4, which states the PCAM should operate in the long-term to balance the interests of the utility shareholders and ratepayers. The proposal to institute a rolling cap in effect would allow one period of exceptionally high costs in a single year to affect ratepayers for many years, and vice versa.

Q. Do you agree with this proposed change?

A. No.

Q. Why do you believe that a rolling cap is a poor choice for ratemaking?

A. Staff worries that ratepayer interests will not be maintained with the rolling cap and potentially causes intergenerational equity concerns. For example,

---

43 See Staff/2301, Ahmed – Dlouhy – Jent – Pileggi/6.
44 *Ibid*.

assume that the rolling cap is met in one year, which would trigger recovery/refund of costs into a second year. Suppose further that a new customer comes onto the system in the second year where the rolling cap would recover costs from the previous PCAM year. In this scenario, costs would be recovered from the new customers that had no role in creating the previous year's costs. It appears PGE has not considered this aspect.

Q. Did PGE specify the length of time over which it would amortize the power costs?

A. No. PGE had indicated that the power costs incurred can be amortized over a longer period to provide customer price stability, and the period can be longer than one year. The company thinks it is unlikely that any single-year variance would need to be amortized over a longer period, as the year 2021 was the only instance where the total PCAM variance would have resulted in an amount greater than 2.5 percent of PGE's total revenues. PGE also noted that the 2021 power cost variance was approved for a two-year amortization in Docket No. UE 406. In a related example, the amounts deferred through UM 2115 and UM 2156 were recently approved for amortization over seven years, even though costs associated with the extreme weather events in these deferrals were incurred over just a couple years.[45]

Q. Do you have any other concerns with the rolling cap proposal?

A. Yes. PGE had stated that power costs could be amortized over a longer period if the situation arises. If costs are amortized over a longer period, this can lead

[45] See Staff/2301, Ahmed – Dlouhy – Jent – Pileggi/7.

to customers paying these costs in rates for a longer period. Added to this, PGE indicated that intergenerational issues when costs are recovered from non-cost causers were not raised as a major concern concerning the time length of amortization.[46] PGE has not specified how and why this is not an issue worth considering in light of recent DEI initiatives and focus on equity issues. Staff on the other hand is aware of the effect this will have on future customers. These customers are likely subject to higher rates in general, which compounds the effects of this proposal on intergenerational equity.

Q. What is Staff's recommendation regarding the proposed rolling cap?

A. Staff does not support the rolling cap proposal and recommends the Commission not adopt PGE's proposal. At the highest level, PGE's proposed PCAM rolling cap violates Principle 4. There are intergenerational equity concerns about whether PGE has considered tradeoffs regarding power costs incurred by cost causers and recovered from new potential customers. In their testimony, PGE has not identified and conveyed why there should be no intergenerational issues when costs are amortized, and has not put forward compelling reasons that would have assuaged the mismatch issues. Furthermore, the length of time over which incurred power costs are amortized can result in such costs being in rates longer and customers having to pay for a longer period.

---

[46] *Ibid*.

Q. Does Staff support any changes to the PCAM?

A. Yes, in Staff/1300, Issue 1 Staff discusses their support of PGE's proposal to have a passthrough of qualifying facilities (QFs) costs.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: ISHRAQ AHMED,
CURTIS DLOUHY,
JULIE JENT,
ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2301

Non-Confidential Responses to Data Requests in Support Of Opening Testimony

June 13, 2023

March 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 181
Dated March 10, 2023

Request:

Please refer to PGE/400, Sims–Outama/30. If PGE's proposal to remove the deadband, eliminate the earnings test, and have 90/10 sharing was in effect from calendar 2015 to the present, please provide a table that displays for each year the true-up power cost amount that retail customers would have been charged in rates as well, as what retail customers were charged under the current framework. Please provide the electronic workbook with all cells and formulae intact used in reply to this question.

Response:

Attachment 181-A provides the estimated PCAM collections and refunds had PGE's proposal to remove PCAM deadbands and the earnings test been in effect for years 2015 through 2021.
Attachment 181-B provides PGE's actual PCAM collections/refunds for years 2015-2021.
PGE's 2022 PCAM is not yet complete.

PGE's CONF Response to DR 181 Attachment A is available in electronic spreadsheet format only.

PGE's CONF Response to DR 181 Attachment B is available in electronic spreadsheet format only.

March 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 182
Dated March 10, 2023

Request:

When the positive power cost variance of $30 million from the deadband was set in 2007, how many basis points in terms of return on equity did that represent?

a. For UE 416, how many basis points return on equity does $30 million represent?

Response:

The $30 million upper power cost deadband was established in PGE's 2011 general rate case (Docket No. UE 215). The power cost deadbands for the PCAM originally established by the Commission in PGE's 2007 GRC (UE 180) ranged from 75 basis points ROE below the NVPC baseline to 150 basis points ROE above the baseline.

Based on the 2007 GRC rate base and the 50/50 capital structure approved by the Commission in UE 180, a $30 million power cost variance represented 181 basis points ROE.
Based on the 2011 GRC rate base and the 50/50 capital structure approved by the Commission in UE 115, a $30 million power cost variance represented 116 basis points ROE.

a. Based on the 2024 rate base and 50/50 capital structure proposed by PGE, a $30 million power cost variance represents 70 basis points ROE.

See Attachment 182-A for related calculations.

PGE's CONF Response to DR 182 Attachment A is available in electronic spreadsheet format only.

April 12, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 399
Dated March 29, 2023

Request:

Refer to Sims – Outama/36. Company discusses the +/- 2.5% rolling cap to smooth impacts from large single year customer price changes due to power costs. Please explain the basis of how Company arrived at the 2.5% threshold. If there was any quantitative analysis to inform this number, please provide the electronic workbook with all cells and formulae intact used in reply to this question. How does this Cap interplay with, if at all, with any overall statutory rate cap for amortizations? Please explain.

Response:

PGE's proposed rolling cap was set at +/- 2.5% as it strikes a balance between amortizing differences as soon as practicable after the year incurred and maintaining customer price stability. In attempting to strike the above balance, PGE based the +/- 2.5% on the 10-year average all-urban inflation rate observed at the time of filing (i.e., 2013-2022), which was 2.5%.

PGE's proposed price cap does not interplay with any statutory price caps pursuant to ORS 757.259, as Schedule 126 would be an automatic adjustment clause pursuant to ORS 757.210.

April 12, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 400
Dated March 29, 2023

Request:

Refer to Sims – Outama/36. Company suggests amortizing power costs over a long period to help provide customer price stability from year-to-year. Does PGE have a specific length of time over which it would spread the amortization? If so, please explain in detail including what trade-offs are being considered such as costs being paid for by the cost causers.

Response:

PGE Exhibit 400, page 36 refers to the rolling cap of +/- 2.5% as a means of allowing amortization over a *longer* period (i.e., longer than one year); not necessarily a long period. In the history of PGE's PCAM,[1] 2021 is the only instance where the total PCAM variance (i.e., prior to the application of any sharing or deadbands) would have resulted in an amount greater than 2.5% of PGE's total revenues and after the application of PGE's proposed 90/10 sharing, the 2021 variance would have also been below 2.5%.[2] As such, it is unlikely that any single year variance would need to be amortized over a long period. However, PGE did not consider a specific length of time, though we do note that the 2021 power cost variance was approved for a two-year amortization through Docket No. UE 406. Additionally, amounts deferred through Docket Nos. UM 2115 and UM 2156 totaling approximately $100 million were recently approved for amortization over a seven-year period. Intergenerational issues were not raised as a major concern over that length of time and it is doubtful that any PCAM variance would be amortized over a longer period of time.

[1] 2007 to present.

[2] The total power cost variance of $61.6 million was approximately 2.6% of PGE's 2022 revenues and approximately 2.4% after the application of PGE's proposed 90/10 sharing.

CASE: UE 416
WITNESS: ISHRAQ AHMED,
CURTIS DLOUHY,
JULIE JENT,
ROSE PILEGGI

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2302

Confidential Responses to Data Requests in Support Of Opening Testimony

June 13, 2023

PGE's CONF Response to DR 169 Attachment A is available in electronic spreadsheet format only.

CASE: UE 416
WITNESS: ISHRAQ AHMED,
CURTIS DLOUHY
JULIE JENT,
ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2302

Workpapers in Support
Of Opening Testimony

June 13, 2023

CASE: UE 416
WITNESSES: Melissa Nottingham and Scott Shearer

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2400

OPENING TESTIMONY
Schedule 300 Billing Rates, Submersible Transformers, and Reconnection Fees

June 13, 2023

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

A. My name is Melissa Nottingham. I am the Consumer Services and Residential Service Protection Fund (RSPF) Manager for the Public Utility Commission of Oregon (Commission). Our 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/2401.

Q. Please state your name, and occupation.

A. My name is Scott Shearer. I am an analyst employed in the Rates and Telecommunications Services Section of the OPUC's Rates, Safety and Utility Performance Program.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/2402.

Q. What is the purpose of your testimony?

A. Staff examined the charges and updates proposed in PGE's Schedule 300.

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared the following supporting exhibits:

Exhibit Staff/2403 (Data Requests and Responses).

Q. How is your testimony organized?

A. Our testimony is organized as follows:

ISSUE 1. SCHEDULE 300 BILLING RATES

Q. What items related to Schedule 300 Billing Rates did Staff examine?

A. Staff examined the proposed price increases for Special Meter Reading charge, Meter Test Charge, Field Visit Charge, Customer Interval Data to Customers, and the Qualified Facility Monthly Service Charge. Table 1 shows the breakdown of each of these charges, the current rate, the proposed rate, and any proposed change to the charge.

Q. What methodology was used by PGE to calculate the increase charges?

A. PGE used the hourly rate of the employee completing the work, a four percent expected annual labor increase, the administrative costs for the employee including transportation costs to calculate a loaded hourly rate for the labor. Once the labor cost was determined, the new charge was calculated by multiplying the loaded labor costs by the average duration to complete the task.

Q. Does staff have any concerns with this approach?

A. The method is a standard utility practice for this type of charge. The goal is to approximate an amount closest to actual costs for the work. While variations may occur due to the distance traveled by the employee to complete the work or the additional complexity for a particular customer's bill, using an average for the time to complete the work is reasonable. Staff does note when asked for additional information on the time to complete a record or .5 hours at the meter, PGE was unable to provide the shortest, longest, and medium reconnect time. See DR 482. PGE stated it does not track the time for each reconnection. Without the reconnection times, an average of .5 hours cannot be validated.

While Staff had some concerns with PGE's statement, the time is reasonable considering travel time and the time to complete a reconnection at the meter.

Table 1

Schedule 300 - Billing Rates	Current Price	Proposed Price	Price Increase	Percentage Increase
Special Meter Reading Charge (non-network)	$17.00	$25.00	$8.00	47%
Meter Test Charge	$75.00	$140.00	$65.00	87%
Field Visit Charge	$20.00	$50.00	$30.00	150%
Customer Interval Data (12 months) to Customers	$100.00	Remove	N/A	N/A
Qualified Facility Monthly Service Charge	$10.00	$151.00	$141.00	1410%

Q. Please describe PGE's proposal for the Special Meter Reading Charge?

A. PGE is proposing to increase the price customers who have non-network meters installed from $17.00 to $25.00. PGE used a labor cost analysis to calculate the proposed rate.

Q. What is the purpose for the Special Meter Reading Charge?

A. When PGE first implemented Automated Metering Infrastructure (AMI), the Commission determined that customers should have the option to opt-out of having an AMI Meter installed. The Commission also required those customers to pay the costs to install a non-AMI meter and pay the costs PGE incurred to read the meters each month.

Q. Why doesn't the charge adopted in Commission's Order No. 08-245, in Docket No. UE 189, PGE's AMI implementation, stay in place as determined at that time?

A. The charge was originally determined based on the actual costs PGE incurred to send personnel to the individual customer location, read and record the meter reading, and input the reading back into PGE's system for billing.

The original charge was never intended to be static, but for PGE to recover the additional costs incurred to perform the system. To this end, the Company may request to change the amount of the customer charge based on the current costs to provide the service.

Q. Does Staff agree with the Company's proposed Special Meter Reading Charge?

A. Yes. Staff reviewed the charge, PGE workpapers, and responses to Staff's Data Requests. Staff agrees with PGE's proposed calculations, as they accurately depict PGE's increased costs to provide the service.

Q. Please describe PGE's proposal for the Meter Test Charge?

A. PGE is proposing to increase the price charged to customers who request a second meter test in a twelve-month period from $75.00 to $140.00. PGE used a labor cost analysis to calculate the proposed rate.

Q. Does Staff agree with the Company's proposed Special Meter Reading Charge?

A. Yes. Staff reviewed the charge, PGE workpapers, and responses to Staff's Data Requests. Staff agrees with PGE's proposed calculations, as they accurately depict PGE's increased costs to provide the service.

Q. Please describe PGE's proposal for the Field Visit Charge?

A. PGE is proposing to increase the price charged to customers who request a second meter test in a twelve-month period from $20.00 to $50.00. PGE used a labor cost analysis to calculate the proposed rate.

Q. Does Staff agree with the Company's proposed Field Visit Charge?

A. Yes. Staff reviewed the charge, PGE workpapers, and responses to Staff's Data Requests. Staff agrees with PGE's proposed calculations, as they accurately depict PGE's increased costs to provide the service.

Q. Please describe PGE's proposal for the Customer Interval Data?

A. PGE is proposing to remove this completely from the tariff. Per PGE, this data is readily available to all customers through its online portal, via the customer's account page.

Q. Does Staff agree with the Company's proposed Customer Interval Data?

A. Yes. Staff reviewed the charge and PGE workpapers. Staff agrees with PGE's explanation and reasoning, as the data and information related to meter reading is now available online, and PGE is no longer required to do extra work to complete an interval data review to provide this information to customers. Staff recommends the Commission direct PGE to communicate to all customers the information is available upon request to inform customers without or with limited internet access.

Q. Please describe PGE's proposal for the Qualified Facility Monthly Service Charge?

A. PGE is proposing to increase the monthly charge for customers who have a Qualified Facility installation from $10.00 to $151.00. In addition, they propose moving the charge from the Schedule 201 Tariff to the Schedule 300 Tariff. PGE used a labor cost analysis to calculate the proposed rate.

Q. Does Staff agree with the Company's proposed Qualified Facility Monthly Service Charge?

A. Yes. Staff reviewed the charge, PGE workpapers, and responses to Staff's Data Requests. Staff notes that while this increase appears extreme at 1,410 percent, the last time this charge was reviewed and approved was in Docket No. UE 180, Order No. 07-015, nearly 17 years ago. In 2022, the monthly charge was applied 638 times representing approximately 53 customers.

Staff agrees with PGE's proposed calculations, as they accurately depict PGE's increased costs to provide the service. Staff also agrees that moving the charge into Schedule 300 makes sense as it consolidates where these charges are found in the tariff. Staff notes that this charge will be applicable to new contracts going forward.

As such, Staff recommends clarifying language be added to the tariff, that specifies the charges apply to contracts signed after the effective date of the tariffs only, and that previously signed contracts retain the original billing rate.

ISSUE 2. SUBMERSIBLE TRANSFORMERS

Q. Please describe PGE's proposal for the Submersible Transformers?

A. PGE is requesting the Commission approve removing the option for customers to choose installation of a Submersible Transformer for aesthetic purposes.

Q. What is a Submersible Transformer?

A. Also known as an underground transformer or vault, it is a style of transformer that is flat and even with the ground. It is designed to provide reliable and efficient power distribution in underground or submerged environments.

Q. Who is responsible for the costs to install and maintain a Submersible Transformer?

A. PGE and its customers share these costs. Per PGE, customers are charged a fee for choosing the option of a Submersible Transformer based on the cost of the transformer itself, and the estimated costs to maintain the transformer.

However, PGE also states that the cost to maintain these transformers is greater than other transformer options and extrapolates that the rest of the customers are paying for these customers choice. Per the Company's response to OPUC DR 148, PGE estimates costs for Annual submersible transformer maintenance - $50.29 and Utilization Transformers, submersibles - $782.00, however, there does not appear to be a formal cost study showing the full maintenance costs differences between Pad-mount and submersible transformers.

Q. Does Staff agree with the Company's proposed removal of the Submersible Transformer option?

A. Ultimately, no. While Staff agrees with PGE argument that customers should pay the costs attributable to their choice, Staff disagrees that the answer is to simply no longer offer the option. Staff believes there may be other valid reasons for removing the option for customers, but based on the information and data PGE provided there is not sufficient evidence to for Staff to agree with PGE's request to remove this item from the tariff.

Staff recommends the Commission deny PGE's request to remove the customer's choice to have a submersible transformer for aesthetic reasons. Staff further recommends the Commission require PGE to conduct a cost study on the long-term incremental maintenance costs for submersible transformers along with a cost differential between these and standard Pad-mount transformers and submit the request to update the costs for a submersible transformer in a future rate proceeding.

ISSUE 3. RECONNECT FEES

Q. Please describe Schedule 300's Reconnect Fees.

A. Currently, PGE charges all customers the same reconnect fee to turn on power after the meters are disconnected for nonpayment of bills. The reconnect fees are based on an estimated average of the cost to send the appropriate employee to the meter and manually reconnect the meter. Fees vary based on the day and time the activity occurs reflecting the costs for various labor rates for work occurring during business hours, after business hours, on weekends, and holidays. The labor costs are multiplied by the average time calculated for the employee to complete the work.

The company is proposing an increase in the reconnect fee from $27 to $50 for a reconnection during business hours and $80 to $190 for reconnects outside of business hours. The cause of the is due to increased labor costs. The company does not charge for disconnecting the meter either at the customer's request or if the disconnection is based on non-payment of bills.

Table 2

Credit Related Disconnection and Reconnection Rates (Rule H)		
Disconnection	No Charge	
Reconnection During Business Hours	**Current**	**Proposed**
At Meter Base	$27	$50
Reconnection After Hours		
At Meter Base	$80	$190

Q. Does the proposed fee approximate the cost of the service provided to the company?

A. The proposed reconnect fee is based on the costs for an employee to drive to the meter and complete the activity is reasonable. Based on PGE's response to OPUC DR 144, Staff calculates approximately 32 percent of PGE's meters have the ability for a remote reconnect eliminating the need a visit to the meter, as shown in Table 3.

Table 3

Meter Type	Remote	Non-Remote	Non-Smart	Total
Meter Count	298,538	621,351	158	920,047
Percentage	*32%*	*68%*	*0%*	*100%*

However, based on an analysis of PGE's response to OPUC DR 726 provided as Attachment A, Staff finds that the number of reconnections accomplished via remote capabilities is 79 percent of all reconnections (Table 4).

Table 4.

YEAR	Meter Reconnection by Type	Yearly Totals	Percentage
2019	Non-Remote AMI Meter	8657	33%
	Remote AMI Meter	17824	67%
2020	Non-Remote AMI Meter	987	22%
	Remote AMI Meter	3586	78%
2021	Non-Remote AMI Meter	341	18%
	Remote AMI Meter	1565	82%
2022	Non-Remote AMI Meter	1330	10%
	Remote AMI Meter	11780	90%
Totals	*Non-Remote AMI Meter*	*11315*	*10%*
	Remote AMI Meter	*34755*	*90%*

In the first 4 months of 2023, the remote reconnection rate goes up to 94 percent of all reconnections.

The cost to the Company for a remote reconnect is significantly lower than the current amount charged to customers. Per the PGE's response to OPUC DR 482 in Attachment A, the remote reconnect cost to the Company is \$4.43 and does not vary based on the time of day the reconnect occurs.

Based on reconnect data provided by the company, Staff is concerned that applying the same fee for metering with differing reconnect capabilities is not equitable. Using reconnect data provided by the company and the number of meters with remote connect capabilities, Staff estimates the Company has saved a significant amount by charging fees which do not represent the costs the company has incurred to complete the work.

Table 5[1]

	2019	2020	2021	2022	Total
Total Reconnects	26481	4573	1906	13110	46074
Remote Reconnects	17824	3586	1565	11780	34755
Fees Charged for Remote	\$481,248	\$96,822	\$42,255	\$318,060	\$938,385
Actual Costs for Remote	\$78,960	\$15,885	\$6,932	\$52,185	\$153,964
Difference	**\$402,287**	**\$80,936**	**\$35,322**	**\$295,892**	**\$784,420**

Q. When is a remote disconnect meter is installed?

A. In response to OPUC DR 728, PGE states it installs remote reconnect AMI meters on all new residential premises limited to form 2S (120/240V) or 12S (120/208V) and class 200 meters. If an existing residential meter without remote connect capability is removed or exchanged, it will be replaced with a remote reconnect capable meter. PGE also began exchanging non-remote residential meters with remote capable disconnect meters in 2020 at non-

[1] Per PGE, these numbers include Covid moratorium figures as well as standard year figure.

owner-occupied locations, sites without a contract, and any site visited for credit purposes.

Q. What are the potential impacts for low-income customers?[2]

A. As of the time of drafting this testimony, it is unclear the specific impact on low-income customers. That said, low-income customers experience higher rates of disconnection than non-low-income customers. Historically, this has effectively made low-income households the largest contributor to credit-related reconnection charges.[3] Further, remote capable AMI meters are disproportionately installed on credit challenged customers. The criteria PGE uses to install a remoted enabled AMI meter is targeted to renters and meters with a history of prior disconnections for nonpayment per Staff DR 728. To the extent these customers can be reconnected remotely, but are charged a higher fee, low-income reconnect fees disproportionately subsidize non-remote reconnections and contribute to excess recovery by the utility.

By charging the nonremote reconnect charge to all customers, low-income customers are not receiving the full benefit of OAR 860-21-330(1), which requires reconnect fees to be waived two times per calendar year for meters with remote capability. Meters without remote reconnect capability, the reconnect fee is waived once a year for low-income customers. PGE's practice of charging all customers a nonremote reconnect fee allows the company to

[2] See also, Staff/2200, Exhibit Scala 600

[3] This disparity is partially mitigated by the outcomes of AR 653 which revised Division 21 rules, effective September 30, 2022, OAR 860-21-330(1) provides additional protections to qualified low-income household, including two no-cost reconnections per year for remote capable meters and one on-cost reconnection per year for non-remote capable meters.

waive the fee one time per calendar year even if the customer has a remote reconnect capable meter.

Q. What is Staff's recommendation regarding the reconnection fees?

A. Staff recommends the reconnection fee be set at $4.43 based on PGE's reported cost to perform a remote AMI reconnection. Based on the information provided in the application and data requests, it appears PGE is moving towards rolling out remote capable AMI meters throughout its territory, thus further reducing the need for manual intervention to reconnect service.

SUMMARY. STAFF RECOMENDATIONS

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff recommends the following:

1. Direct PGE to communicate with all customers the ability to receive usage data from the company upon request.
2. Add clarifying language to Schedule 300, that specifies the charges apply to contracts signed after the effective date of the tariffs only, and that previously signed contracts retain the original billing rate.
3. Deny PGE's request to remove the customer's choice to have a submersible transformer for aesthetic reasons and require PGE to conduct a cost study on the long-term incremental maintenance costs for submersible transformers along with a cost differential between these and standard Pad-mount transformers and submit the request to update the costs for a submersible transformer in a future rate proceeding.
4. Set the reconnection fee to $4.43 for all standard AMI reconnections, regardless of remote capabilities, based on PGE's reported cost to perform a remote AMI reconnection.

Our recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

Witness Qualification Statement

Name: Melissa Nottingham

Employer: Public Utility Commission of Oregon

Title: Consumer Services and Residential Service Protection Fund (RSPF) Manager

Address: 201 High Street SE, Suite 400
Salem, Oregon 97301

Education: Bachelor of Arts in English, Arizona State University

Experience:

My employment at the Public Utility Commission began on May 1, 2022. During my tenure, I manage a team of 14 employees overseeing consumer complaints, the Oregon Lifeline Program, and the Telecommunication Devices Access Program. Part of my role includes sponsoring and participating in dockets related to Oregon Administrative Rules Division 21 and other consumer protection by regulated utilities in Oregon. I have provided testimony for UM 1908 and UM 2203, and provided comments for AR 653, UM 2237, and ADV 1391.

Prior to my employment at the Public Utility Commission, I worked for PacifiCorp for 25 years. PacifiCorp is a multi-jurisdictional regulated electric utility. From 2010 until my departure in 2022, I was a Regulatory Manager. My responsibilities included ensuring regulatory compliance in six states including Oregon. I provided testimony in general rate cases in six states focusing on the company's Schedule 300 fees and any company tariff modifications. Other duties included: representing the company in formal customer complaints and small claims court, overseeing contracts for new service for loads more than 1 megawatt, sponsoring modifications to the company's rules, and participating in each state's administrative rule dockets.

CASE: UE 416
WITNESS: SCOTT SHEARER

PUBLIC UTILITY COMMISSION
OF
OREGON

Staff Exhibit 2402

Witness Qualification Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Scott Shearer
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Rates, Safety, and Utility Performance Program
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Corban University Salem, Oregon Bachelor of Science in Business, Organizational Leadership
EXPERIENCE:	2014 - Current - Heritage Grove Credit Union Board of Directors Provide strategic direction for a credit union with assets of 130 million dollars. Reviewing and approving monetary expenditures and budget. 2007 - Current - Oregon Public Utility Commission Utility Analyst Research and analysis of utility company filings; including rulemaking, affiliated interests, utility purchase and sale, jurisdiction, and rate case dockets. Telecommunications Specialist/Consumer Specialist/Senior Compliance Specialist Reviewing and applying Oregon Administrative Rules to tariffs in relation to consumer complaints. 2006 - 2007 - Oregon Department of Justice/Division of Child Support, Administrative Specialist Researching responsible parties in Child Support orders 1999 - 2006 - EPIQ Systems/Poorman Douglas Corp. Claims Analyst/Senior Claims Analyst Reviewing and implementing orders and settlements for the largest Class Action Lawsuit administrator in the United States. Auditing and processing class action lawsuits with payouts from two-hundred thousand to over one billion dollars to claimants.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 140
Dated March 9, 2023

Request:

For each of the service fees listed below, please provide the cost analysis for how PGE calculated the proposed new rate(s). Please include the origin of the 4% increase for labor rates applied to increases, payroll loading, tool loading, transportation loading, and how the amount of labor needed to perform each service was determined:

a. Special Meter Reading Charge (non-network) – Rule H.4E
b. Meter Test Charge – Rule M.1C
c. Field Visit Charge – Rule H.2
d. Monthly Service Charge – Schedule 201 and 202
e. Disconnection/Reconnection – Rule H

Response:

For each of the services listed above the cost analysis is provided in the workpapers contained in Exhibit 1300.

Confidential Attachment 140-A provides the origin for the 4% increase in labor rates The increase in labor rates comes from the August 2022 Global Insights Report, in tab P&W1A, "Wages & Salaries."

Attachment 140-B provides the loading percentages for all the service fees listed above except the Monthly Service Charge. The loading percentages are from PGE's 2022 Accounting Practices and Procedures Bulletin effective September 9, 2022.

Confidential Attachment 140-C provides the non-union loading percentages for the Monthly Service Charge The non-union loading percentages are provided by PGE's corporate accounting department.

The amount of labor needed to perform each service is the estimated average time it takes to perform each service.

Attachments 140-A and 140-C are protected information and subject to Protective Order No. 23-019

Portland General Electric Company
ACCOUNTING PRACTICES AND PROCEDURES BULLETIN

2022 RATES FOR BILLING JOBS **APPB: 2022-01**
August 30, 2022

This APPB establishes the current rates for billing jobs. For instructions and procedures for the billing of goods and services, refer to APPD 5-201-1 (General Instructions for Billing Jobs). These rates should be used in accordance with guidelines established in the abovementioned APPD. The effective date of the rate change is September 9, 2022.

Exhibit 1
Loading and Transportation Rates

Regional Line Crew Labor Rates (Maximo)

	Straight Time Rate [1]	Overtime Rate	High Time Rate [2]	Premium Pay ("Golden Time") Adder [3]
Average crew member hourly rate	$ 55.51	$ 111.02	$ 111.02	$ 55.51
DOSE overhead [4]	99.36	99.36	99.36	-
Payroll loading	39.41	18.87	48.85	9.44
Tool loading	8.88	8.88	8.88	-
Transportation loading [5]	22.20	22.20	22.20	-
Regional Line Crew hourly rates to be used [6]	**$ 225.36**	**$ 260.33**	**$ 290.31**	**$ 64.95**

Substation Operations and Other Distribution Departments

	Straight Time Rate	Overtime Rate
Labor	Actual Labor	Actual Labor
DOSE overhead	179%	90%
Payroll loading	71%	17%
Tool loading	16%	8%
Transportation loading [5]	40%	20%

Stores loading (all departments) [7]	**17%**	
Automobile mileage rate (all departments) [5]	**$0.585**	per mile

Portland General Electric Company
ACCOUNTING PRACTICES AND PROCEDURES BULLETIN

[1] Average crew member hourly rate, updated annually per union agreement, is determined by a calculation of crew members (March 1, 2022 – February 29, 2024). Rates were updated as of February 21, 2022.

[2] "High Time" – Per Article 18.1.16 of the agreement, work performed at a height of eighty (80) feet or more shall be paid at the Overtime Rate for a minimum of one hour. Per Article 20.2 of the agreement, Overtime Rate is two (2) times regular rate of pay.

The payroll loading rate is calculated using a blended straight time/overtime loading rate.

[3] "Premium Pay" adder to be charged to customer when billing job from previous day causes line crew members to be paid premium pay on the following day.

A combined payroll tax and injuries-and-damages loading of 17% is applied to the straight-time average crew member hourly rate.

"Premium Pay" – Per Article 20.6 of the agreement, work shall be paid at the overtime rate for the regular shift when an employee has not had 8 ½ hours relief from previous overtime work and must include 6 hours OT outside the employee's regular schedule.

[4] DOSE overhead covers the cost of engineering and support functions for line crews. The rate is determined by calculating the average of two years actuals of the amount of DOSE balance divided by the amount of line crew labor.

[5] Transportation loading covers the cost of all vehicles other than automobiles, regardless of type. The rate is determined by calculating the five-year average of the amount of transportation charges charged to crew work divided by the actual amount of line crew labor. Automobiles are charged at the IRS Standard Mileage Rate for the current year.

[6] These are the rates to be used for both estimates and actual billings when detailed labor breakdown is not required or available.

[7] Stores Issues - Obtain the pricing for materials from the PeopleSoft Materials Management System. Multiply the total price of materials by the stores loading rate.

NOTE: For the sale of surplus items or storeroom materials not related to a billing job, use the Purchasing & Material Form MDSR (Material Disposal and Sales Request) in the Storeroom Procedures Manual (SPD 700-1).

Corporate Planning has an Excel template to assist with billings. If additional charges or fees are to be applied these should be discussed with your Corporate Planning Analyst prior to finalizing the billing document.

Portland General Electric Company
ACCOUNTING PRACTICES AND PROCEDURES BULLETIN

2022 RATES FOR BILLING JOBS **APPB: 2022-01**
August 30, 2022

Exhibit 2
ELECTRIC & SERVICES FOR
STONE CREEK AND PORT OF SAINT HELENS
EFFECTIVE 9/9/2022

	Stone Creek [2]	Port of St Helens [3]
Payroll Loading:		
Straight time	76%	76%
Overtime	17%	17%
Tool loading [1]	16%	16%
Stores Loading	17%	17%
Vehicle - Light-duty trucks Under 14,000 GVW [1]	$12.80/hr	$12.80/hr

[1] Tools and vehicle rates are applied to generation crews only. All other vehicle expenses are charged directly to the applicable operating unit.

[2] Stone Creek loading rates are billed under the Operating and Maintenance Agreement between PGE and Eugene Water & Electric Board effective April 1, 2010 (PGE Audit # 40426-00), Amendment No. 1 effective July 1, 2020.

[3] Port of St. Helens loading rates are billed under the Project Operations Agreement between PGE and Port of St. Helens effective August 30, 2006 (PGE audit # 50152-00).

Portland General Electric Company
ACCOUNTING PRACTICES AND PROCEDURES BULLETIN

2022 RATES FOR BILLING JOBS **APPB: 2022-01**
August 30, 2022

Exhibit 3
ELECTRIC & SERVICES FOR
PELTON REG-DAM EFFECTIVE 9/9/2022

I. Non-Distribution labor loading rates (includes hydro plant departments, engineering, environmental services):

Straight time	76%
Overtime	17%

II. Distribution labor loading rates (transmission and distribution departments):

Straight time	76%
Overtime	17%
Tools	16%
Vehicles	$12.80/hr (Light-duty trucks udner 14,000 GVW)
Stores Loading	17%

Vehicle expenses incurred by non-distribution departments are charged directly to the Pelton Reg-Dam operating unit.

Labor, tools, vehicles and store loadings are determined annually and are effective January 1. Union labor rates change based on the Union labor agreement, typically March 1 but can also occur more or less frequently. Changes in union labor rates require a corresponding update to loadings.

Pelton Reg-Dam loading rates are billed under the Operating and Maintenance Agreement between PGE and Warm Springs Power Enterprises Agreement effective November 2000 (PGE Audit # 45646-00) and the Change Order Agreement between PGE and Warm Springs Power Enterprises Agreement effective June 1, 2004 (PGE Audit # 45646-01).

Approved by: Jeff Stevens 8/30/2022
Jeff Stevens Date
Manager, Corporate Accounting

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 141
Dated March 9, 2023

Request:

For each of the service fees listed below, please provide details on often each fee was charged for calendar years 2019 through 2022, please note any anomalies in the data, such as the effect the Covid-19 moratoriums had on these fees, if applicable:

a. Special Meter Reading Charge (non-network) – Rule H.4E
b. Meter Test Charge – Rule M.1C
c. Field Visit Charge – Rule H.2
d. Monthly Service Charge – Schedule 201 and 202
e. Disconnection/Reconnection – Rule H

Response:

Service Fees	2019	2020	2021	2022
Special Meter Reading Charge (non-network)	966	1,451	1,616	1,956
Meter Test Charge[1]	0	0	0	0
Field Visit Charge[2]	9,795	2,263	965	64
Monthly Service Charge – Schedule 201 and 202[3]	241	402	628	638
Reconnections[4]	25,263	4,250	156	4,689

[1] Rule M.1C: "Charge is only imposed if a Customer or ESS requests such a meter test more than once in a 12-month period."
[2] PGE's Second Supplemental Filing of Advice No. 22-21 added language for low-income exclusions to Rule H in accordance with the Division 21 rulemaking, effective September 30, 2022. Rule H.2: "The first Field Visit Charge within a rolling 12-month period will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008."
[3] Existing QFs under PGE's proposal would not be charged under the proposed rate in Schedule 300.
[4] PGE's Second Supplemental Filing of Advice No. 22-21 added language for low-income exclusions to Rule H in accordance with the Division 21 rulemaking, effective September 30, 2022. Rule H.3A: "The reconnection charge for the first two remote reconnections or first nonremote reconnection in a calendar year will be waived for Residential Customers who qualify as an eligible Low-Income Residential Customer as that term is defined in OAR 860-021-0008."

The Covid19 moratorium reduced the number of Field Visit Charges and Reconnection Fees. See the Stipulated Agreements in Commission Order No. 20-401 related to the Field Visit Charge and Disconnections/Reconnections and updates made in Commission Order Nos. 21-057, 21-164, 21-236 and 21-483.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 142
Dated March 9, 2023

Request:

Please explain the reasoning for the site visit fee and the reconnection fee to be the same. What incentive does the customer have to pay to avoid disconnection?

Response:

1. The Field Visit Charge and Standard Reconnection Fee at Meter Base are the same rate because these tasks are both performed by a Field Connect Representative and are estimated to take the same amount of time regardless of the task. To avoid treating customers within the same rate class differently based on their meter's ability to remotely reconnect, the same standard reconnection fee is applied.
2. Access to electricity and possible future reconnection fees are incentives for customers to avoid disconnection.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 143
Dated March 9, 2023

Request:

For the Monthly Service Charges listed in Schedule 201 and 202, please provide:

a. Will each Qualifying Facilities contract be updated to reflect the new fee and;
b. If not, what is the justification for grandfathering prior contracts

Response:

A. Prior Qualifying Facilities (QF) contracted with PGE will not be updated to reflect the new fee.
B. PGE cannot update the Monthly Service Charge for QFs with executed Power Purchase Agreements (PPA) because the PPA includes the vintage of Schedule 201 effective at the time the PPA was signed. PGE's Schedule 201, which is incorporated into the PPA, establishes a $10 monthly service charge. As part of the PPA contract, PGE is unable to update or change the monthly service charge.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 144
Dated March 9, 2023

Request:

Please provide the following data, broken down by zip code, for each customer class (i.e. residential, commercial, etc.):

a. Count of Smart Meters that support remote disconnect/reconnect functionality;
b. Count of Smart meters that do not support remote disconnection/reconnect functionality; and
c. Count of Non-network meters that require a site visit to read, disconnect, and reconnect service.
d. For each of the items listed in a-c above, please provide a monthly breakdown, by zip code, for all non-payment disconnections, dated to the end of the Covid-19 moratorium.

Response:

Attachment 140-A provides the response to parts a, b and c.

In response to part d, PGE did not perform any disconnections for non-payment during the Covid-19 moratorium.

UE 416

PGE's Response to OPUC DR 144

Attachment A

ZIP CODE	CUSTOMER CLASS	REMOTE CONNECT AMI METER
97002		329
	Commercial/Industrial	35
	Residential	292
	State	2
	Summary Billing	
97003		5,499
	Commercial/Industrial	35
	Residential	5,464
	State	
	Summary Billing	
97004		142
	Commercial/Industrial	37
	Residential	105
	Summary Billing	
97005		7,700
	Commercial/Industrial	64
	Residential	7,636
	State	
	Summary Billing	
97006		10,544
	Commercial/Industrial	25
	Residential	10,519
	State	
	Summary Billing	
97007		6,578
	Commercial/Industrial	22
	Residential	6,556
	Summary Billing	
97008		5,707
	Commercial/Industrial	3
	Residential	5,704
	State	
	Summary Billing	
97009		430
	Commercial/Industrial	49
	Residential	380
	State	1
	Summary Billing	
97011		91
	Commercial/Industrial	2
	Residential	89
97013		228
	Commercial/Industrial	39

	Residential	189
	State	
	Summary Billing	
97015		**3,606**
	Commercial/Industrial	20
	Residential	3,585
	State	
	Summary Billing	1
97017		**109**
	Commercial/Industrial	17
	Residential	91
	Summary Billing	1
97019		**181**
	Commercial/Industrial	12
	Residential	169
	State	
	Summary Billing	
97020		**78**
	Commercial/Industrial	1
	Residential	77
97022		**248**
	Commercial/Industrial	28
	Residential	220
	Summary Billing	
97023		**1,253**
	Commercial/Industrial	65
	Residential	1,188
	State	
	Summary Billing	
97024		**2,399**
	Commercial/Industrial	29
	Residential	2,370
	State	
	Summary Billing	
97026		**317**
	Commercial/Industrial	5
	Residential	312
	State	
	Summary Billing	
97027		**1,538**
	Commercial/Industrial	13
	Residential	1,525
	State	
	Summary Billing	

UE 416
PGE's Response to OPUC DR 144
Attachment A

97028		**193**
	Commercial/Industrial	5
	Residential	188
	State	
97030		**7,497**
	Commercial/Industrial	30
	Residential	7,465
	State	
	Summary Billing	2
97032		**394**
	Commercial/Industrial	14
	Residential	380
	State	
	Summary Billing	
97034		**2,083**
	Commercial/Industrial	38
	Residential	2,045
	State	
	Summary Billing	
97035		**4,467**
	Commercial/Industrial	19
	Residential	4,446
	State	
	Summary Billing	2
97036		
	Commercial/Industrial	
	Residential	
97038		**1,439**
	Commercial/Industrial	66
	Residential	1,373
	State	
	Summary Billing	
97041		
	Commercial/Industrial	
	State	
97042		**141**
	Commercial/Industrial	21
	Residential	119
	State	1
	Summary Billing	
97045		**5,494**
	Commercial/Industrial	149
	Residential	5,345
	State	

UE 416
PGE's Response to OPUC DR 144
Attachment A

	Summary Billing	
97049		**225**
	Commercial/Industrial	16
	Residential	208
	State	1
97051		
	Commercial/Industrial	
97055		**1,563**
	Commercial/Industrial	59
	Residential	1,500
	State	
	Summary Billing	4
97056		**2**
	Commercial/Industrial	1
	Residential	1
97060		**2,411**
	Commercial/Industrial	43
	Residential	2,368
	State	
	Summary Billing	
97062		**5,398**
	Commercial/Industrial	27
	Residential	5,371
	State	
	Summary Billing	
97067		**335**
	Commercial/Industrial	12
	Residential	323
	State	
	Summary Billing	
97068		**2,203**
	Commercial/Industrial	39
	Residential	2,164
	State	
	Summary Billing	
97070		**5,657**
	Commercial/Industrial	26
	Residential	5,630
	State	1
	Summary Billing	
97071		**3,245**
	Commercial/Industrial	69
	Residential	3,176
	State	

UE 416
PGE's Response to OPUC DR 144
Attachment A

	Summary Billing	
97078		**3,954**
	Commercial/Industrial	19
	Residential	3,935
	Summary Billing	
97079		
	Commercial/Industrial	
97080		**4,621**
	Commercial/Industrial	24
	Residential	4,597
	State	
	Summary Billing	
97086		**4,878**
	Commercial/Industrial	37
	Residential	4,841
	State	
	Summary Billing	
97089		**620**
	Commercial/Industrial	44
	Residential	576
	State	
	Summary Billing	
97101		**251**
	Commercial/Industrial	16
	Residential	235
	State	
97106		**337**
	Commercial/Industrial	10
	Residential	326
	State	1
97109		**17**
	Commercial/Industrial	3
	Residential	14
	State	
97111		**332**
	Commercial/Industrial	26
	Residential	306
	State	
	Summary Billing	
97113		**2,106**
	Commercial/Industrial	30
	Residential	2,076
	State	
	Summary Billing	

UE 416
PGE's Response to OPUC DR 144
Attachment A

97114		**223**
	Commercial/Industrial	14
	Residential	209
	State	
97115		**367**
	Commercial/Industrial	24
	Residential	343
	State	
97116		**125**
	Commercial/Industrial	16
	Residential	109
	State	
97117		**59**
	Commercial/Industrial	9
	Residential	50
	State	
97119		**344**
	Commercial/Industrial	24
	Residential	320
	State	
	Summary Billing	
97123		**7,091**
	Commercial/Industrial	88
	Residential	7,002
	State	
	Summary Billing	1
97124		**10,728**
	Commercial/Industrial	75
	Residential	10,652
	State	
	Summary Billing	1
97125		**1**
	Commercial/Industrial	1
	Residential	
97127		**454**
	Commercial/Industrial	3
	Residential	451
97128		**80**
	Commercial/Industrial	9
	Residential	71
97132		**4,273**
	Commercial/Industrial	77
	Residential	4,179
	State	

	Summary Billing	17
97133		**508**
	Commercial/Industrial	19
	Residential	489
	State	
	Summary Billing	
97137		**84**
	Commercial/Industrial	9
	Residential	75
	State	
97140		**2,528**
	Commercial/Industrial	50
	Residential	2,478
	State	
	Summary Billing	
97148		**271**
	Commercial/Industrial	20
	Residential	251
	State	
	Summary Billing	
97201		**2,312**
	Commercial/Industrial	7
	Residential	2,304
	State	1
	Summary Billing	
97202		**8,207**
	Commercial/Industrial	74
	Residential	8,132
	State	
	Summary Billing	1
97203		**5,415**
	Commercial/Industrial	39
	Residential	5,375
	State	
	Summary Billing	1
97204		**174**
	Commercial/Industrial	13
	Residential	159
	State	1
	Summary Billing	1
97205		**1,120**
	Commercial/Industrial	6
	Residential	1,114
	State	

UE 416
PGE's Response to OPUC DR 144
Attachment A

	Summary Billing	
97206		**7,184**
	Commercial/Industrial	73
	Residential	7,111
	State	
	Summary Billing	
97208		
	Commercial/Industrial	
97209		**7,918**
	Commercial/Industrial	27
	Residential	7,890
	State	
	Summary Billing	1
97210		**2,861**
	Commercial/Industrial	25
	Residential	2,836
	State	
	Summary Billing	
97211		**3**
	Commercial/Industrial	
	Residential	3
	State	
97212		
	State	
97213		**914**
	Commercial/Industrial	8
	Residential	906
	State	
	Summary Billing	
97214		**6,707**
	Commercial/Industrial	78
	Residential	6,625
	State	3
	Summary Billing	1
97215		**2,131**
	Commercial/Industrial	36
	Residential	2,095
	Summary Billing	
97216		**786**
	Commercial/Industrial	13
	Residential	773
	State	
	Summary Billing	
97217		**4,909**

UE 416
PGE's Response to OPUC DR 144
Attachment A

	Commercial/Industrial	45
	Residential	4,862
	State	
	Summary Billing	2
97218		
	Commercial/Industrial	
	Summary Billing	
97219		**4,387**
	Commercial/Industrial	41
	Residential	4,345
	State	1
	Summary Billing	
97221		**1,641**
	Commercial/Industrial	9
	Residential	1,632
	State	
	Summary Billing	
97222		**6,129**
	Commercial/Industrial	42
	Residential	6,086
	State	
	Summary Billing	1
97223		**9,368**
	Commercial/Industrial	40
	Residential	9,328
	State	
	Summary Billing	
97224		**6,446**
	Commercial/Industrial	19
	Residential	6,427
	State	
	Summary Billing	
97225		**5,086**
	Commercial/Industrial	28
	Residential	5,057
	State	1
	Summary Billing	
97227		**115**
	Commercial/Industrial	3
	Residential	111
	State	
	Summary Billing	1
97229		**9,595**
	Commercial/Industrial	44

	Residential	9,551
	State	
	Summary Billing	
97230		**5,201**
	Commercial/Industrial	33
	Residential	5,167
	State	
	Summary Billing	1
97231		**263**
	Commercial/Industrial	19
	Direct Access Retail Account	
	Residential	243
	State	1
	Summary Billing	
97232		**2,546**
	Commercial/Industrial	9
	Residential	2,536
	State	
	Summary Billing	1
97233		**6,515**
	Commercial/Industrial	36
	Residential	6,479
	Summary Billing	
97236		**4,173**
	Commercial/Industrial	41
	Residential	4,132
	State	
	Summary Billing	
97239		**3,766**
	Commercial/Industrial	19
	Residential	3,747
	State	
	Summary Billing	
97240		
	Commercial/Industrial	
97251		
	Commercial/Industrial	
97266		**3,719**
	Commercial/Industrial	53
	Residential	3,665
	State	
	Summary Billing	1
97267		**3,200**
	Commercial/Industrial	34

	Residential	3,166
	State	
	Summary Billing	
97280		
	Commercial/Industrial	
97286		
	Commercial/Industrial	
97291		
	Commercial/Industrial	
97294		
	Commercial/Industrial	
97301		10,086
	Commercial/Industrial	103
	Residential	9,980
	State	2
	Summary Billing	1
97302		6,936
	Commercial/Industrial	93
	Residential	6,840
	State	
	Summary Billing	3
97303		3,869
	Commercial/Industrial	32
	Residential	3,837
	State	
	Summary Billing	
97304		221
	Commercial/Industrial	12
	Residential	209
	State	
97305		7,766
	Commercial/Industrial	81
	Residential	7,685
	State	
	Summary Billing	
97306		5,327
	Commercial/Industrial	43
	Residential	5,284
	State	
	Summary Billing	
97310		
	State	
	Summary Billing	
97311		

UE 416
PGE's Response to OPUC DR 144
Attachment A

	State	
97312		
	Commercial/Industrial	
97317		**3,169**
	Commercial/Industrial	59
	Residential	3,109
	State	
	Summary Billing	1
97325		**25**
	Commercial/Industrial	2
	Residential	23
97338		**26**
	Commercial/Industrial	2
	Residential	24
97347		**310**
	Commercial/Industrial	9
	Residential	301
	State	
97352		**19**
	Commercial/Industrial	5
	Residential	14
97362		**455**
	Commercial/Industrial	17
	Residential	438
97371		**18**
	Commercial/Industrial	1
	Residential	17
97373		
	Commercial/Industrial	
97375		**118**
	Commercial/Industrial	13
	Residential	105
97378		**627**
	Commercial/Industrial	28
	Residential	599
	State	
97381		**1,818**
	Commercial/Industrial	50
	Residential	1,768
	State	
97385		**34**
	Commercial/Industrial	6
	Residential	28
	State	

UE 416
PGE's Response to OPUC DR 144
Attachment A

97392		**514**
	Commercial/Industrial	29
	Residential	481
	State	
	Summary Billing	4
97396		**433**
	Commercial/Industrial	14
	Residential	419
	State	
Grand Total		**298,538**

UE 416
PGE's Response to OPUC DR 144
Attachment A

NON-REMOTE CONNECT AMI METER	NON-AMI METER	TOTAL
3,058	1	3,388
1,088		1,123
1,944	1	2,237
25		27
1		1
6,360	1	11,860
735		770
5,616	1	11,081
1		1
8		8
2,108	2	2,252
425		462
1,673	2	1,780
10		10
7,042	2	14,744
2,372		2,436
4,589	2	12,227
17		17
64		64
10,084	1	20,629
1,618		1,643
8,437	1	18,957
12		12
17		17
13,161	1	19,740
906		928
12,220	1	18,777
35		35
7,376	4	13,087
1,128		1,131
6,204	4	11,912
13		13
31		31
4,174	1	4,605
1,120		1,169
3,025	1	3,406
5		6
24		24
466		557
66		68
400		489
3,189	1	3,418
1,008		1,047

UE 416

PGE's Response to OPUC DR 144

Attachment A

2,172	1	2,362
7		7
2		2
7,546	**1**	**11,153**
1,917		1,937
5,537	1	9,123
39		39
53		54
1,248		**1,357**
205		222
1,033		1,124
10		11
1,317	**2**	**1,500**
250		262
1,052	2	1,223
14		14
1		1
374		**452**
76		77
298		375
1,630	**1**	**1,879**
399		427
1,229	1	1,450
2		2
4,815	**5**	**6,073**
987		1,052
3,781	5	4,974
26		26
21		21
2,788		**5,187**
494		523
2,281		4,651
4		4
9		9
1,381		**1,698**
464		469
897		1,209
10		10
10		10
3,868	**4**	**5,410**
450		463
3,402	4	4,931
7		7
9		9

UE 416
PGE's Response to OPUC DR 144
Attachment A

758		**951**
125		130
619		807
14		14
10,143	**2**	**17,642**
2,088		2,118
7,966	2	15,433
6		6
83		85
1,954	**1**	**2,349**
587		601
1,360	1	1,741
6		6
1		1
7,227	**2**	**9,312**
749		787
6,379	2	8,426
1		1
98		98
8,227	**4**	**12,698**
1,268		1,287
6,900	4	11,350
11		11
48		50
23		**23**
21		21
2		2
6,186	**1**	**7,626**
1,172		1,238
4,984	1	6,358
4		4
26		26
7		**7**
5		5
2		2
1,421	**1**	**1,563**
310		331
1,099	1	1,219
7		8
5		5
20,355	**8**	**25,857**
3,265		3,414
16,961	8	22,314
31		31

UE 416
PGE's Response to OPUC DR 144
Attachment A

98		98
1,580		**1,805**
146		162
1,430		1,638
4		5
6		**6**
6		6
8,012	**2**	**9,577**
1,458		1,517
6,515	2	8,017
9		9
30		34
35		**37**
7		8
28		29
6,827		**9,238**
1,059		1,102
5,737		8,105
22		22
9		9
8,036	**5**	**13,439**
2,017		2,044
5,999	5	11,375
15		15
5		5
1,441		**1,776**
401		413
1,037		1,360
2		2
1		1
10,714		**12,917**
1,160		1,199
9,524		11,688
8		8
22		22
7,683	**2**	**13,342**
1,753		1,779
5,825	2	11,457
20		21
85		85
9,104		**12,349**
1,924		1,993
7,162		10,338
17		17

1		1
5,662	2	9,618
497		516
5,160	2	9,097
5		5
1		1
1		1
12,909	4	17,534
905		929
11,985	4	16,586
3		3
16		16
9,261	4	14,143
967		1,004
8,262	4	13,107
7		7
25		25
5,190	4	5,814
741		785
4,434	4	5,014
5		5
10		10
1,683	1	1,935
363		379
1,319	1	1,555
1		1
1,634	5	1,976
361	1	372
1,259	4	1,589
14		15
85		102
15		18
68		82
2		2
1,546		1,878
354		380
1,187		1,493
2		2
3		3
4,014		6,120
706		736
3,297		5,373
1		1
10		10

UE 416
PGE's Response to OPUC DR 144
Attachment A

2,358		**2,581**
785		799
1,569		1,778
4		4
1,717	**1**	**2,085**
337		361
1,371	1	1,715
9		9
1,066	**1**	**1,192**
333		349
732	1	842
1		1
288		**347**
71		80
216		266
1		1
1,701	**2**	**2,047**
391		415
1,306	2	1,628
1		1
3		3
14,254		**21,345**
2,587		2,675
11,504		18,506
9		9
154		155
14,079	**2**	**24,809**
3,074		3,149
10,880	2	21,534
22		22
103		104
23		**24**
5		6
18		18
1,174		**1,628**
94		97
1,080		1,531
654		**734**
227		236
427		498
9,784	**1**	**14,058**
1,849		1,926
7,842	1	12,022
8		8

UE 416
PGE's Response to OPUC DR 144
Attachment A

85		102
2,364	**3**	**2,875**
476		495
1,881	3	2,373
4		4
3		3
871		**955**
448		457
412		487
11		11
8,661	**1**	**11,190**
1,639		1,689
7,008	1	9,487
9		9
5		5
1,455		**1,726**
340		360
1,105		1,356
1		1
9		9
5,703	**1**	**8,016**
634		641
4,991	1	7,296
72		73
6		6
14,533	**5**	**22,745**
2,511		2,585
11,984	5	20,121
6		6
32		33
9,106		**14,521**
1,389		1,428
7,702		13,077
6		6
9		10
832	**1**	**1,007**
571	1	585
250		409
		1
11		12
2,427		**3,547**
307		313
2,117		3,231
1		1

2		2
16,471	**5**	**23,660**
1,516		1,589
14,926	5	22,042
5		5
24		24
1		**1**
1		1
9,460		**17,378**
2,097		2,124
7,342		15,232
12		12
9		10
6,905	**3**	**9,769**
1,815		1,840
5,069	3	7,908
5		5
16		16
16		**19**
9		9
4		7
3		3
1		**1**
1		1
2,457		**3,371**
244		252
2,206		3,112
5		5
2		2
11,551	**6**	**18,264**
2,802	1	2,881
8,708	5	15,338
9		12
32		33
6,056	**4**	**8,191**
477		513
5,577	4	7,676
2		2
3,919	**2**	**4,707**
458		471
3,448	2	4,223
8		8
5		5
9,706	**2**	**14,617**

UE 416
PGE's Response to OPUC DR 144
Attachment A

1,592		1,637
8,056	2	12,920
22		22
36		38
4		**4**
3		3
1		1
14,446	**12**	**18,845**
1,251		1,292
13,144	12	17,501
33		34
18		18
4,228	**2**	**5,871**
302		311
3,911	2	5,545
10		10
5		5
11,398	**5**	**17,532**
1,865		1,907
9,482	5	15,573
25		25
26		27
14,125	**1**	**23,494**
2,370		2,410
11,709	1	21,038
37		37
9		9
11,192	**5**	**17,643**
1,622		1,641
9,557	5	15,989
11		11
2		2
7,607	**6**	**12,699**
1,101		1,129
6,467	6	11,530
30		31
9		9
366		**481**
51		54
312		423
2		2
1		2
20,252	**4**	**29,851**
1,505		1,549

18,733	4	28,288
11		11
3		3
12,493	**1**	**17,695**
2,027		2,060
10,442	1	15,610
11		11
13		14
2,346	**4**	**2,613**
584		603
1		1
1,740	4	1,987
19		20
2		2
3,555		**6,101**
776		785
2,753		5,289
7		7
19		20
9,913	**1**	**16,429**
1,085		1,121
8,797	1	15,277
31		31
10,721		**14,894**
925		966
9,769		13,901
1		1
26		26
6,964		**10,730**
749		768
6,200		9,947
13		13
2		2
1		**1**
1		1
12		**12**
12		12
11,116		**14,835**
1,360		1,413
9,699		13,364
24		24
33		34
10,737	**5**	**13,942**
1,031		1,065

UE 416
PGE's Response to OPUC DR 144
Attachment A

9,674	5	12,845
6		6
26		26
1		**1**
1		1
1		**1**
1		1
1		**1**
1		1
1		**1**
1		1
12,141	**2**	**22,229**
2,754	1	2,858
9,194	1	19,175
104		106
89		90
13,104	**7**	**20,047**
2,612		2,705
10,405	7	17,252
25		25
62		65
8,030		**11,899**
1,125		1,157
6,851		10,688
11		11
43		43
1,464		**1,685**
330		342
1,128		1,337
6		6
10,129	**3**	**17,898**
2,131		2,212
7,953	3	15,641
8		8
37		37
9,407	**1**	**14,735**
779		822
8,609	1	13,894
2		2
17		17
31		**31**
30		30
1		1
1		**1**

UE 416
PGE's Response to OPUC DR 144
Attachment A

1		1
3		**3**
3		3
6,572	**4**	**9,745**
1,229		1,288
5,298	4	8,411
26		26
19		20
211		**236**
78		80
133		156
302		**328**
80		82
222		246
695	**1**	**1,006**
199		208
493	1	795
3		3
142		**161**
34		39
108		122
1,538		**1,993**
456		473
1,082		1,520
139		**157**
51		52
88		105
1		**1**
1		1
528		**646**
113		126
415		520
2,823		**3,450**
572		600
2,243		2,842
8		8
6,072	**5**	**7,895**
1,375		1,425
4,665	5	6,438
32		32
177		**211**
50		56
125		153
2		2

UE 416
PGE's Response to OPUC DR 144
Attachment A

1,863		2,377
392		421
1,464		1,945
6		6
1		5
1,196	1	1,630
241		255
950	1	1,370
5		5
621,351	185	920,074

March 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE's *First Revised* Response to OPUC Data Request 144
Dated March 9, 2023

Request:

Please provide the following data, broken down by zip code, for each customer class (i.e. residential, commercial, etc.):

a. Count of Smart Meters that support remote disconnect/reconnect functionality;
b. Count of Smart meters that do not support remote disconnection/reconnect functionality; and
c. Count of Non-network meters that require a site visit to read, disconnect, and reconnect service.
d. For each of the items listed in a-c above, please provide a monthly breakdown, by zip code, for all non-payment disconnections, dated to the end of the Covid-19 moratorium.

Original Response (dated March 23, 2023):

Attachment 140-A provides the response to parts a, b and c.

In response to part d, PGE did not perform any disconnections for non-payment during the Covid-19 moratorium.

Revised Response (dated March 28, 2023):

Attachment 144-A provides the response to parts a, b and c.

In response to part d, PGE did not perform any disconnections for non-payment during the Covid-19 moratorium.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 145
Dated March 9, 2023

Request:

Please provide the cost analysis used to determine the fee charges for remote disconnection/ reconnection capable meters versus manually disconnection/reconnection (requires PGE personnel to go out to the customers location). Please include in the analysis, details and data related to differences to the internal processes for Smart meters versus non-network meters.

Response:

The cost analysis for reconnection fees is provided in the Schedule 300 workpapers contained in Exhibit 1300.

PGE charges the same reconnection fee to all customers regardless of whether their meter is able to be disconnected/reconnected remotely or manually. PGE does not charge different amounts based on meter type because the customer does not choose their meter type in most cases.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 146
Dated March 9, 2023

Request:

What options are available for customers requesting a submersible transformer?

Response:

For a residential single phase submersible request, PGE offers options such as a standard pad mount transformer, standard overhead transformer, or screening options if the customer is concerned about aesthetics. For commercial applications, PGE offers a Class A vault option, which puts the transformer inside the building, standard pad mount and standard overhead transformers. In all instances, the submersible is considered a non-standard installation.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 147
Dated March 9, 2023

Request:

How many requests has the company received for a submersible transformer over the past five years?

Response:

PGE does not track requests for submersible transformers. In the last 5 years PGE has installed 58 single phase submersible transformers for customer requested jobs.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 148
Dated March 9, 2023

Request:

What is the estimated costs for ongoing upkeep of a submersible transformer? Could these costs be included in the installation estimate to avoid the concern about other customers paying for the ongoing upkeep?

Response:

The estimated costs for ongoing upkeep of a submersible transformer are:

- Annual submersible transformer maintenance - $50.29
- Utilization Transformers, submersibles - $782.00

PGE does include these costs in the submersible transformer installation charges as described in Schedule 300, page 3.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 149
Dated March 9, 2023

Request:

Please describe the fee to research PCB content in a transformer.

a. How often was this fee charged for each calendar year from 2019 to 2022.
b. How many PCB containing transformers does PGE still maintain in its service territory?

Response:

a. The PCB Inquiry Fee was charged for 5 transformers in 2019, 1 in 2020, 1 in 2021, and 0 in 2022.
b. As a practice, PGE has historically not purchased or installed PCB transformers in its system. However, over the years, PGE has acquired other utility infrastructure with PCB contamination, or there has been cross-contamination in the transformer fluids from manufacturers or installers. PGE has approximately 193,600 total distribution transformers in service. From 2016-2020, PGE undertook significant efforts to assess and remove PCB and PCB-Contaminated transformers from its system under the PCB Transformer Replacement Program; however, PCBs do remain mostly in very low concentrations. The Toxic Substances Control Act (TSCA) defines “PCB-Contaminated Transformers” as those with 50 - 499 parts per million (ppm) PCBs and “PCB Transformers” as those with concentrations over 500 ppm. In PGE’s distribution system, we have approximately 760 known PCB-Contaminated Transformers remaining in service. In addition to the concentrations defined and regulated by TSCA, PGE has used laboratory tests of mineral oil to determine PCB concentrations down to as little as 1 ppm. We estimate that PGE has approximately 17,500 transformers in service with detectable levels of PCBs between the testing level and 50 ppm. Approximately 17,400 transformers have unknown PCB content or concentration.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 150
Dated March 9, 2023

Request:

How does PGE estimate the cost to install conduit on a wood pole for the purposes of street lighting?

Response:

PGE estimates the cost to install a 1" conduit on a wood pole for the purpose of streetlighting based on the cost of materials and labor needed per installation. Material costs are variable depending on pole height. The minimum cost for the 1" conduit unit installation today is $313.00.

March 23, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 151
Dated March 9, 2023

Request:

How often does the company install conduit on a wood pole for street lighting (annual estimate)?

Response:

PGE performs the Schedule 300 installation of conduit on a wood pole for street lighting on average 9 times annually.

April 18, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 482
Dated April 4, 2023

Request:

The company provided Schedule 300 rates based on an average of costs for the activity. The reconnect rate provided average company costs for a non-network reconnect. Please provide the cost per transaction for a remote reconnect during business hours and if applicable, after hours. Include workpapers.

Response:

Attachment 482-A provides the cost to PGE per remote reconnect.

PORTLAND GENERAL ELECTRIC
Remote Reconnect Cost per Transaction
2024

2023 Average Meter Operations Coordinator Hourly Rate	$33.82
Expected Annual Labor Rate Increase	4.0%
2024 Forecasted Average Meter Operations Coordinator Hourly Rate	$35.17
Budgeted Labor Loadings	1.51
2024 Forecasted Average Meter Operations Coordinator Loaded Hourly Rate	$53.11
Average Job Duration	5 minutes
2024 Average Cost to PGE per Remote Reconnection	**$4.43**

April 18, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 483
Dated April 4, 2023

Request:

Schedule 300 Workpapers filed with the Reconnect Rate state the duration for a business hours reconnected is .5 hours. Of the data the company averaged what was the shortest, longest, and the median reconnection time.

Response:

PGE objects to this request in that it is unduly burdensome and requires new analysis since PGE does not track the time for each reconnection. Without waiving said objection, PGE states as follows:
The duration of a reconnection depends on the distance of the crew dispatched and the location of the meter. PGE does not collect data on the duration of each reconnection trips.

April 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 542
Dated April 14, 2023

Request:

Please provide a sample copy of the current standard QF contract, that includes the monthly fee charges.

Response:

All of PGE's standard QF contracts and related schedules can be found at the following link: https://portlandgeneral.com/renewable-installers/interconnection-resource-library

The monthly fee charge can be found in Schedule 201: Qualifying Facility 10 MW or Less Avoided Cost Power Purchase on Sheet No. 201-20. Schedule 201 is incorporated by reference in the standard QF contracts.

April 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 543
Dated April 14, 2023

Request:

Please provide a sample copy of the proposed standard QF contract, that includes the monthly fee charges.

Response:

See PGE's response to OPUC Data Request 542 for the current contract. PGE proposed a change to Schedule 201 that would move the Monthly Service Charge to Schedule 300 – for details, please see PGE Exhibit 1309.

April 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 544
Dated April 14, 2023

Request:

For QF contracts:

a. What is the process for renegotiation of QF contracts?
   i. Would a QF's renegotiated contract continue to receive the monthly service charge based on the current rate/original contract.

   Or,

   ii. Would they be subject to the new, proposed rate?

Response:

The process for renegotiation of a QF contract is the same as that for an initial QF contract and included in Schedule 201. See also PGE's response to OPUC Data Requests 542 and 543. The monthly service charge for which the QF would be responsible will depend upon the terms and conditions of the QF contract and Schedule 201 in effect at that time. Most QFs execute a standard PURPA contract that is reviewed and approved by the Commission. In the next few months, PGE will be updating its standard PURPA contract in light of the recent changes to OAR 860-029 adopted in Order No. 23-152 (April 25, 2023).

April 28, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 545
Dated April 14, 2023

Request:

Please describe the reasons, and any supporting contract text from existing contracts, as to why the proposed revised monthly fee cannot be applied to existing contracts.

Response:

PGE objects to this request on the basis that it seeks a legal conclusion. Without waiving its objection, PGE responds as follows.

See PGE's response to OPUC Data Request 544. The proposed monthly fee cannot be applied to existing contracts because the "then current Schedule 201" is included as part of the contract at execution. In other words, existing contracts contain language from the Schedule 201 in effect at execution that the monthly service charge will be $10 per month. PGE cannot change or update that provision for existing contracts which were signed when the then-current Schedule 201 specified the monthly service charge at $10 per month.

May 19, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 726
Dated May 5, 2023

Request:

Please provide a monthly breakdown for each of calendar years 2019-2023 inclusive, of the following:

a. Number of reconnects for:

i. Remote connect AMI meters,

ii. Non-remote connect AMI meters, and

iii. Non-AMI meters.

Response:

Attachment 726-A provides a monthly breakdown of the number of reconnects for remote connect AMI meters, non-remote connect AMI meters and non-AMI meters from 2019 through April 2023.

YEAR	DEVICE DESCRIPTION	January	February	March	April	May	June	July	August	September	October	November	December
2019	NON-REMOTE CONNECT AMI METER	743	583	980	1,395	1,175	922	734	575	479	482	325	264
	REMOTE CONNECT AMI METER	1,103	709	1,324	2,087	1,860	1,636	2,079	1,428	1,358	1,798	1,289	1,153
2020	NON-REMOTE CONNECT AMI METER	386	393	133	8	3	1	2	17	9	3	16	16
	REMOTE CONNECT AMI METER	1,454	1,462	605	10	1	2	2	2	7	4	4	33
2021	NON-REMOTE CONNECT AMI METER	4	4	18	46	33	40	39	36	38	30	30	23
	REMOTE CONNECT AMI METER	11	15	8	8	7	9	6	39	201	326	465	470
2022	NON-REMOTE CONNECT AMI METER	70	35	52	29	92	239	185	192	111	153	93	79
	REMOTE CONNECT AMI METER	404	635	932	988	1,069	982	978	1,556	1,188	1,394	951	703
2023	NON-AMI METER				1								
	NON-REMOTE CONNECT AMI METER	107	35	131	52								
	REMOTE CONNECT AMI METER	1,609	735	2,180	633								

May 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 727
Dated May 5, 2023

Request:

For 2022 and 2023 calendar years inclusive, by meter type (Remote connect AMI meters, Non-remote connect AMI meters, and Non-AMI meters), please provide the number of reconnect fees charged for:

a. All customers,

b. Customers designated as low-income who had charges waived, and

c. Customers designated as low-income who were charged reconnect fees.

Response:

PGE objects to this request as it is unduly burdensome and requires new analysis to the extent the data was not available to track waived charges until February 2023. Subject to and without waiving its objections, PGE responds as follows:

Attached 727-A provides the number of reconnect fees charged by meter type (remote connect AMI meters, non-remote connect AMI meters, and non-AMI meters) for all customers, customers designated as low-income who had charges waived, and customers designated as low-income who were charged reconnect fees. PGE followed the COVID-19 Stipulation Agreement in Docket No. UM 2114 approved by Order No. 20-401, in which PGE and other utilities agreed to not apply reconnection fees to residential customers before October 1, 2022. Although the OAR Chapter 860, Division 21 rule revisions was effective on September 30, 2022, PGE requested and was granted a temporary waiver for the remainder of 2022 from OAR 860-021-0330(1)(2) due to ongoing customer care and billing system upgrades. While low-income customers were not charged reconnection fees, on January 31, 2023, PGE implemented system changes to track the low-income protections for waived charges and reconnect fees.

The number of reconnect fees in 2022 provided in PGE's response to Staff Data Request No. 141 included waived reconnect fees.

UE 416

PGE's Response to OPUC DR 727
Attachment A

		a. All Customers	b. Customers designated as low-income who had charges waived	c. Customers designated as low-income who were charged reconnect fees
2022	Remote connect AMI meters	864	N/A	3
2022	Non-remote connect AMI meters	236	N/A	1
2022	Non-AMI meters	-	N/A	-
2023	Remote connect AMI meters	4,988	848	99
2023	Non-remote connect AMI meters	387	25	5
2023	Non-AMI meters	-	-	-

May 19, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 728
Dated May 5, 2023

Request:

Please provide PGE's criteria for installing remote reconnect AMI meters, including, but not limited to:

a. Standard procedure for determining installation,

b. Special criteria such as number of reconnects, etc.,

c. Other criteria, such as access/location of meter base,

d. Any other scenarios/situations that PGE would use to determine the need to install a remote capable smart meter.

Response:

a. PGE installs remote reconnect AMI meters on all new residential premises limited to form 2S (120/240V) or 12S (120/208V) and class 200 meters. If an existing residential meter without remote connect capability is removed/exchanged, it will be replaced with a remote reconnect capable meter.
b. See response to part c.
c. Attachment 728-A provides the minimum requirements for AMI meters at PGE that will meet or exceed the latest applicable ANSI C12 standards. PGE's Electric Service Requirements, https://downloads.ctfassets.net/416ywc1laqmd/2PmrU1CptipEQUJAD1Ooyb/a117078d490246f00770e34bed073a62/ESR_Current_Book.pdf, Section 3.9 provides meter installation guidelines, and section 5 provides meter locations and clearances guidelines.
d. PGE began exchanging non-remote residential meters with remote disconnect meters in 2020 at non-owner occupied locations, sites without a contract, and any site visited for credit purposes. The initial phase of the project consisted of 25,000 meters exchanged in 2020. The exchanges decreased through 2022 due to supply chain delays experienced in 2021 and 2022. Also, there are a small number of commercial customers with remote reconnect AMI meters. If a commercial customer has a meter base with 120/240V and class 200 (i.e., shops, barns), they may have a remote capable meter.

AMI Meter Requirements

Purpose

Meter Operations Standard 2.2.3 — *AMI Meter Requirements* —provides minimum requirements for AMI revenue meters at PGE Meters that will meet or exceed latest applicable ANSI C12 standards.

References

ESR	*PGE Electric Service Requirements*
ANSI C12.1	*Electric Meters – Code for Electricity Metering*
ANSI C12.10	*Physical Aspects of Watthour Meters – Safety Standard*
ANSI C12.18	*Protocol Specification for ANSI Type 2 Optical Port*
ANSI C12.20	*Electricity Meters – 0.1, 0.2, and 0.5 Accuracy Classes*

Definitions

Delivered............... Energy that is supplied by PGE to the customer
Received............... Energy that is produced by the customer and supplied to PGE
TOU .... Time of Use

Meter Requirements

Forms

The following meter forms will be available:

Form	Class	Voltage	Notes
1S	200	120V	Indicated by voltage in bold with shaded background, e.g. **120V**
2S	200	240V	
2S	200	120-480V	
2S	320	240V	
3S	20	120-480V	
4S	20	120-480V	
5S (35S)	20	120-480V	
6S (36S)	20	120-480V	
9S (8S)	20	120-480V	
12S	200	120-480V	
16S	200	120-480V	

Voltage Range

Operating voltages are required to be between 120VAC to 480VAC.

Adjustment

Meters shall not have any calibration or accuracy adjustment.

Functions and Upgrades

The following functions and upgrades will be available:

- TOU
- VAr
- Bi-directional quantities (e.g. Net metering)
- External outputs (e.g. KYZ pulses), for non-residential meters
- Non-volatile memory storage of meter program and billing quantities

Demand

- Meters will be capable of a 30-minute demand interval
- Demand will be capable of being electronically reset using PGE's current AMI system
- Meter will be capable of deactivating the demand reset plunger using manufacturer software
- Demand reset plunger will be sealable
- Demand will be programmable to reset as a recurring event on a specific date and time

TOU Option

- Meters will be capable of registering TOU energy
- Meters will have minimum four TOU rates
- Calendar will be capable of being electronically updated using PGE's current AMI system

Load Profile

- Residential meters will have minimum two channels of load profile data
- Non-residential meters will have minimum eight channels of load profile data

KYZ Option

- Non-residential meters will have option of KYZ functionality
- KYZ option will have minimum of two KYZ outputs
- KYZ pulse weight will be scalable from 0.075 to 100000 using manufacturer software.

Optical Port

- Non-residential meters will have an ANSI Type 2 optical port, as specified in ANSI C12.18
- Optical port will be accessible without removal of meter cover

Remote Connect/Disconnect

- Residential meters (Form 2S, class 200 and Form 12S, class 200) will have remote connect/disconnect capability.
- Meters will have visible indication of switch status
- Meters will be identified on faceplate as remote connect

Cover

- Cover will be made of acrylic or polycarbonate materials
- Cover will be sealable with “T” type seals
- Faceplate will be visible through front of cover
- For non-residential meters, cover will have an ANSI Type 2 optical port

Ring

- Meters will seal with a standard socket ring

Blades

- Meter terminal blades will be beveled and meet ANSI C12.10 dimensions

Operating Conditions

- Meter will be capable of operating within temperature range of -40°C to +85°C, as measured inside meter cover
- Meter will be capable of operating within humidity range of 0% to 95% noncondensing humidity

Frequency

- Meters will operate at 60Hz

Display Modes

Meters will have three display modes: normal, alternate, and test.

Registers will have minimum two-digit ID number

Normal Displays

The following displays will be available in normal display mode:

- Total kWh
- Shoulder kWh
- On-peak kWh
- Off-peak kWh
- Total peak kW
- Shoulder-peak kW

- On-peak kW
- Off-peak kW
- Total kVArh
- Shoulder kVArh
- On-peak kVArh
- Off-peak kVArh
- Total peak kVAr
- Shoulder-peak kVAr
- On-peak kVAr
- Off-peak kVAr
- Current date
- Current time
- Remote connect status, if applicable

Alternate Displays

Alternate mode will be activated on the external of the meter and/or using manufacturer software. The following displays will be available in alternate display mode:

- All displays listed in Normal Displays section
- Date of last reset
- Program ID
- Transformer ratio/Meter multiplier
- Demand interval length
- Number of power outages
- Number of demand resets
- Power factor
- Total kVA
- Per phase voltage
- Per phase current

Test Mode Displays

Test mode will be activated on the external of the meter and/or using manufacturer software. The following displays will be available in alternate display mode:

- All displays listed in Normal Displays section
- Date of last reset
- Program ID

Load Indicator

- Meter will indicate and display energy flow direction

Voltage Indicator

- Meter will indicate and display nominal voltage

Display

- Meter will have LCD or equivalent display
- Display will be readable from 10 feet
- Display will be readable when exposed to direct sunlight
- Display will be capable of operating within temperature range of -40°C to +85°C, as measured inside meter cover

Battery

All removable batteries will meet following requirements:

- Minimum operational life of two years
- Minimum shelf life of ten years

All permanent batteries will meet following requirements:

- Minimum operational life of fifteen years
- Minimum shelf life of ten years

Factory Program

- Meters will be programmed at factory per PGE program requirements

Warnings/Errors/Failures

- Meters will be capable of detecting internal hardware failure and communicating failure(s) using PGE's current AMI system

Communication Module

- Communication modules will be FCC compliant and compatible with PGE's current AMI system
- Information transmitted to PGE's current AMI system will include:
    - Unique meter identifier(s)
    - Register data
    - Interval data
    - Instantaneous measurements, e.g. voltage, current, frequency
    - Demand reset date/time
    - Tamper indicators

Inspection

PGE will inspect a sample lot of meters upon delivery from supplier and perform testing per ANSI/ASQ Z1.4 to ensure compliance with requirements.

Documentation

Manufacturer will provide hardware, software, and manuals.

ANSI C12 certification and test results will be provided upon request.

Revision History

Revision	*Revised on*	*Description*	*Authored by*	*Approved by*
0	2/25/2020	Initial document creation	J. Wilson	B. Simpson

May 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 773
Dated May 10, 2023

Request:

In additional to the information provided in Staff's Data Request 757, please provide the same breakdown based on Standard versus After Hours reconnect fees for:

a. All customers,
b. Customers designated as low-income who had charges waived, and
c. Customers designated as low-income who were charged reconnect fees.

Response:

PGE objects to this request as it is unduly burdensome and requires new analysis to the extent the data was not available to track waived charges until February 2023. Subject to and without waiving its objections, PGE responds as follows:

Attached 773-A provides the data provided in Attached 727-A additionally separated out by Standard versus After Hours reconnect fees. PGE followed the COVID-19 Stipulation Agreement in Docket No. UM 2114 approved by Order No. 20-401, in which PGE and other utilities agreed to not apply reconnection fees to residential customers before October 1, 2022. Although the OAR Chapter 860, Division 21 rule revisions was effective on September 30, 2022, PGE requested and was granted a temporary waiver for the remainder of 2022 from OAR 860-021-0330(1)(2) due to ongoing customer care and billing system upgrades. While low-income customers were not charged reconnection fees, on January 31, 2023, PGE implemented system changes to track the low-income protections for waived charges and reconnect fees.

The number of reconnect fees in 2022 provided in PGE's response to Staff Data Request No. 141 included waived reconnect fees.

UE 416
PGE's Response to OPUC DR 773
Attachment A

			a. All Customers	b. Customers designated as low-income who had charges waived	c. Customers designated as low-income who were charged reconnect fees
2022	Remote connect AMI meters	Standard Hours	775	N/A	-
2022	Remote connect AMI meters	After Hours	89	N/A	3
2022	Non-remote connect AMI meters	Standard Hours	227	N/A	-
2022	Non-remote connect AMI meters	After Hours	9	N/A	1
2022	Non-AMI meters	Standard Hours	-	N/A	-
2022	Non-AMI meters	After Hours	-	N/A	-
2023	Remote connect AMI meters	Standard Hours	4,371	825	13
2023	Remote connect AMI meters	After Hours	617	23	86
2023	Non-remote connect AMI meters	Standard Hours	337	25	3
2023	Non-remote connect AMI meters	After Hours	50	-	2
2022	Non-AMI meters	Standard Hours	-	-	-
2022	Non-AMI meters	After Hours	-	-	-

May 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 774
Dated May 10, 2023

Request:

Please review PGE Exhibit 1300, Schedule 300 Calculations Temporary Services 2021 Rate workpapers, which lists two separate Outside Services for temporary overhead services. The worksheet named Final Calculations 2024, item U (cell F40), lists $60.00 for temporary over service, however, the worksheet named Temp OH Perm Service 2024 (cell F34) lists the Outside Services as $83.00. Please explain the discrepancy and clarify which amount is correct.

Response:

The $83 figure in cell F34 on worksheet 'Temp OH Perm Service 2024' is the correct amount. See cell R26 on worksheet 'Unit Costs_As of 12-01-22' for the source of the $83 figure.

The 'Final Calculations 2024' tab was not fully updated and does not provide the correct amount.

CASE: UE 416
WITNESSES: Lisa Gorsuch

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2500

Opening Testimony Service Quality Measures (SQM) and Physical Security Costs

June 13, 2023

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

A. My name is Lisa Gorsuch. I am a manager employed in the Emergency Management Section of the Utility Safety, Reliability and Security Division of the Oregon Public Utility Commission (OPUC). My business address is a 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/2501.

Q. What is the purpose of your testimony?

A. My Testimony addresses two issues:

Q. Did you prepare any exhibits for this docket?

A. No.

ISSUE 1. PHYSICAL SECURITY

Q. Did you review PGE's physical security testimony in this docket?

A. Yes, I did.

Q. Do you have any perspectives on either the expected spend or the general direction outlined in PGE's testimony?

A. Yes. I do. PGE is correct that physical security issues seem to have increased over the recent past. While PGE outlined its staffing experience as it transitioned from an outsourced security firm to an internal team, they provided very limited information about the scope of work this team is responsible for, the measurable deliverables it is required to produce, and how this work moves forward investment in security expenditures which will result in more physically security assets, notably the 561 locations to which they point.

Q. Do you have other concerns about the high-level plan laid out by PGE?

A. Yes, I do. I believe that the staffing and its cost is merely the beginning of a large potential set of costs customers will be expected to fund to make PGE's facilities more secure. I am not comfortable that Staff will have sufficient insight into the decisions being made and the investments being undertaken to help ensure the best investment choices are being made. I look forward to seeing evidence of the decision-making process that prioritizes various assets and establishes the best possible mitigations for the risks and the facilities.

Q. How do you propose PGE provide such information?

A. First, I think it is important for the utilities to maintain relationships and awareness as the industry evolves its security practices, which includes calibration of critical security with industry workgroups. To this end, updates provided confidentially could maintain Staff awareness as PGE gains such knowledge. Additionally, as investments are chosen and made, Staff and decision makers should be informed, also in a secure manner. I would point to the annually filed Gas Safety Plans as a potential model which could be used to summarize such activities.

Q. What should these plans include?

A. At minimum they should have some form of risk ranking for each location, the planned mitigation, when it is anticipated to be completed, its cost, and any interim mitigation measure the Company will use to maintain security given the current risks. Realistically it would also be helpful that this risk ranking be dovetailed with other investments that the Company would be considering, such as resilience investments, such as storm hardening. The plans should also provide an understanding of the progress made to date regarding overall security needs and a full description of how much more is needed.

Q. Do you take issue with the aspect regarding staffing and these positions being treated as new costs within this rate case?

A. Yes. I have some concerns with the manner in which this cost estimation appears to augment a very large change in rates charged to customers. There seems to be no recognition of available FTEs positions within PGE overall which were included in the most recent general rate case and were not filled. Such vacancy savings are not discussed at all in determining the incremental cost of this program but rather accrue to the Company. Further, it does not seem that PGE's cost estimates recognize a corresponding reduction in the amount paid to the outsource vendors to perform this work as PGE itself takes on more of that workload.

ISSUE 2. SERVICE QUALITY MEASURES (SQM)

Q. Please explain Service Quality Measures and their use?

A. Service quality measures act as objective service level agreements that can be used to establish performance for specific time periods. They serve as thermometers to gauge how the utility is completing its core mission in delivering safe, reliable energy to customers.

Q. Please discuss the history of SQMs in Oregon?

A During the late 1990s, in the midst of potential deregulation of the electric industry, there was concern about how deregulation might diminish customer service and other core activities that electric utilities must perform.

During that time, the Commission opened stipulations among parties, including Staff and the Company, that contained performance standards that were called Service Quality Measures, or SQMs. The SQMs included consequences such that if a utility fell below an acceptable performance level, the utility was assessed a minor penalty, through a slight reduction in revenue requirement. If the utility failed to achieve the extreme performance band, there was a much more substantial reduction in revenue requirement.

Q. What was PGE's history with SQMs?

A. In UM 814, PGE reported annually on a group of measures demonstrating its performance against the objective criteria.

Q. What areas were there SQMs designated for?

A SQMs were outlined for reliability performance measures, including sustained and momentary outage frequency as well as sustained outage duration and average restoration duration. There were also measures related to customer complaints where the utility was found to be "at fault", as well as performance against inspection/correction, vegetation management, and safety goals.

Q. How did the SQMs support operational efficiency and transparency in how well the utilities were performing their functions?

A. They supported operational efficiency and transparency for the utilities by clearly outlining what targets they were expected to achieve. Further, SQMs had required reporting provisions which enabled the OPUC and others to recognize when and where utilities were meeting performance standards. Utilities, including PGE, were required to report performance and spending, both actual and budgets, relative to those key operational elements. This allowed laser focus for the companies, while also allowing OPUC to help ensure that performance objectives for dollars planned and expended were in harmony.

Q. Do you perceive these measures have relevance given the current pressures within the electric utility environment?

A. Yes, these measures are relevant and can achieve the transparency and line-of-sight related to operational performance that would be useful. Specifically, SQMs (or a similar performance measure) could be set which would help act as a "mile marker" to explain objectively how the utility is performing its obligations to provide safe, reliable power, in between rate cases.

Q. Why do you see this as better than discovery during rate cases?

A. It's important to clarify expectations with regards to performance, which SQMs provide. It is also valuable to have interim reporting to gauge how the utility is achieving the primary performance. We also consider it highly useful to have an organized set of data from which to judge how well the utility is achieving each and all of those key measures.

Q. Does the OPUC have interim check-ins with utilities?

A. Yes. There are a variety of ways that the utilities and OPUC maintain alignment, however there is not a comprehensive "report card" which affords certainty to the customers about what has been judged critical. Nor has this been clearly outlined between the utility and the OPUC. The development of SQMs and agreement of specific performance levels against those SQMs could drive better outcomes for all.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 416
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2501

Witness Qualifications Statement

June 13, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Lisa Gorsuch

EMPLOYER: Public Utility Commission of Oregon

TITLE: Emergency Preparedness Manager
Safety, Reliability, and Security Division

ADDRESS: 201 High Street SE Suite 100
Salem OR 97302-1166

EDUCATION: College-level coursework in financial accounting, business law, business management, and economics. Degree in Fire Science and Paramedic Certification. Training program with the Center for Public Utilities at New Mexico University. Training programs with the National Association of Regulatory Utility Commissioners' (NARUC) and the Annual Regulatory Studies Program at Michigan State University. I have completed 9 Federal Emergency Management Agency (FEMA) Incident Command System (ICS) Emergency Management Certifications including, ICS 100, 120, 200, 230, 235, 700, 702, 706, and 800. I have completed training and received certification from the US Department of Homeland Security for Protected Critical Infrastructure Information (PCII) as a PCII authorized user.

EXPERIENCE: Relevant experience while working for the Public Utility Commission of Oregon (PUC) as the current Emergency Preparedness Manager and previously serving as in the capacity of Senior Utility Analyst is as follows:

I have managed technical staff as the lead of many complex cases, including, but not limited to, Integrated Resource Plans, Purchased Gas Cost Adjustments, Legislative Investigations, Rulemakings, and Emergency Operation Plans. I have approximately 20 years of work experience in analyzing complex energy utility industry issues, identifying key drivers and devising options and proposed actions to resolve defined problems. I have performed economic and financial analysis of electric and natural gas utility issues. I have been responsible for analyzing and developing recommendations on issues including, but not limited to, renewable energy, energy efficiency, safety and customer service, service quality measures, main and service line extensions, advertising, customer communications and various tariff applications, setting appropriate rates, wildfire mitigation, energy security, and emergency response and recovery. I have analyzed various utility proposals that I recommended for approval, rejection, or alternative actions to the Administrator, Director of the Utility Program, and Commissioners. In addition, I have written technical reports, training materials, public comments, staff reports, testimony, conference presentations, statistical reports, case status reports, administrative rules, and emergency operation plans. I currently serve as natural gas subcommittee vice chair and serve on the critical infrastructure subcommittee as a member for NARUC.

OTHER EXPERIENCE: Senior Enforcement Agent with the Oregon Department of Revenue as a member of a multijurisdictional organized crime task force from 1999 - 2004. My responsibilities included, but we’re not limited to, investigating criminal cases for prosecution. In addition, served as liaison between the task force and Oregon State Legislators.

CASE: UE 416
WITNESS: Scott C. Lundquist

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2600

REDACTED
OPENING TESTIMONY
Cybersecurity
Subject to Protective Order No. 23-039

June 13, 2023

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

A. My name is Scott C. Lundquist. I have been a Consultant with QSI Consulting, Inc. for sixteen years. My business address is 107 Murphy Drive, Pennington, NJ 08534.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2601.

Q. What is the purpose of your testimony?

A. My testimony addresses PGE's cybersecurity strategy, practices, and performance, to inform the Commission as to whether PGE is taking the right actions to protect its operations from cyber-oriented breaches and other harms, and the efficacy of its cybersecurity spending.

To that end, my testimony reviews the Company's experiences with cybersecurity breaches/events, its recent and planned changes to its cybersecurity defenses, the year-by-year cost trends for its cybersecurity functions, and the reasonableness and prudence of the cybersecurity expenses and investments that are claimed in its 2024 Test Year.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/2602. ......PGE Non-Confidential Responses to Data Requests
Exhibit Staff/2603. .... PGE Confidential Responses to Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your testimony.

A. My principal findings and recommendations are as follows:

- The threats posed to PGE and similarly-situated energy companies from cyberattacks are real and growing. While the relative magnitude of the Company's cybersecurity costs is quite small in the context of this general rate case, Staff believes that PGE's planned cybersecurity expenditures must be examined to ensure that they are being applied in the most effective manner.
- PGE has an established cybersecurity strategy that is aligned with industry standards, and PGE appears to be taking appropriate actions to execute that strategy.
- PGE did not experience any cybersecurity breaches over the past five years, nor incur any costs from such breaches. PGE also appears to be in compliance with NERC's requirements for critical infrastructure protection.
- PGE is seeking a $4.1-million increase in its total cybersecurity O&M spending in the test year relative to 2022, a 27 percent increase. After examining its O&M expenses and major capital project investments relating

to cybersecurity, I have found no need for any disallowances from rate base or expenses associated with cybersecurity.

- One area of potential concern is that PGE currently has several important positions in its cybersecurity staffing that are unfilled, and some have been vacant for many months. I recommend that the Commission direct the Company to report at the end of each quarter through 2023-2024 on its progress towards filling each of those vacant positions.
- I also recommend that the Company share the results of its next benchmarking assessment with the Commission as soon as they become available. This will allow the Commission to stay apprised of PGE's cybersecurity performance as the Company continues to adapt to the latest challenges the industry confronts.
- Of course, the other energy companies that the Commission regulates are also facing similar cybersecurity challenges. Rather than address those challenges in individual company rate cases or other separate proceedings, I recommend that the Commission consider opening an investigation that would include all of the energy companies it regulates, plus other stakeholders, to obtain additional information and formulate actions it could take to encourage further progress in strengthening the cybersecurity defenses of their critical infrastructure in Oregon.

Issue 1. Overview of Cybersecurity Threats and PGE's Defensive Strategy

Q. How does cybersecurity fit into the overall objectives of this proceeding?

A. PGE's cybersecurity expenditures represent a small fraction of the Company's proposed overall revenue requirement at issue in this proceeding.[1] Nevertheless, if spent effectively, those dollars can significantly reduce PGE's vulnerability to potential cyberattacks on its IT systems and other critical infrastructure systems. For that reason, Staff believes that PGE's planned cybersecurity expenditures must be examined to ensure that they are being applied in the most effective manner, taking into account the Company's cyber defense strategy and the changing conditions in the cyber domain. My testimony is intended to provide that examination.

Q. What is the current status of cyberattacks and threats for companies such as PGE?

A. Unfortunately, the threats posed to PGE and similarly-situated utilities by cyberattacks are real and growing. The most recent Annual Threat Assessment of the U.S. Intelligence Community ("Assessment") continues to identify both aggressive nation states, including Russia, North Korea, and China, and trans-national criminal organizations as sources of cyberattacks that could harm companies such as PGE that possess important assets of the

---

[1] PGE has proposed approximately $19 million in cybersecurity expenses in the 2024 Test Year. (Staff/2602, PGE Response to OPUC DR No. 660, Attachment B, tab d.) This amount is under one percent of its total proposed revenue requirement of $2,671.5 million as shown in PGE/200, Batzler – Ferchland/ 1. ($19 million / $2,671.5 million = 0.7 percent.)

U.S. energy infrastructure.[2] For example, the Assessment states "China almost certainly is capable of launching cyber attacks that could disrupt critical infrastructure services within the United States, including against oil and gas pipelines, and rail systems."[3] It also concludes that "[t]ransnational organized ransomware actors continue to improve and execute high-impact ransomware attacks, extorting funds, disrupting critical services, and exposing sensitive data."[4]

Q. What is the actual recent experience of energy sector companies, are they being targeted for cyberattacks?

A. Yes, they are. Leading vendors of cyberattack detection and incident response services have confirmed these threats with statistics based on their clients' experiences with cyberattacks. IBM Security's latest X-Force Threat Intelligence report based on its year 2022 data states that "10.7% of [IBM's] X-Force incident response cases occurred in the energy sector. Energy organizations, including electric utilities and oil and gas companies, were the fourth-most attacked industry—the same as 2021..."[5] While IBM offers its X-Force services worldwide, 46 percent of the energy sector incidents it responded to had occurred in North America.[6] And when the sector was ranked against other business sectors in North America, "Energy firms rose to

2 Office of the Director of National Intelligence, Annual Threat Assessment, 2/6/2023. Available from: https://www.dni.gov/index.php/newsroom/reports-publications/reports-publications-2023
3 *Id.* at page 10.
4 *Id.* at page 31.
5 IBM Security, X-Force Threat Intelligence Index 2023, at page 46. Available from: https://www.ibm.com/downloads/cas/DB4GL8YM
6 Id.

the top of the victim list in North America, constituting 20% of all attacks to which X-Force responded in 2022."[7]

Moreover, while energy companies' IT systems have been the traditional target of these cyberattacks, the Operational Technology (OT) systems of energy companies are facing increasing risks as well.

Q. What are Operational Technology (OT) systems?

A. One leading cybersecurity vendor, Fortinet, has defined OT systems in these terms:

> Operational technology (OT) is the use of hardware and software to monitor and control physical processes, devices, and infrastructure. Operational technology systems are found across a large range of asset-intensive sectors, performing a wide variety of tasks ranging from monitoring critical infrastructure ICIJ to controlling robots on a manufacturing floor. OT is used in a variety of industries including manufacturing, oil and gas, electrical generation and distribution, aviation, maritime, rail, and utilities.[8]

In the electrical sector, these systems control many components of bulk power systems and the electric grid, and therefore are integral parts of that critical infrastructure.

Q. What has been the long-term trend in the vulnerability of OT systems to cyberattacks?

A. The IBM's X-Force report also provides information on those trends, based on data IBM has been collecting for nearly 30 years. As shown in my Figure 1

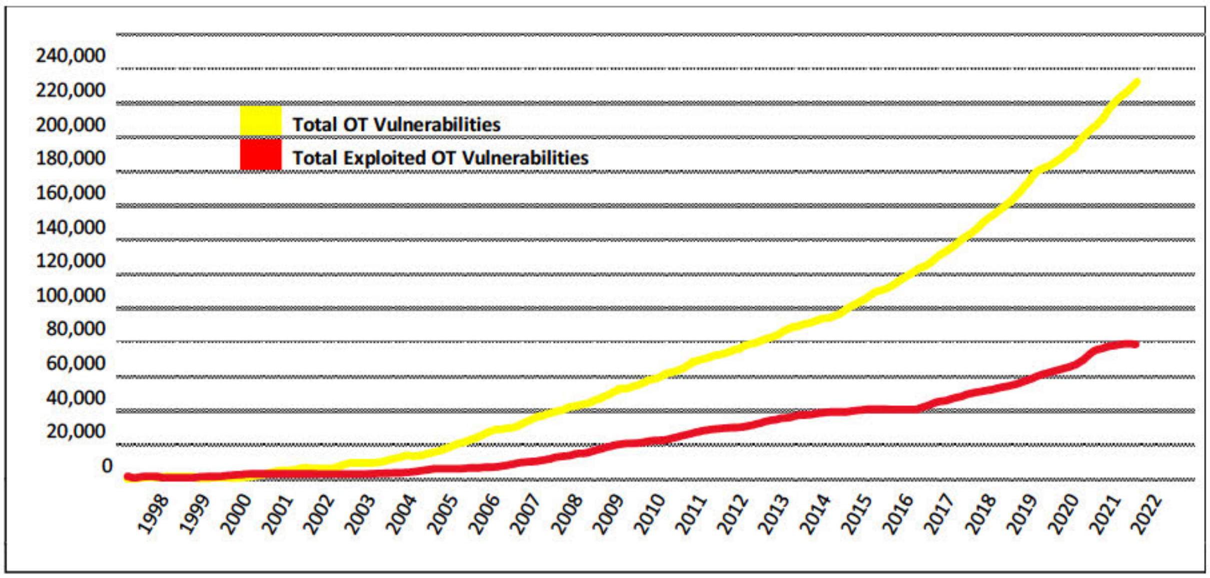
---

7 *Id.* at page 36.

8 Fortinet, "What is Operational Technology (OT)?" Available at: https://www.fortinet.com/solutions/industries/scada-industrial-control-systems/what-is-ot-security#:~:text=Operational%20technology%20(OT)%20is%20the,processes%2C%20devices%2C%20and%20infrastructure

below, the cumulative number of identified OT vulnerabilities logged in IBM's tracking database remained low until the early 2000s, when it began to become significant, and it has continued to rise steadily until the present day. On a compound average growth rate (CAGR) basis, the 2004 to 2022 cumulative number of OT vulnerabilities has risen 19% annually,[9] to a total of 228,167 in 2022.[10] While growing at a lower rate, the number of those vulnerabilities known to have been exploited has risen to 78,156 by 2022.[11]

Figure 1. Operational Technology Vulnerability Trends



Q. What factors have been driving this increasing vulnerability for OT systems?

A. There are several factors increasing the vulnerability of OT systems and their attractiveness as cyberattack targets.

---

9 Using the standard formula for CAGR and assuming the 2004 value was approximately 10,000, I have calculated this CAGR as (228,167 / 10,000) ^ (1/18) - 1 = 19.0%.

10 Source: IBM Security, X-Force Threat Intelligence Index 2023, at p. 15. Available from: https://www.ibm.com/downloads/cas/DB4GL8YM

11 *Id.*

- First, compared to IT, these systems tend to be longer-lived and slower to change, so that the software that runs them is often old and unsupported, without the benefit of security patches to protect against vulnerabilities as attackers discover them.
- Second, the cost savings and flexibility afforded by internet-enabled digitization is driving many companies to interconnect their OT to their IT systems and the internet. While the benefits of doing so are undeniable, that also opens up new attack surfaces on those OT systems, which can be accessed remotely through those interconnections.
- And third, the potential disruptions that successful attacks on OT could cause are immense, putting lives as well as property and revenues at risk.

For these reasons, the companies operating critical infrastructure, including energy companies, should make protecting their OT from cyberattacks an urgent priority.

Q. Is there any recent illustration of the damage that a cyberattack on an energy company's OT could cause?

A. Yes. To date, the most damaging cyberattack on a U.S. energy company was the ransomware attack on Colonial Pipeline in May 2021. The attacker used a compromised password to break into the company's IT systems and block access to its servers until a multi-million dollar ransom was paid in bitcoin. Colonial's management feared that the lock-out could spread to the OT controlling its pipelines, so they decided to preemptively shut down their 5,500 mile pipeline network for five days.[12]

Hence while the actual cyberattack never reached the company's OT, its consequences unfolded as if it had, with severe impacts far beyond the company. At that time, Colonial was transporting nearly half of the East Coast's gasoline, diesel and jet fuel along the East Coast, from the Gulf of Mexico to New York City. The shut-down of its pipeline network had ripple effects across the region, including panic-buying of gasoline by consumers, localized gas shortages, short-term price increases and even price gouging.[13]

While those disruptions fortunately proved to be of short duration, this dramatic exposure of the vulnerability of the energy sector spurred additional federal and state governmental actions. These included not only the imposition of new regulations by the Transportation Security Administration (TSA) on pipeline operators, but also new cybersecurity initiatives by the White House, the Department of Homeland Security and states including Colorado, New York, and Utah – all aimed at encouraging energy companies and other

---

[12] See "Cyberattack Forces a Shutdown of a Top U.S. Pipeline", The New York Times, 5/8/2023 (updated 5/13/2023). Available from: https://www.nytimes.com/2021/05/08/us/politics/cyberattack-colonial-pipeline.html And Kimberly Wood, "Cybersecurity Policy Responses to the Colonial Pipeline Ransomware Attack", the Georgetown Environmental Law Review, 3/7/2023. Available from: https://www.law.georgetown.edu/environmental-law-review/blog/cybersecurity-policy-responses-to-the-colonial-pipeline-ransomware-attack/

[13] *Id.*

operators of critical U.S. infrastructure assets to strengthen their protections against cyber threats.[14]

Q. What is the industry's current cybersecurity framework as devised by the National Institute of Standards and Technology (NIST)?

A. NIST administers a comprehensive framework of cybersecurity protections that is intended to reduce cyber-related risks to critical infrastructure in the U.S. Developed in collaboration with industry stakeholders, the framework includes standards, guidelines, and practices, but is voluntary rather than government mandated or enforced. The current version, 1.1, was adopted in 2018 and is complex, with a Core consisting of five Functions, 23 Categories, and 108 Subcategories, along with 6 supporting Informative References.[15] In response to the evolving nature of cyber technology and cybersecurity issues, NIST is also working on a successor version 2.0 Framework, with a Core 2.0 discussion draft issued for comment in April 2023.[16]

Q. Does PGE have an established cybersecurity strategy that is aligned with the NIST version 1.1 Framework?

A. Yes. In response to Staff discovery, PGE provided its latest cybersecurity planning and strategy document on a confidential basis.[17] **[BEGIN**

---

[14] *Id.* See also, Mike Elgan, "One Year After the Colonial Pipeline Attack, Regulation Is Still a Problem," Security Intelligence (IBM Security), July 11, 2022. Available from: https://securityintelligence.com/articles/colonial-pipeline-federal-regulation-update/

[15] NIST, Framework for Improving Critical Infrastructure Cybersecurity, SP 800-53 Rev 1.1 (2018). Available from: https://nvlpubs.nist.gov/nistpubs/CSWP/NIST.CSWP.04162018.pdf The counts of Core features are from the associated NIST Framework v1.1 Presentation, available from: https://www.nist.gov/cyberframework/framework .

[16] See https://www.nist.gov/cyberframework/updating-nist-cybersecurity-framework-journey-csf-20

[17] Staff/2603, PGE Response to OPUC DR No. 661, Confidential Attachment 661-A.

CONFIDENTIAL] [redacted]

[END CONFIDENTIAL]

PGE touched on this key initiative in its opening testimony, stating that "PGE is also completing a significant buildout of cybersecurity capabilities in the Operational Technology space," which is occurring in the context of its deployment of grid modernization technologies that can increase potential cyberattack surfaces.[18]

[BEGIN CONFIDENTIAL] [redacted].

- [redacted] **[END CONFIDENTIAL]**

[18] PGE/610/1.

This initiative is reflected in PGE's response to discovery on its Zero Trust Architecture (ZTA) plans, where the Company states: "PGE has been incorporating ZTA into our cybersecurity strategy to enhance security for all network access, including internal and remote access, for all devices connecting to the PGE network. Our current rate case proceeding includes a $652,000 capital ask related to ZTA (P37477 – Zero Trust). This project specifically focuses on deploying zero-trust network access (ZTNA) network architecture."[19]

While I have not attempted to conduct a comprehensive evaluation of PGE's cybersecurity strategic plan and related actions, these through-lines from its overall strategy to specific plans and approved capitalized projects provide some reassuring evidence that the Company has a mature cybersecurity strategy that it is executing.

Q. Has PGE benchmarked its cybersecurity performance against that of other energy companies?

A. Yes, it has. **[BEGIN CONFIDENTIAL]** [redacted]

[19] Staff/2602, PGE Response to OPUC DR No. 662. ZTNA is designed to grant remote users (as well as on-premises employees) access to a corporate IT network's applications, data, and other resources on a "need-to-know" basis, to prevent unauthorized and potentially malicious activities. Implementing ZTNA is an important first step towards establishing a comprehensive "zero trust" security posture.

[redacted]

[redacted]

[redacted]

20 Staff/2602, PGE Response to OPUC DR No. 661, Confidential Attachment A, page 7.
21 *Id.*

[redacted] **[END CONFIDENTIAL]**

Q. Should the Commission direct PGE to submit to it the results of the Company's next cybersecurity performance benchmarking?

A. Yes. Benchmarking exercises of this kind are valuable and worth repeating on a regular basis. While the results discussed above were encouraging at the time, given the quickly-evolving nature of cyberattacks and defenses they may not be representative of PGE's current cybersecurity status. I recommend that the Commission direct the Company to share the results of its next cybersecurity benchmarking assessment with it as soon as they become available. Doing so will help keep the Commission apprised of PGE's cybersecurity performance as the Company continues to adapt to the latest challenges the industry confronts.

Q. Given the growing importance of ensuring that the energy companies regulated by the Commission are adequately protecting themselves from cyberattacks on their critical infrastructure, should the Commission consider a further investigation of that issue?

A. Yes. While this testimony provides some initial insight into PGE's performance with respect to this issue, all of the energy companies regulated by the Commission are confronting similar challenges in this area. Rather than address those challenges in individual company rate cases or other separate proceedings, I recommend that the Commission consider opening an

[22] *Id.*

investigation that would include all of the energy companies it regulates, plus other stakeholders, to obtain additional information and formulate actions it could take to encourage further progress in strengthening the cybersecurity defenses of their critical infrastructure in Oregon.

Issue 2. PGE Compliance With NERC's CIP Reliability Standards

Q. Is PGE subject to any standards for its cybersecurity systems and practices?

A. Yes. While the Commission does not impose any direct cybersecurity standards on PGE, FERC applies certain standards to the cybersecurity systems and practices of Bulk Electric System (BES) operators, including PGE, pursuant to Section 215 of the Federal Power Act (FPA).[23] FERC's designated Electric Reliability Organization (ERO), the North American Electric Reliability Corporation (NERC), develops cybersecurity-focused Critical Infrastructure Protection (CIP) standards, as part of the larger suite of BES reliability standards that it administers.[24] PGE has been subject to those CIP standards for cybersecurity since the first set of such standards became effective in July 2008.[25]

Q. Has PGE generally been in compliance with these CIP standards?

A. Yes, that is my understanding. As these standards continue to evolve over time, PGE and other BES operators are subject to periodic audits to assess their ongoing compliance. PGE has been subject to triennial audits by the Western Electricity Coordinating Council (WECC) for that purpose. PGE's most recent WECC audit occurred in June 2020. That audit evaluated PGE's compliance with 14 CIP requirements for a three-year period ending in March

---

23 The reliability section of the FPA has been codified at 16 USCS § 824o.
24 See NERC, U.S. Reliability Standards, at: https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx
25 *See id.*, downloadable "One-Stop-Shop" spreadsheet, at row 49.

2020. The audit found one instance of potential non-compliance, but no enforcement action was taken.[26] PGE's next triennial WECC audit of CIP standards is currently scheduled for the third quarter of 2023.[27]

---

26 Staff/2603, UE 394 PGE Response to OPUC DR No. 450, 8/30/2021. The CIP standard at issue for potential partial non-compliance, CIP 010-2, related to certain alleged omissions in PGE's documented plan for Transient Cyber Assets and Removable Media used with its high impact BES Cyber Systems. This CIP became inactive on 9/30/2020. See NERC's "One-Stop-Shop" spreadsheet, at row 132.

27 See WECC's draft audit schedule for 2023, at: https://www.wecc.org/Pages/Compliance-UnitedStates.aspx

<u>Issue 3. Cybersecurity Breaches and Their Cost Impacts on PGE</u>

Q. Have you investigated PGE's experience with cybersecurity breaches over the past several years, including any costs it has incurred due to such breaches?

A. Yes. In discovery, Staff asked PGE to identify and provide key details of each cybersecurity breach or other incident it had experienced from 1/1/2021 to date that resulted in a disruption to an internal IT system, its billing system(s), or any Critical Infrastructure Systems.[28] Second, Staff also asked PGE to provide details of any costs that it had incurred as a result of each such cybersecurity breach and incident.[29] And third, Staff asked PGE to provide its responses to Staff's DR No. 453 in the Company's previous GRC, Case UE 394, that also addressed its experience with cybersecurity breaches.

Q. What information did PGE provide in response to those questions?

A. In its responses to those questions, PGE indicated the following:

- It had not experienced any cybersecurity breach or other incident of that kind from 1/1/2021 to 5/9/2023 (its Data Response date);[30]
- Consequently, it had not incurred any such incremental expenditures (costs) resulting from such a breach or incident during that timeframe; nor had it included any such incremental expenditures in the 2024 test year;[31] and

---

[30] Staff/2602, PGE Response to OPUC DR No. 664.
[31] Staff/2602, PGE Response to OPUC DR No. 665.

- As of 8/30/2021, the Company also had not experienced any data breach or damage to its digital or physical systems due to an external cyber intrusion for the past five years (i.e., back to at least 8/30/2017).[32]

While informative, one cannot infer from these responses that there have been no attempted cyberattacks on PGE's critical systems, as such incidents might have gone undetected, and/or might not have caused disruption (e.g. as might occur with a data loss incident). Nevertheless, the absence of known incidents and adverse consequences suggests that the Company's cybersecurity strategy and defenses are offering some significant protection.

[32] Staff/2602, PGE Response to OPUC DRs No. 663 (containing PGE response to PUC DR No. 453 in Case UE 394).

Issue 4. PGE's Proposed Increase in Cybersecurity Costs

Q. How much spending on cybersecurity O&M has PGE included in the 2024 Test Year?

A. PGE's has indicated that its budgeted spending on cybersecurity O&M expenses in the 2024 Test Year totals $19.286 million.[33]

Q. How does that spending level compare to its historical trends for cybersecurity O&M expense?

A. The following table presents PGE's reported figures for its Operations and Maintenance (O&M) cybersecurity spending for 2018 through to the 2024 Test Year. The orange dots represent PGE's year-to-year expense values and the blue line illustrates their trend over the 2018-2024 timeframe. As shown on the chart, in 2019 PGE had nearly doubled its expenditure level in 2019, as it ramped up its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** The figures for 2018-2022 are actual expenditures,[34] whereas years 2023 and TY2024 are budgeted expenses.[35] Note that the 2021 and 2022 actual spending amounts were well under their budgeted levels, by $2.6 million and $1.5 million, respectively. Based on the expense values shown below (including the corrected 2024

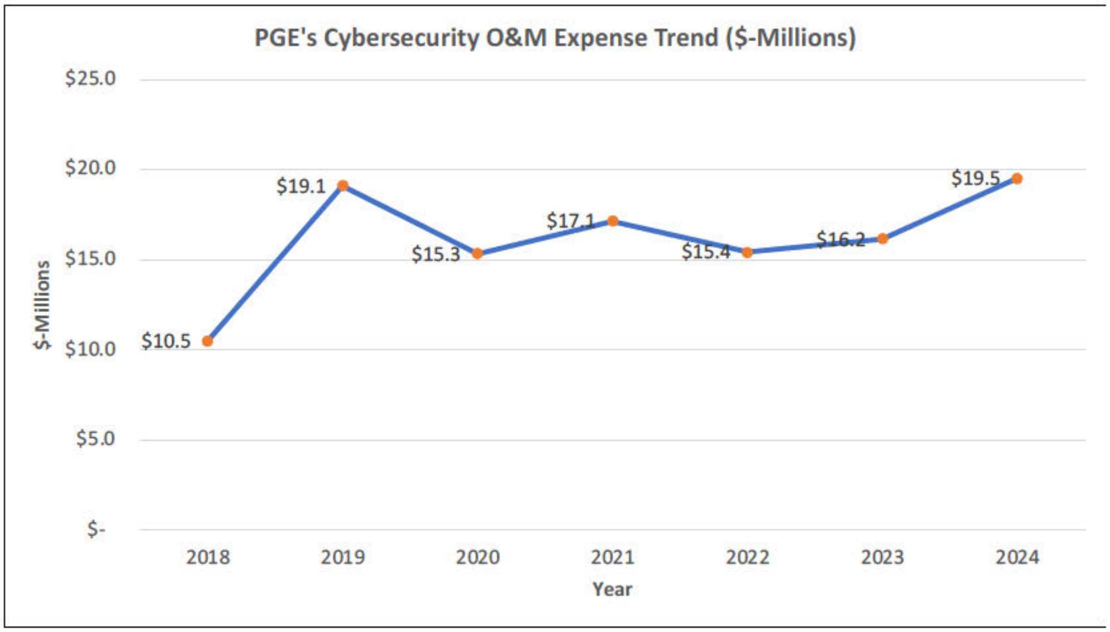
33 See Staff/2602, PGE Response to OPUC DR No. 660-d, Attachment B, at tab d., column K (total budgeted TY2024 expense for cybersecurity = $19.286 million). In fact, that figure appears to be slightly understated due to a calculation error, with the actual amount based on the departmental figures PGE has provided equaling $19.520 million. (This is simply the sum of cells K47-K55 in tab d.)

34 Staff/2602, UE 394 PGE Response to OPUC Data Request 451, dated August 16, 2021 (for years 2018-2020) and Staff/2602, PGE Response to OPUC Data Request No. 660, Attachment B, at tab "d." (for years 2021 and 2022).

35 Staff/2602, PGE Response to OPUC Data Request No. 660, Attachment B, at tab "d."

value), PGE is seeking a $4.1 million increase in its total cybersecurity O&M spending in the test year relative to its $15.4 million actual expenditures in 2022, a 27 percent increase.

Figure 3: PGE's O&M Expenses for Cybersecurity



Q. Does that 27 percent spending increase appear reasonable?

A. Yes. The additional $4.1-million in O&M spending appears reasonable in light of PGE's augmentation of its cybersecurity activities as I have described above. Some of the spending amounts associated with those activities are:

- A $1.85 million increase in the budget for Dept. 226-OT Cybersecurity in 2023 (and sustained into the test year), which appears justified in view of the expanded OT monitoring requirements created by its recent OT visibility project.[36]

---

[36] Staff/2602, PGE Response to OPUC Data Request No. 660, Attachment B, at tab "d"; and Staff/2602, PGE Response to OPUC Data Request No. 668, part a.

- Approximately $115,000 annually for PGE's new service contract with Mandiant, which is providing an enhanced level of cybersecurity incident response and recovery support services.[37]
- Another anticipated $225,000 in 2024 expenditures to improve the Company's SIEM capabilities.[38]

Finally, as I had observed above, PGE's actual 2022 cybersecurity expenses were $1.5 million less than its budgeted amount. Some of that reduction was presumably related to the seven unfilled job positions within its cybersecurity departments at that time, an issue that I address in more detail in the next section of my testimony (see Issue 5 below). To the extent that PGE is successful in filling those positions, they will need to be funded, which will eliminate some of the interim cost savings the Company experienced from that situation in 2022.

Q. In addition to examining the O&M expenses you have just discussed, have you also evaluated the reasonableness of its capital investments supporting cybersecurity?

A. Yes. PGE has indicated that its annual spending on cybersecurity-related capital investments totaled $0.47 million in 2021, $2.19 million in 2022, and is forecasted to total $1.1 million in 2023.[39] **[BEGIN CONFIDENTIAL]** [redacted]

37 UE 416 PGE/610, Ajello – Batzler/1.
38 Staff/2602, PGE Response to OPUC Data Request No. 668, part b.
39 Staff/2602, PGE Response to OPUC Data Request No. 660, Attachment B, at tab "d."

[redacted]

Q. Please describe PGE's Operational Technology Project.

A. [redacted]

40 UE 416 PGE/600, Ajello – Batzler/34 and UE 416 PGE/610, Ajello – Batzler/1.

41 Staff/2603, PGE Response to OPUC DR No. 628, Confidential Attachment 628-A, PJF #P37336 (excerpts).

42 *Id.*

43 *Id.*

[redacted] **[END CONFIDENTIAL]**

Q. How do you assess the benefits from this project?

A. This project's cybersecurity benefits to the Company, and by extension its ratepayers, are significant. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

Q. Did you find that the costs of this project were likely to have been reasonably incurred?

A. Yes. My review of this project's PJF did not find any evidence of imprudent spending, cost over-runs or other adverse consequences to rate payers. My understanding is that the major vendors and products selected for this project are well-suited for its requirements and that they operate in competitive

[44] *Id.*
[45] *Id.*
[46] *Id.*

markets. For example, Nozomi is recognized as an industry leader in OT cybersecurity and its Guardian product has been given consistently high ratings by customers, according to Garter's product review platform.[47] No capital costs for this project are included in the 2024 test year, and the test year O&M expenses for these new capabilities are relatively small and appear reasonable.[48] Consequently, I find no need for any disallowances from rate base or expenses associated with this project.

---

47 See Gartner Peer Insights, Nozomi Networks Reviews, where the Guardian project received 4.8 stars out of 5.0 on 91 verified peer reviews. Available from: https://www.gartner.com/reviews/market/operational-technology-security/vendor/nozomi-networks/reviews?marketSeoName=operational-technology-security&vendorSeoName=nozomi-networks&sort=-helpfulness&pid=68906

48 PGE Response to OPUC DR #668.

Issue 5. PGE's Staffing Of Its Cybersecurity Organization

Q. Have you reviewed PGE's staffing of its cybersecurity departments?

A. Yes. PGE has supplied supplemental information in this area in response to Staff discovery. That information disclosed that the Company has several important positions in its cybersecurity staffing that are unfilled, and some have been vacant for many months. PGE has listed 53 cybersecurity positions within its organization, and it reported that seven of them are currently unfilled, for more than a year on average.[49] Those unfilled positions are listed in the following table.

Table 1. Vacant Positions within PGE's Cybersecurity Departments

Department	Unfilled Positions	# Headcount budgeted 2023
226 - OT Cybersecurity	P009147 6167 - Senior IRM Security Analyst (Unfilled)	1
	P009159 IRM Cyber Security Analyst/Senior IRM Cyber Security Analyst (Unfill	1
	P009479 IRM or Senior IRM Security Analyst (Unfilled)	1
608 - Enterprise Security	P013175 CISO, Cyber Security & IT Governance (Unfilled)	1
	P009135 Manager Information Risk (Unfilled)	1
773 - Info Security Operations	P009277 ISOC Operational Security Analyst (Unfilled)	1
775 - Cybersecurity	P009619 Enterprise Security Business Systems Analyst (Unfilled)	1

As shown in the table above, they include the key role of PGE's Chief Information Security Officer (CISO), which has been vacant since 12/2/2022 (five months). In addition, three Analyst/Senior Analyst positions within the Operational Technology (OT) Cybersecurity group (Dept. 226) are vacant and have been unfilled for long periods of time (8 months, 21 months, and 37 months). The OT Cybersecurity group is responsible for safeguarding the

[49] Staff/2602, PGE Response to OPUC DR No. 660, Attachment B, at tab c.

cybersecurity of the Company's Operational Technology, which as I have explained is critical infrastructure.

Q. Should the Commission be concerned about these vacancies?

A. Yes. While certainly concerning, the problem is not surprising, as the rise in cybersecurity attacks on corporate, government and other institutional IT systems in recent years has meant that demand for qualified IT personnel with cybersecurity training and skills has generally outpaced the supply, on an industry-wide basis. The severity of this issue had caused the state of Connecticut to include "Address the cybersecurity skills shortage" as one of four major objectives for its state Cybersecurity Strategy issued in March 2022.[50]

Given the importance of maintaining effective cybersecurity protections, I recommend that the Commission direct the Company to report at the end of each quarter through 2023-2024 on its progress towards filling each of those vacant positions identified in Table 1, and any additional cybersecurity-related positions that open up subsequently.

Q. Does this conclude your testimony?

A. Yes.

---

[50] See State of Connecticut Cybersecurity Strategy, Version 3.14, March 9, 2022 ("CT Cybersecurity Strategy"), at pages 4 and 7-8. Available from: https://portal.ct.gov/connecticut-cybersecurity-resource-page

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESS: Scott C. Lundquist

STAFF EXHIBIT 2601

Witness Qualifications

Scott C. Lundquist
Consultant to
QSI Consulting, Inc.

107 Murphy Drive
Pennington, NJ 08534
(508) 654-2013 Office
slundquist@qsiconsulting.com

Biography

Mr. Lundquist serves as a consultant to QSI, performing regulatory, technical, and economic analysis, project management, and client support services for projects involving telecommunications regulation and economics. Prior to joining QSI in 2007, Mr. Lundquist served as a Vice President and Partner of Economics and Technology, Inc. (ETI), a Boston-based consulting firm. Over the course of his 36-year career in the field, Mr. Lundquist has participated in hundreds of contested state-level and federal telecommunications regulatory proceedings, often preparing and/or sponsoring expert testimony, reports, and comments. He has developed expertise in virtually all areas of modern telecommunications regulation and policy, including service costs and pricing, network interconnection, implementation of competition policies, incentive regulation, and next-generation broadband, enterprise and wireless services.

Mr. Lundquist has worked extensively with computerized cost models for telecommunications networks and services, including most of the major cost models introduced in U.S. regulatory proceedings. He also has participated in dozens of state PUC cases to apply incentive regulation to incumbent local exchange carriers, and advised on the criteria for when reduced regulation is appropriate. He has gained in-depth knowledge of all aspects of incentive regulation, including measurement of carrier productivity gains and the specification of productivity offsets, monitoring of service quality, indexing and pricing rules, and impacts on investment and innovation. In addition, Mr. Lundquist has substantial experience with traditional ratemaking issues, including general rate cases, revenue requirement and rate design, cost allocation, and tariffing matters. Other areas in which Mr. Lundquist has significant professional experience include universal service, broadband and Internet access issues, intercarrier compensation, and next-generation enterprise services for medium/large commercial and government users (SD-WAN, SASE, ZTA).

Mr. Lundquist has served as an expert witness on these types of issues in over 35 proceedings before 20 state public utility commissions. He regularly works with a wide range of clients including competitive services providers, consumer advocates, and regulatory commission staff. Mr. Lundquist has served as QSI's lead consultant on telecommunications matters to the New Mexico Attorney General's Office (NMAGO) for over a decade. Mr. Lundquist also has played a central role in QSI's work on behalf of the U.S. General Services Administration since 2011, including extensive analysis of carriers' invoiced taxes and fees, and co-authoring a series of white papers on new telecommunications technologies and their impacts on federal government agencies. He has also advised regulatory agencies and foreign ministries on regulatory practices, and has developed and undertaken on-site training programs for regulatory staff in China and the Philippines.

QSI consulting, inc.

Scott C. Lundquist

Educational Background

Bachelor of Arts, Psychology and Social Relations
Harvard College – Cambridge, Massachusetts
1985

Professional Experience

QSI Consulting, Inc.
June 2007 – Present
Consultant

Independent Consultant
Jan. 2005 – May 2007

Economics and Technology, Inc.
Boston, Massachusetts
2002 – 2004
Vice President, Equity Partner, and
Board of Directors member

1996 – 2001
Vice President

1988 – 1996
Consultant / Senior Consultant

1986 – 1988
Analyst / Senior Analyst

Scott C. Lundquist

Selected Reports

The following are several illustrative QSI reports to which Mr. Lundquist contributed substantial research, analysis, and/or writing.

Bringing Zero Trust Architecture Solutions to EIS Customers: Market Research and Pricing Models, prepared by QSI for the U.S. General Services Administration, November 2022.

Network-as-a-Service (NaaS) Overview and Ordering Guide, prepared by QSI on behalf of the U.S. General Services Administration. January 2021.

QSI Evaluation of Frontier's Second Quarter Service Quality Metrics Report, prepared for the Minnesota Department of Commerce and filed in MNPUC Docket P405-P407/CI-18-122, October 2020.

SD-WAN Overview and Ordering Guide, for Enterprise Infrastructure Solutions (EIS), *version 2.0*, prepared by QSI for the U.S. General Services Administration, August 2020.

SD-WAN Implementation Guide, for Enterprise Infrastructure Solutions (EIS), prepared by QSI for the U.S. General Services Administration, October 2019.

Modernizing Communications Infrastructure in Federal Buildings: Strategies for Managing Technology Transition for Building Management and Life Safety Applications, prepared by QSI for the U.S. General Services Administration, November 2018.

Network Services 2025, Strategic Telecommunications Planning & Analysis: Industry Trends and Emerging Technologies and the Potential Impact on Federal Acquisitions, prepared by QSI for the U.S. General Services Administration, December 2017.

Audit Report: The Efficiency and Effectiveness of the Kansas Universal Service Fund, prepared by QSI for the Kansas Department of Revenue, October 2014.

The Ohio Telecom Modernization Act (S.B. 162): Examining the Impacts of Telecom Deregulation on Ohio's Economy and Residential Consumers, prepared by QSI for the Ohio Consumers' Counsel, June 2012.

Verizon Networx Universal – CDRL 106 for March 31, 2011: An Analysis of State and Local Taxes/Surcharges Applied to US Government Invoices, prepared by QSI on behalf of the U.S. General Services Administration, December 2011.

Scott C. Lundquist

QSI consulting, inc.

Expert Testimony – Profile

The information below is Mr. Lundquist's best effort to identify all proceedings wherein he has either sponsored pre-filed written testimony, an expert report or provided live testimony at hearing.

Before the Alabama Public Service Commission
Docket No. 27178
Re: Generic Proceeding: Costs and Rates of BellSouth's Operations Support System (OSS)
On behalf of National ALEC Association/Prepaid Communications Association

Direct Testimony	May 20, 2000
Cross-examination	June 13, 2000

Before the California Public Utilities Commission
Application 01-12-026
Re: Global NAPs, Inc. Petition for Arbitration of an Interconnection Agreement with Verizon California Inc. F/K/A GTE California, Inc. (U-6449-C) Pursuant to Section 252(b) of the Telecommunications Act of 1996
On behalf of Global NAPs, Inc.

Direct Testimony	December 20, 2001
Cross-examination	February 11, 2002

Before the California Public Utilities Commission
Application 01-11-045
In *Re: Petition by GNAPS, Inc. for Arbitration of an Interconnection Agreement with Pacific Bell Telephone Company Pursuant to Section 252(b) of the Telecommunications Act of 1996*
On behalf of Global NAPs, Inc.

Direct Testimony	November 30, 2001
Cross-examination	February 11, 2002

Before the California Public Utilities Commission
Docket No. 98-11-024
Re: Petition by Pacific Bell (U 1001 C) for Arbitration of an Interconnection Agreement with Pac-West Telecom, Inc. (U 5266 C) Pursuant to Section 252(b) of the Telecommunications Act of 1996
On behalf of Pac West Telecom, Inc.

Direct Testimony	February 8, 1999
Cross-examination	February 24, 1999

Before the California Public Utilities Commission
Docket No. A.96-08-41
Re: Petition of AT&T Communications of California, Inc. for Arbitration Pursuant to Section 252 of the Federal Telecommunications Act of 1996 to Establish an Interconnection Agreement with GTE California, Inc.
On behalf of AT&T of California, Inc.

Oral Testimony	October 3, 1996

Scott C. Lundquist

Before the Connecticut Public Utilities Commission
Docket No. 95-06-17
Re: Application of SNET for Approval to Offer Unbundled Loops, Ports, and the Associated Interconnection Arrangements and Application of SNET for Approval to Offer Wholesale Local Basic Service and Certain Related Features and to Implement a Universal Service Fund
On behalf of New England Cable Television Association
Direct Testimony September 8, 1995

Before the Delaware Public Service Commission
Docket No. 02-235
Re: Global NAPs, Inc. Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Verizon Delaware Inc. f/k/a Bell Atlantic-Delaware, Inc.
On behalf of Global NAPs, Inc.
Direct Testimony September 18, 2002
Rebuttal Testimony October 2, 2002
Cross-examination November 4, 2002

Before the District of Columbia Public Service Commission
Formal Case No. 1011
Re: In the Matter of Review by the Commission Into Verizon DC's Compliance with the Conditions of 47 U.S.C. §271(c)
On behalf of the Office of People's Counsel of the District of Columbia
Affidavit September 30, 2002
Cross-examination waived

Before the Federal Communications Commission, Washington, D.C.
CC Docket No. 01-318, CC Docket No. 98-56, et al
Re: Performance Measurements and Standards for Unbundled Network Elements and Interconnection; and
Performance Measurements and Reporting Requirements For Operations Support Systems, Interconnection, and Operator Services and Directory Assistance
On behalf of Focal Communications Corp., Pac-West Telecomm, Inc., and US LEC Corp.
Declaration January 21, 2002

Before the Hawaii Public Utilities Commission
Docket No. 7702
Re: Instituting a Proceeding on Communications, Including an Investigation of the Communications Infrastructure of the State of Hawaii
On behalf of AT&T Communications of Hawaii, Inc.
Rebuttal Testimony August 28, 1997
Cross-examination October 17, 1997

Scott C. Lundquist

Before the Illinois Commerce Commission
Docket No. 02-0253
Re: Global NAPs Illinois, Inc. Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Verizon North Inc. f/ka/ GTE North Incorporates and Verizon South Inc. f/k/a GTE South Incorporated
On behalf of Global NAPs, Inc.

Direct Testimony	May 16, 2002
Rebuttal Testimony	June 4, 2002
Cross-examination	June 11, 2002

Before the Illinois Commerce Commission
Docket No. 01-0786
Re: Petition of Global NAPs, Inc. for Arbitration Pursuant to Section 252(b) of The Telecommunications Act of 1996 to Establish an Interconnection Agreement with Illinois Bell Telephone Company d/b/a Ameritech Illinois
On behalf of Global NAPs, Inc.

Direct Testimony	December 28, 2001
Cross-examination waived	

Before the Maryland Public Service Commission
Case No. 9123
In the Matter of the Commission's Inquiry Into Verizon Maryland Inc.'s Provision of Local Exchange Telephone Service Over Fiber Optic Facilities
On behalf of the Maryland Office of People's Counsel

Direct Testimony	June 19, 2008
Rebuttal Testimony	July 17, 2008
Surrebuttal Testimony	August 12, 2008
Cross-examination	August 26, 2008

Before the Maryland Public Service Commission
Case No. 8879
Re: Investigation into Rates for Unbundled Network Elements Pursuant to the Telecommunications Act of 1996
On behalf of the Maryland Office of People's Counsel

Rebuttal Testimony	September 5, 2001
Surrebuttal Testimony	October 15, 2001
Cross-examination	December 7, 2001

Before the Massachusetts Department of Telecommunications and Energy
DTE 01-70
Re: Complaint of Fiber Technologies Networks, LLC Pursuant to G.L.c.166 § 45.00 et seq. Regarding access to poles owned or controlled by Shrewsbury's Electric Light Plant
On behalf of Fiber Technologies Networks, LLC

Direct Testimony	November 9, 2001
Cross-examination waived	

Scott C. Lundquist

QSI consulting, inc.

Before the Minnesota Public Utilities Commission, Office of Administrative Hearings
PUC Docket No. P-421/CI-01-1371
Re: In the Matter of a Commission Investigation into Qwest's Compliance with Section 271(c)(2)(B) of the Telecommunications Act of 1996: Checklist Items 1, 2, 4, 5, 6, 11, 13, and 14,
On behalf of the Minnesota Department of Commerce
Affidavit — June 10, 2002
Cross-examination — September 9, 2002

Before the Minnesota State Office of Administrative Hearings for the Minnesota Public Utilities Commission
PUC Docket No. P-421/CI-01-1370, OAH Docket No. X-2500-14485-2
Re: Commission Investigation into Qwest's Compliance with Section 271(c)(2)(B) of the Telecommunications Act of 1996: Checklist Items 3, 7, 8, 9, 10 and 12
On behalf of the Minnesota Department of Commerce
Affidavit — January 28, 2002
Cross-examination — March 6, 2002

Before the Nevada Public Utilities Commission
Docket No. 01-10018
Re: Petition of Global NAPs, Inc. for the Arbitration of an Interconnection Agreement with Central Telephone Company - Nevada, d/b/a Sprint of Nevada, Pursuant to Section 252 of the Telecommunications Act of 1996,
On behalf of Global NAPs, Inc.
Direct Testimony — December 4, 2001
Cross-examination waived

Before the Nevada Public Service Commission
Docket No. 96-9035
Re: A Petition by the Regulatory Operations Staff to Open an Investigation into the Procedures and Methodologies that Should Be Used to Develop Costs for Bundled or Unbundled Telephone Services or Service Elements in the State of Nevada
On behalf of AT&T Communications of Nevada
Direct Testimony — May 9, 1997
Rebuttal Testimony — May 23, 1997
Cross-examination — June 11, 1997

Before the New Jersey Board of Public Utilities
Docket No. TO00060356
Re: Review of Unbundled Network Elements Rates, Terms and Conditions of Bell Atlantic-New Jersey, Inc.
On behalf of the State of New Jersey, Division of the Ratepayer Advocate
Direct Testimony — October 12, 2000
Cross-examination — January 26, 2001

Scott C. Lundquist

Before the New Jersey Board of Public Utilities
Docket No. TO99120934
Re: Application of Bell Atlantic-New Jersey, Inc. for Approval of a Modified Plan for an Alternative Form of Regulation and to Reclassify All Rate Regulated Services as Competitive Services
On behalf of the State of New Jersey, Division of the Ratepayer Advocate
Direct Testimony September 8, 2000
Cross-examination waived

Before the North Carolina Utilities Commission
Docket No. P-1141 Sub1
Re: Global NAPs North Carolina, Inc. Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Verizon South, Inc. f/ka/ GTE South Incorporated
On behalf of Global NAPs, Inc., Direct Testimony April 19, 2002
Rebuttal filed May 24, 2002
Cross-examination July 23, 2002

Before the North Dakota Public Service Commission
Case No. PU-08-61 / PU-08-176
Re: Midcontinent Communications, a South Dakota partnership, Complainant v. Missouri Valley Communications, Inc., Respondent; and Missouri Valley Communications, Inc. Application for Suspension or Modification Pursuant to 47 U.S.C. § 251(F)(2)
On behalf of Midcontinent Communications
Direct Testimony July 2, 2008
Cross-examination July 9, 2008

Before the Ohio Public Utilities Commission
Case No. 02-876-TP-ARB
Re: In the Matter of Global NAPs, Inc. Petition for Arbitration Pursuant to 47 U.S.C. §252(b) of Interconnection Rates, Terms and Conditions with Verizon North Inc. f/k/a GTE North
Direct Testimony May 30, 2002
Cross-examination June 6, 2002

Before the Ohio Public Utilities Commission
Case No. 01-3096-TP-ARB / Case No. 01-2811-TP-ARB
Re: Global NAPs, Inc. Petition for Arbitration Pursuant to 47 U.S.C. § 252(b) of Interconnection Rates, Terms and Conditions with Ohio Bell Telephone Company d/b/a Ameritech Ohio; and *Global NAPs, Inc. Petition for Arbitration Pursuant to 47 U.S.C. § 252(b) of Interconnection Rates, Terms and Conditions with United Telephone Company of Ohio d/b/a Sprint*
On behalf of Global NAPs, Inc.
Direct Testimony February 12, 2002
Cross-examination February 19, 2002

Scott C. Lundquist

Before the Ohio Public Utilities Commission
Docket No. 96-922-TP-UNC
Re: Review of Ameritech Ohio's Economic Costs for Interconnection, Unbundled Network Elements, and Reciprocal Compensation for Transport and Termination of Local Telecommunications Traffic
On behalf of the Ohio Consumers' Counsel
Direct Testimony — January 17, 1997

Before the Rhode Island and Providence Plantations Public Utilities Commission
Docket No. 3437
Re: Global NAPs, Inc. Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish and Interconnection Agreement with Verizon New England, Inc. d/b/a Verizon Rhode Island, Inc. f/k/a New England Telephone & Telegraph Co. d/b/a Bell Atlantic - Rhode Island
On behalf of Global NAPs, Inc.
Direct Testimony — August 28, 2002
Rebuttal Testimony — September 6, 2002
Cross-examination — September 26, 2002

Texas Public Utilities Commission
Docket No. 18509
Re: Public Utility Commission, Application of Southwestern Bell Telephone Company for Rate Group Re-Classification Pursuant to Section 58.058 of the Texas Utility Code
On behalf of the Texas Office of Public Utility Counsel
Direct Testimony — August 18, 1998
Cross-examination — September 9, 1998

Before the Vermont Public Service Board
Docket No. 6742
Re: Global NAPs, Inc. Petition For Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Verizon New England, Inc. d/b/a Verizon Vermont, Inc. f/k/a New England Telephone & Telegraph Co. d/b/a Bell Atlantic – Vermont
On behalf of Global NAPs, Inc.
Direct Testimony — September 11, 2002
Rebuttal Testimony — October 7, 2002
Cross-examination — October 25, 2002

Before the Vermont Public Service Board
Docket No 6209
Re: Investigation Into The Acquisition and Use of Central Office Codes by Local Exchange Carriers in Vermont
On behalf of Global NAPs, Inc.
Affidavit — October 17, 2002

Scott C. Lundquist

Before the Washington Utilities and Transportation Commission
Docket No. UT-023003
Re: In the Matter of the Review of: Unbundled Loop and Switching Rates; the Deaveraged Zone Rate Structure; and Unbundled Network Elements, Transport, and Termination (Recurring Costs)
On behalf of AT&T Communications of the Pacific Northwest, Inc.

Responsive Testimony	April 20, 2004
Cross-examination	May 28, 2004

Before the Washington Utilities and Transportation Commission
Docket No. UT-950200
Re: In the Matter of the Request of US West Communications, Inc. for the Increase in its Rates and Charges
On behalf of Washington Utilities and Transportation Commission Staff

Direct Testimony	August 11, 1995
Cross-examination	January 15, 1996

Before the Washington Utilities and Transportation Commission
Docket No. UT-941464, et al
Re: WUTC, Complainant vs. US West, Respondent; TGC Seattle and Digital Direct of Seattle, Inc., Complaint vs. US West, Respondent; TCG Seattle, Complainant v. GTE Northwest, Inc., Respondent; GTE Northwest, Inc., Third Party Complainant v. US West, Third Party Respondent; Electric Lightwave, Inc., Complaint v. GTE Northwest, Inc., Respondent
On behalf of Staff of the Washington Utilities and Transportation Commission

Direct Testimony	April 17, 1995

Before the Washington Utilities and Transportation Commission
Docket Nos. U-89-2698-F, U-89-3245-P
Re: Washington Utilities and Transportation Commission, Complainant vs. US WEST Communications, Inc., Respondent; Application of US WEST Communications, Inc., for an Alternative Form of Regulation
On behalf of TRACER

Direct Testimony	June 23, 1993
Cross-examination	July 1, 1993

Before the Wisconsin Public Service Commission
Docket No. 5846-TR-102
Re: Application of CenturyTel of Central Wisconsin, LLC, as a Telecommunications Utility, for Authority to Establish Permanent Telephone Rates, Docket No. 2055-TR-102; *Application of Telephone USA of Wisconsin, LLC, as a Telecommunications Utility, for Authority to Establish Permanent Telephone Rates*
On behalf of AT&T Communications of Wisconsin, L.P.

Direct Testimony	May 31, 2002
Rebuttal Testimony	June 21, 2002
Cross-examination	June 26, 2002

Scott C. Lundquist

Before the Wisconsin Public Service Commission
Docket No. 2815-TR-103
Re: Application of CenturyTel of the Midwest-Kendall, Inc. for Rate Increase and Petition for Emergency Order for Rate Increase
On behalf of AT&T Communications of Wisconsin, L.P.

Direct Testimony	June 19, 2001
Rebuttal Testimony	July 3, 2001

Cross-examination waived

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESS: Scott C. Lundquist

STAFF EXHIBIT 2602

PGE Non-Confidential Responses to Data Requests

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 628
Dated April 24, 2023

Request:

For all capital projects other than transmission and distribution in excess of $3 million constructed by PGE that that are included in the UE 416 rate base:

Please provide all briefings to PGE management on the status of all capital projects in excess of $3 million that PGE proposes to be included in the UE 416 rate base that reflects capitalized plant not included in current rates.

Response:

OPUC Data Request Nos. 628-633 ask PGE to delineate capital projects by those “constructed by PGE” and those “constructed by other companies for PGE.” PGE objects to these data requests on the basis that they are unduly burdensome, vague and calls for speculation as the phrase “constructed by PGE” is undefined.

PGE often uses third-party contractors and vendors to perform work on capital projects. PGE does not track capital projects by the undefined categories of “constructed by PGE” and “constructed by other companies for PGE,” making it unduly burdensome for PGE to attempt to categorize capital projects that way.

Notwithstanding its objections, PGE responds as follows:

PGE provides the project justification forms (PJF) for all capital projects other than transmission and distribution in excess of $3 million included in the UE 416 rate base (excludes P22449-P22449 Colstrip Capital Proj PPL) here:

- PGE’s response to CUB Data Request No. 025 provides the PJF for P36167 - FY: Repower Faraday Units 1-5.
- Confidential Attachment 628-A provides the remaining PJFs.

PGE management (specifically, the Business Sponsor Group) receives a copy of the PJF for each in-flight project when the project manager submits a proposed budget revision.

Attachment 628-A contains protected information and is subject to General Protective Order No. 23-039.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 660
Dated April 25, 2023

Request:

Identify each PGE internal group that deals with cybersecurity issues, and provide the information requested below. This should include the Integrated Security Operations Center (ISOC), any sub-groups with ISOC, and also any additional groups or personnel within other areas of the Company who regularly address cybersecurity issues.

a. An organizational chart showing how each group fits into the PGE management and organizational structure;

b. The current staffing of each group, by job title, area of responsibility, and number of FTE employees in each job role.

c. Explain if PGE considers each group to be fully-staffed currently, and identify any positions that are currently unfilled; if unfilled positions exist, indicate how many weeks they have been unfilled.

d. The total annual budget for each group for calendar years 2021 through 2023, and what PGE forecasts for the 2024 test year; also provide those budget figures broken out between O&M expense and capital investments.

Response:

a. Attachment 660-A provides the requested information.

b. Attachment 660-B, tab “b” provides the requested information.

c. Not every group is currently fully staffed. Attachment 660-B, tab “c” provides further detail.

d. Attachment 660-B, tab “d” provides the requested information.

Excerpt from

Attachment B

to PGE Response to OPUC DR. No. 660

Cybersecurity Staffing and Budget

Full Dept	Title	# Headcount budgeted 2023
226 - OT Cybersecurity	Senior Cyber Security Control Systems Analyst	1
	IRM Cyber Security Analyst	1
	Senior Operational Compliance Analyst	1
	IRM Cyber Security Analyst	1
	P009147 Senior IRM Security Analyst (Unfilled)	1
	P009159 IRM Cyber Security Analyst/Senior IRM Cyber Security Analyst (Unfilled)	1
	P009479 IRM or Senior IRM Security Analyst (Unfilled)	1
	Staff Service Asset & Configuration Analyst	1
	IRM Cyber Security Analyst	1
	Senior Cyber Security Control Systems Analyst	1
	Senior Operational Compliance Analyst	1
	IRM Cyber Security Analyst	1
	Senior Operational Compliance Analyst	1
	IT Change Analyst	1
	Senior Service Asset & Configu	1
226 - OT Cybersecurity Total		15
608 - Enterprise Security	Office Administrator	1
	Senior IT Project Manager	**1**
	P013175 CISO, Cyber Security & IT Governance (Unfilled)	1
	IT Project Manager	1
	P009135 Manager Information Risk (Unfilled)	1
	Senior Director Security	1
608 - Enterprise Security Total		6
756 - IT Disaster Recovery Services	IRM Cyber Security Analyst	1
	Disaster Recovery Specialist	**1**
	Senior Cyber Security Operations Analyst	1
	Senior Cyber Security Operations Analyst	1
	Senior Disaster Recovery Specialist	1
	Business Systems Analyst	1
756 - IT Disaster Recovery Services Total		6
773 - Info Security Operations	Senior ISOC Operational Security Analyst	1
	P009277 ISOC Operational Security Analyst (Unfilled)	1
	IRM Cyber Security Analyst	**1**
	Staff Cyber Security Control Systems Analyst	1
	Staff ISOC Operational Security Analyst	1
	ISOC Operational Security Analyst	1
	ISOC Operational Security Analyst	1
	Staff ISOC Operational Security Analyst	1
773 - Info Security Operations Total		8
775 - Cybersecurity	Senior IT Project Manager	1
	Principal IT Project Manager	1
	Senior Service Asset & Configuration	1
	P009619 Enterprise Security Business Systems Analyst (Unfilled)	**1**
	Manager IT Resilience & Disaster Recovery	1
	Senior IT Project Manager	1
	Manager Project Management	1
	Manager Cyber Security Control	1
	Manager Integrated Security Operations	**1**
775 - Cybersecurity Total		9
786 - Integrated Security Program	Staff Application Developer	1
	Application Developer	1
	Senior Application Developer	1
	Senior Application Developer	1
	Application Developer	1
	Senior Cyber Security Control	1
	Senior Application Developer	1
	Disaster Recovery Specialist	1
	Senior IT Solutions Architect	1
786 - Integrated Security Program Total		**9**
Total Cybersecurity current Headcount		**53**

Full Dept	Title	# Headcount budgeted 2023	Date became vacant	Current Date	Weeks unfilled
226 - OT Cybersecurity	P009147 6167 - Senior IRM Security Analyst (Unfilled)	1	4/21/2020	5/1/2023	158
	P009159 IRM Cyber Security Analyst/Senior IRM Cyber Security Analyst (Unfilled)	1	8/14/2021	5/1/2023	89
	P009479 IRM or Senior IRM Security Analyst (Unfilled)	1	9/10/2022	5/1/2023	33
226 - OT Cybersecurity Total		**3**			
608 - Enterprise Security	P013175 CISO, Cyber Security & IT Governance (Unfilled)	1	12/2/2022	5/1/2023	21
	P009135 Manager Information Risk (Unfilled)	1	9/1/2022	5/1/2023	35
608 - Enterprise Security Total		**2**			
773 - Info Security Operations	P009277 ISOC Operational Security Analyst (Unfilled)	1	5/30/2022	5/1/2023	48
773 - Info Security Operations Total		**1**			
775 - Cybersecurity	P009619 Enterprise Security Business Systems Analyst (Unfilled)	1	9/10/2022	5/1/2023	33
775 - Cybersecurity Total		**1**			
		7			

PGE's Response to OPUC DR 660 Att B
p. 3 of 4, Tab d

Cybersecurity O&M	Dept plus Description	Year 2021 Budget	2021 Actual	Year 2022 Budget	2022 Actual	Year 2023 Budget	Year 2024 Budget
	226 - OT Cybersecurity	$1,297,589	$1,216,922	$1,406,416	$1,463,032	$3,259,397	$3,423,240
608: Enterprise Security	608 - Enterprise Security	$	$	$	$	$1,100,080	$1,469,976
	708 - Digital Programs	$2,643,015	$2,223,025	$2,301,167	$1,871,124	$1,425,038	$1,522,007
	756 - IT Disaster Recovery Services	$829,503	$933,051	$891,345	$1,349,563	$1,326,010	$1,410,058
	771 - Information Risk Management	$2,225,150	$1,888,249	$1,902,648	$1,466,429	$	$ -
	772 - Integrated Security Ops Ctr	$1,943,353	$1,910,456	$1,687,853	$1,407,915	$	$2,234,000
	773 - Info Security Operations	$3,051,869	$2,657,484	$2,347,000	$2,048,371	$2,346,469	$2,460,103
	775 - Cybersecurity	$4,018,356	$3,930,133	$2,426,631	$3,335,588	$4,457,309	$4,659,801
	786 - Integrated Security Program	$3,778,313	$2,384,443	$3,996,272	$2,483,400	$2,246,967	$2,340,617
Cybersecurity O&M Total		**$19,787,150**	**$17,143,763**	**$16,959,332**	**$15,425,424**	**$16,161,270**	**$19,285,802**

Cybersecurity Capital	Dept plus Description	Year 2021 Budget	2021 Actual	2022 Budget	2022 Actual	2023 Budget
	226 - OT Cybersecurity	$-	$ 98,998	$ 5,394,815	$ 5,754,672	$ 529,352
	737 - IT Governance	$-	$ 127,804	$-	$ 1,066,892	$ 507,273
	756 - IT Disaster Recovery Services	$-	$ (2,202)	$-	$ 1,029	
	771 - Information Risk Management	$-	$ 2,418			
	772 - Integrated Security Ops Ctr	$-	$ 74,866	$-	$ 43,432	
	773 - Info Security Operations	$-	$ 9,092	$-	$ 61	$ 7,757
	775 - Cybersecurity	$-	$ 144,280	$-	$ 512,254	
	786 - Integrated Security Program	$-	$ 13,284	$ 29,232	$ 233,517	$ 63,718
Cybersecurity Capital Total		**$-**	**$ 468,540**	**$ 5,424,047**	**$ 7,611,857**	**$ 1,108,100**

Dept plus Description	
226 - OT Cybersecurity	
608 - Enterprise Security	
708 - Digital Programs	
756 - IT Disaster Recovery Services	
771 - Information Risk Management	
772 - Integrated Security Ops Ctr	This $2.2 million was inadvertently budgeted to dept. 772 (which closed in 2023 due to a re-org) and should have been budgeted to dept. 773.
773 - Info Security Operations	
775 - Cybersecurity	
786 - Integrated Security Program	

Dept plus Description
226 - OT Cybersecurity
737 - IT Governance
756 - IT Disaster Recovery Services
771 - Information Risk Management
772 - Integrated Security Ops Ctr
773 - Info Security Operations
775 - Cybersecurity
786 - Integrated Security Program

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 661
Dated April 25, 2023

Request:

Please provide PGE's latest cybersecurity planning and strategy document(s) that describe the Company's approach to identify, protect, detect, respond, and recover from cybersecurity breaches and disruptions of its systems.[1]

Response:

Confidential Attachment 661-A provides the requested information.

Attachment 661-A contains protected information and is subject to General Protective Order No. 23-039.

[1] Ref: NIST Cybersecurity Framework (version 1.1), at: https://www.nist.gov/cyberframework

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 662
Dated April 25, 2023

Request:

Has PGE been implementing Zero Trust Architecture ("ZTA") as part of its cybersecurity strategy? To the extent not addressed in the document(s) provided in response to DR 661 above, explain in detail, PGE's implementation plan for ZTA, including:

a. The Company's planned steps towards ZTA;
b. Its timeline for those steps;
c. Its budget projections for ZTA-implementing projects; and
d. Any impediments PGE believes exist for implementing ZTA throughout its IT infrastructure.
e. If PGE has no plans to implement ZTA, please explain in detail why not.

Response:

Yes, PGE has been incorporating ZTA into our cybersecurity strategy to enhance security for all network access, including internal and remote access, for all devices connecting to the PGE network. Our current rate case proceeding includes a $652,000 capital ask related to ZTA (P37477 – Zero Trust). This project specifically focuses on deploying zero-trust network access (ZTNA) network architecture. PGE is also planning further investments in ZTA to integrate principles of identity and access governance, device health, network protection, and application and data protection. However, the scope, budget, or timelines for these additional components of ZTA beyond the ZTNA project have not been fully developed.

a. <u>ZTNA:</u> Project Zero Trust consists of several main workstreams necessary to initiate PGE's journey towards a zero-trust network:
    a. Upgrade existing Palo Alto Firewalls to version 10.1 or higher and deploy within PGE's private and public cloud networks.
    b. Deploy Global Protect for remote access users and internal communications.
    c. Configure Firewalls to segregate endpoint traffic from datacenter assets.
    d. Additional application specific micro-segmentation within PGE's datacenters and cloud environments.

ZTA: PGE is planning further investments in ZTA to integrate principles of identity and access governance, device health, network protection, and application and data protection. PGE also plans to invest in logging, detection, and response capabilities, enabling automation of functions currently performed through manual log correlation. While the scope of the projects and timelines for this effort have not yet been fully defined, PGE intends to include enhancements to identity verification, certificate and secrets management, rationalization of identity stores, network inspection, data classification and protection, and anomaly detection and response.

b. ZTNA: Expected in-service date is November 2023.

   ZTA: No specific timeline(s) have been defined.

c. ZTNA: As stated earlier, our current rate case proceeding capital ask includes $652,000 for the Zero Trust project.

d. ZTNA: Potential network outages for PGE users, including customers, during planned maintenance windows might occur. These will be managed through the PGE change control process. Additionally, there may be a learning curve for PGE users to utilize the new Global Connect client and extra firewall rules review/remediation to ensure necessary access for all PGE devices.

   ZTA: Challenges for PGE in implementing ZTA include required architectural changes to PGE's cloud PaaS and IaaS deployments, a proliferation of identity stores related to cloud deployments, and competing IT-related priorities that impact the availability of implementation resources. PGE has not defined a timeline for extending ZTA into operational technology (OT) networks and we are currently assessing the network architecture to determine the scope and challenges of an OT implementation.

e. Not applicable, as PGE is implementing ZTA.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 663
Dated April 25, 2023

Request:

Please provide PGE's complete responses to Staff's Data Requests 449 through 453 in its prior general rate case UE 394, including any confidential attachments.

Response:

Attachment 663-A provides PGE's responses to OPUC Data Request Nos. 449 through 453 from Docket No. 394.

Confidential Attachment 663-B provides Confidential Attachment 453-A from Docket No. 394.

Attachment 663-B contains protected information and is subject to General Protective Order No. 23-039.

Excerpt from

Attachment A

to PGE Response to OPUC DR. No. 663

PGE Responses to Staff's Data Requests 450 and 451 in UE 394

August 30, 2021

To: Brian Fjeldheim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 450
Dated August 24, 2021

Request:

Has PGE ever had a cybersecurity audit performed by a federal or state agency? If yes, please provide a summary of the most recent cybersecurity audit findings.

Response:

PGE has not been subject to a federal or state agency cybersecurity audit and neither is it subject to a periodic federal or state agency cybersecurity audit. PGE, however, has had audits of our compliance with North American Electric Reliability Corporation (NERC) Reliability Standards, including the Critical Infrastructure Protection (CIP) standards. Those Reliability Standards are made mandatory by the Federal Energy Regulatory Commission. Western Electricity Coordinating Council (WECC) conducts triennial audits of PGE's compliance with a subset of the NERC standards. PGE's most recent WECC audit was held in June of 2020. That audit evaluated PGE for compliance with 14 CIP requirements for the period of April 12, 2017, to March 16, 2020. The audit found one instance of potential non-compliance. The audit alleged that PGE had a potential non-compliance with CIP-010-2 Requirement 4 because PGE failed to include Sections 2.3 and 3.2.2 security objectives in its documented plan for Transient Cyber Assets and Removable Media used with its high impact BES Cyber Systems. WECC has yet to take any further action regarding this alleged violation.

August 30, 2021

To: Brian Fjeldheim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 451
Dated August 16, 2021

Request:

On an annual basis, for each of the past five years, how much money did PGE spend on cybersecurity? Please indicate whether these expenditures were recorded as expenses or capital additions/rate base.

Response:

Expenses in the table below identify cybersecurity O&M expenses. Please see PGE's response to Data Request No. 461 for capital investment in cybersecurity.

2018	2019	2020	2021	2022
$ 10,514	$ 19,115	$ 15,333	$ 18,924	$ 19,606

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 664
Dated April 25, 2023

Request:

For years 2021, 2022, and 2023 to date, identify each cybersecurity breach or other incident that resulted in a disruption to a PGE internal IT system, its billing system(s), or any Critical Infrastructure Systems. In your response, provide the following information:

a. The starting date of the incident and its total duration (hours/minutes);
b. The type of incident (e.g., a systems breach, a DDoS attack, data theft/loss, ransomware attack).
c. Identify the specific PGE systems that were impacted by the incident.
d. Provide all reports produced by PGE or any of its third party cybersecurity services vendors concerning the incident.

Response:

For the years 2021, 2022, and 2023 to date, PGE has not experienced a cybersecurity breach or other incident that resulted in a disruption to a PGE internal IT system, its billing system(s), or any Critical Infrastructure Systems.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 665
Dated April 25, 2023

Request:

For years 2021, 2022, and 2023 to date, provide the incremental expenditures incurred by PGE as a result of the cybersecurity breaches and incidents identified in response to DR 664. Also provide any forecast of such incremental expenditures that PGE has developed for the test year 2024.

Response:

For the years 2021, 2022, and 2023 to date, PGE has not incurred any incremental expenditures as a result of cybersecurity breaches and incidents identified in response to OPUC Data Request No. 664. Consequently, PGE has not included any such incremental expenditures in the 2024 test year.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 668
Dated April 25, 2023

Request:

Ref: PGE Exhibit 610 ("PGE is also completing a significant buildout of cybersecurity capabilities in the Operational Technology space"), provide and explain PGE's latest plans for this initiative. Your response should include further discussion of, but not be limited to, PGE's projects involving the following systems cited in Exhibit 610: Nozomi Networks' Guardian system and Verve Industrial's Security Center. In addition:

a. Specify the costs of all programs within the scope of this buildout that are included in test year 2024, broken out by capital investments vs. expenses.
b. Ref: PGE Exhibit 610, specify the costs of the Company's initiative to improve the SIEM capabilities of its existing LogRhythm or potential successor technology that are included in test year 2024, broken out by capital investments vs. expenses.

Response:

PGE is focusing on enhancing cybersecurity capabilities in the Operational Technology (OT) space throughout 2023 and 2024. This includes deploying Nozomi Networks' Guardian technology to networks at PGE's generating facilities and ingress/egress points between the control center and other operational systems. The Guardian technology is a passive detection system that allows PGE's security operations staff to detect anomalous communications and misconfigurations early on. Verve Industrial's Security Center is an active polling technology specifically designed for operational technologies and is being deployed to communicate with all primary operational technology systems at PGE. This system provides notifications of vulnerabilities, configurations, accounts, and other security-relevant information, which is then used to establish and monitor a secure baseline.

a. No capital costs are included in the 2024 test year. The following expenses associated with the buildout of cybersecurity capabilities in the OT space are included in the 2024 test year:
    a. $0.5 million for support and maintenance of the Verve Security Center.
    b. $0.2 million for applying security patches and software updates to servers and workstations that operate PGE's generation plants.

b. No capital costs are included in the 2024 test year. The following expenses associated with PGE's initiative to improve the SIEM capabilities are included in the 2024 test year:
    a. $100,000 for co-pilot services, such as collaborating with vendors to optimize tools for increased alarming and response capabilities.
    b. $50,000 for a cloud-based artificial intelligence subscription, which enables alarms to determine if a suspicious or malicious event is occurring based on the normalization of PGE's environment.
    c. $50,000 to enhance alarms and rules for incident response
    d. $25,000 to parse logs from the OT environment and new technologies

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 670
Dated April 25, 2023

Request:

Ref: PGE Exhibit 610, provide Mandiant's "current service level agreement" cited therein, and any replacement "enhanced pre-paid contract" that PGE has executed with Mandiant (as "expected in early 2023"). In addition:

a. Specify the costs of Mandiant's services (pursuant to either agreement) that are included in test year 2024 expenses.

Response:

Confidential Attachment 670-A provides Mandiant's enhanced pre-paid contract which is the current service level agreement.

PGE has included approximately $115,000 in 2024 test year expenses associated with the costs of Mandiant's services.

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESS: Scott C. Lundquist

STAFF EXHIBIT 2603

PGE Confidential Responses to Data Requests

CONFIDENTIAL

Subject to General Protective Order No. 23-039

Excerpt from

Attachment A

to PGE Response to OPUC DR. No. 628

Pages from Project Justification Form for P37336
P37336 - Operational Technology Visibility_Redacted

CONFIDENTIAL

Subject to General Protective Order No. 23-039

Attachment A

to PGE Response to OPUC DR. No. 661

PGE Cybersecurity Planning and Strategy Documents

CONFIDENTIAL

Subject to General Protective Order No. 23-039

CASE: UE 416
WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2700

OPENING TESTIMONY

Plant Balances (Other than Transmission and Distribution, Faraday Repowering Project, and Non-Cyber Security IT)

Major Maintenance Accrual (MMA)

Fuel Stock and CO_2 Allowances

June 13, 2023

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

A. My name is August Ankum, Ph.D. I am the Chief Economist and a founding partner of QSI Consulting, Inc., a consulting firm engaged in this proceeding by the Public Utility Commission of Oregon (OPUC). My business address is 626 Avenue B, Trevose/Feasterville, Pennsylvania 19053.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2701.

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

A. My name is Warren R. Fischer, C.P.A., C.G.M.A. I am a Certified Public Accountant, and I serve as the Chief Financial Officer of, and partner in, QSI Consulting, Inc., a consulting firm engaged in this proceeding by OPUC. My business address is 2500 Cherry Creek South Drive, Suite 319, Denver, Colorado, 80209-3279.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2702.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is as follows:

1. Evaluate PGE's actual and forecasted additions to plant-in-service since its last Commission-approved rate base was established in Docket No. UE 394 (UE 394) Order No. 22-129 excluding the Transmission and Distribution Federal Energy Regulatory Commission (FERC) plant

categories, the Faraday Repowering Project, and all non-cyber security related Information Technology (IT) investment,[1]

2. Major maintenance accruals ("MMAs"),
3. Fuel stock, and
4. CO_2 allowances.[2]

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared the following supporting exhibits:

Exhibit Staff/2703. .... PGE Workbook (UE 416 4-21-23 Exhibit Support_2024_Errata)
Exhibit Staff/2704. ......PGE Non-Confidential Responses to Data Requests
Exhibit Staff/2705. .... PGE Confidential Responses to Data Requests
Exhibit Staff/2706.... PGE Highly Confidential Responses to Data Requests
Exhibit Staff/2707. .... Summary of PGE's Plant Additions
Exhibit Staff/2708. ....List of Project Justification Forms Examined
Exhibit Staff/2709. .... Confidential Project Justification Form Evaluation Tables
Exhibit Staff/2710. .... Summary of Project Justification Form Results
Exhibit Staff/2711. .. Testing of Sample Confidential Monthly Project Status and Other PGE Program Reports
Exhibit Staff/2712. .... Summary of Restated MMA Adjustment
Exhibit Staff/2713. ... Restated GRC MMA Workpaper (Highly Confidential)

Q. How is your testimony organized?

A. Our testimony is organized as follows:

[1] Staff witness Robert Edmond Young addresses Transmission, Distribution, and IT capital additions in Staff/2100. Staff witness Rose Pileggi addresses the Faraday Repowering Project in Staff/1800.

[2] Mr. Fischer discusses plant capital additions and balances. Dr. Ankum discusses the issues of MMAs, fuel stock and CO_2 allowances. CO_2 allowances are discussed only to the extent that they are included in PGE's Fuel Stock. Dr. Ishraq Ahmed discusses Cap-and-Trade / Invest programs and associated CO_2 allowances.

Q. Please summarize your recommendations.

A. For the issues discussed herein, we make the following recommendations:

<u>Issue 1—Plant Additions Other than Transmission, Distribution, Faraday Repowering Project, and Non-Cyber Security IT:</u>

1. PGE needs to identify all proposed capital additions from the plant balances approved in UE 394 as of April 30, 2022 through the forecast period ending December 31, 2023, of the current GRC. Currently, it has identified additions from its actual FERC balances as of April 30, 2022, which are different than its UE 394 plant balances.
2. PGE needs to provide officer attestations for projects greater than $3 million expected to close by December 31, 2023, or where the closing date is unclear in its PJFs.
3. PGE should explain whether the projects having potential cost overruns in our PJF review are due to events beyond PGE's control or whether they are due to a lack of adequate oversight.
4. PGE should identify all capital projects where cost reimbursement is pending from insurance or warranty claims.

<u>Issue 2—Major Maintenance Accruals (MMA):</u>

1. We recommend a reduction in MMAs of approximately $1 million. This adjustment is driven by corrections of several inaccuracies in PGE's projections of major maintenance costs and balances.

2. We also recommend a corresponding reduction of the test year MMA balances of approximately $95 thousand (an increase in rate base by the equivalent amount).

Issue 3—Fuel Stock:

1. We found a large number of methodological errors in PGE's fuel stock calculations. They caused us to adjust both the quantities of PGE's gas and oil stock (in terms of dth and barrels) as well as the prices PGE used for valuations.
2. For all the reasons discussed herein, we recommend reducing fuel stock in the rate base by approximately $17.4 million.

Issue 4—CO2 Allowances:

1. PGE's filing did not include CO2 allowances, but PGE indicated in discovery that it inadvertently omitted including $3 million CO2 allowances in its fuel stock. The Company noted that it will update its filing to correct this omission. As the Company prepares its rebuttal testimony, we urge the Company to provide more substantial support for its *stock* of CO2 allowances. Like Staff did in UE 394, we look for a clear demonstration that CO2 allowances are in fact *used and useful* before they are included in the rate base, as PGE proposes.
2. For now, in the absence of substantive support for its stock of CO2 allowances and given that the Company does not necessarily need to hold a substantial stock at this point, we provisionally recommend that PGE's $3 million in CO2 allowances be disallowed.

ISSUE 1. PLANT ADDITIONS OTHER THAN TRANSMISSION, DISTRIBUTION, FARADAY REPOWERING PROJECT, AND NON-CYBER SECURITY IT

Q. What tasks did you perform to test the propriety of PGE's plant additions?

A. We performed the following.

1. Compared the plant balances from UE 394 rate case Order No. 22-129 with the 2023 forecasted plant balances in the current case.
2. Attempted to identify all plant additions by plant category made since the rate effective date of the UE 394 rate case order or plant additions not previously included in rates except for:
    a. Transmission and Distribution plant,
    b. the Faraday Repowering Project, and
    c. all non-cyber security related IT plant.
3. Reviewed documents for plant additions in the assigned scope of work and developed narrative summaries of projects in excess of $3 million.
    a. Reviewed project budgets by year.
    b. Identified completed projects at the time of PGE's filing and those PGE asserts will be placed in service before the rate effective date of January 1, 2024.
    c. Flagged projects not yet in service that require PGE officer attestation.

Q. Were you able to perform each of the assigned tasks with the information filed by PGE with its General Rate Case (GRC) application including its responses to the OPUC's Standard Data Requests (SDR)?

A. No. All of the information we relied upon to evaluate the propriety of PGE's proposed additions to its Plant in Service was produced through multiple rounds of data requests propounded by Staff and other intervenors in the case.

Q. Please provide a summary of the documents you reviewed to perform the tasks you listed above.

A. We reviewed the following documents in the current case and in PGE's most recent GRC, UE 394. We reference specific documents relied upon by footnote throughout our testimony.

1. The direct testimony and supporting exhibits on revenue requirement, rate base, capital projects for transmission, distribution, and production projects in this case.[3]
2. PGE's direct and reply testimony on revenue requirement, rate base and capital budgeting for transmission, distribution, and production projects in UE 394 and Staff's opening testimony on PGE's transmission and distribution projects.[4]
3. Data request responses in the current case and in UE 394.
4. Commission Order No. 22-129 in UE 394.

Q. How is this section of your testimony organized?

A. We address each of the three primary tasks listed above in subsections (A), (B), and (C).

<u>Issue 1(A) Plant in Service Comparison from UE 394 to 2023 Forecasted Plant in Service at December 31, 2023</u>

Q. Were you able to reconcile PGE's plant balances from UE 394 to PGE's forecasted 2023 plant balances at December 31, 2023 in this case?

A. No.

[3] See PGE/200, Batzler-Ferchland, PGE/700, Bekkedahl-Jenkins, and PGE 800, Jenkins - Bekkedahl.

[4] See UE 394 PGE/200, Tooman-Batzler, UE 394 PGE/800, Jenkins-Bekkedahl, UE 394 PGE/1800 Bekkedahl–Ewers, UE 394 Staff/700, Hanhan, and UE 394 Staff/800, Sayen.

Q. Why is this an important task to perform?

A. It is necessary to ascertain the universe of PGE's capital additions placed in service or that are still under construction but expected to be in service from the rate effective date of PGE's last GRC in UE 394 to the end of its rate base forecast period in UE 416—December 31, 2023.

Q. Why were you unable to perform this reconciliation with the information filed by PGE in its application?

A. No. We were unable to perform the reconciliation for two reasons. First, PGE's calculation of the rate base comparison between (1) its asserted Commission-approved amounts from UE 394 Order No. 22-129 and (2) its current Test Year amounts do not agree with those in the stipulated schedules in the order. For example, PGE's Ex. 208 in this case contains the following values for Plant in Service and Net Utility Plant.

Table 1.
PGE's Schedule of UE 394 Plant in Service and Net Utility Plant[5]

Line No.	Line	UE 394 Approved Order No. 22-129	Test Year at GRC Rates	2024 Variance to Approved
1	Plant in Service	10,951,085	12,249,545	1,298,460
2	Less: Accumulated Depreciation/Amortization	(4,887,187)	(5,441,309)	(554,122)
3	Accumulated Deferred Taxes	(690,748)	(667,288)	23,460
4	Accumulated Deferred ITC			
5				
6	**Net Utility Plant**	5,373,150	6,140,947	767,798

5 Staff/2703, *UE 416 4-21-23 Exhibit Support_2024_Errata.xlsx*, tab Ex 208 Rate Base Delta.

Conversely, Ex. 302 from Appendix C to UE 394 Order No. 22-129 reflects the following amounts.

Table 2. UE 394 Order No. 22-129 Gross Plant and Net Utility Plant ($000s)[6]

	Base Business 2022	Blank	Total Results
	(1)	(2)	(3)
25 Avg. Gross Plant	11,465,733		11,465,733
26 Avg. Accum. Deprec. / Amort	(5,279,126)		(5,279,126)
27 Avg. Accum. Def Tax	(696,026)		(696,026)
28 Avg. Accum. Def ITC	-		-
29 **Net Utility Plant**	5,490,581	-	5,490,581
30 Misc. Deferred Debits	6,294		6,294
31 Operating Materials & Fuel	67,724		67,724
32 Misc. Deferred Credits	(73,887)		(73,887)
33 Working Cash	68,379	-	68,379
34 **Rate Base**	5,559,092	-	5,559,092
35 **Rate of Return**	6.813%		6.813%
36 **Implied Return on Equity**	9.500%		9.500%

PGE provided the following reasons for the difference between the two schedules in Tables 1 and 2 in its response to Staff DR No. 814.[7]

Response:

There are two differences that account for the delta between Order No. 22-129, Appendix C, Stipulating Parties/302/2 (Appendix C) and PGE Exhibit 200 work paper Exhibit Support_2024_Errata.xlsx, Ex 208 Rate Base Delta, Column C.

1. Colstrip is included in Appendix C but not in Ex 208. The amounts attributed to Colstrip can be found in PGE's response to OPUC Data Request No. 813, Attachment 813-A.
2. Appendix C reflects settled amounts prior to PGE's final November 15, 2021 net variable power cost (NVPC) update for 2022. This update reduced PGE's 2022 NVPC by approximately $375,000, which had a corresponding impact to PGE's working cash amount included in rate base. The final NVPC amount and corresponding changes to PGE's revenue sensitive amounts, including working cash, can be found in PGE's response to OPUC Data Request No. 813, Attachment 813-A.

[6] *See In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 394, Order No. 22-129, Appendix C, p. 14 (April 25, 2022).

[7] Staff/2704.

The following excerpt from PGE's response to Staff DR No. 813, Attachment A, confirms PGE's qualitative description of the reconciliation difference with the amounts in question tying to Tables 1 and 2.

Table 3. PGE Reconciliation of UE 394 Rate Base Pre-Colstrip Exclusion to Post-Colstrip Exclusion

Line No.	Line	Total Results	Colstrip	Total Net of Colstrip
33	**Average Rate Base**			
34	Avg. Gross Plant	11,465,733	514,648	10,951,085
35	Avg. Accum. Deprec. / Amort	(5,279,126)	(391,939)	(4,887,187)
36	Avg. Accum. Def Tax	(696,026)	(5,278)	(690,748)
37	Avg. Accum. Def ITC	-	-	-
38	**Avg. Net Utility Plant**	5,490,581	117,432	5,373,150

Q. What is the second reason that you could not reconcile PGE's plant balances from UE 394 to PGE's forecasted 2023 plant balances as of December 31, 2023, in this case?

A. The UE 394 Plant in Service amount in PGE/208 filed with PGE's application in this rate case was not disaggregated into the FERC plant categories necessary to compare the forecasted 2023 additions and ending plant balances in UE 416 to their functional equivalents in the UE 394 case.

Q. What could PGE have produced with its application that would have provided the information necessary to perform this reconciliation?

A. PGE could have produced schedules that started with its UE 394 plant balances as of May 1, 2022 and then detailed all additions, retirements, and adjustments through December 31, 2023 similar to schedules it produced in its response to AWEC DR No. 39. The excerpts below reflect PGE's reconciliations from actual Plant in Service as of December 31, 2022, instead of May 1, 2022, to forecasted Plant in Service as of December 31, 2023 at both an aggregated and disaggregated level.

Table 4. PGE's 2024 GRC – Net Plant Reconciliation – Exc. Colstrip Steam & RFP Projects[8]

		[1] Adjustments to FERC Basis Net Plant			Jan 2023 - Dec 2023 [2]					
	FERC Basis GL Balance 12/31/22	Remove Leases in Accounts 1011%	ARO Adjustment to Rate Base	Adjusted 12/31/22 Balance	Forecasted Additions	Forecasted Depreciation & Amortization Expense (Annualized less Vintage Rolloff)	Provision Activity related to Vehicles (not in D&A Exp) Annualized less Vintage Rolloff)	Forecasted Retirements	ARO Adjustment to Rate Base	12/31/2023 Forecasted Ending Balance
Gross Plant	$ 11,831,007,710	$ (350,587,756)	$ (27,383,533)	$ 11,453,036,421	$ 916,742,327	$ -	$ -	$ (116,658,204)	$ -	$ 12,253,120,544
Accumulated Reserve	$ (5,072,111,941)	$ -	$ (64,418,370)	$ (5,136,530,312)	$ -	$ (421,605,283)	$ (8,968,083)	$ 116,658,204	$ 7,320,360	$ (5,443,125,113)
Net Plant	**$ 6,758,895,769**	**$ (350,587,756)**	**$ (91,801,904)**	**$ 6,316,506,109**	**$ 916,742,327**	**$ (421,605,283)**	**$ (8,968,083)**	**$ -**	**$ 7,320,360**	**$ 6,809,995,431**

Table 5. PGE's 2024 GRC - Plant/Reserve Unbundling - Forecasted Ending Balances[9]

Gross Plant

Functional Class	Actuals 12/31/2022		Remove Leases in Accounts 1011%	ARO Adjustment to Rate Base	Adjusted 12/31/22 Balance	Forecasted Additions	Forecasted Retirements	12/31/2023 Forecasted Ending Balance
Hydro	*727,945,276*	[redacted]	*(167,294,823)*		[redacted]	*217,613,039*	*(1,134,021)*	[redacted]
Other Production	*3,398,647,060*	[redacted]	*(179,524,545)*		[redacted]	*66,278,555*	*-*	[redacted]
Steam Production [1]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
Generation	[redacted]	4,126,592,336	(346,819,368)	(27,383,533)	3,752,389,435	283,891,594	(1,134,021)	4,035,147,007
Distribution	[redacted]	4,812,640,139	-	-	4,812,640,139	374,930,777	(35,114,675)	5,152,456,241
General Plant	[redacted]	945 499 575	(3 768 388)	-	941 731 187	91 031 589	(75 266 486)	957 496 290
Intangible - Software	[redacted]	632 346 660	-	-	632 346 660	137 445 160	-	769 791 819
Intangible - Other	[redacted]	197 901 158	-	-	197 901 158	824 011	-	198 725 169
Transmission	[redacted]	1,116,027,843	-	-	1,116,027,843	28,619,196	(5,143,022)	1,139,504,017
Ending Balance		**11,831,007,710**	**(350,587,756)**	**(27,383,533)**	**11,453,036,421**	**916,742,327**	**(116,658,204)**	**12,253,120,544**
				From Net Plant Recon Tab	**11,453,036,421**			**12,253,120,544**
				Check	-			-

Q. Does PGE acknowledge that May 1, 2022, is the relevant start date to evaluate its proposed capital additions to rate base?

A. Yes. Messrs. Bekkedahl and Jenkins reference May 1, 2022, as the relevant start date for the new capital projects PGE includes in its proposed rate base in UE 416.

[8] Staff/2703, PGE Response to AWEC DR No. 039, *UE 416_AWEC DR 039_Attach A.xlsx*, tab Net Plant Recon Detailed.

[9] Staff/2703, PGE Response to AWEC DR No. 039, *UE 416_AWEC DR 039_Attach A.xlsx*, tab Unbundling Source Data.

Issue 1(B) Examination of Plant Additions by Plant Category Made Since the UE 394 Rate Case Order and plant additions not previously included in rates.

Q. Are the forecasted plant additions in Tables 3 and 4 the total plant additions at issue in this case?

A. No. The $916.7 million excludes capital additions from May 1, 2022, through December 31, 2022.

Q. What are the total plant additions PGE seeks Commission approval for?

A. According to the numbers presented in this GRC, new plant additions total $1.298 billion. This amount is the difference between UE 394 approved Plant in Service (excluding Colstrip plant balances in Table 3) and its UE 416 Test Year Plant in Service in Table 1 above. However, combining PGE's forecasted plant additions from December 31, 2022, through December 31, 2023, with actual plant additions from April 30, 2022, through December 31, 2022, that PGE identified in its response to Staff DR No. 817 results in a total of $1.416 billion or $118 million more than in PGE's Test Year as shown in the excerpt below from PGE's response.

Table 6. PGE Plant Additions – 4/30/2022 through 12/31/2023[10]

Gross Plant

		May 2022-December 2022 Activity (additions only) [1]				
		(1)			(2)	(3 = 1 + 2)
Functional Class	**FERC Balance - Actuals 4/30/22**	**Additions**	**Additions (ARC)**	**Adjusted 12/31/22 Balance**	**Forecasted Additions**	**TOTAL ADDITIONS - 4/30/2022 THROUGH 12/31/2023**
Hydro	*723,090,966*	*11,606,657*	-	[redacted]	*217,613,039*	*229,219,696*
Other Production	*3,384,597,478*	*32,635,201*	*1,459,436*	[redacted]	*66,278,555*	*98,913,756*
Steam Production [1]	*536,785,321*	*9,553,296*	-	[redacted]		*9,553,296*
Generation	4,644,473,764	53,795,154	1,459,436	3,752,389,435	283,891,594	337,686,748
Distribution	4,563,260,983	259,444,915	-	4,812,640,139	374,930,777	634,375,692
General Plant	922,494,019	54,558,855	-	941,731,187	91,031,589	145,590,443
Intangible - Software	598,467,051	33,879,609	-	632,346,660	137,445,160	171,324,768
Intangible - Other	197,802,202	98,955	-	197,901,158	824,011	922,967
Transmission	1,021,774,422	95,644,178	-	1,116,027,843	28,619,196	124,263,374
Ending Balance	**11,948,272,441**	**497,421,665**	**1,459,436**	**11,453,036,421**	**916,742,327**	**1,414,163,992**

[1] **Columns containing retirements, accounting adjustments and the Colstrip exlusion were omitted for presentation purposes.**

Q. Has PGE explained the difference between the two capital addition totals?

A. No. PGE should address this difference in its rebuttal testimony.

Q Is there another difference PGE needs to explain in its rebuttal testimony?

A. Yes. PGE needs to reconcile the $483 million difference between its final approved gross plant balances as of April 30, 2022, per the UE 394 order shown in Table 2 above ($11.4657 billion) with its actual FERC balance ($11.9483 billion) as of April 30, 2022, noted in Table 6 above. Since the Colstrip plant balances are included in both amounts, it is not clear what the reasons for the difference are. This $483 million difference may represent another pool of capital additions that need to be evaluated since the end of the UE 394 GRC.

[10] Staff/2704, PGE response to Staff DR No. 817, Attachment A.

Q. Were you able to break out PGE's Test Year plant additions in more detail?

A. Yes. We first reviewed PGE's direct testimony in this case on capital projects, which is found in PGE/600 (IT projects), PGE/700 (Transmission & Distribution projects), and PGE/800 (Production projects). We then filled in gaps for projects not explicitly referenced in PGE's direct testimony from listings of capital projects provided in discovery. The table below from Staff/2707 is a summary breakout of PGE's proposed capital additions.

Table 7. Summary of PGE's UE 416 Gross Plant Additions[11]

SUMMARY OF PGE PLANT ADDITIONS IN UE 416
5/1/2022 - 12/31/2023

LINE #	CAPITAL ADDITION CATEGORIES	FULLY LOADED COSTS ($ MILLIONS)	REFERENCE
1	TRANSMISSION, DISTRIBUTION AND GRID MODERNIZATION	$ 754.8	PGE 700/4, Table 1
2	CORPORATE IT	$ 87.5	PGE 600/25, Table 5 and
3	OTHER IT NOT EXPLICTLY REFERENCED IN TESTIMONY	$ 28.5	
4	PRODUCTION		
5	BEAVER EMISSIONS REDUCTION PROGRAM	$ 56.9	PGE 800/3/LINE 9
6	BIGLOW PHASE I WIND ENHANCEMENT PROGRAM	$ 7.3	PGE 800/4/LINE 6
7	TUCANNON WIND ENHANCEMENT PROGRAM	$ 1.7	PGE 800/4/LINE 20
8	FARADAY REPOWERING PROJECT	$ 189.7	PGE 800/47/LINES 7-21
9	ALL OTHER CAPITAL ADDITIONS IN UE 416 RATE BASE > $3 MILLION	$ 161.1	STAFF DR NO. 807, ATTACHMENT A
10	ALL OTHER CAPITAL ADDITIONS IN UE 416 RATE BASE < $3 MILLION	$ 11.1	DIFFERENCE BETWEEN TOTAL ADDITIONS ON LINE 11 AND THE SUM OF LINES 1 - 9
11	TOTAL UE 416 CAPITAL ADDITIONS	$ 1,298.5	

11 Staff/2707.

Q. What portion of PGE's capital additions are you addressing in this testimony?

A. We address all capital additions greater than $3 million except transmission and distribution, the Faraday Repowering Project, and all non-cyber security related IT plant. This represents approximately $227 million,[12] or 17 percent, of the $1.299 billion in Table 7.

Issue 1(C) Project Document Review for Plant Additions

Q. What were your criteria in evaluating PGE's UE 416 plant additions?

A. We used five criteria in evaluating the individual projects that comprise PGE's UE 416 plant additions in our assigned scope of work.

1. How much, if any, of the project is or will be in service by December 31, 2023, before the proposed January 1, 2024 rate effective date in accordance with ORS 757.355(1)?
2. Are there cost overruns that Oregon ratepayers should not bear?
3. Are there costs for which PGE is getting reimbursed, i.e., by insurance or warranties?
4. Are there indications of any capital project failures within PGE's supporting documentation that ratepayers should not be liable for?
5. What amount, if any, of the proposed costs could be deferred to future years without jeopardizing plant safety or reliability?

Q. What actions did you take address these criteria?

A. We first reviewed PGE's direct testimony and workpapers supporting its UE 416 capital additions. We found that neither provided the level of detail necessary to evaluate the propriety of the individual projects that comprise total

---

[12] Sum of Lines 5-7 and 9 Table 7.

plant additions. We then proceeded to do the following to obtain the more granular information necessary to evaluate PGE's capital projects.

1. We requested lists of PGE's capital projects greater than $3 million in value that are included in the UE 416 rate base along with the expected in-service dates, the actual or estimated final cost, the FERC account category the plant was or will be assigned to, and copies of the Project Justification Forms (PJFs) supporting the project.[13]
2. We requested briefings issued to PGE management on the status of each project as well as resource loaded schedules.[14]
3. We reviewed PGE's capital budgeting process documentation and testimony filed in UE 394 and issued discovery in UE 416 to probe deeper into this process and to ascertain if any changes had occurred.[15]
4. We requested copies of all post-completion reports for the selected projects in our scope of work.[16]
5. We requested detailed line-item budgets,[17] PGE Project Manager reports for projects where actual costs exceeded the forecast by 10 percent or more,[18] and the Monthly Project Status Reports prepared by PGE Project Managers.[19]
6. We reviewed PGE's New Construction Budget Report for 2023 filed with the OPUC to compare project costs to PGE's UE 416 costs and propounded discovery seeking explanations for differences between the two data sets.[20]

Q. Did you receive all the documents you requested from PGE in discovery?

A. No. PGE was forthcoming with some of its responses to discovery requests for capital project lists, PJFs supporting those capital projects, and its capital

---

13 Staff/2704, PGE Responses to Staff DR Nos. 626, 627, 634, 635, 807, and 809.

14 Staff/2704, PGE Responses to Staff DR Nos. 628, 629, 630, and 808. Staff/2705, PGE Confidential Attachments to Staff DR Nos. 628 and 808.

15 UE 394 PGE/1800, Bekkedahl – Ewers; Staff/2704, PGE Response to Staff DR No. 706.

16 Staff/2704, PGE Response to Staff DR No. 706.

17 Staff/2704, PGE Response to Staff DR No. 788. Staff/2705, PGE Confidential Attachment 788 A.

18 Staff/2704, PGE Response to Staff DR No. 707.

19 Staff/2704, PGE Responses to Staff DR Nos. 789 and 790.

20 Staff/2704, PGE Response to Staff DR No. 791.

budgeting process. However, when we requested a comprehensive list of all capital projects in its UE 416 rate base, PGE only listed projects valued at $3 million or greater in plant categories other than transmission, distribution, and grid modernization as noted in its response to Staff DR No. 807 below.[21]

Request:

Referring to UE 394_OPUC DR 311_Attach A, provide a schedule of all UE 416 plant additions by project number from April 30, 2022 through December 31, 2023. Additions should be broken out in the same manner as UE 394_OPUC DR 311_Attach A such as Table 1 Grouping fields, By Function fields, and In Service Dates.

Response:

PGE objects to this request on the basis of ambiguity and lack of clarity given that PGE's response to OPUC Data Request No. 311 in UE 394 was specific only to transmission and distribution capital additions. Notwithstanding its objection, PGE responds as follows:

Attachment 807-A provides the following information for all transmission and distribution and grid modernization capital projects: Funding Project number, Funding Project Name, Capital Additions, Business Sponsor Group, and categorization as described in PGE Exhibit 700.

Attachment 807-A also provides the following information for all other capital projects greater than $3 million: Funding Project number, Funding Project Name, Capital Additions, and Business Sponsor Group.

PGE also failed to provide the requested Project Manager reports on all projects where actual costs exceeded forecasts by 10 percent or more and failed to provide all post completion reports.

Q. What are PJFs?

A. PJFs are the primary reporting tool used by PGE to manage its capital projects throughout the planning, funding, execution, and close-out stages. The

[21] Staff/2704, PGE response to Staff DR No. 807 and Attachment A.

following excerpt from PGE's reply testimony in UE 394 summarizes how PJFs are used by PGE.[22]

> **Q. Please summarize what a PJF is and what it provides.**
>
> A. The PJF is a form populated by Project Managers and maintained within PGE's project management software, PowerPlan. For each project, the PJF contains the business justification, scope, budget, schedule, project alternatives considered, and possible project risks. This is also where any revisions to the project are input for approval or rejection by the chain of approvers.
>
> The PJF contains a running list of all requested and approved changes to capital funds and a brief summary of why the change was requested. To be clear, when the revision shows an increase or decrease to an annual budget or the total project budget, this is the ***net sum*** of all changes requested during that revision. In some cases, there may be increases and decreases to certain items, but only the net change is shown in the revision summary. Typically, the justification text boxes will briefly describe the cause for both increases and decreases but may not describe every change if they are relatively small.
>
> The "Revision Summary" shows the approved budget changes, referred to by a revision number. Finally, the PJF summarizes the need for the project and the risks of not completing the project. Some projects, such as reliability-driven projects, will also have a whitepaper providing a more extensive justification of the project need and risks of not completing the

22 UE 394 PGE/1800, Bekkedahl – Ewers/25.

Q. What are the Project Manager reports you had difficulty getting from PGE?

A. PGE refers to these as Monthly Status Project Reports, and it describes them as follows in comparison to the PJFs.[23]

> f. While in the execution phase, on a monthly basis, the Project Manager reviews actual spend compared to budget; updates forecast of spend timing; reports and takes action on significant variances; and updates in-service dates. Confidential Attachment 706-A provides an example of a monthly report prepared by a Project Manager for a project in the Generation, Transmission and Distribution Project Management Office.
>
> Project Justification Forms, provided in PGE's responses to OPUC Data Request Nos. 586 and 628, are produced when Project Managers request approval to modify the budget of a project. The PJF provides documentation of the business justification, project schedule and approved budget.

The Monthly Project Status Reports track spending and cost variances monthly on a more granular level for each project than the PJFs. The PJFs primarily track project and funding approval along with budget changes during the various phases of the project. We discuss our review of the PJFs supporting each project valued at $3 million or more first and then separately discuss our review of a sample of Monthly Project Status Reports on select projects.

23 Staff/2704, PGE Response to Staff DR No. 706(f).

EVALUATION OF PROJECT JUSTIFICATION FORMS

Q. What general approach did you take to evaluate the PJFs supporting PGE's capital projects?

A. At our request, PGE produced confidential copies of PJFs for all capital projects other than transmission and distribution greater than $3 million that PGE included in the rate base in this GRC.[24] This totaled 37 PJFs for projects including 14 IT and two distribution projects we culled from the group since they are in Mr. Young's scope of work.

We then listed each of the projects in our assigned scope of work in a spreadsheet to summarize the project descriptions and to cross reference the projects to other schedules produced by PGE that reflect actual costs closed to plant or forecasted costs expected to close to plant by December 31, 2023.[25] This allowed us to test the population in two directions by: (1) assessing whether projects PGE asserts are included in the UE 416 rate base are listed on its schedules containing amounts that comprise its additions to rate base, and (2) assessing whether projects on PGE's schedules of capitalized project costs or forecasted capital additions have a supporting PJF produced for review. The table below summarizes the 21 projects we evaluated.

[24] Staff/2705, PGE Response to Staff DR No. 628, Confidential Attachment A.

[25] Staff/2704, PGE Response to Staff DR No. 807, Attachment A.

Table 8. Summary of PGE Capital Projects by FERC Plant Category

			ESTIMATED FULLY LOADED UE 416 COSTS ($ MILLIONS)					
LINE	PROJECT NAME	PROJECT NUMBER	HYDRO PRODUCTIO	STEAM PRODUCTIO	GENERAL PLANT	OTHER PRODUCTIO	INTANGIBLE PLANT	TOTAL
1	Hydro Control System Upgrade	P36134	$ 11.9	$ -	$ -	$ -	$ -	$ 11.9
2	Vintage Vehicle Replacement II	P36394	$ -	$ -	$ 32.4	$ -	$ -	$ 32.4
3	Field Area Network Project	P36723	$ -	$ -	$ 6.5	$ -	$ -	$ 6.5
4	BR Beaver Modernization	P36836	$ -	$ -	$ -	$ 56.9	$ -	$ 56.9
5	Facilities Upgrades-EV Readiness	P37017	$ -	$ -	$ 9.5	$ -	$ -	$ 9.5
6	Facilities Management Fitness	P37093	$ -	$ -	$ 7.0	$ -	$ -	$ 7.0
7	WSH Restore Facilities post-fire	P37118	$ 10.1	$ -	$ -	$ -	$ -	$ 10.1
8	Eastern Gen Admin Building-Carty	P37176	$ -	$ -	$ -	$ 7.8	$ -	$ 7.8
9	Salem LC EIFS Replacement	P37240	$ -	$ -	$ 6.2	$ -	$ -	$ 6.2
10	CY Purchase 2023 Outage Components	P37353	$ -	$ -	$ -	$ 3.8	$ -	$ 3.8
11	PN Rewind Unit 2 Generator	P37416	$ 4.1	$ -	$ -	$ -	$ -	$ 4.1
12	TR - Rebuild Tower I-10	P37459	$ -	$ -	$ -	$ 3.8	$ -	$ 3.8
13	Energy Tracker Replacement	P37487	$ -	$ -	$ -	$ -	$ 3.8	$ 3.8
14	Biglow I Wind Enhancement Program	P37509	$ -	$ -	$ -	$ 7.3	$ -	$ 7.3
15	P23528 - Clackamas PME - Recreation, Aesthet	P23528	$ -	$ -	$ 3.1	$ -	$ -	$ 3.1
16	P35172 - PSES - Generation Fitness Fund	P35172	$ -	$ -	$ 4.2	$ -	$ -	$ 4.2
17	P36116 - Wind Generation Fitness Program	P36116	$ -	$ -	$ 8.7	$ -	$ -	$ 8.7
18	P36449 - PRB Upgrade Governors & Exciters	P36449	$ -	$ -	$ 3.5	$ -	$ -	$ 3.5
19	P37162 - Bill Redesign	P37162	$ -	$ -	$ 6.2	$ -	$ -	$ 6.2
20	P37251-PACS 2.0	P37251	$ -	$ -	$ 4.4	$ -	$ -	$ 4.4
21	P37376-CS Rewind Unit 1 CTG & STG	P37376	$ -	$ -	$ 5.9	$ -	$ -	$ 5.9
	TOTAL CAPITAL ADDITIONS		$ 26.1	$ -	$ 97.6	$ 79.5	$ 3.8	$ 206.9

Q. What steps did you take to evaluate the PJFs produced by PGE?

A. We performed a page-by-page review of the PJFs produced in response to Staff DR Nos. 628 to examine approved spending and budget revisions, project justification reasons, cost summaries, project description and scope, alternatives considered, benefits of the project, and project ranking codes.[26] Each of these are sections within a PJF. We then summarized project descriptions, the expected in-service date, and the actual or expected fully

[26] Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628.

loaded capital additions from other PGE schedules produced in discovery since the amounts in the PJFs reflect only incurred or direct costs, before labor loadings, allocated overhead, and AFUDC are added. Finally, we addressed each of the five criteria listed above at the beginning of section Issue 1(C). The confidential excerpt below from Confidential Staff/2705 is an illustrative example of the table we created for each PJF produced in response to Staff DR No. 628, Confidential Attachment A, documenting the results of our review.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What are the results of your PJF review?

A. The following table summarizes our findings from the review of the PJFs.

Table 10. Summary of PJF Review[27]

	CAPITAL ADDITIONS AT ISSUE IF FLAG IS "YES" (MILLIONS)	COUNT OF PROJECTS WHERE CRITERIA ARE MET / NOT MET			
Criteria of Review		YES	NO	UNCLEAR	TOTAL
Approximate Actual or Expected Capital Addition (may exclude loadings, overheads, and AFUDC)		N/A	N/A	N/A	N/A
Criterion #1 – In service by 12/31/2023?	$ 90.9	11	0	10	21
Criterion #1A – Officer Attestation Required	$ 192.4	19	2	0	21
Criterion #2 – Evidence of Cost Overruns?	$ 22.8	3	18	0	21
Criterion #3 - Are there costs PGE is getting reimbursed for by insurance or warranties?	$ 14.0	2	19	0	21
Criterion #4 – Evidence of any project failures?	$ 14.0	2	19	0	21
Criterion #5 – Possibility of deferral to future years with jeopardizing safety or reliability?	$ 35.5	2	18	1	21

Table 10 shows the capital additions we reviewed by number of projects and total cost, and how the projects measure up against the five criteria described above. For example, the first criterion is whether the project will be in in service by the rate effective date. The row titled Criterion #1 shows the number of projects that have or are expected to close by December 31, 2023, and those projects for which the forecasted close date is unclear. Criterion #1A shows the number of projects with forecasted plant closing dates by December 31, 2023, but after PGE's application date for this GRC. We are advised that the OPUC's practice in prior cases is to require Company officer

27 Staff/2709.

attestations for projects that are not completed before the final round of testimony but are forecasted to be in service before the rate effective date.

Q. What is the significance of the results for Criterion #1 and Criterion #1A?

A. Criterion #1 indicates that 11 projects have specific anticipated closing dates by December 31, 2023 and 10 other projects were marked as "UNCLEAR" due to ambiguous language in the PJF or the lack of a clear in-service date in PGE's supporting capital additions schedules. A total of only $90.9 million in forecasted capital additions associated with the 11 projects has specific plant-in-service dates by December 31, 2023.[28]

In Criterion #1A, there are 19 projects that may require officer attestation due to (1) a closing date after February 15, 2023 (the GRC application date) or (2) an unclear closing date. Some of the 11 projects above with closing dates on or before December 31, 2023, and all of the other 10 projects in Criterion #1 are included in Criterion #1A's findings. As noted in Table 10, the forecasted capital additions associated with the projects evaluated under this criterion is approximately $192.4 million.

Q. What are the issues with the three projects you flagged as having potential cost overruns in Criterion #2?

A. Each of the three flagged projects had unexpected cost increases during the project's life cycle, which requires an evaluation and determination of ratepayer

28 The dollar value associated with each criterion is distinct from all other criteria and should not be considered cumulative.

liability. The first project, noted in confidential Table 9 above, experienced an increase in the total expected budget of $3.46 million in June 2021 due to the escalation in material prices between construction estimates prepared by PGE personnel as well as increased labor costs due to the inefficiencies caused by the COVID-19 pandemic. It also experienced an increase in engineering costs is driven by changes in the balance between internal engineering resources and external resources. After an initial reduction in the total project budget of $0.43 million in January 2022, an increase of $1.35 million was authorized four months later in May 2022 due to changes in material availability increasing lead times. It is not clear whether ratepayers should bear 100% of these cost increases. We will evaluate this issue further based on PGE's rebuttal testimony on capital project issues.

The second project, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[29] Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628, **[BEGIN CONFIDENTIAL]** [redacted] **END CONFIDENTIAL]**

[redacted]

[END CONFIDENTIAL]

The third project, **[BEGIN CONFIDENTIAL]** [redacted] :

[redacted]

[END CONFIDENTIAL]

As noted in Table 10 above, the total capital additions associated with these three projects exhibiting cost overrun issues is approximately $22.8 million.

Q. What is the issue with the two projects in Table 10 flagged for pending cost reimbursements in Criterion #3?

A. PGE incurred damages to plant for which it is seeking reimbursement from insurance and/or warranties in connection with the following projects: **[BEGIN CONFIDENTIAL]** ([redacted]

[30] Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628, **[BEGIN CONFIDENTIAL]** [redacted], [redacted] **[END CONFIDENTIAL]**

[redacted] **[END CONFIDENTIAL]** As noted in Table 10 above, the total capital additions associated with these three projects exhibiting cost overrun issues is approximately $14 million. We will continue to evaluate the appropriate ratemaking treatment to address any reimbursement PGE may receive from insurance to avoid double recovery, and if necessary, to determine the reasonableness of requiring ratepayers to bear costs associated with the damages.

Q. Describe the two projects you flagged as having some indication of potential project failure in Criterion #4.

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** As noted in Table 10 above, the total capital additions

31 Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

32 Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

associated with these two projects exhibiting cost overrun issues is approximately $14.0 million.

Q. Are there projects that could have capital spending deferred to future years that you evaluated under Criterion #5?

A. Yes. There are two projects with the potential of capital spending deferral. **[BEGIN CONFIDENTIAL]** [redacted].[34] **[END CONFIDENTIAL]** As noted in Table 10 above, the total capital additions associated with these two projects that could have deferred spending is approximately $35.5 million.

[33] Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[34] Staff/2704 and PGE Response to Staff DR No. 628. Staff/2705 and Confidential Attachment A to Staff DR No. 628, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Monthly Project Status Report Selection

Q. What was PGE's objection to providing the monthly Project Manager reports?

A. PGE asserted that the request was overly broad and unduly burdensome since the request covered monthly reports for several hundred capital projects.[35] After receiving PGE's response, we realized that the request applied to all capital projects supporting its UE 416 additions to rate base instead of the project threshold of $3 million or more that we are evaluating. However, PGE did not propose an alternative to narrow the scope of projects meeting this criterion.

Q. Did PGE propose such an alternative for its post completion reports?

A. Yes. While objecting on similar grounds to the monthly Project Manager reports, PGE stated it was providing post completion reports for transmission and distribution projects in excess of $3 million.[36] While our request was not limited to transmission and distribution projects, at least PGE agreed to an alternative scope of reports.

Q. Did you issue additional discovery to narrow the scope of your request?

A. Yes. We narrowed the scope of our request to projects greater than $3 million in cost and to PGE producing Monthly Project Status Reports on a quarterly

[35] Staff/2704, PGE Response to Staff DR No. 707(a).
[36] Staff/2704, PGE Response to Staff DR No. 706(e).

basis for the selected projects.[37] This reduced the number of capital projects to less than 100.[38]

Q. How did PGE respond to your follow-up data requests?

A. PGE contacted us informally before the data request response deadline to determine whether a sample of 10-15 projects would be acceptable to reduce the volume of reports it would have to produce. We agreed to select 15 projects with the caveat that we may request reports for additional projects if we find issues of concern regarding PGE's project management.

Q. Did you receive the requested information in time to evaluate it before filing this testimony?

A. Yes. PGE produced confidential reports in response to Staff DR No. 789, Confidential Attachment A, which are included in Staff/2705.

Q. What was the universe of projects you selected projects from to create the sample?

A. There are a total of 81 capital projects meeting the $3 million or greater threshold. In our assigned scope of work, there are 29 projects in the Production, General Plant, and Intangible Plant FERC categories.[39] In Mr. Young's scope of work, there are 38 Transmission and Distribution Plant projects and 14 IT projects.[40]

---

[37] Staff/2704, PGE Responses to Staff DR Nos. 789 and 790.

[38] Staff/2704. Based on the number of projects listed in PGE Responses to Staff DR Nos. 588, 626, and 627.

[39] Sum of projects in these FERC categories from Staff/2704, PGE's responses to Staff DR Nos. 626, 627, and 628 excluding the Faraday Repowering Project and non-cyber security IT projects.

[40] Staff/2704, PGE Responses to Staff DR Nos. 588, 626, and 627.

In our scope of work, we were able to identify 21 of the projects PGE is proposing to include in the UE 416 rate base meeting the $3 million or greater criterion. These 21 projects total approximately $206.9 million in fully loaded costs as shown in the table below. These projects span the following FERC category types with the term "fully loaded" defined as direct costs plus overheads and AFUDC.

Table 11. Assigned Capital Projects by FERC Category

	ESTIMATED FULLY LOADED UE 416 COSTS ($ MILLIONS) FROM CWIP OR FORECASTED 2023 BALANCES (OTHER THAN T&D, FARADAY REPOWERING, & IT PROJECTS)					
# OF PROJECTS	HYDRO PRODUCTION	STEAM PRODUCTION	GENERAL PLANT	OTHER PRODUCTION	INTANGIBLE PLANT	TOTAL
3	$ 26.1					$ 26.1
0		$ -				$ -
12			$ 97.6			$ 97.6
5				$ 79.5		$ 79.5
1					$ 3.8	$ 3.8
21	**$ 26.1**	**$ -**	**$ 97.6**	**$ 79.5**	**$ 3.8**	**$ 206.9**

Q. How was the sample constructed?

A. We added the number of projects in both Mr. Young's scope of work (52) and ours (29) to calculate a universe of 81 projects. Using a sample size of 15 projects, we determined that Mr. Young's proportional share was nine projects (56.7% X 15), and our proportional share was six (43.3% X 15) rounded to the nearest integer. Mr. Young describes how he selected his nine projects in Ex. 2100. Our selections were based on the proportion of project counts within five distinct groups and use of a Microsoft Excel random number generator. Ultimately, we selected the project or projects within the following groups with the highest random number: (1) Hydro Production, (2) General Plant, (3) Intangible Plant, (4) Other Production, and (5) Projects not listed on PGE's rate case capital addition schedules. The following table is the sample of projects chosen for testing with the six projects we evaluated highlighted.

Table 12. Staff Sample of 15 Projects to Evaluate Monthly Reports[41]

STAFF SAMPLE OF 15 PROJECTS FROM THOSE REQUESTED IN STAFF DR NOS. 789 AND 790 FOR MONTHLY PROJECT STATUS REPORTS ON A QUARTERLY BASIS

SELECTION #	PROJECT	PROJECT DESCRIPTION	FERC CATEGORY
1	P37218	OH FITNES Distribution	Distribution
2	P36680	Brookwood Substation Conversion	Distribution
3	P36679	Orenco Substation 115kV Rebuild	Transmission
4	P37160	Helvetia Substation Phase 2	Distribution
5	P37061	OH FITNES Transmission	Transmission
6	P36417	Replace/Rewind Failed Transformers	Transmission
7	P35995	Downtown UG Core Cable Replacement	Distribution
8	P36373	Blue Lake Phase II	Transmission
9	P36953	Memorial Substation Build	Distribution
10	P36838	RB: Replace Turbine Shut-off Valves	Hydro Production
11	P37133	CTO Network Fitness	General
12	P37176	Eastern Gen Admin Building-Carty	Other Production
13	P37314	Project 360 Bundle 1	Intangible
14	P37251	P37251-PACS 2.0	General
15	P37533	P37533-2022 Microsoft Enterprise Agreement	Intangible

Q. Did you receive the Monthly Project Status Reports for the sample of projects?

A. Yes, we did in PGE's response to Staff DR No. 789, Confidential Attachment A.

[41] Confidential Staff/2711.

Q. What did your evaluation of the Monthly Project Status Reports reveal?

A. We found no material variances in any of the reports supporting the six projects selected for testing. Each of the reports showed the progression of actual or actual plus committed spending versus either budgeted, allocated, or forecasted spending based on the type of report used to support the specific project. Confidential Staff/2711 contains tables for each of the six projects summarizing our review of the monthly reports produced by PGE.

ISSUE 2. MAJOR MAINTENANCE ACCRUALS

Q. Please describe the Major Maintenance Accruals (MMA) Mechanism.

A. Major Maintenance Accruals is an accounting treatment used by PGE to smooth certain "major" maintenance expenses. According to PGE, major maintenance costs are "lumpy" and "vary dramatically from year to year." [42] Under the MMA mechanism PGE develops a multi-year forecast of major maintenance expenses and calculates yearly accrual amounts (constant over the forecast period) to be collected through customer rates. These yearly accrual amounts are designed to better balance and synchronize expenses and collections over the multi-year forecast period.

Q. Has the Commission previously reviewed and approved this mechanism for PGE?

A. Yes. The Commission previously authorized PGE to use this mechanism for five facilities: Carty, Coyote Springs, Port Westward 1 and Port Westward 2, as well as the Kelso-Beaver (KB) B Pipeline.[43] The Commission also previously approved the mechanism for Colstrip and Boardman, but PGE is not including any costs associated with these coal plants in its GRC filing. In UE 394, the Commission approved annual MMA amounts for these facilities totaling approximately $15.7 million.[44]

---

42 PGE/800, Jenkins – Bekkdahl/13.

43 Commission added MMA mechanisms for the above listed facilities through the following orders: Orders No. 95-1216 (Coyote Springs), Order No. 13-459 (Port Westward 1), Order No. 14-422 (Port Westward 2), Order No. 15-356 (Carty) and Order No. 22-129 (KB Pipeline).

44 PGE/804, Jenkins – Bekkdahl.

Q. What time horizon does PGE use for its MMA mechanism?

A. PGE uses a five-year forecast and amortization period for its MMA mechanism.

Q. Has PGE provided documents supporting its proposed increases in MMAs?

A. Yes. PGE's calculations in support for the requested increase in MMA annual amount are contained in PGE's confidential workpaper "*2024 GRC MMA Work Paper_Final.xlsx*" ("*2024 GRC MMA Work Paper")*. We included this workpaper in Staff/2713, where we also inserted additional Tabs to restate PGE's analysis.

Q. What does PGE propose regarding MMAs in this filing?

A. As can be seen in Table 10 below, PGE is proposing to set MMAs for the five facilities at $17.2 million,[45] which is an increase of approximately $1.5 million compared to MMAs authorized in UE 394,[46] and an increase of $1.8 million if compared to 2022 actuals.[47]

PGE testimony further explains that the total requested increase over 2022 actuals ($1.8 million) is comprised of *two amounts*:

1. An *increase* of $5.3 million in MMA expense charged to generation Operations and Maintenance (O&M) expense accounts; and

[45] PGE/800, Jenkins – Bekkdahl/15.

[46] PGE/800, Jenkins – Bekkdahl/15.

[47] PGE/800, Jenkins – Bekkdahl/15. Amounts approved in UE 394 MMAs became effective in May 2022.

2. A *decrease* of $3.4 million to MMA amounts recorded under Account 456, Other Revenue.[48]

The following table summarizes the changes in MMAs and the two components proposed by PGE:

Table 13. Comparison of PGE's Proposal with Amounts Authorized in UE 394[49]

($1,000,000)

Measure	UE 394 Approved MMAs	2022 Actual MMAs	2024 GRC Requested MMAs	Delta: Requested minus UE 394 Approved	Delta: Requested minus 2022 Actuals
TOTAL	**$15.7**	**$15.3**	**$17.2**	**$1.5**	**$1.8**
Including: MMAs in Other Revenue Account 4560002	**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**	$2.0	-$1.5	**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**	-$3.4
MMAs in Generation O&M Accounts	**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**	$13.4	$18.6	**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**	$5.3

Q. Why is PGE separating the proposed MMAs into two components, O&M expense, and Other Revenue?

A. As PGE explained in UE 394, PGE is required to separate the cost associated with MMA into these two components (O&M Expense and Other Revenue) so that Other Revenue captures a *true up* of under- or over-collected MMA-related

48 PGE/804, Jenkins – Bekkdahl. See also PGE/800, Jenkins – Bekkdahl/15.

49 Compiled from PGE/804, Jenkins – Bekkdahl and Staff/2705, PGE Response to AWEC DR No. 113, Confidential Attachment I, Tab "2020-2022 MMA Adjustment." Amounts approved in UE 394 exclude Colstrip.

costs since the last GRC.[50] PGE also clarified that this amount is still part of the overall MMA amount to be recovered in rates.[51]

Q. What is the primary driver behind PGE's proposed increases in MMAs?

A. PGE estimates an increase in major maintenance expense during 2024-2028, which is the forecasting period for which MMAs in this case are developed. The increase is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [52] compared to PGE's forecast of major maintenance expense it developed for period 2022-2026 in docket UE 394.

Q. Do you agree with PGE's estimate of its future major maintenance expenses during the relevant five-year forecast period?

A. No. We identified several inaccuracies in PGE's calculations that caused the Company to overstate its forecast for major maintenance expenses. Our correction of these inaccuracies reduced the five-year total forecasted major maintenance expense by approximately four percent.

Q. Please summarize the inaccuracies you found.

A. We found the following inaccuracies:

- Escalation Factors used to forecast major maintenance contract costs are overstated.

---

50 UE 394 PGE/1400, Tooman – Batzler/13-14.

51 UE 394 PGE/1400, Tooman – Batzler/14.

52 This percent was derived from PGE's confidential MMA workpapers: 2024 GRC MMA Workpaper (included in Staff/2713), and workpaper for case UE 394, which was provided in this docket in response to AWEC DR No. 113 as attachment I and included in Staff/2705. In both workpapers, PGE's forecast for major maintenance expense (contained in Tab Summary) was summed up across the five forecast years and five facilities, and then the total from this case was divided by the total from UE 394.

- For one facility, vendor rates for year 2022 (listed in the PGE's 2024 GRC MMA Workpaper) did not agree with the historical-year-2022-accounting paper for this facility.
- Two inaccuracies in the calculations of year 2023 overall MMA balances. In both cases PGE confirmed in a data response that corrections were due.
  - For one facility, year 2023 beginning balance did not agree with the value found in the historical year 2022 accounting paper for this facility.
  - For another facility, year 2023 amortization contained what appears to be a typographical error—a positive rather than a negative sign—in the PGE's 2024 GRC MMA Workpaper.
- PGE's projection of the rate base portion associated with MMAs is inconsistent with its forecast of the expense side of MMAs.
  - PGE's forecast starts with October 2022 actuals, while more recent, December 2022 data are available and were utilized in PGE's "main" MMA analysis.
  - PGE's forecast does not match the estimates of MMA Deferral Balances that appear within PGE's "main" MMA analysis. In other words, the two sources appear to forecast the same thing, but the results are different.

In what follows, we discuss each of these in more detail.

Q. Please elaborate further on the inaccuracies you found in PGE's forecast of major maintenance expenses.

A. PGE's 2024 GRC MMA Workpaper shows forecast expenses by facility, month, and type of major maintenance expense. While PGE's testimony represented these expenses as "lumpy" and "cyclical,"[53] they are in fact mostly attributable to *regular* and *relatively stable* payments that are dictated by PGE's Long Term Service Agreements (LTSAs) with equipment vendors.[54]

Q. Please discuss these LTSA related payments/fees.

A. The LTSA related payments/fees **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. How does PGE forecast these LTSA related fees?

A. PGE's calculations start with **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. Did you audit PGE's forecast of its LTSA fees?

A. Yes, we took several steps to audit PGE's forecasts. First, in order to verify rates and escalation factors contained in PGE's 2024 GRC MMA Workpaper, we requested and received from PGE its actual vendor LTSAs.[55]

---

53 PGE/800, Jenkins – Bekkdahl/13.

54 This is evident from the examination of PGE's 2024 GRC MMA Workpaper, which is included in Staff/2713.

55 Staff/2706, PGE Supplemental Response to Staff DR No. 611 (containing highly confidential vendor contracts).

Next, we reviewed historical accounting papers detailing MMA-related additions and amortizations in 2019-2022 provided by PGE in response to AWEC DR No. 113.[56]

Q. What did you find?

A. Based on the review of these highly confidential vendor LTSAs, we established that in some cases, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

A. For two facilities, PGE *assumed* **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for each year between 2022 and 2028. However, in reality, these facilities' LTSAs **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. Is there further evidence that [BEGIN HIGHLY CONFIDENTIAL] [redacted] **[END HIGHLY CONFIDENTIAL]?**

A. Yes. A recent forecast by the Oregon Office of Economic Analysis[57] projects that CPI for U.S. Urban consumers will increase between 2022 and 2023 by

[56] Staff/2705, Attachments A through D and F to PGE Response to AWEC DR No. 113.

[57] Oregon Economic and Revenue Forecast, Office of Economic Analysis, March 2023 available at https://www.oregon.gov/das/OEA/Documents/forecast0323.pdf, p. 44.

3.9%, and after that it will be increasing annually at even more modest rates of under 2.2%.

Q. How did you correct the above-discussed inaccuracies in PGE's forecast of major maintenance expenses?

A. We restated **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]. **[END HIGHLY CONFIDENTIAL]** [58]

Q. Did you find another inaccuracy that needed correcting?

A. Yes. We found another deficiency. Specifically, we found that for one facility **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for year 2022 (listed in the PGE's 2024 GRC MMA Workpaper[59]) did not agree with the historical-year-2022-accounting paper for this facility. (This paper was provided by PGE in its response to data request AWEC 113.[60]) The discrepancy is especially problematic since year 2022 is the starting year to which **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. *Thus, because the starting values are incorrect, the forecasts for all subsequent years are invalid*.

---

58 Staff/2713, Tab "Assumptions QSI" containing this update.

59 Staff/2713.

60 Staff/2705.

Q. How did you correct this inaccuracy?

A. We updated these inaccurate values in the PGE's 2024 GRC MMA Workpaper forecast with the values observed in the historical year 2022 accounting paper.[61]

Q. Did you correct any other inaccuracies in the PGE MMA calculations?

A. Yes. We found and corrected *two* inaccuracies related to the calculation of the year 2023 overall MMA balances (difference between cumulative life-to-date MMA collections and major maintenance expense). In both cases, PGE confirmed in data responses that corrections were due.

First, Port Westward 1, year 2023 beginning balance (which is the same as year 2022 ending balance) did not agree with the value found in the historical year 2022 accounting paper for this facility provided by PGE in response to AWEC DR No. 113.[62] PGE confirmed in a data response to our data request[63] that the amounts contained in PGE attachment responsive to AWEC DR No. 113 are more accurate (newer) numbers.

Second, with regard to Port Westward 2, its year 2023 amortization contained what appears to be a typographical error—a positive rather than a negative sign—in the PGE's 2024 GRC MMA Workpaper. PGE confirmed in a data response to our data request[64] that this correction is appropriate.

---

[61] Staff/2713, Tab "Assumptions QSI" containing this update.

[62] Staff/2705, PGE Response to AWEC DR No. 113, confidential attachment C.

[63] Staff/2704, PGE Response to Staff DR No. 615.

[64] Staff/2704, PGE Response to Staff DR No. 775.

Q. What is the cumulative, overall impact of all of the above corrections?

A. The overall impact of all above-discussed corrections is a reduction of MMAs by approximately $1 million. Staff-adjusted MMAs represent an increase over MMAs approved in UE 394 of approximately $0.5 million. The following table summarizes this impact:

Table 14. Comparison of PGE's Proposal with Amounts Authorized in UE 394[65]

($1,000,000)

Measure	UE 394 Approved MMAs	2022 Actual MMAs	2024 GRC Requested MMAs	Delta: Requested minus UE 394 Approved	Delta: Requested minus 2022 Actuals
TOTAL - PGE Filing	$15.7	$15.3	$17.2	$1.5	$1.8
TOTAL - ADJUSTED BY STAFF	$15.7	$15.3	$16.2	$0.5	$0.8
Delta: Adjusted by Staff minus PGE Filed	$0.0	$0.0	-$1.0	-$1.0	-$1.0

Q. Did you find any other material inaccuracies in the PGE filing related to MMAs?

A. Yes. We found that PGE's projection of the rate base portion associated with MMAs is inconsistent with its forecast of the expense side of MMAs.

By way of background, MMAs affect not only PGE's income statement (O&M expense and Other Revenue accounts), but also PGE's balance sheet. MMA Deferral Balances are included in the PGE's rate base in this case, with

65 Developed by comparing PGE-requested amounts contained in PGE/804, Jenkins – Bekkdahl with Staff/2712 (which is a restated version of PGE/804, Jenkins – Bekkdahl). Staff/2713 (highly confidential) for the restatement calculations.

the total amount being negative $1.871 million in the Test Year and composed of balances for four plants.[66] PGE explained in response to our data request how this amount is developed and provided the underlying workpaper: [67] For each facility at issue, PGE took October 2022 actual balances (cumulative life-to-date differences between collections and expenses) and then forecasted forward to December 2023 by estimating collections and expenses for each month between November 2022 and December 2023.

Q. What is deficient in PGE's method of forecasting the rate base portion associated with MMAs?

A. There are two deficiencies. First, PGE's forecast starts with October 2022 actuals, while more recent, December 2022 data are available and were utilized in PGE's "main" MMA analysis – the analysis that develops the requested MMAs (PGE 2024 GRC MMA Workpaper).

Second, this forecast does not match the estimates of MMA Deferral Balances that appear within PGE's "main" MMA analysis. In other words, the two sources appear to forecast the same thing, but the results are different. Based on our restated version of PGE 2024 GRC MMA Workpaper (Staff/2713), a more accurate forecast of MMA Deferred Balances for year end 2023 is negative $1.775 million, or an increase in rate base of approximately $95,000.

---

[66] PGE/208 includes sub-item MMA under category "Deferred Debits." PGE's workpaper to Exhibit 200 (Staff/2703) provides additional detail, showing how it is split between four facilities, Carty, Coyote Springs and the two Port Westward plants in Tab "Rate Base Data".

[67] Staff 2704, PGE Response to Staff DR No. 617.

Q. Please summarize your proposed adjustments for MMAs.

A. The following table summarizes our proposed adjustments.

Table 15. Comparison of PGE's Proposed MMAs with OPUC Staff Adjustments

($1,000,000)

Measure	PGE Filing	Adjusted by Staff	Delta: Staff minus PGE Filing
Expense/Revenue accounts:			
MMAs in Other Revenue Account 4560002	-$1,461,881	-$1,461,881	$0
MMAs in Generation O&M Accounts	$18,629,700	$17,614,731	-$1,014,969
TOTAL 2024 MMAs	**$17,167,819**	**$16,152,850**	**-$1,014,969**
Rate Base:			
2023 MMA Deferred Balances	**-$1,870,761**	**-$1,775,320**	**$95,441**

ISSUE 3. FUEL STOCK

Q. What is fuel stock.

A. In simple terms, fuel stock is a stock—i.e., an “inventory”—of fuel that PGE keeps on hand for certain of its thermal generating plants. In the instant proceeding, PGE’s fuel stock is associated with its Westside Thermal Plants, the PW/Beaver complex: this complex is comprised of PGE’s gas thermal plants PW1, PW2, Beaver Units 1-7, and Beaver Unit 8.[68]

Fuel stock as fuel reserves differs from the Company’s Annual Tariff Update (“AUT”) fuel in that instead of being a *pass-through* expense it is treated as a stock and included in the rate base; i.e., the Company earns a return on its fuel stock.

Of course, there is no fuel stock associated with PGE’s hydro-, solar- and wind-power plants.

Q. What type of fuels does PGE keep in stock?

A. There are three types of fuel that PGE keeps in stock:

- Gas
- Oil
- Coal

Two qualifications are in order here.

First, PGE does not include coal in its GRC filing. (In fact, PGE notes that all costs associated with its coal plants—Boardman and Colstrip—are

68 See, UE 416 / PGE / 300 / Schwartz – Outama – Cristea / 34 / Footnote 26.

excluded).[69] While coal is still identified in the workpapers, there are zero balances.

Second, PGE also keeps a “stock” of CO2 allowances that is grouped in with the fuel stock. However, while CO2 allowances are related to certain PGE power sales and the associated greenhouse gas (“GHG”) emissions, CO2 allowances are *essentially different from stocks of thermal fuels* (i.e., gas, oil, and coal). CO2 allowances are discussed separately in the next section.

An added complication with respect to CO2 allowances is that PGE claims to inadvertently have omitted them in its GRC filing. While the CO2 allowances are included as a category in the workpapers, the workpapers do not carry the dollar balances forward to be included in the rate base. Per its response to discovery, the Company intends to correct this omission in its rebuttal testimony.[70]

Q. Where in PGE’s filling is the fuel stock found?

A. The money PGE has invested in its fuel stock is found in the *rate base.* It is grouped in with PGE’s inventory of operating materials under “Operating Materials and Fuel Stocks,” as can be seen in Table 13, below.

[69] Staff/2704, PGE Response to Staff DR No. 640, April 25, 2023.

[70] Staff/2704, PGE Response to Staff DR No. 642 (d), April 25, 2023.

Table 16. Fuel Stock Location in Rate Base

PGE
UE 416
Exhibit 207
Rate Base
Scaled (Thousands)

Line No.	Line	Based on Ending Balances
1	Plant in Service	12,249,545
2	Less: Accumulated Depreciation/Amortization	(5,441,309)
3	Accumulated Deferred Taxes	(667,288)
4	Accumulated Deferred ITC	
5		
6	**Net Utility Plant**	6,140,947
7		
8	**Operating Materials and Fuel Stocks**	91,228
9		

Q. How much of $91 million in Operating Materials and Fuel Stock is related to fuel?

A. About one third ($31.5 million) is related to PGE's fuel stock—to be precise, it is $31,484,573.[71]

Q. What is the composition on PGE's fuel stock in this case?

A. About **[BEGIN CONFIDENTIAL]** [redacted]

[71] Staff/2704, PGE Response to Staff DR No. 340 (e).

[72] Table constructed from information provided in Staff/2705, PGE Response to Staff DR No. 639_Attachment A_CONF, Excel column P.

Table 17. Composition of PGE's Fuel Stock in UE 416

[redacted]

[END CONFIDENTIAL]

Again, PGE excludes cost associated with its coal plants, Colstrip, and Boardman;[73] accordingly, there is no coal and PGE removed oil associated with Colstrip.

Q. In which account is PGE's fuel stock, $31,484,573, found?

A. The figure is a combination of two accounts:

- 1510001: Fuel Stock-Purchase & Transport Oil
- 1510008: Fuel Stock-Store Natural Gas

The two accounts were rolled up into one line item for reporting purposes, specified as Fuel Oil & Gas.

[73] Staff/2704, PGE Response to Staff DR No. 640, April 25, 2023.

Q. How did PGE calculate the $31,484,573?

A. The $31,484,573 above was forecast (for December 2023) by PGE using the starting point of *actual October 31, 2022* ending balances for accounts 1510001 and 1510008:

- For *gas inventories*, actual period ending (October 31, 2022) inventory is used as the starting basis. This is then adjusted on a monthly forecast basis using (i) a forecast % change in inventory multiplied against (ii) a forecast weighted average cost of gas to adjust the monthly balance.[74]
- For *oil inventories,* PGE made *no* adjustments since October 31, 2022.

The variation in PGE's forecasted fuel balances[75] is seen in Figure 1, below.[76] The value, $31,484,573, of the terminal period (December 2023) is included by PGE as the fuel stock value in its rate base.

---

[74] Staff/2704, PGE Response to Staff DR No. 639, April 25, 2023.

[75] These values do not represent PGE's actual balances, but rather as based on various assumptions. We will examine these assumptions and make recommendations for select adjustments.

[76] Staff/2705, PGE Response to Staff DR No. 639, Attachment A_CONF, April 25, 2023.

Figure 1. PGE's Forecasted Fuel Balances Since October 2022

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Is all of PGE's fuel stock assigned to Production?

A. Yes. In unbundling its rate base, PGE's notes that "fuel inventories are assigned to Production."[77]

Q. Have you reviewed PGE's fuel stock calculations?

A. Yes. We have reviewed PGE's GRC filing (testimony and work papers) as well as the Company's answers to various discovery served by OPUC and other parties.

[77] PGE / 200, Batzler - Ferchland / 30 / lines 7-8.

Q. Do you consider all of PGE's fuel stock investments to be prudent?

A. No. A significant portion of PGE's fuel stock is imprudent and should be disallowed. Specifically, we recommend adjustments to PGE's stock of gas and oil.

<u>Overview of Adjustments and Summary of Results</u>

Q. On a conceptual level, what adjustments did you make?

A. On a conceptual level, it is useful to think of PGE's fuel stock in terms of the following equations:

- *Gas Stock ($) = Price ($) x Quantity (dth)*
- *Oil Stock ($) = Price ($) x Quantity (dth)*

For each (gas and oil), we make adjustments to both the *price* and the *quantity*.

Q. What adjustments are you making to PGE's *<u>gas</u>* stock?

A. PGE reports a gas stock of about **[BEGIN CONFIDENTIAL]** [redacted].[78] **[END CONFIDENTIAL]** This is made up of three components—fixed, semi-fixed and variable:

1) Fixed—Cushion gas[79]
2) Semi-Fixed—Contingency gas[80]
3) Variable—Gas for PGE's Westside Thermal Facilities (gas turbines)

---

[78] Staff/2705, PGE Response to Staff DR No. 639_Attacment A_CONF.

[79] As is discussed below, cushion gas supports gas pressure in underground reservoirs, keeps out lower quality gas, water, etc. Cushion gas is a fixed amount to remain constant.

[80] As is discussed below, contingency gas is backup to cover for possible interruptions of North Mist's access to the Northwest pipeline, the sole gas supply for North Mist. Contingency gas is a fixed amount to remain constant.

Again, for each of these components we make adjustments to both the *quantity (dth)* and the *price ($)*.

The composition of PGE's gas stock can be seen in the chart below.

Figure 2. Composition of PGE's Gas Stock[81]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What adjustments are you making to *__gas__* and *__oil__* stocks?

A. Following the conceptual notion that *Stock = P x Q*, we make the following adjustments.

Gas Price Adjustments:

- Cushion gas should be priced at *historic* prices (when it was purchased), not *forecasted* prices (replacement costs) as proposed by PGE.

[81] Staff/2705, PGE Response to Staff DR No. 647 Attach A_CONF, Dated April 25, 2023.

- Contingency gas should be priced at United States Energy Information Administration ("EIA") forecasted lower prices.
- Variable gas should be priced at EIA forecasted lower prices.

<u>Gas Quantity Adjustments:</u>

- Variable gas is adjusted downward to reflect average balances as opposed to peak balances as proposed by PGE.
- Contingency gas is adjusted down because PGE has other means of covering for contingencies (pipeline interruptions).

<u>Oil Price Adjustments:</u>

- Contingency oil should be priced at EIA forecasted lower prices.

<u>Oil Quantity Adjustment</u>

- Contingency oil is adjusted down because PGE has other means of covering for contingencies (pipeline interruptions).
- Contingency oil is adjusted down to reflect that it will be phased out, as Beaver is converted to single-source gas only.

Q. Please provide the results of your adjustments and your recommended fuel stock balances.

A. The results of our adjustments and our recommended fuel stock balances are summarized in the table below.

Table 18. Comparison of PGE's and Staff's Fuel Stock

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

For comparison, it is worthwhile to compare the above results with those reported by PGE in previous years and proceedings (see table below).[82] Note that coal stock is now being excluded by PGE.

Table 19. Comparison to PGE Fuel Stock Balances in Prior Years

UE 394 DR 779 - Fuel Inventories - Forecast Ending Balances					
	UE 319 Forecast Dec-17	UE 335 Forecast Dec-18	Mar 2019 Forecast Dec-19	Mar 2020 Forecast Dec-20	UE 394 Forecast Dec-21
Gas & Oil	**$ 9,216,707**	**$ 9,575,000**	**$ 20,889,113**	**$ 16,946,317**	**$ 16,730,697**
Coal	$ 21,162,543	$ 16,151,000	$ 17,016,022	$ 3,421,384	$ 8,571,894
Fuel Totals	$ 30,379,251	$ 25,726,000	$ 37,905,135	$ 20,367,701	$ 25,302,590

In what follows, we will discuss each of our adjustments in detail.

[82] Staff/2704, PGE Response to UE 394 Staff DR No. 779, PGE states:

> Attachment 779-A provides forecast 2017 and 2018 year-end balances as filed in PGE's last two general rate cases (Docket Nos. UE 319 and UE 335) and a forecast 2021 year-end balance consistent with the forecast used in PGE's current general rate case. Additionally, as PGE did not file a general rate case between UE 335 and UE 394, Attachment 779-A provides a year-end 2019 forecast balance, based on a March 2019 forecast, with actuals through February 2019 and a year-end 2020 forecast balance, based on a March 2020 forecast, with actuals through February 2020. (UE 394 Staff DR No. 779).

Q. Do you have preliminary observations on PGE's fuel stock policies?

A. Yes; we have two.

First, it is important to note that PGE's fuel stock investments are not an absolute technical or operational necessity but mostly driven by financial considerations. In fact, PGE's North Mist gas storage facility—which holds all of PGE's gas stock—went into operation only in 2018; *thus, prior to 2018 the Company operated without this storage facility*.[83] Moreover, PGE's fuel stock only serves about half of PGE's Westside Thermal Plants (PW1, PW2, and Beaver) with roughly 1100MWa of generation.[84] Specifically, the fuel oil for Beaver and the North Mist gas reserves for PW1 currently provide fuel redundancy for 51 percent of the west side generating facilities in on-peak hours. The 51 percent represents the average capacity of PW1 (i.e., approximately 400 MW) and two Beaver units (i.e., approximately 160MW).[85] *The other plants of the PW/Beaver complex operate without fuel stock*.

Second, there is a divergence between PGE's financial interests and the ratepayers' interests. That is, given that the fuel stock is included in rate base, the Company will earn a return on the investment, irrespective of whether the magnitude of the fuel stock is optimal. As such, the Company has a financial interest in over-stocking fuel. For this reason, among others, it is important to

83 The Company did operate a separate, smaller facility, Mist.

84 Staff/2704, PGE Response to Staff DR No. 650, Dated April 25, 2023.

85 *Id.*

evaluate whether PGE's investments in fuel stock are prudent: i.e., are the permanent portions of the fuel stock investments used and useful.

Q. Does PGE have a clearly defined policy for its fuel stock?

A. No. As the Company states: "PGE does not have a company policy regarding fuel stock requirements."[86]

The Company also notes that it has not performed a financial analysis that balances / weighs the costs of permanently maintaining fuel stocks against alternative means of accommodating its electricity demand.[87] In other words, there is no demonstration that the Company's fuel stock is financially optimal.

As discussed herein, we demonstrate that it is in fact not optimal, and we recommend select adjustments to protect the interest of ratepayers.

Adjustment #1. Price of Cushion Gas

Q. What is cushion gas?

A. Cushion gas is a volume of gas that is maintained at a constant pressure in an underground gas storage facility. This gas cushion serves primarily two purposes.

First, cushion gas is used to maintain the pressure in a storage reservoir at a constant level. This pressure in the reservoir also determines the amount of gas that can be stored as well as the rate at which gas can be withdrawn.

---

86 Staff/2704, PGE Response to Staff DR No. 342, Dated March 16, 2023.

87 Staff/2704, PGE Response to Staff DR No. 653, Dated April 25, 2023.

Second, cushion gas provides a buffer between the stored gas and the walls of the storage reservoir. This helps to protect the reservoir from damage and prevents the stored gas from escaping into the surrounding rock.

On an incidental basis, cushion gas can also be used in the event of an emergency to balance the supply and demand for gas. During such an emergency, the stored cushion gas can be temporarily withdrawn from the reservoir to be replenished by injecting gas at a later point.

Q. What is North Mist's maximum storage capacity and how much of it is cushion gas.

A. North Mist's maximum storage capacity is about 4,100,000 dth. PGE asserts that about 1,200,000 dth is the *minimal level that needs to be maintained*.[88] This minimal level in turn is comprised of two categories: cushion gas and contingency gas. The latter (discussed separately below) is to ensure that certain Westside Thermal Plants have fuel in the event North Mist's access to the Northwest Pipeline is disrupted.

The relative magnitude of PGE's cushion and contingency gas levels are shown below in Table 17.[89]

88 Staff/2704, PGE Response to Staff DR No. 341, Dated March 16, 2023.
89 Staff/2705, PGE Response to Staff DR No. 647_ Attach A_CONF, Dated April 25, 2023.

Table 20. PGE's Cushion and Contingency Gas

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

PGE's North Mist is typically not filled to maximum capacity. We will treat PGE's gas stock in three separate categories: (i) cushion gas, (ii) contingency gas, and (iii) gas stock *net* of cushion and contingency gas.

Q. What is the dollar value of cushion gas that PGE includes in rate base?

A. As the table below shows, PGE includes about **[BEGIN CONFIDENTIAL]** [redacted]

[90] The dth data are from Staff/2704, PGE Response to Staff DR No. Staff DR No. 341, Dated March 16, 2023.

[90] Staff/2705, PGE Response to Staff DR No. 647, Attach A_CONF, Dated April 25, 2023. The $/dth is from Staff/2705, PGE Response to Staff DR No. 639, Attach A_CONF, Dated April 25, 2023, Cell P5.

[redacted]

[END CONFIDENTIAL]

Q. Is this figure incorrectly inflated?

A. Yes, by about half.

Q. Please explain.

A. PGE incorrectly uses projected *replacement* prices for cushion gas that are high while it should have used the lower *historic* prices at which the cushion gas was acquired.

Q. Please discuss how PGE bases its cushion gas stock on replacement prices.

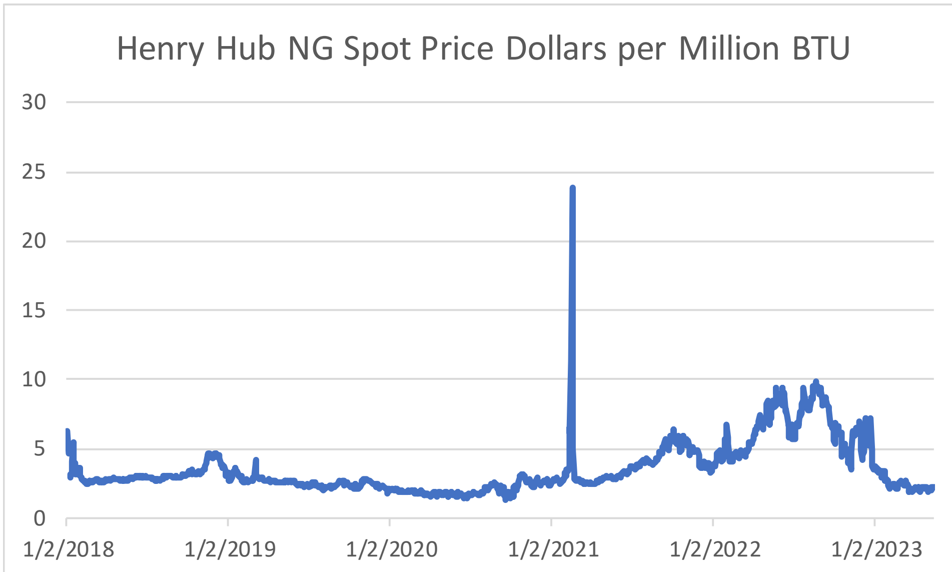
A. PGE calculates its gas fuel stock by multiplying gas *prices* times *quantities* (i.e., P x Q). For price, the Company uses the gas prices from the 15-month period October 2022 through December 2023. As noted above, this is not correct.

Due in part to geopolitical events (e.g., Russia's invasion of Ukraine), gas prices over this 15-month period are unusually high from a historic perspective

[91] The dth data are from Staff/2704, PGE Response to Staff DR No. 647, Dated April 25, 2023. The $/dth is from Staff/2705, PGE Response to Staff DR No. 639, Attach A_CONF, Dated April 25, 2023, Cell P5.

(See Figure 3, below). *More importantly, they are also not the correct prices to be used*.

Figure 3: Henry Hub Natural Gas Spot Prices from 1/2018 – 12/2023[92]



Q. What would be the correct price(s) to use for cushion gas?

A. As noted, cushion gas should be valued at historic prices.

Q. Please explain why cushion gas should be valued at historic prices.

A. Cushion gas represents a *permanent* investment—i.e., it is permanently stored at North Mist and does not get used as fuel for the Westside Thermal Facilities. As such, it should be valued at historic prices.

Q. What are the historic prices for valuing cushion gas?

A. Cushion gas should be valued at the historic prices that prevailed when PGE purchased gas at the inception date of North Mist's operation in 2018 and

92 The figure is taken from the EIA website. https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm There was a tremendous spike in U.S. natural gas prices in the week of February 19, 2021 following an arctic storm that resulted in the Texas power crisis.

2019. As noted in Figure 3 above, those historic gas prices were *less than half* than the October 2022 – December 2023 prices PGE used in its calculations.

To wit, the average implied gas price (per dth) paid by PGE over the historic acquisition period (2018-2019) was *$2.93.*[93] This contrasts starkly with the implied gas price (per dth) used by PGE of *$6.50*, *which is more than twice as high.*[94] (See table below.) Although we do not use them, the table below also shows EIA's referenced Henry Hub gas prices for comparison.[95]

Table 22. PGE's Implied Gas Prices at North Mist

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

93 The corrected $/dth of $2.93 is the average $/dth for 2018 and 2019. These were calculated from PGE Response to Staff DR No. 344_Attach B, Dated March 16, 2023. Cell I19/H19 and K19/J19, for dth 2018 and 2019, respectively.

94 Staff/2704, PGE Response to Staff DR No. 344_Attach B, Dated March 16, 2023. Cell Q19/P19.

95 https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm

Q. What revision in PGE's fuel stock is needed to reflect a corrected valuation of North Mist's cushion gas?

A. Using historic prices for cushion gas, PGE's fuel stock is reduced by about $2.8 million, as shown in the table below.[96]

Table 23. Staff Adjustment to PGE's Fuel Stock

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

<u>Adjustment #2. Contingency Gas and Variable Gas</u>

Q. Does PGE overstate its contingency and variable gas stock balances?

A. Yes. Aside from the cushion gas adjustment (discussed above), the Company further overstates its gas stock of $24 million by about another *$10.864 million*. Following the conceptual notion that *Stock = P x Q*, this figure reflects a *quantity* adjustment and a *price* adjustment. (For ease of calculations, we discuss these two adjustments in reverse order.) They are:

[96] As before, the dth data are from Staff/2705, PGE Response to Staff DR No. 647_Attach A_CONF, Dated April 25, 2023. The $/dth is from Staff/2705, PGE Response to Staff DR No. 639_Attach A_CONF, Dated April 25, 2023, Cell P5. As noted above, the corrected s/dth were calculated from Staff/2704, PGE Response to Staff DR No. 344_Attach B, Dated March 16, 2023. Cell I19/H19 and K19/J19, for dth 2018 and 2019, respectively.

Adjustment 2(a): Average Balances

PGE's gas stock should reflect *average* balances and not just a year-end balance (December), which is a peak month.

Adjustment 2(b): EIA Prices

PGE's gas stock should reflect that the EIA predicts considerably lower prices for 2023 and 2024 than PGE's.

In what follows, we will discuss these two necessary adjustments in more detail.

Q. Please discuss Adjustment 2(a)—Average Balances.

A. As discussed previously, PGE uses the projected end-of-year gas balances for December 2023.[97] This is incorrect.

Q. Please explain why this is incorrect.

A. December 2023 balances—which are balances in one of PGE's peak months—are significantly higher than the *average gas balances* for 2023.[98] In fact, December 2023 is projected to be the highest gas balance of the entire year, 2023.

---

97 Staff/2704, PGE Response to Staff DR No. 639, April 25, 2023.

98 As discussed earlier, PGE forecasts its gas fuel stock using the starting point of actual October 31, 2022 ending balances for accounts 1510001 and 1510008. For gas fuel stock, actual period ending inventory is used as the starting basis, which is then adjusted on a monthly forecast basis using a forecast % change in inventory multiplied against a forecast weighted average cost of gas to adjust the monthly balance. The forecast is projected through December 2023. Staff/2704, PGE Response to Staff DR No. 639, April 25, 2023.

Figure 4, below, shows the variation in PGE's gas balances projected for 2023.[99]

Figure 4. PGE's Projected 2023 Natural Gas Balances

[BEGIN CONFIDENTIAL]

[redacted]

[BEGIN CONFIDENTIAL]

Q. How should PGE have valued its contingency and variable gas stock?

A. The Company should instead have used *average* gas balances for 2023.

Q. Please explain why PGE should have used average gas balances.

A. The contingency and variable gas fuel stock balance is included in the rate base to allow stockholders a return on money invested in gas stock. But since gas balances will vary over the course of 2023, the December 2023 figure will *significantly overstate* the amount investors have actually invested in PGE's

99 Staff/2705, PGE Response to Staff DR No. 639_Attachment A_CONF, April 25, 2023.

gas fuel stock over the course of a year (the test year). They will in effect over earn.

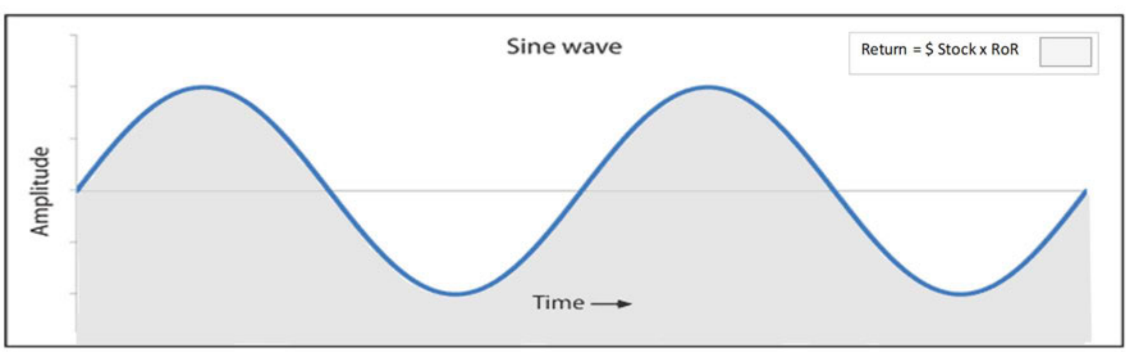
Q. Why does PGE's method of picking December 2023 (a peak month) lead to overearnings?

A. The notion is simple. The peak month does not represent an accurate estimate of how much PGE's investors have invested in fuel stock over the course of a year.

Q. Can you graphically illustrate the stockholders' overearnings under PGE's method?

A. Yes. Stylizing the variations in PGE's fuel stock as a sinus function, oscillating around an average level of investment, the notion may be graphically depicted as shown in the figure below. Theoretically, PGE's investors should be earning the shaded area under curve, which would be *at any point in time* the dollar value in fuel stock *times* a Commission approved rate of return ("RoR"): *Return = $Fuel Stock x RoR*.

Figure 5. PGE's Approved Rate of Return on Fuel Stock



By contrast, PGE's method results in earnings greatly in excess of what would be the theoretically correct amount. The resulting overearnings are illustrated in the figure below.

[BEGIN CONFIDENTIAL]

Figure 6. PGE's Forecasted Rate of Return on Fuel Stock

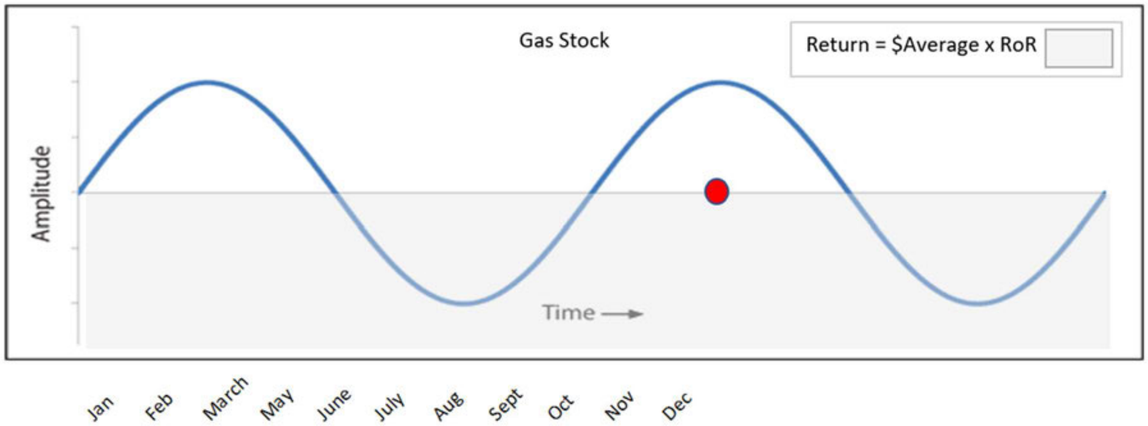
[redacted]

[END CONFIDENTIAL]

Q. Would the use of average gas stock balances correct for this error?

A. Yes. As is seen in the figure below, the use of average balances corrects for this error. That is, by using average balances, PGE's investors will on average receive the correct return on their investments.

Figure 7. PGE's Rate of Return on Fuel Stock Average Balances



Q. In correcting this error, should you exclude adjustments to the previously adjusted cushion gas portion of the gas stock?

A. Yes. The adjustment should only be made to the gas stock *net of cushion gas*. The portion[100] to which the adjustment should be made is shown in Figure 8, below.[101]

[100] Note that the percentages do not add to 100 percent because North Mist is rarely filled to maximum capacity.

[101] Staff/2705, PGE Response to Staff DR No. 647_Attach A_CONF, Dated April 25, 2023.

Figure 8. PGE's Fuel Stock Balance Net of Cushion Gas

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Have you recalculated PGE's gas stock (net of cushion gas) based on average balances?

A. Yes. Our calculations are found in Table 24, below.[102]

[102] Staff/2705, PGE Response to Staff DR No. 639_Attch A_CONF, Dated April 25, 2023. Cushion gas was previously calculated under Adjustment #1.

Table 24. PGE's Adjusted Fuel Stock Net of Cushion Gas at Average Balances

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Turning to *Adjustment 2(b)—EIA Prices*, what gas prices did PGE use?

A. PGE bases its gas stock on balances calculated over 15 months (October 2022 – December 2023) with a weighted average price per dth of *$5.60*.[103] This is considerably higher than what is projected by the EIA.

[103] Staff/2705, PGE Response to Staff DR No. 639_Attch A_CONF, Dated April 25. Excel: AVERAGE(B5:P5).

Q. By contrast, what are the EIA's projected gas prices for 2023 and 2024?

A. As seen in Table 25 (below), the EIA's projected gas prices for 2023 and 2024 are $2.91/ dth and $3.72/ dth, respectively. These prices are lower than the weighted average $5.60 / dth that PGE uses. In fact, PGE's projected per dth gas prices are about *91% and 59% higher than the EIA's*.

Table 25 EIA's Forecasted Gas Prices in 2023 and 2024[104]

Natural Gas	2021	2022	2023	2024
Natural gas price at Henry Hub (dollars per million Btu)	3.91	6.42	*2.91*	*3.72*
U.S. dry natural gas production (billion cubic feet per day)	94.57	98.13	*101.09*	*101.24*
U.S. natural gas consumption (billion cubic feet per day)	83.90	88.53	*87.54*	*86.05*

Q. Do the EIA's lower gas prices for 2023 and 2024 make intuitive sense?

A. Yes. First, the world is gradually adjusting to the turmoil in energy markets brought about by Russia's invasion of Ukraine.[105] Next, as can be seen in the above table, U.S. supply of natural gas is projected to increase while U.S.

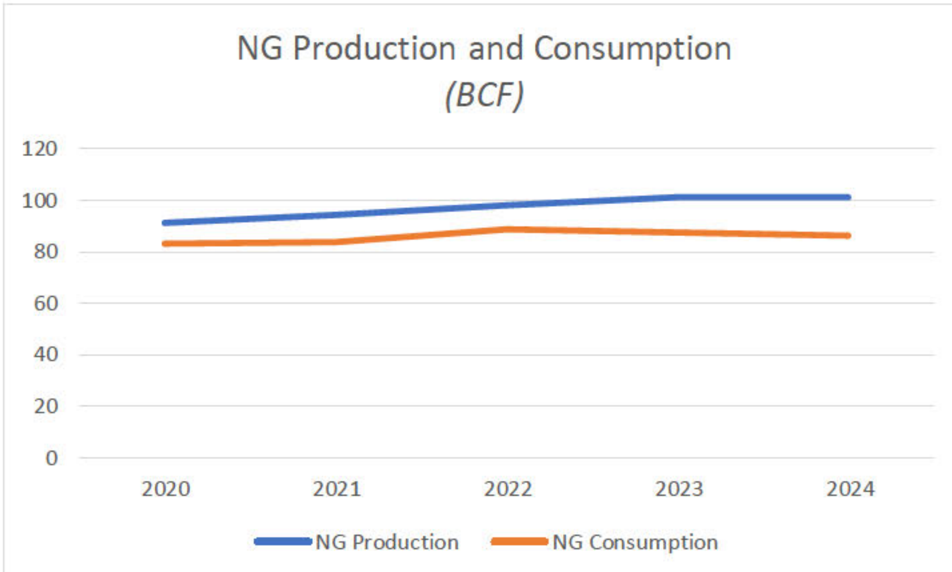
---

[104] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA): https://www.eia.gov/outlooks/steo/report/natgas.php

[105] For example, see https://www.nbcnews.com/news/world/why-russia-s-ukraine-invasion-spiked-energy-prices-4-charts-n1289799

consumption of natural gas is projected to decrease. These developments are also seen in Figure 9, below.[106]

Figure 9. Projected U.S. Natural Gas Consumption



Thus, with increased U.S. gas supplies (production) and a slight fallback in U.S. demand (consumption) for gas, simple market dynamics suggest that per dth gas prices should come down, as projected by the EIA.

Q. Have you adjusted PGE's gas stock for EIA-based prices?

A. Yes. We used EIA's price projection for 2024 as the relevant price per dth for natural gas. This resulted in a further downward adjustment of 34% of PGE's gas fuel stock. The 34 percent adjustment factor is calculated as shown in Table 26, below.[107]

---

106 Based on data from EIA: https://www.eia.gov/outlooks/steo/data/browser/#/?v=3

107 Based on data from EIA: https://www.eia.gov/outlooks/steo/data/browser/#/?v=3 ; PGE's $/dth was previously discussed.

Table 26. Adjustment Factor Based on EIA 2024 Forecast

[redacted]

[END CONFIDENTIAL]

<u>Adjustment #3. PGE's Contingency Gas is Excessive</u>

Q. Does PGE maintain a gas stock for contingencies?

A. Yes. As discussed above, PGE maintains a gas stock to keep PW1 going for seven peak days in case of an emergency in which North Mist's access to the Northwest Pipeline is disrupted. As previously shown in Table 20 (repeated here for convenience), PGE's contingency gas stock constitutes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[108] Staff/2705, PGE Response to Staff DR No. 647_Attach A_CONF, Dated April 25, 2023.

Table 20. PGE's Cushion and Contingency Gas

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does PGE overstate its stock of contingency gas?

A. Yes. The Company overstates its stock of contingency gas by about *$1.687 million*.

Following again the conceptual notion that *Stock = P x Q*, this $1.687 million reflects: (i) an adjustment of *quantity* (dth); and (ii) an adjustment in *price* (per dth).

Q. Please discuss the quantity and price adjustments that are necessary.

A. Specifically, the following *price* and *quantity* adjustments are needed:

Adjustment 3(a)—Price:

PGE's stock of contingency gas should reflect that the EIA predicts considerably lower *prices* for 2023 and 2024 than PGE.

Adjustment 3(b)—Quantity:

PGE's stock of contingency gas *volumes* (dth) (quantity) should be adjusted by 50 percent to reflect the following three considerations:

- There are many ways in which PGE can meet its energy demand in the event of a contingency. Also, in incidental situations of extreme emergencies, North Mist's cushion gas can temporarily be used as well;
- PGE fails to provide adequate support for the likelihood that emergencies will occur during peak days; and,
- PGE fails to provide an analysis that maintaining a permanent stock of contingency gas is cheaper than purchasing power.

Q. Turning first to *Adjustment 3(a)—Price*, have you already provided a discussion of why EIA prices should be used?

A. Yes. We have already discussed that the EIA projects lower gas prices than those used by PGE. There is no need to repeat that discussion.

Q. Have you also already made the necessary *price* adjustment in your re-calculation of PGE's gas stock (net of cushion gas).

A. Yes. When we re-valued PGE's gas stock, we applied EIA's lower prices to all of PGE's gas stock *net* of its stock of cushion gas (which we separately re-priced based on the historic prices of the cushion gas purchases). Therefore, no further *price* adjustments are needed.

Q. Turning to *Adjustment 3(b)—Quantity*, you noted three reasons that warrant an adjustment to PGE's stock of contingency gas. Please discuss the first of those.

A. PGE's stock of contingency gas should be reduced because the Company fails to consider that there are many ways in which the Company can meet energy demand in the event of a pipeline outage. First, North Mist's generally holds enough gas supply to accommodate temporary pipeline outages. Second, PGE's other facilities may be used to compensate for a disruption of gas supplies. Third, PGE can purchase power. Last, North Mist's cushion gas can temporarily be used in case of extreme emergencies.

Q. Please explain how cushion gas can temporarily be used in extreme emergencies.

A. This aspect of cushion gas—*its availability during emergencies*—is well-recognized. For example, Pacific Gas & Electric ("PG&E") notes the following in its discussion of cushion gas:

> According to EIA, *base gas* (or *cushion gas*) is defined as the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.
>
> Measures of base gas, working gas, and working gas capacity also can also change from time to time. These changes occur, for example, when a storage operator reclassifies one category of natural gas to the other, often as a result of new

> wells, equipment, or operating practices (such a change generally requires approval by the appropriate regulatory authority). *Finally, storage facilities can withdraw base gas for supply to market during times of particularly heavy demand, although by definition, this gas is not intended for that use.*[109] (*Emphasis added*.)

That is, PG&E recognizes—along with the EIA—that in case of emergencies cushion gas can be used to temporarily meet peak energy demand. Again, PGE ignores this in its fuel stock calculations.

Q. Did PGE provide an assessment of the likelihood of emergencies, motivating the need to permanently maintain a stock of contingency gas?

A. No. When asked to list examples of outages that warrant maintaining a sizable stock of contingency gas the PGE could not provide a single instance of a significant outage that over a sustained period affected the Northwest Pipeline. (The Northwest pipeline provides gas to the Company's North Mist storage facility.) The Company's answer was as follows:

> Because there is no business need or requirement, PGE did not maintain records of all instances in the last ten years when there were gas pipeline disruptions. However, one example is

109 https://www.pge.com/pipeline/news/newsdetails/index.page?title=20210610_2445_news#:~:text=According%20to%20EIA%2C%20base%20gas%20%28or%20cushion%20gas%29,also%20can%20also%20change%20from%20time%20to%20time.

the October 2018 gas pipeline rupture near Prince George in Canada, British Columbia, that caused natural gas supply shortages in the Pacific Northwest region. Additionally, as described in PGE Exhibit 300, Section III.F, natural gas prices in Western US have soared in Q4 of 2022 due to several factors, including pipeline constraints and reduced natural gas flows, according to the U.S. Energy Information Administration.[110]

Q. Would the potential of an occasional pipeline outage of relatively short duration warrant PGE's stock of contingency gas?

A. No. North Mist is typically already well stocked to accommodate demand surges or interruptions in gas supply, if such an interruption were to occur. Moreover, as noted previously, PGE's fuel oil for Beaver and the North Mist gas reserves for PW1 currently provide fuel redundancy only for 51% of the Westside Thermal Plants in on-peak hours. The 51% represents the average capacity of PW1 (i.e., approximately 400 MW) and two Beaver units (i.e., approximately 160MW).[111] *The other plants of the PW/Beaver complex operate without a contingency fuel stock*.

[110] Staff/2704, PGE Response to Staff DR No. 648, April 25, 2023.
[111] Staff/2704, PGE Response to Staff DR No. 650, April 25, 2023.

Q. You noted that, in case of a sustained pipeline outage that interrupts North Mist's gas supply during peak periods, PGE could also purchase power. Please explain.

A. Yes. In fact, North Mist does *not* provide fuel for all of the Company's Westside Thermal Facilities; thus, PGE may already have to purchase power in the event of a pipeline interruption. As PGE notes:

> During a contingency event, like a pipeline disruption that reduces or eliminates gas supply from the regional pipeline infrastructure, […] some portions of the generation (e.g., all of PW2 and up to four Beaver turbines) *would need to be replaced with power purchases* at potentially high market prices, because there would be no fuel supply available.[112]
>
> (Emphasis added.)

Q. Does the possibility that PGE may have to purchase power at high prices necessarily justify maintaining a permanent stock of contingency gas?

A. No. Clearly, there is a trade-off between the *permanent cost* of maintaining a stock of contingency gas and the possibility that at some point in the future the Company may have to *purchase power at high prices* during a sustained interruption of gas supplies. Indeed, for almost half of its Westside Thermal Facilities, PGE already has to rely on possible power purchases in the event of

[112] Staff/2704, PGE Response to Staff DR No. 650, April 25, 2023.

a pipeline interruption. But this does not prove the prudency of PGE's permanent investment in contingency gas.

Q. Did PGE do a financial analysis to examine this trade-off and to justify maintaining a stock of contingency gas?

A. No, PGE did not. As the Company notes:

> "[…] PGE did *not* conduct specific financial analyses to compare maintaining storage reserves at North Mist that support PW1 plant dispatch during potential supply disruption events with the cost of equivalent market energy purchases."[113] (Emphasis added.)

Q. In the absence of a financial analysis of this trade-off—between on the one hand the costs of maintaining a permanent stock of contingency gas and on the other the possibility of having to purchase power—would the Company have an incentive to *overstock* North Mist?

A. Yes. As discussed, fuel stock is included in the rate base and earns a return. The Company has no incentive to minimize its stock of contingency gas. The contrary is true.

Q. In sum, given the various ways in which PGE can accommodate energy demand in the event of a power outage, is PGE's permanent stock of

[113] Staff/2704, PGE Response to Staff DR No. 653, April 25, 2023.

contingency gas for just seven days of peak demand for some of the Westside Thermal Facilities justified?

A. No. To summarize, in the event of a unique power outage that is not only *sustained* but also occurs *during peak demand periods*, the Company can accommodate energy demand without the need for permanent stock of contingency gas in the following ways:

- PGE can use North Mist's existing gas storage supplies. (Average gas balances are typically already well above the minimal level of cushion gas.)
- If North Mist is running low, then PGE can temporarily tap into cushion gas supplies.
- Except for at extreme peak periods, PGE's other power plants may be able to absorb the deficiencies caused by the pipeline interruption.
- The Company can purchase power.

Q. Do you recommend a reduction in PGE's stock of contingency gas?

A. Yes. We recommend a 50 percent reduction in PGE's stock of contingency gas. This still provides for an additional 3.5 days of peak demand in the event all other options are depleted.

Q. Have you calculated the reduction in PGE's fuel stock associated with this recommendation?

A. Yes. As shown in Table 29 (below), this recommendation regarding PGE's stock of contingency gas would further reduce PGE's fuel stock by about *$1.687 million*.

Table 28. OPUC Staff's Adjustments to PGE's Contingency Gas

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Adjustment #4. PGE Overvalues Oil Stock

Q. What is the magnitude of PGE's Oil Stock?

A. As shown in Table 14 (above), PGE reports an oil stock of almost **[BEGIN CONFIDENTIAL]** [redacted] **END CONFIDENTIAL]**

Q. What is the purpose of PGE's oil stock?

A. It is contingency fuel for PGE's Beaver generation facility. According to PGE, the purpose of its oil stock is as follows:

> Oil inventory levels are based on the amount required to fuel PGE's Beaver Plant operations at full load for approximately *four to five days during heavy load hours*. Oil (diesel) is used at Colstrip to start the units. Typically, Colstrip will store sufficient diesel on site to support *three to five starts per year for each unit*.[114]

In other words, the purpose of PGE oil stock is twofold:

[114] Staff/2704, PGE Response to Staff DR No. 341, Dated March 16, 2023.

1. PGE's oil stock serves as a *contingency fuel* to power Beaver in case of gas pipeline interruptions (similar to the above description of PGE's stock of contingency gas), and,
2. PGE's oil (diesel) stock serves to start Colstrip.

Q. Has PGE indicated that all costs associated with Colstrip—including fuel costs (e.g., oil)—are excluded from its GRC filing?

A. Yes.[115]

Q. In sum, does this mean that PGE's oil stock serves only one purpose: contingency fuel for Beaver in the event of a pipeline/gas supply interruption?

A. Yes.

Q. Do the same problems exist here that you just discussed with respect to PGE's stock of contingency gas?

A. Yes. The same concerns apply here. In view of those concerns (and the many alternatives available to PGE), we find that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in *permanent oil stock* for a contingency—that may never happen—is excessive. (See our previous discussion of this issue with respect to PGE's contingency gas.)

Q. Do you have additional concerns regarding PGE's oil stock balance?

A. Yes. Following, again, the conceptual notion that *Stock = P x Q*, we have two additional concerns:

[115] Staff/2704, PGE Response to Staff DR No. 640, Dated April 25, 2023.

Adjustment 4(a)—Price:

PGE's oil stock is valued at *$105 per barrel of oil*.[116] That price is too high in view of projected developments in oil markets.

Adjustment 4(b)—Quantity:

PGE plans to phase out Beaver's ability to run on oil in 2024 and 2025. This invalidates the treatment of PGE's oil reserves as a stock to be included in the rate base.

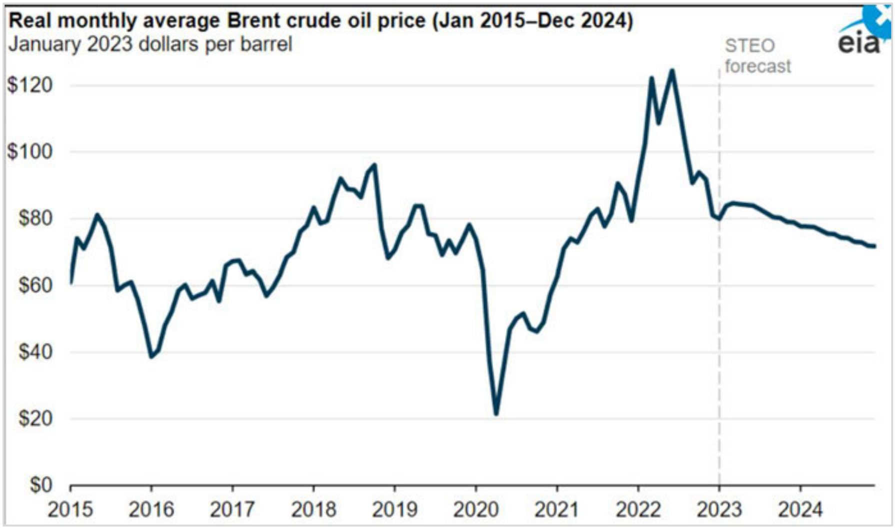
Q. Turning to *Adjustment 4(a)—Price*, does EIA project oil prices well below the $105 used by PGE for its oil stock?

A. Yes. PGE's oil stock reflects prices as of October 2022.[117] As Figure 10 below shows, oil prices at the end of 2022 are significantly higher than what is projected by EIA for 2024.

[116] Staff/2704, PGE Response to Staff DR No. 344_Attach B, Dated March 16, 2023. Calculated in Excel: Cells Q12/P12.

[117] Staff/2704, PGE Response to Staff DR No. 639, Dated April 25, 2023.

Figure 10. EIA Oil Price Forecast for 2024[118]



Specifically, EIA forecast prices around $80/barrel:

> EIA forecasts that oil prices will fall in 2023 and 2024. We expect that Brent crude oil prices will average $83 per barrel (b) in 2023 and $78/b in 2024, down from $101/b in 2022, mainly because we expect global oil production to outpace consumption. However, three key factors—Russia's oil production and ability to export petroleum products, several non-OPEC countries' ability to increase oil production, and China's loosening of COVID-related restrictions—could meaningfully affect our oil price outlook.[119]

[118] EIA forecast: https://www.eia.gov/outlooks/steo/report/BTL/2023/01-brentprice/article.php#:~:text=EIA%20forecasts%20that%20oil%20prices%20will%20fall%20in,we%20expect%20global%20oil%20production%20to%20outpace%20consumption.

[119] EIA forecast: https://www.eia.gov/outlooks/steo/report/BTL/2023/01-brentprice/article.php#:~:text=EIA%20forecasts%20that%20oil%20prices%20will%20fall%20in,we%20expect%20global%20oil%20production%20to%20outpace%20consumption.

Q. Does PGE itself assert that its oil stocks should be valued at the lower of cost or market ("LCM")?

A. Yes. PGE states its oil stock is valued at the lower of cost or market (LCM).[120]

Q. At a minimum, does this mean that PGE's oil stock should be reduced to reflect the LCM?

A. Yes. At a minimum, PGE's oil stock should be revalued at $80.50/barrel (average of $83 and $78 projected by EIA). This implies a 23 percent reduction PGE's oil stock from **[BEGIN CONFIDENTIAL]** [redacted][121] **[END CONFIDENTIAL]**

Q. Turning to Adjustment 4(b)—Quantity, you noted that PGE's oil reserves should no longer be treated as a stock to be included in the rate base. Please explain.

A. Yes. The notion of treating fuel stock as a component of the rate base is that it represents a permanent investment over which stockholders should be allowed to earn a return. That rationale is undermined by PGE's plans to convert the Beaver plant into a single-source facility: i.e., *it will no longer be able to use oil*.

As PGE explains:

> However, as part of the multi-year Beaver Emission Reduction Program (see PGE Exhibit 800), PGE is *removing fuel oil firing* capability at the Beaver plant. In *2024*, fuel oil firing capability will be removed from an additional two Beaver turbines, resulting in *four of the six Beaver turbines unable to consume*

[120] Staff/2704, PGE Response to Staff DR No. 340, Dated March 16, 2023.

[121] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

> *fuel oil*. Fuel oil firing capability will be removed from the final two Beaver turbines in *2025*.[122]

In other words, since the need for oil will disappear in 2023, over the Test Year period of 2024, and entirely in 2025, PGE's stock of contingency oil lacks the permanence of a stock.[123]

Q. Given that PGE is phasing out the use of oil for its Beaver plant, will PGE's reported stock of oil still be "*used and useful*," as required to be included in the rate base?

A. No. We must presume that as PGE's is phasing out its ability to use oil for the Beaver plant, PGE's reported oil stock by definition will no longer be *used and useful*. As such, it should be disallowed, at least in part.

While PGE's oil stock may not be phased out in linear fashion, the problem is that over time PGE's oil stock may either dwindle in volume, or as a matter of public utility accounting: i.e., as the Beaver plant is converted, not all of PGE's reported oil stock will be used and useful. The problem is graphically illustrated in Figure 11, below.

---

122 Staff/2704, PGE Response to Staff DR No. 650, Dated April 25, 2023.

123 Also, see PGE's discussion in UE 416 / PGE / 800 / Jenkins – Bekkedahl / 3. PGE notes:

> "In order to keep this plant operating reliably within 1 emission requirements, upgrades to modernize the plant are necessary. Work on the Beaver Emissions Reduction Program is planned to be completed in the coming years and will entail upgrading the existing natural gas turbine combustion systems from a dual fuel system to a single fuel dry low nitrogen oxide (NOx) system, reducing the overall emissions for the plant as the turbines are upgraded. The upgraded units will operate on natural gas as the fuel source. The combustion upgrade will allow for greater availability and reliability while meeting PGE's commitment to reduce emissions at the Beaver plant. *The capital investment associated with the upgrades that is expected to close to plant by* ***December 31, 2023***, is $56.9 million."

Figure 11. Illustrative Decline in PGE's Beaver Plant Oil Stock

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What do you recommend for PGE's oil reserves?

A. Our recommendation is twofold:

1. We recommend that the Commission disallow *50 percent* of PGE's oil stock. This reflects that not all of PGE's oil will continue to be used and useful—if any of it is used and useful at all. That is, as with PGE's stock of contingency gas, PGE has various means of meeting electricity demand in emergency situations, other than through contingency oil. These alternatives in themselves obviate the need for PGE's stock of contingency oil.
2. Also, PGE may actually sell off its oil stock over time. (To the extent that PGE does sell off its oil stock, we presume that the rate payers will be credited with the proceeds from such sales.)

Q. Given that you have already revalued PGE's oil stock for a price adjustment (*Adjustment 4(a)—Price*), what is the residual oil stock that PGE should be allowed to include in the rate base?

A. Recognizing that we have already reduced PGE's oil stock from **[BEGIN CONFIDENTIAL]** [redacted].[124] **[END CONFIDENTIAL]**

<u>**Cumulative Results of Adjustments #1 - #4 (*Gas & Oil*)**</u>

Q. You have recommended four adjustments to PGE's reported fuel stock of $31.485 million. Please present the cumulative impact of those adjustments.

A. Tables 30 and 31 (below) summarize our recommended adjustments and their impact on PGE's (i) *gas stock* and (ii) *oil stock*.

Table 29. Cumulative Impact of Gas Adjustment Nos. 1-3

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

[124] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Table 30. Cumulative Impact of Oil Adjustment Nos. 4(a) and 4(b)

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How do your results compare to PGE's proposed fuel stock balances?

A. Table 32, below, compares PGE's proposed fuel stock balances and Staff's.

Table 31. PGE's vs. OPUC Staff's Fuel Stock Balances

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What are your recommendations?

A. For reasons discussed herein, we recommend that the Commission adopt our adjustments and approve PGE's fuel stocks for gas and oil as we calculated and identified in summary Tables 30 through 32, above.

ISSUE 4. CO_2 ALLOWANCES

Q. To the extent that CO_2 allowances are associated with cap-and-trade / invest programs (i.e., California's and Washington's), are CO_2 allowances and those programs discussed by another member of the OPUC Staff?

A. Yes; they are discussed by Dr. Ishraq Ahmed. Our discussion here concerns only the extent to which PGE includes CO_2 allowances as fuel stock in the rate base, in *Operating Materials and Fuel Stock*.

Q. Does PGE list CO_2 allowances as part of its actual fuel stocks?

A. Yes. As part of its fuel stock workpapers, PGE lists about $3 million in CO_2 allowances for December 2022.[125] They are grouped in with coal fuel (for Colstrip and Boardman) as noted in Table 33 below.[126]

Table 32. PGE's CO_2 Allowances at December 31, 2022

Coal	$
Boardman	$ -
Colstrip	$ 3,494,977
CO2 Allowances	$ 3,020,985
Total Coal	**6,515,961**

Q. Are all of those CO_2 allowances associated with California's Cap-and-Trade program?

A. Yes. PGE does not yet have CO_2 allowances associated with Washington's Cap-and Invest program. As the Company notes:

> PGE has yet to purchase any Washington Cap-and-Invest Program allowances, there are no amounts recorded within

[125] Staff/2704, PGE Response to Staff DR No. 344_Attach B, Dated March 16, 2023.

[126] As previously noted, PGE does not include any costs associated with its coal plants in its GRC.

> PGE's actual inventory balances, nor any amounts forecast within PGE's test year rate base.[127]

Q. Oddly, does PGE claim that it failed to include CO_2 allowances in its GRC filing?

A. Yes. In response to a OPUC data request, PGE stated:

> PGE's fuel inventory test year forecast is derived from PGE's financial forecasting modeling software, which summarizes fuel inventory into two primary categories (i.e., oil & gas and coal) for reporting and forecasting purposes. Because PGE's carbon allowances are rolled up under coal in this software, *they were inadvertently excluded* from PGE's test period revenue requirement forecast. PGE's normal method of forecasting carbon allowances simply carries forward the most recent actual period ending balance. No additional assumptions are made. *PGE will update its revenue requirement within reply testimony* to correctly reflect the current balance of carbon allowances in inventory. *As of March 31, 2023 the current inventory balance was $3,020,973*.[128] (Emphasis added.)

Q. While PGE has not yet included CO_2 allowances in its Fuel Stock (Operating Materials and Fuel Stocks) account in the rate base, should the Commission allow PGE to include the full $3,020,973 in Fuel Stocks?

A. No, allowances are essentially different from fuels, such as oil and gas. Unlike fuel that needs to be available to instantaneously meet the Company's electricity demand, CO2 allowances can be purchased and sold at opportune times independent of the particular timing of electricity demand. This

[127] Staff/2704, PGE Response to Staff DR No. 732 (d), May 19, 2023.

[128] Staff/2704, PGE Response to Staff DR No. 642 (d), May 9, 2023

characteristic of CO_2 allowance warrants a different justification for building up and maintaining a stock.

Q. What are CO_2 allowances?

A. CO2 allowances are “permits”, typically issued by a government entity (state or federal) under an emissions cap-and-trade regulatory program, that allow its owner to emit one ton of a pollutant, greenhouse gases (“GHG”), such as CO_2e. They are “tradable rights,” representing 1 ton of CO_2-equivalent pollutants that were not released into the atmosphere.[129]

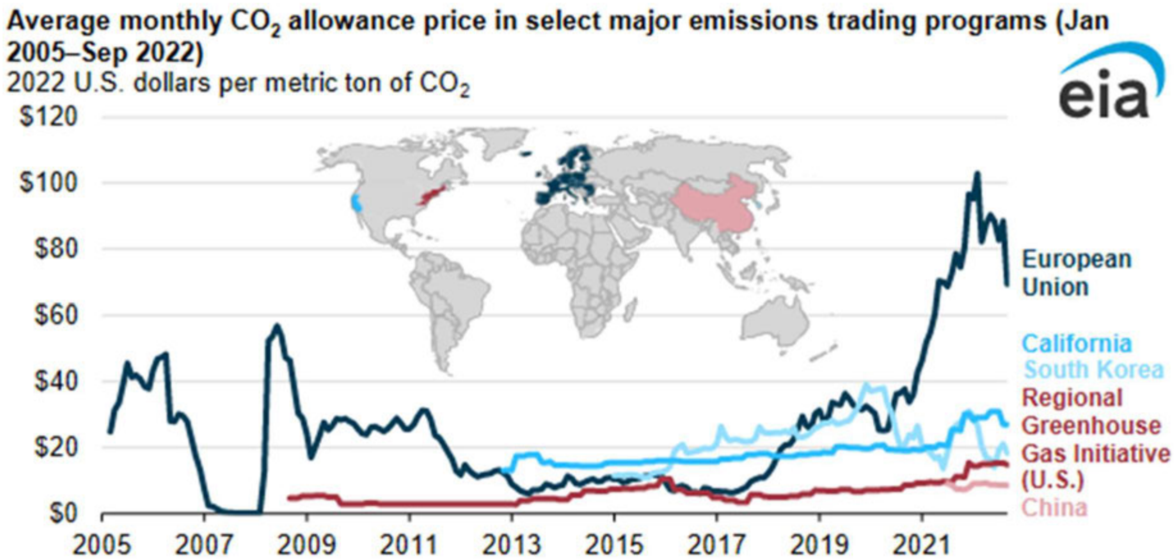
Under a cap-and-trade system, the supply of GHG allowances is limited by the mandated ‘cap.’ Allowances can be allocated freely by the governing program, be *purchased when auctions are held, or be purchased from other entities that have excess.*

Q. Are carbon markets growing and increasingly sophisticated?

A. Yes. The growth in carbon markets is discussed by the EIA and seen in the figure below. While European carbon markets are more advanced, markets in the United States are growing, mostly due to California’s cap-and-invest program, but now also Washington’s cap-and-invest program.

[129] For example, PGE anticipates having to obtain CO_2 allowances because it will likely exceed the threshold of 25,000 $MTCO_2e$ (metric ton of CO_2 equivalent) of GHG emissions when it sells power that sinks in Washington.

Figure 12. EIA Average Monthly CO_2 Allowances in Major Trading Programs[130]



Q. Is PGE now subject to cap-and-trade regulations from Oregon's neighboring states, causing it to consider the cost of CO_2 allowance in its dispatch decisions?

A. Yes. Oregon's neighboring states, California[131] and Washington,[132] have cap-and-trade/invest programs in place. This means that PGE should now consider the cost of CO_2 allowances when it wheels power that sinks in those states. It also raises the question of whether and to what extent PGE should hold a stock of CO_2 allowances.

---

130 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

131 California adopted cap-and trade regulations in 2010 and 2022. https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program

132 The states of Washington adopted a cap-and invest program as part of its Clean Energy Transformation Act (CETA), in 2019. https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act/Cap-and-invest

Again, the issue of cap-and-trade / invest programs is discussed in more detail by Staff witness Dr. Ahmed.

Q. Have GAAP and FASB issued accounting rules for CO_2 allowances?

A. No.[133] As PGE notes, "To the best of our knowledge, there are currently no standards under US GAAP that are specific to carbon offsets or credits."[134]

Q. How has PGE elected to treat CO_2 allowances from an accounting perspective?

A. We asked this question of PGE, and the Company answered that it is treating CO_2 allowances as "inventory." Specifically, the Company answered as follows: [135]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

133 https://advisory.kpmg.us/articles/2023/carbon-offsets-credits-ifrs-accounting-standards.html

134 Staff/2704, PGE Response to Staff DR No. 738, Dated May 5, 2023.

135 Staff/2705, PGE Response to Staff DR No. 642_Attachment A_CONF, Dated May 5, 2023.

Q. Would building up an "optimal" inventory of CO_2 allowances involve a set of complex calculations?

A. Yes. As we noted, CO_2 allowances are different from other fuel stock components in that the Company has considerable leeway in timing its acquisitions. However, given that PGE needs to acquire CO_2 allowances through auctions with an often-finite supply, prices can be volatile. At the same time, holding an excess stock of CO_2 allowances is costly too, and may become more so in the future.

Q. You said that PGE has leeway in timing its acquisitions of CO_2 allowances. Please Explain.

A. As PGE itself notes, there are auctions and secondary markets where CO_2 allowances can be obtained:

> Auctions available to PGE are presently the auctions initiated by the Washington Department of Ecology. Secondary markets available to PGE would include brokers, bilateral trading partners, and exchanges (e.g., PGE anticipates the Intercontinental Exchange will facilitate trading of Washington allowances at a future date).[136]

Of course, the ready availability of auctions and secondary markets mitigate against holding a substantial stock of CO_2 allowances.

[136] Staff/2704, PGE Response to Staff DR No. 744, Dated May 5, 2023.

Q. Did PGE perform a financial analysis to support its $3 million stock of CO_2 allowances?

A. No. We asked that question of PGE, and the Company answered as follows: "PGE does not have financial calculations used to determine an optimal stock of CO_2 allowances."[137]

Q. What did Staff recommend with respect to PGE's stock of CO_2 allowances in UE 394?

A. Staff found that CO_2 allowances do not meet the requirement that investments included in the rate base be "used and useful" and recommended disallowing them. Given that UE 394 was settled, the Commission did not rule on this recommendation.

Q. What are your recommendations?

A. As noted, PGE inadvertently omitted including its stock of $3 million CO_2 allowances. The Company noted that it will update its filing to correct this omission—as the Company prepares its rebuttal testimony, we urge the Company to provide more substantial support for its *stock* of CO_2 allowances. Like Staff in U394, we look for a clear demonstration that CO_2 allowances are in fact used and useful before they are included in the rate base, as PGE proposes.

For now, in the absence of substantive support for its stock of CO_2 allowances and given that the Company does not necessarily need to hold a

[137] Staff/2704, PGE Response to Staff DR 744 (h), May 19, 2023.

substantial stock at this point, we provisionally recommend that PGE's stock of CO_2 allowances of $3 million be disallowed.

Of course, we reserve the right to review the Company's rebuttal testimony, claims and work papers, and change our recommendation accordingly.

Q. Does this conclude your testimony?

A. Yes.

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESS: August Ankum

STAFF EXHIBIT 2701 Witness

Qualifications

August H. Ankum, Ph.D.

Partner
Chief Economist
QSI Consulting, Inc.
gankum@qsiconsulting.com

Biography

Dr. Ankum is a founding partner of QSI and serves as the firm's Chief Economist. Dr. Ankum assists corporate and government clients with economic and financial analyses and issues related to public policy and public utility regulation. While there is a special focus on regulated industries, such as telecommunications, electric, gas and maritime shipping, and rate case/revenue requirement/cost allocation analyses, Dr. Ankum's work experience generally encompasses the following:

- econometric modelling and economic growth and employment forecasts
- industrial organization and competitive market analysis
- due diligence and asset evaluations
- complex litigation, breach of contract and damages calculations, intellectual property disputes
- regulatory policy, tariff issues, rate cases (cost of service, rate design, cost of capital)
- interconnection and contract negotiations and billing disputes

Dr. Ankum also assists corporate and government clients with antitrust issues related to proposed mergers and acquisitions, such as:

- general market dominance/competitiveness analysis
- application of U.S. DoJ/FTC standards for merger approvals
- projected impact of mergers on affiliated transactions, economic and financial viability, quality and availability of products and services, and end-user/retail and wholesale prices

Before co-founding QSI in 1999, Dr. Ankum was President of Ankum & Associates, Inc., which provided economic consulting services for a variety of companies and public agencies. Prior to that, in 1996, he served as Senior Economist for MCI Telecommunications Corporation's Public Policy Division, and before that, in 1995, as a Manager in the Regulatory and External Affairs Division of Teleport Communications Group, Inc. (subsequently purchased by AT&T). While at MCI and TCG, Dr. Ankum worked as an economist and provided advice on public policy issues before the FCC and state public utility commissions.

Dr. Ankum began his career at the Texas Public Utility Commission, in 1987, where he worked as an economist on electric utility and telecommunications issues.

Educational Background

Ph.D., Economics *University of Texas, Austin, Texas*	1992
Master of Arts, Economics *University of Texas, Austin, Texas*	1987
Bachelor of Arts, Economics *Quincy College, Quincy, Illinois*	1982

Professional Experience

QSI Consulting (1999 to Current)	Founding Partner, Chief Economist
Ankum & Associates (1996 - 1999)	Founding Partner and President
MCI (1995 - 1996)	Senior Economist
TCG (1994 - 1995)	Manager
Public Utility Commission of Texas (1987 – 1994)	Chief Economist, and Economist.

EXPERT TESTIMONY

The information below is Dr. Ankum's best effort to identify all proceedings wherein he has provided pre-filed written testimony, an expert report, live testimony or participated in some other meaningful way (e.g., affidavit, deposition).

Civil Litigation and Arbitrations

Ingham County Circuit Court
Case No. 04-689-CK
T&S Distributors, LLC Custom Software, Inc., Arq, Inc., Absolute Internet, Inc., CAC Medianet, Inc,. ACD Telecom, Inc., and Telnet Worldwide, Inc. V. Michigan Bell Telephone Company, d/b/a SBC Michigan.
On behalf of ACD Telecom, Inc. and Telnet Worldwide, Inc.

JAMS Reference No.1340005643
Case No. 05-C-6250
Cingular Wireless, LLC, a Delaware Limited Liability Company V. PlatinumTel Communications, LLC, a Delaware Limited Liability Company
On behalf of PlatinumTel Communications, LLC.

U.S. District Court, Northern District of Illinois Eastern Division
Case No. 05-C-6250
Cingular Wireless, LLC, a Delaware Limited Liability Company V Omar Ahmad
On behalf of Omar Ahmad.

United States District Court, Northern District of Texas Dallas Division
Civil Action No. 09-CV-1268
Southwestern Bell Telephone Company, et. al. Plaintiffs, vs. IDT Telecom, Inc., Entrix Telecom, Inc., and John Does 1-10, Defendants.
On behalf of IDT

United States District Court, Northern District of Texas, Fort Worth Division.
Case No. 4:09-cv-755-A
Transcom Enhanced Services, Inc. v. Qwest Corporation
On behalf of Transcom

District Court for the Eastern District of Texas, Sherman Division
Case Nos. 4:11-MC-0053, 4:11-MC-0054, 4:11-MC-0055; Case No. 11-42464, and Adversary Proceeding No. 11-4160
IN RE: Halo Wireless, Inc. Debtor
On behalf of Halo Wireless, Inc.

Superior Court Judicial District of Hartford
Complex Litigation No. (Xo7) HHD-CV-10-6013996S,
BTHRIFTY, LLC, Plaintiff, v. Comcast Spotlight, LLC, et al, Defendants
On behalf of Comcast Spotlight, LLC

United States District Court Northern District of Texas, Dallas Division
Civil Action No. 09-CV-1268
Southwestern Bell Telephone Company, et al, Plaintiffs, vs. IDT Telecom, Inc., ENTRIX Telecom, Inc., and John Does, 1-10, Defendants.
On behalf of IDT Telecom, Inc.

United States District Court for the Western District of Arkansas
Civil Action No: 5:14-cv-5275-TLB
*In Re Global Tel*Link Corporation ICS Litigation.*
On behalf of Counsel for Plaintiffs

U.S. District Court for the Eastern District of Pennsylvania
Civil Action No.: 2:12-cv-00859-JD
Comcast Cable Communications, LLC; TVWorks, LLC; and Comcast MO Group, Inc., V Sprint Communications Company, L.P.; Sprint Spectrum L.P.; and Nextel Operation, Inc., Defendants: Sprint Communications Company, L.P. and Sprint Spectrum L.P., Counterclaim-Plaintiffs, V Comcast Cable Communications, LLC; Comcast IP Phone, LLC; Comcast Business Communications, LLC; and Comcast Cable Communications Management, LLC, Counterclaim- Defendants.
At the request of counsel for the Comcast entities.

State of Michigan, In the Circuit Court for the County of Washtenaw
Civil Action: Case. 17-1024-CB
MERIT NETWORK, INC., a Michigan non-profit corporation, Plaintiff, v. AMCOMM TELECOMMUNICATIONS, INC., a Michigan corporation, Defendant.
At the request of counsel for Merit Network, Inc.

United States District Court District of South Carolina Charleston Division
Case No: 2:17-cv-02562-DCN
Crown Castle NG East LLC (Plaintiff) v. City of Charleston (Defendant)
At the request of counsel for Crown Castle NG East LLC

District Court, City and County of Denver, State of Colorado
Case Number: 2018CV31548
CORESITE DENVER, LLC (Counterclaim-Defendant) v. DGEB MANAGEMENT, LLC, a Colorado limited liability company, DGEB MMR, LLC, a Colorado limited liability company, and NANCY CASADOS, an individual. (Counterclaimants)
On behalf of Counterclaimants

In the United States District Court for the Eastern District of Wisconsin
Civil Case No. 2:08-CV-00724-LA
UNITED STATED OF AMERICA, ex rel. TODD HEATH, Plaintiff-Relator, v. WISCONSIN BELL, INC., Defendant,
On behalf of Plaintiff-Relator

American Arbitration Association, Arbitration No. 01-21-0002-4566
Southwestern Bell Telephone Company d/b/a AT&T Texas & AT&T Missouri
Claimants v. USIC Locating Services, LLC *Respondent*

Superior Court of the State of California, County of Los Angeles
Case No. 21STCV39637
Smithfield Packaged Meats Corp. (f/k/a John Morrell & Co.)
On behalf of Smithfield Packaged Meats Corp.

U.S. District Court, Middle District of Florida– Orlando Division Case No. 6:17-cv-00236-PGB-TBS
Local Access, LLC., Plaintiff, Counterclaim Defendant v. Peerless Network, Inc. Defendant, Counterclaim Plaintiff v. Blitz Consulting, LLC., Counterclaim Defendant
On behalf of Peerless Network, Inc.

Administrative Law Proceedings and Other Activities

Chicago Clean Energy Coke/Coal Gasification to SNG Project, Analysis of Return on Equity per Section 9-220(h-3)(1)(B) of Public Act 97-96, October 12, 2011
In re Proposed Contracts between Chicago Clean Energy, Inc. and Ameren Illinois Company and Between Chicago Clean Energy, Inc. and Northern Illinois Gas Company for the Purchase and Sale of Substitute Natural Gas Under the Provisions of Illinois Public Act 97-0096.
On behalf of Illinois Power Agency, presented in Illinois Commerce Commission
Docket 11-0710

Cost of Capital Analysis for Cooperatives
Cost of Capital for Cooperatives and other Issues, prepared on behalf of the Utah Office of Consumer Services, 2013.

Before the Michigan House Committee on Energy and Technology
Presentation on House Bills 4257 (Re: Switched Access Charges)
On behalf of Michigan Internet and Telecommunications Alliance

Before the Arkansas Public Service Commission
Docket No. 15-011-U
In the Matter of SourceGas Arkansas for Approval of a General Change in Rates and Tariffs
On behalf of Arkansas Office of the Attorney General

Before the Arkansas Public Service Commission
Docket N. 15-034-U
In the Matter of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover all Investments and Expenses in Compliance with Rules Regulations or Requirements Relating to the Public health, Safety, or Environment under the Federal Clean Air Act
On behalf of Arkansas Office of the Attorney General

Before the Arkansas Public Service Commission
Docket No. 15-015-U
In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service
On behalf of Arkansas Office of the Attorney General

Before the Arkansas Public Service Commission
Docket No. 15-098-U
In the Matter of the Application of CenterPoint Energy Resources Corp., D/B/A CenterPoint Energy Arkansas Gas, for a General Change or Modification in its Rates, Charges and Tariffs
On behalf of Arkansas Office of the Attorney General

Before the Arkansas Public Service Commission
Docket No. 16-052-U
In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs
On behalf of Arkansas Office of the Attorney General

Before the New Mexico Public Regulation Commission
Case No. 15-00261-UT
In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advioce Notice No. 513,
On behalf of the City of Albuquerque and Bernalillo County

Before the New Mexico Public Regulation Commission
Case No. 16-00276-UT
In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advioce Notice No. 533,
On behalf of the City of Albuquerque

Before the State Corporation of the State of Kansas
Docket No. 15-TKOG-236-COM
In the Matter of the Complaint Against of Texas-Kansas-Oklahoma Gas, LLC, (Respondent) for an Order for Adjustment and Refund of Unfair, Unreasonable and Unjust rates for the Sale of Natural Gas for Irrigation based on Inaccurate and/or false pressure base measurements. By Circle H. Farms, LLC, Richard L. Hanson, Rome Farms and Stegman Farms Partnership (Complainants)
On behalf of Texas-Kansas-Oklahoma Gas, LLC, (Respondent)

Before the Hawaii Public Utility Commission
Docket No. 2019-0117
Application for Approval of a General Rate Increase and Certain Tariff Changes
On behalf of Young Brothers, LLC

Before the California Public Utilities Commission
Consolidated Docket
Joint Application of AT&T Communications of California, Inc. (U 5002 C) and WorldCom, Inc. for the Commission to Reexamine the Recurring Costs and Prices of Unbundled Switching in Its First Annual Review of Unbundled Network Element Costs Pursuant to Ordering Paragraph 11 of D.99-11-050
On behalf of ATT and MCI

Before the Public Utilities Commission of the State of Colorado
Docket No. 10A-350T
Joint Application of Qwest Communications International, Inc. and CenturyLink, Inc. for Approval of Indirect Transfer of Control of Qwest Corporation, et al.
On behalf of Integra Telecom, Level 3 Communications, PAETEC Business Services, Cbeyond Communications, and Covad Communications Company

Before the Public Utilities Commission of the State of Colorado
Docket No. 08F-259T
Qwest Communications Company, LLC, (Complainant), v. MCIMetro, XO Communications Services, Time Warner Telecom, Granite Telecommunications, Eschelon Telecom, Arizona DialTone, CAN Communications, Bullseye Telecom, Inc., ComTel Telecom Assets, LP, Earnest Communications, Inc., Level3 Communications, LLC, and Liberty Bell Telecom, LLC. (Respondents)
On behalf of Eschelon Telecom, XO Communications Services, Granite Telecommunications, and ACN Communication Services

Before the Public Utilities Commission of the State of Colorado
Docket No. 07A-211T
In the Matter of Qwest Corporation's Application, Pursuant to Decision Nos. C06-1280 and C07-0423, Requesting that the Commission Consider Testimony and Evidence to Set Costing and Pricing of Certain Network Elements Qwest Is Required to Provide Pursuant to 47 U.S.C. §§ 251(B) and (C)
On Behalf of CBeyond Communications, Comcast Phone of Colorado, Covad Communications Company, Integra Telecom, PAETEC Business Services, XO Communications Services

Before the Connecticut Department of Public Utility Control
Docket No. 02-05-17
DPUC Investigation of Intrastate Carrier Access Charges
On behalf of AT&T and MCI

Before the Connecticut Department of Public Utility Control
Docket Nos. 09-04-21, 08-12-04
DPUC Investigation into the Southern New England Telephone Company's Cost of Service Re: Reciprocal Compensation and Transit Services
On Behalf of the Connecticut Department of Utility Control

Before the Delaware Public Service Commission
PSC Docket No. 00-025
Petition of Focal Communications Corporation of Pennsylvania For Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Bell Atlantic – Delaware, Inc.
On behalf of Focal Communications Corporation of Pennsylvania

Public Service Commission of the District of Columbia
Formal Case No. 1040
In the Matter of the Investigation into Verizon Washington, D.C. Inc.'s Universal Emergency Number 911 Services Rates in the District of Columbia
Advisor to the Public Service Commission of the District of Columbia

Before the Florida Public Utilities Commission
Docket No. 990649B-TP
Investigation into Pricing of Unbundled Network Elements
On behalf of AT&T Communications of the Southern States, MCImetro Access Transmission Services, MCI WorldCom Communications, and Florida Digital Network

Before the Florida Public Utilities Commission
Docket No. 030829-TP
In the Matter of Complaint of FDN Communications for Resolution of Certain Billing Disputes and Enforcement of UNE Orders and Interconnection Agreements with BellSouth Telecommunications, Inc.
On behalf of Florida Digital Network d/b/a FDN Communications

Before the Georgia Public Service Commission
Docket No. 6352-U
AT&T Petition for the Commission to Establish Resale Rules, Rates and terms and Conditions and the Initial Unbundling of Services
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 94-0048
Adoption of Rules on Line-Side Interconnection and Reciprocal Interconnection
On behalf of Teleport Communications Group, Inc.

Before the Illinois Commerce Commission
Docket No. 94-0096
Proposed Introduction of a Trial of Ameritech's Customer First Plan in Illinois
On behalf of Teleport Communications Group, Inc.

Before the Illinois Commerce Commission
Docket No. 94-0117
Addendum to Proposed Introduction of a Trial of Ameritech's Customer First Plan in Illinois
On behalf of Teleport Communications Group, Inc.

Before the Illinois Commerce Commission
Docket No. 94-0146
AT&T's Petition for an Investigation and Order Establishing Conditions Necessary to Permit Effective Exchange Competition to the Extent Feasible in Areas Served by Illinois Bell Telephone Company
On behalf of Teleport Communications Group, Inc.

Before the Illinois Commerce Commission
Docket No. 95-0315
Proposed Reclassification of Bands B and C Business Usage and Business Operator Assistance/Credit Surcharges to Competitive Status
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket 94-480
Investigation Into Amending the Physical Collocation Requirements of 83 Ill. Adm. Code 790
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 95-0458
Petition for a Total Local Exchange Wholesale Tariff from Illinois Bell Telephone Company d/b/a Ameritech Illinois and Central Telephone Company Pursuant to Section 13-505.5 of the Illinois Public Utilities Act
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 95-0296
Citation to Investigate Illinois Bell Telephone Company's Rates, Rules and regulations For its Unbundled Network Component Elements, Local Transport Facilities, and End office Integration Services
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 96-AB-006
In the Matter of MCI Telecommunications Corporation Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish and Interconnection Agreement with Illinois Bell Telephone Company d/b/a Ameritech Illinois
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 96-AB-007
In the Matter of MCI Telecommunications Corporation Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish and Interconnection Agreement with Central Telephone Company of Illinois
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 96-0486
Investigation into forward looking cost studies and rates of Ameritech Illinois for interconnection, network elements, transport and termination of traffic
On behalf of MCI Telecommunications Corporation

Before the Illinois Commerce Commission
Docket No. 98-0396
Phase II of Ameritech Illinois TELRIC proceeding
On behalf of MCIWorldCom

Before the Illinois Commerce Commission
Docket No. 00-0700
Illinois Commerce Commission On its Motion vs Illinois Bell Telephone Company Investigation into Tariff Providing Unbundled Local Switching with Shared Transport
On behalf of AT&T Communications of Illinois, Inc., and WorldCom, Inc.

Before the Illinois Commerce Commission
Docket No. 02-0864
In the Matter of: Illinois Bell Telephone Company, Filing to Increase Unbundled Loop and Nonrecurring Rates (Tariffs Filed December 24, 2002)
On Behalf of WorldCom, Inc., McLeodUSA Telecommunications Services, Inc., Covad Communications Company, TDS Metrocom, Allegiance Telecom of Illinois, RCN Telecom Services of Illinois, Globalcom, Z-Tel Communications, XO Illinois, Forte Communications, and CIMCO Communications

Before the Indiana Regulatory Commission
Cause No. 39948
In the matter of the Petition of MCI Telecommunications Corporation for the Commission to Modify its Existing Certificate of Public Convenience and Necessity and to Authorize the Petitioner to Provide certain Centrex-like Intra-Exchange Services in the Indianapolis LATA Pursuant to I.C. 8-1-2-88, and to Decline the Exercise in Part of its Jurisdiction over Petitioner's Provision of such Service, Pursuant to I.C. 8-1-2.6
On behalf of MCI Telecommunications Corporation

Before the Indiana Regulatory Commission
Cause No. 40178
In the matter of the Petition of Indiana Bell Telephone company, Inc. For Authorization to Apply a Customer Specific Offering Tariff to Provide the Business Exchange Services Portion of Centrex and PBX Trunking Services and for the Commission to Decline to Exercise in Part Jurisdiction over the Petitioner's Provision of such Services, Pursuant to I.C. 8-1-2.6
On behalf of MCI Telecommunications Corporation

Before the Indiana Regulatory Commission
Cause No. 40603-INT-01
MCI Telecommunications Corporation Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish and Interconnection Agreement with Indiana Bell Telephone Company d/b/a Ameritech Indiana
On behalf of MCI Telecommunications Corporation

Before the Indiana Regulatory Commission
Cause No. 40611
In the matter of the Commission Investigation and Generic Proceeding on Ameritech Indiana's Rates for Interconnection Service, Unbundled Elements and Transport and Termination under the Telecommunications Act of 1996 and Related Indiana Statutes
On behalf of MCI Telecommunications Corporation

Before the Indiana Regulatory Commission
Cause No. 40618
In the Matter of the Commission Investigation and Generic Proceeding on GTE's Rates for Interconnection, Service, Unbundled Elements, and Transport under the FTA 96 and related Indiana Statutes
On behalf of MCI Telecommunication Corporation

Before the Indiana Regulatory Commission
Cause No. 40611-S1
In the matter of the Commission Investigation and Generic proceeding on the Ameritech Indiana's rates for Interconnection, Unbundled Elements, and Transport and Termination Under the Telecommunications Act of 1996 and Related Indiana Statutes
On behalf of WorldCom, Inc., AT&T Communications of Indiana

Before the Indiana Utility Regulatory Commission
Cause No. 42393
In the Matter of the Commission Investigation and Generic Proceeding of Rates and Unbundled Network Elements and Collocation for Indiana Bell d/b/a SBC Indiana Pursuant to the Telecommunications Act of 1996 and Related Indiana Statues
On Behalf of WorldCom, McLeodUSA Telecommunications Services, Covad Communications Company, Z-Tel Communications

Before the Iowa Utilities Board
Docket No. SPU-2010-0006
In RE: Qwest Communications International, Inc. and CenturyTel, Inc.
On behalf of PAETEC Business Services

Before the Iowa Utilities Board
Docket No: RPU-00-01
IN RE: US West Communications, Inc.
On behalf of McLeodUSA Telecommunications Services

Before the State of Maine Public Utilities Commission
Dockets Nos. 2007-611, 2008-214 through 2008-218, 2009-41-44.
CRC Communications of Maine, Inc., Investigation Pursuant to 47 U.S.C. §251(f)(1) Regarding CRC Communications of Maine's Request of Lincolnville, Telephone Company, UniTel, Inc., Oxford Telephone Company, Oxford West Telephone Company, Tidewater Telecom, Inc.
On behalf of CRC Communications and Time Warner Cable

Before the Maryland Public Utilities Commission
Case No. 8988
In the matter, The Implementation of the Federal Communications Commission's Triennial Review Order
On behalf of Cavalier Telephone

Before the Massachusetts Department of Energy and Transportation
D.P.U. 96-83
NYNEX/MCI Arbitration
On behalf of MCI Telecommunications Corporation

Before the Massachusetts Department of Energy and Transportation
Docket 01-20
Investigation into Pricing based on TELRIC for Unbundled Network Elements and Combinations of Unbundled Networks Elements and the Appropriate Avoided Cost Discount for Verizon New England, Inc. d/b/a Verizon Massachusetts' Resale Services
On behalf of Allegiance, Network Plus, El Paso Networks, and Covad Communications Company

Before the Massachusetts Department of Energy and Transportation
Docket 01-03
Investigation by the Department of Telecommunications and Energy on its own Motion into the Appropriate Regulatory Plan to succeed Price Cap Regulation for Verizon New England, Inc. d/b/a Verizon Massachusetts' intrastate retail telecommunications services in the Commonwealth of Massachusetts
On behalf of Network Plus

Before the Massachusetts Department of Telecommunications and Energy
D.T.E. 03-60
Proceeding by the Department on its own Motion to Implement the Requirements of the Federal Communications Commission's Triennial Review Order Regarding Switching for Mass market Customers
On behalf of Conversent Communications of Massachusetts

Before the Massachusetts Department of Telecommunications and Cable
D.T.E. 06-61
Investigation by the department on its own Motion as to the Propriety of the Rates and Charges Set Forth in the following tariff: M.D.T.E. No. 14, filed with the Department on June 16, 2006, to become Effective July 16, 2006, by Verizon New England, Inc. d/b/a Verizon Massachusetts
On behalf of Broadview networks, DSCI Corporation, InfoHighway Communications, Metropolitan Telecommunications of Massachusetts a/k/a MetTel, New Horizon Communications, and One Communications

Before the Massachusetts Department of Telecommunications and Cable
D.T.E. 07-9
Department Investigation into the Intrastate Access Rates of Competitive Local Exchange Carriers
On behalf of One Communications, PAETEC Communications, RNK Communications, and XO Communications Services

Before the Massachusetts Department of Telecommunications and Cable
D.T.E. 10-2
Petition of Choice One Communications of Massachusetts Inc., Conversent Communications of Massachusetts Inc., CTC Communications Corp. and Lightship Telecom LLC For Exemption from Price Cap on Intrastate Switched Access Rates as Established in D.T.C. 07-9
On behalf of One Communications

Before the Michigan Public Service Commission
Case No. U-10647
In the Matter of the Application of City Signal, Inc. for an Order Establishing and Approving Interconnection Arrangements with Michigan Bell Telephone Company
On behalf of Teleport Communications Group, Inc.

Before the Michigan Public Service Commission
Case No. U-10860
In the Matter, on the Commission's Own Motion, to Establish Permanent Interconnection Arrangements Between Basic Local Exchange Providers
On behalf of MCI Telecommunications Corporation

Before the Michigan Public Service Commission
Case No. U-11280
In the Matter, on the Commission's Own Motion, to consider the total service long run incremental costs and to determine the prices for unbundled network elements, interconnection services, resold services, and basic local exchange services for Ameritech Michigan
On behalf of MCI Telecommunications Corporation

Before the Michigan Public Service Commission
Case No. U-11366
In the matter of the application under Section 310(2) and 204, and the complaint under Section 205(2) and 203, of MCI Telecommunications Corporation against Ameritech requesting a reduction in intrastate switched access charges
On behalf of MCI Telecommunications Corporation

Before the Michigan Public Service Commission
Case No. U-13531
In the matter, on the Commission's own motion, to review the costs of telecommunications services provided by SBC Michigan
On behalf of AT&T, Worldcom, McLeodUSA, and TDS Metrocom

Before the Michigan Public Service Commission
Case No. U-11831
In the Matter of the Commission's own motion, to consider the total service long run incremental costs for all access, toll, and local exchange services provided by Ameritech Michigan
On behalf of MCIWorldCom, Inc.

Before the Michigan Public Service Commission
Case No. U-11830
In the matter of Ameritech Michigan's Submission on Performance Measures, Reporting, and Benchmarks, Pursuant to the October 2, 1998 Order in Case No. U-11654
On behalf of Covad Communications, McLeodUSA Telecommunications Services, LDMI Telecommunications, Talk America, and XO Communications Services

Before the Michigan Public Service Commission
MPSC Case No. U-14952
In the matter of the formal complaint of TDS Metrocom, LLC, LDMI, Telecommunications, Inc and XO Communications Services, Inc against Michigan Bell Telephone Company, d/b/a AT&T Michigan, or in the alternative, an application
On behalf of TDS Metrocom, LDMI Telecommunications, and XO Communications Services

Before the Minnesota Public Utilities Commission
Docket No. P-421, et al./PA-10-456
In the Matter of the Joint Petition for Approval of Indirect Transfer of Control of Qwest Operating Companies to CenturyLink
On behalf of Cbeyond Communications, Charter FiberLink, Integra Telecom, Level 3 Communications, PAETEC Business Services, TDS Metrocom, Orbitcom and POPP.com

Before the Minnesota Public Utilities Commission
PUC Docket No. P-442, 421, 3012 /M-01-1916
In Re Commission Investigation Of Qwest's Pricing Of Certain Unbundled Network Elements
On behalf of Otter Tail Telecom, Val-Ed Joint Venture d/b/a 702 Communications, McLeodUSA Telecommunications, Eschelon Telecom, and USLink

Before the Minnesota Public Utilities Commission
PUC Docket No . P-421/AM-06-713
OAH Docket No. 3-2500-17511-2
In the Matter of Qwest Corporation's Application for Commission Review of TELRIC rates Pursuant to 47 U.S.C. § 251
On behalf of Integra Telecom of Minnesota, McLeodUSA Telecommunications Services, POPP.com, Covad Communications Company, TDS Metrocom, and XO Communications

Before the Minnesota Public Utilities Commission
PUC Docket #P-421/CI-05-1996
OAH Docket No. 12-2500-17246-2
In the Matter of a Potential Proceeding to Investigate the Wholesale Rate Charged by Qwest
On behalf of Integra Telecom, McLeodUSA Telecommunications Services, POPP.com, Covad Communications Company, TDS Metrocom, and XO Communications

Before the Montana Public Service Commission
Docket No. D2010.5.55
In the Matter of Joint Application of Qwest Communications International, Inc. and CenturyLink, Inc., for Approval of Indirect Transfer of Control of Qwest Corporation, Qwest Communications Company, LLC, and Qwest LD Corp.
On behalf of Integra Telecom

Before the New Jersey Board of Public Utilities
Petition of Focal Communications Corporation of New Jersey For Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Bell Atlantic
On behalf of Focal Communications Corporation of New Jersey

Before the New Jersey Board of Public Utilities
Docket No. TO00060356
I/M/O the Board's Review of Unbundled Network Elements Rates, Terms and Conditions of Bell Atlantic-New Jersey, Inc.
On behalf of WorldCom, Inc.

Before the New Jersey Board of Public Utilities
Docket No. TO03090705
In The Matter, The Implementation Of the Federal Communications Commission's Triennial Review Order
On behalf of Conversent Communications of New Jersey

Before the New Jersey Board of Public Utilities
Docket No. TX08090830
In the Matter of the Board's Investigation and review of Local Exchange Carrier Intrastate Access Rates
On behalf of One Communications, PAETEC Communications, US LEC of Pennsylvania, Level3 Communications, and XO Communications Services

Before the New Mexico Public Regulation Commission
Case No. 11-00340-UT
In the Matter of the Petition of Qwest Corporation d/b/a CenturyLink QC For a Determination That Telecommunications Services Are Subject to Effective Competition in New Mexico
On behalf of the United States Department of Defense and all Other Federal Executive Agencies

Before the New Mexico Public Regulation Commission
Case No. 11-00305-UT
In the Matter of the Joint Petition for Determination of MCI Communications Services, Inc. d/b/a Verizon Business Services, et al. to Eliminate Certain Filing Requirements
On behalf of the United States Department of Defense and all Other Federal Executive Agencies

Before The New Mexico Public Regulation Commission
Case No. 96-307-TC
Brooks Fiber Communications of New Mexico, Inc. Petition for Arbitration
On behalf of Brooks Fiber Communications of New Mexico, Inc.

Before The New Mexico Public Regulation Commission
Case No. 3495, Phase B
In the matter of the consideration of costing and pricing rules for OSS, collocation, shared transport, non-recurring charges, spot frames, combination of network elements and switching.
On behalf of the Commission Staff

Before the New York Public Service Commission
Case Nos. 95-C-0657, 94-C-0095, 91-C-1174
Commission Investigation into Resale, Universal Service and Link and Port Pricing
On behalf of MCI Telecommunications Corporation

Before the New York Public Service Commission
Case 99-C-0529
In the Matter of Proceeding on Motion of the Commission To Reexamine Reciprocal Compensation
On behalf Of Cablevision LightPath, Inc.

Before the New York Public Service Commission
Case 98-C-1357
Proceeding on the Motion of the Commission to Examine New York Telephone Company's Rates for Unbundled Network Elements
On behalf of Corecomm New York, Inc.

Before the New York Public Service Commission
Case 98-C-1357
Proceeding on Motion of the Commission to Examine New York Telephone Company's Rates for Unbundled Network Elements
On behalf of MCIWorldCom

Before the State Of New York Public Service Commission
Case 02-C-1425
In The Matter, Proceeding on Motion of the Commission to Examine the Processes, and Related Costs of Performing Loop Migrations on a More Streamlined (e.g., Bulk) Basic
On behalf of Conversent Communications of New York, LLC

Before the Public Utilities Commission of Ohio
Case No. 96-888-TP-ARB
In the Matter of MCI Telecommunications Corporation Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish and Interconnection Agreement with Ameritech Ohio
On behalf of MCI Telecommunications Corporation

Before the Public Utilities Commission of Ohio
Case No. 96-922-TP-UNC.
In the Matter of the Review of Ameritech Ohio's Economic Costs for Interconnection, Unbundled Network Elements, and Reciprocal Compensation for Transport and Termination of Local Telecommunications Traffic
On behalf of MCI Telecommunications Corporation

Before the Public Utilities Commission of Ohio
Case No. 00-1368-TP-ATA
In the Matter of the Review of Ameritech Ohio's Economic Costs for Interconnection, Unbundled Network Elements, and Reciprocal Compensation for Transport and Termination of Local Telecommunications Traffic. Case No. 96-922-TP-UNC and In the Matter of the Application of Ameritech Ohio for Approval of Carrier to Carrier Tariff
On behalf of MCIWorldCom and AT&T of the Central Region

Before the Public Utilities Commission of Ohio
Case No. 97-152-TP-ARB
In the Matter of the Petition of MCI Telecommunications Corporation for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Cincinnati Bell Telephone Company
On behalf of the MCI Telecommunications Corporation

Before the Public Utility Commission of Ohio
Case No. 02-1280-TP-UNC
In the Matter of the Review of SBC Ohio's TELRIC Costs for Unbundled Network Elements
On Behalf of MCImetro Access Transmission Services, McLeodUSA Telecommunications Services, Covad Communications Company, XO Communications, and NuVox Communications

Before the Public Utility Commission of Ohio
Case No. 08-45-TP-ARB
In the Matter of the Petition of Communication Options, Inc. for Arbitration of Interconnection Rates, Terms and Conditions and Related Arrangements with United Telephone Company of Ohio d/b/a Embarq Pursuant to Section 252(b) of the Telecommunications Act of 1996
On behalf of Communications Options, Inc.

Before the Oregon Public Utility Commission
Docket UM 1484
In the Matter of CenturyLink, Inc. Application for Approval of Merger between CenturyTel, Inc. and Qwest Communications International, Inc.
On behalf of Covad Communications Company, Charter FiberLink, Integra Telecom, Level 3 Communications and tw telecom

Before the Oregon Public Utility Commission
Docket UM 1481
In the Matter of Staff investigation of the Oregon Universal Service Fund
On behalf of the Oregon Cable Telecommunications Association

Before the Pennsylvania Public Utility Commission
Docket No. I-00940035
In Re: Formal Investigation to Examine Updated Universal Service Principles and Policies for telecommunications Services in the Commonwealth Interlocutory order, Initiation of Oral Hearing Phase
On behalf of MCI Telecommunications Corporation

Before the Pennsylvania Public Utility Commission
Docket No. M-0001352
Structural Separation of Verizon
On behalf of MCI WorldCom

Before the Puerto Rico Telecommunications Regulatory Board
Docket No. 97-0034-AR
Petition for Arbitration Pursuant to 47 U.S.C. & (b) and the Puerto Rico Telecommunications Act of 1996, regarding Interconnection Rates Terms and Conditions with Puerto Rico Telephone Company
On behalf of Cellular Communications of Puerto Rico, Inc.

Before the Public Service Commission of South Carolina
Dockets Nos. 2008-325-C, 2008-326-C, 2008-327-C, 2008-328-C, and 2008-329-C
In Re: Docket No. 2008-325-C - Application of Time Warner Cable Information Services (South Carolina), LLC d/b/a Time Warner Cable to Amend its Certificate of Public Convenience and Necessity to Provide Telephone Services in the Service Area of Farmers Telephone Cooperative, Inc. and for Alternative Regulation
On behalf of Time Warner Cable

Before the Public Utility Commission of South Dakota
Docket TC07-117
In the Matter of the Petition of Midcontinent Communications for the Approval of its Intrastate Switched Access Tariff and for an Exemption from Developing Company-Specific Cost-Based Switched Access Rates
On Behalf of Midcontinent Communications, Inc.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission
Docket No. 2252
Comprehensive Review of Intrastate Telecommunications Competition
On behalf of MCI Telecommunications Corporation

Before the State of Rhode Island and Providence Plantations Public Utilities Commission
Docket Nos. 3550 and 2861
In The Matter, Implementation of the Requirements of the FCC's Triennial Review Order ("TRO")
On behalf of Conversent Communications of Rhode Island, LLC

Before the Tennessee Public Service Commission
Docket No. 96-00067
Avoidable Costs of Providing Bundled Services for Resale by Local Exchange Telephone Companies
On behalf of MCI Telecommunications Corporation

Before the Public Utility Commission of Texas
Docket No. 7790
Petition of the General Counsel for an Evidentiary Proceeding to Determine Market Dominance
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 8665
Application of Southwestern Bell Telephone Company for Revisions to the Customer Specific Pricing Plan Tariff
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 8478
Application of Southwestern Bell Telephone Company to Amend its Existing Customer Specific Pricing Plan Tariff: As it Relates to Local Exchange Access through Integrated Voice/Data Multiplexers
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 8672
Application of Southwestern Bell Telephone Company to Provide Custom Service to Specific Customers
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 8585
Inquiry of the General Counsel into the Reasonableness of the Rates and Services of Southwestern Bell Telephone Company
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 9301
Southwestern Bell Telephone Company Application to Declare the Service Market for CO LAN Service to be Subject to Significant Competition
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 10382
Petition of Southwestern Bell Telephone Company for Authority to Change Rates
On behalf of the Public Utility Commission of Texas

Before the Public Utility Commission of Texas
Docket No. 14658
Application of Southwestern Bell Telephone Company, GTE Southwest, Inc., and Contel of Texas, Inc. For Approval of Flat-rated Local Exchange Resale Tariffs Pursuant to PURA 1995 Section 3.2532
On behalf of the Office of Public Utility Counsel of Texas

Before the Public Utility Commission of Texas
Docket No. 14658
Application of Southwestern Bell Telephone Company, GTE Southwest, Inc., and Contel of Texas, Inc. For Interim Number Portability Pursuant to Section 3.455 of the Public Utility Regulatory Act
On behalf of the Office of Public Utility Counsel of Texas

Before the Public Utility Commission of Texas
Docket Nos. 16226 and 16285
Application of AT&T Communications for Compulsory Arbitration to Establish an Interconnection Agreement Between AT&T and Southwestern Bell Telephone Company, and Petition of MCI for Arbitration under the FTA96
On behalf of AT&T and MCI

Before the Public Utility Commission of Texas
Docket No. 21982
Proceeding to examine reciprocal compensation pursuant to section 252 of the Federal Telecommunications of 1996
On behalf of Taylor Communications

Before the Public Utility Commission of Texas
Docket No. 25834
Proceeding on Cost Issues Severed from PUC Docket 24542
On behalf of AT&T and MCIMetro

Before the Public Utility Commission of Texas
PUC Docket No. 31831
Staff's Petition to Determine whether Markets of Incumbent Local Exchange Carriers (ILECs) Should Remain Regulated
On behalf of the Office of Public Utility Counsel of Texas

Before the Public Utility Commission of Texas
PUC Docket No. 34723
Petition for Review of Monthly Per-Line Support Amounts from the Texas High Cost Universal Service Plan Pursuant to PURA § 56.031 and P.U.C. Subst. R. 26.403
On behalf of the Office of Public Utility Counsel of Texas

Before the Public Utility Commission of Texas
Docket No. 33323
Petition of UTEX Communications Corporation for Post-Interconnection Dispute resolution with AT&T Texas and petition of AT&T Texas for Post Interconnection Dispute Resolution with UTEX Communications Corporation
On behalf of UTEX Communications Corporation

Before the Public Utility Commission of Texas
SOAH Docket No. 473-07-1365
PUC Docket No. 33545
Application of McLeodUSA Telecommunications Services, Inc. for Approval of Intrastate Switched Access rates Pursuant to PURA Section 52.155 and PUC Subst. R. 26.223
On behalf of McLeodUSA Telecommunications Services

Before the Utah Public Service Commission
Docket No. 10-049-16
Joint Application of Qwest Communications International, Inc. and CenturyTel, Inc. for Approval of Indirect Transfer of Control of Qwest Corporation, Qwest Communications Company, LLC and Qwest LD Corporation
On behalf of Integra Telecom, Level 3 Communications, PAETEC Business Services and tw telecom

Before the Utah Public Service Commission
Docket No. 01-049-85
In the Matter of the Determination of the Costs Investigation of the Unbundled Loop of Qwest Corporation, Inc.
On behalf of AT&T and WorldCom

Before the Public Service Commission of Utah
Docket No. 09-049-37
In the Matter of the Complaint of Qwest Corporation against McLeodUSA Telecommunications Services, Inc., d/b/a PAETEC Business Services
On behalf of McLeodUSA Telecommunications Services

Before the Vermont Public Service Board
Docket No. 5713
Investigation into NET's tariff filing re: Open Network Architecture, including the Unbundling of NET's Network, Expanded Interconnection, and Intelligent Networks
On behalf of MCI Telecommunications Corporation

Before the Washington Utilities and Transportation Commission
Docket No. UT-100820
In the matter of Joint Application of Qwest Communications International, Inc. and CenturyTel, Inc. for Approval of Indirect Transfer of Control of Qwest Corporation, Qwest Communications Company LLC, and Qwest LD Corp.
On behalf of Cbeyond Communications, Covad Communications Company, Integra Telecom, Level 3 Communications, PAETEC Business Services and tw telecom

Before the Washington Utilities and Transportation Commission
Docket No. UT-090892
Qwest Corporation (Complainant) v. McLeodUSA Telecommunications Services, Inc., d/b/a PAETEC Business Services (Respondent)
On Behalf of McLeodUSA Telecommunications Services

Before the Public Service Commission of Wisconsin
Cause No. 05-TI-138
Investigation of the Appropriate Standards to Promote Effective Competition in the Local Exchange Telecommunications Market in Wisconsin
On behalf of MCI Telecommunications Corporation

Before the Public Service Commission of Wisconsin
Docket 670-TI-120
Matters relating to the satisfaction of conditions for offering interLATA services (Wisconsin Bell, Inc. d/b/a Ameritech Wisconsin)
On behalf of MCI Telecommunications Corporation

Before the Public Service Commission of Wisconsin
Docket Nos. 6720-MA-104 and 3258-MA-101
In the Matter of MCI Telecommunications Corporation Petition for Arbitration Pursuant to Section 252(b) of the Telecommunications Act of 1996 to Establish an Interconnection Agreement with Wisconsin Bell, Inc. d/b/a Ameritech Wisconsin
On behalf of MCI Telecommunications Corporation

Before the Public Service Commission of Wisconsin
Docket No. 05-TI-349
Investigation Into The Establishment of Cost-Related Zones For Unbundled Network Elements
On behalf of AT&T Communications of Wisconsin, McLeodUSA Telecommunications Services, TDS Metrocom, and Time Warner Telecom

Before the Public Service Commission of Wisconsin
Docket No. 6720-TI-161
Investigation into Ameritech Wisconsin's Unbundled Network Elements
On behalf of AT&T Communications of Wisconsin, WorldCom, Rhythms Links, KMC Telecom, and McLeodUSA Telecommunications Services

<u>Affidavits and Declarations Submitted to the Federal Communications Commission</u>

Before the Federal Communications Commission
File No. EB-04-MD-006
EarthLink, Inc. (Complainant) v. SBC Communications Inc., SBC Advanced Solutions, Inc. (Defendants)
On behalf of Earthlink, Inc.

Before the Federal Communications Commission
CC Docket No. 04-223
In the Matter of Petition of Qwest Corporation for Forbearance Pursuant to 47 U.S.C. §160(c) in the Omaha Metropolitan Statistical Area
On behalf of McLeodUSA Telecommunications Services

Before the Federal Communications Commission
CC Docket No. 01-92
In the Matter of Developing a Unified Intercarrier Compensation Regime
On behalf of NuVox Communications

Before the Federal Communications Commission
CC Docket No. 01-92
In the Matter of Developing a Unified Intercarrier Compensation Regime
On Behalf of Cavalier Telephone, Inc.

Before the Federal Communications Commission
WC Docket No. 05-337 CC Docket No. 96-45 WC Docket No. 03-109 WC Docket No. 06-122 CC Docket No. 99-200 CC Docket No. 96-98 CC Docket No. 01-92 CC Docket No. 99-68 WC Docket No. 04-36
In the Matter of High-Cost Universal Service Support Federal-State Joint Board on Universal Service Lifeline and Link Up Universal Service Contribution Methodology, Numbering Resource Optimization Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Developing a Unified Intercarrier Compensation Regime, Intercarrier Compensation for ISP-Bound Traffic IP-Enabled Services
On behalf of PAETEC

Before the Federal Communications Commission
WC Docket No. 07-97
In the Matter of Petitions of Qwest Corporation for Forbearance Pursuant to 47 U.S.C. § 160(c) in the Denver, Minneapolis-St. Paul, Phoenix, and Seattle Metropolitan Statistical Areas
On behalf of PAETEC

Before the Federal Communications Commission
WC Docket No. 09-223
In the Matter of: Cbeyond, Inc. Petition for Expedited Rulemaking to Require Unbundling of Hybrid, FTTH, and FTTC Loops Network Elements Pursuant to 47 U.S.C. §251(c)(3) of the Act
On behalf of Covad Communications Company

Before the Federal Communications Commission
GN Docket Nos. 09-47, 09-51, 09-137
Comments Sought on Broadband Study Conducted by the Berkman Center for Internet and Society, NBP Public Notice #13
On behalf of Covad Communications Company

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESS: Warren Fischer

STAFF EXHIBIT 2702 Witness

Qualifications

Warren R. Fischer, C.P.A., C.G.M.A.

Chief Financial Officer
QSI Consulting, Inc.

2500 Cherry Creek Drive South
Suite 319
Denver, Colorado, 80209-3279
(303) 722-2684 voice
(303) 883-9014 mobile
WFischer@QSIconsulting.com

Biography

Mr. Fischer is a QSI partner and currently serves as Chief Financial Officer. Mr. Fischer has over 25 years of experience in commercial litigation and regulatory matters involving the telecommunications, energy, maritime, and agricultural industries. Mr. Fischer's professional experience includes two years in public practice with Deloitte LLP and over 10 years of managing financial analysis, reporting and forecasting processes for various multi-national corporations. Mr. Fischer is also certified as both a C.P.A. and Chartered Global Management Accountant.

Mr. Fischer's litigation expertise centers on billing disputes, forensic accounting analyses, damages assessment, merger reviews, historical and forward-looking economic cost methodologies, management audits, and multi-state tax sourcing of income through cost of performance determination. Mr. Fischer's practice as a management consultant includes assisting clients with business planning, forecasting, operational and jurisdictional cost analyses, and building business intelligence platforms.

Mr. Fischer is an experienced and effective expert witness who has provided expert testimony and reports in over 60 proceedings before state and federal courts, 35 state utility commissions, and other administrative agencies.

Mr. Fischer holds active C.P.A licenses in the States of Colorado and California. He earned his Bachelor of Science degree in Business Administration with an emphasis in Accounting from the University of Colorado at Boulder. He is also a member of the American Institute of Certified Public Accountants (AICPA) in the Forensic and Valuation Services Section.

Educational Background

Bachelor of Science, Business Administration (emphasis in Accounting)
University of Colorado at Boulder, Boulder, Colorado — 1984

Certifications / Memberships

Certified Public Account in the States of Colorado and California
Chartered Global Management Accountant
Member of the AICPA
Member of the Forensic and Valuation Services Section of the AICPA

QSI consulting, inc.

Professional Experience

QSI Consulting, Inc.
2000 - Current
Chief Financial Officer

AT&T Corp.
1997 - 2000
Financial Manager
1996 - 1997
Supervisor
Network Services Division

AT&T Wireless Services
1995 - 1996
Marketing Analyst / Planner
Cellular Division

E. & J. Gallo Winery
1994 - 1995
Senior Financial Analyst
1991 - 1994
Operations Accountant

Century 21 Real Estate Corporation
1987 - 1991
Financial Analyst

Deloitte LLP
1985 - 1987
Audit-in-Charge

Expert Testimony – Profile

The information below is Mr. Fischer's best effort to identify all proceedings wherein he has either provided pre-filed written testimony, an expert report or provided live testimony.

American Arbitration Association, Commercial Arbitration Tribunal
Case Number: 01-21-0002-4566
Southwestern Bell Telephone Company and BellSouth Telecommunications, LLC, Claimants, vs. USIC Locating Services, LLC, Respondent
On behalf of Respondent

Expert Report	October 15, 2021
Rebuttal Expert Report	November 5, 2021
Deposition	January 4, 2022
Hearing	March 9, 2022

In the District Court, Nueces County, Texas, 117th Judicial District
Case Number: 2020DCV-2014-B
Southwestern Bell Telephone Company d/b/a AT&T Texas, Plaintiff vs. USIC Locating Services, LLC, Defendant
On behalf of Defendant

Expert Report	October 22, 2021
Deposition	December 15, 2021

In the United States District Court for the Norther District of Illinois, Eastern Division
Case Number: 1:18-cv-03114
CenturyLink Communications, LLC et. al., Plaintiffs/Counter Defendants v. Peerless Network, Inc. et. al., Defendants/Counter Plaintiffs
On behalf of Defendants/Counter Plaintiffs

Expert Report	September 4, 2020
Rebuttal Expert Report	October 20, 2020
Deposition	December 10, 2020

In the United States District Court for the Northern District of Iowa, Central Division
Case Number: 3:18-cv-03075
BTC, Inc. d/b/a BTC, Plaintiff v. AT&T Corp., Defendant
On behalf of Plaintiff
Expert Report August 30, 2019
Rebuttal Expert Report October 31, 2019

In the District Court, City and County of Denver, State of Colorado
Case Number: 2018CV31548
CoreSite Denver, LLC, Plaintiff v. DGEB Management, LLC, DGEB MMR, LLC, and Nancy Casados, Defendants. DGEB Management, LLC and DGEB MMR, LLC, Counterclaimants v. CoreSite Realty Corporation, CoreSite Denver, LLC, CoreSite, L.P., and John and Jane Does 1-10.
On behalf of Defendants and Counterclaimants
Expert Report June 7, 2019
Supplemental Expert Report July 5, 2019
Deposition July 18, 2019
Jury Trial August 20, 2019

In Support of Cross Telephone Company, L.L.C.'s Request for Review of Decision of The Universal Service Administrative Company (USAC Audit ID: HC2016BE031)
On behalf of Cross Telephone, L.L.C.
Declaration January 4, 2019

In the Matter of an Arbitration Under the Arbitration Rules of the ADR Institute of Canada Inc.
Between Zayo Canada Inc. and Zayo Group LLC, Claimants, and Bell Canada and Manitoba Telecom Services Inc., Respondents
On behalf of Claimants
Expert Report July 28, 2017

In the United States District Court of the Western District of Arkansas
Civil Action No. 5:14-cv-5275-TLB
*In Re Global Tel*Link Corporation ICS Litigation*
On behalf of Plaintiffs
Expert Report June 26, 2017
Deposition December 20, 2017

In the United States Bankruptcy Court, District of Nevada
Bankruptcy Case Number: 15-11680-ABL
Adversary Proceeding Number: 16-01003-ABL
Qwest Communications Company, LLC, Plaintiff v. MegaMedia, LLC; Warren Jason; Ted Shpack; David Goodale; David Glickman; Cliff Kaylin; Off The Hook Productions; Syncronet, Inc.; Stock Management Group, LP; Joy Enterprises, Inc; (JEI); Glickman Capital, Inc.; Does 1-10; and Roe Corporations 11 -20, Inclusive, Defendants
On behalf of Defendants
Expert Report January 20, 2017
Rebuttal Expert Report February 17, 2017
Deposition April 6, 2017

In the Circuit Court, Fifth Judicial Circuit, State of South Dakota, County of Brown
Case Number: 06CIV15-000134
James Valley Cooperative Telephone Company, et. al. Plaintiffs vs. South Dakota Network, LLC, et. al., Defendants
On behalf of Plaintiff
Expert Report January 11, 2017
Deposition March 3, 2017

In the United States District Court for the Southern District of New York
Civil Action No. 15-CV-870-(VM) (DF)
Peerless Network, Inc., et. al., Plaintiffs / Counter-claim Defendants, vs. AT&T Corp., Defendant
On behalf of Plaintiffs

Expert Report	August 26, 2016
Rebuttal Expert Report	November 23, 2016
Deposition	January 31, 2017

In the United States District Court for the District of South Dakota, Northern Division
Case Number: 1:14-CV-01018-RAL
Northern Valley Communications, L.L.C., a South Dakota Limited Liability Company; Plaintiff, vs. AT&T Corp., a New York Corporation; Defendant
On behalf of Plaintiff

Expert Report	August 3, 2015
Supplemental Expert Report	January 8, 2016
Rebuttal Expert Report	March 4, 2016
First Supplemental Rebuttal Expert Report	May 11, 2016
Deposition	May 26, 2016
Affidavit	June 15, 2017

In the United States District Court for the District of Minnesota
Case No. 10-cv-00490-MJD-SER
Qwest Communications Company, LLC, Plaintiff, v. Free Conferencing Corp.; Audiocom, LLC; Global Conference Partners; Basement Ventures, LLC; Vast Communications, LLC; Ripple Communications, Inc., Defendants
On behalf of Defendants

Expert Report	June 26, 2014
Deposition	September 12, 2014
Supplemental Expert Report	October 19, 2015
Deposition	February 5, 2016
Trial	August 2, 2016

In the United States District Court for The Middle District of Florida, Jacksonville Division
Civil Action No. 3:13-CV-29-J-32JRK
James D. Hinson Electrical Contracting Co., Inc.; Blythe Development Company; and Calloway Grading, Inc.; Individually and On Behalf Of All Others Similarly Situated; and National Utility Contractors Association, Plaintiffs v. AT&T Services, Inc. and BellSouth Telecommunications, LLC
On behalf of Plaintiffs

Declaration (summary of data within AT&T's CAMS database)	February 13, 2015
Declaration (analysis of claims within AT&T's CAMS database)	July 10, 2015

In the United States District Court for the Northern District of Iowa
Case Number: 5:13-cv-4117
Great Lakes Communication Corporation, an Iowa corporation, Plaintiff, v. AT&T Corp., a New York corporation, Defendant
On behalf of Plaintiff

Expert Report	August 18, 2014
Rebuttal Expert Report	November 5, 2014
Deposition	November 17, 2014

In the United States District Court for the Southern District of Iowa
Case Number: 4:07-cv-00078-JEG-RAW
Qwest Communications, Corporation, Plaintiff, v. Superior Telephone Cooperative, et al., Defendants
On behalf of Defendants
Expert Report — August 30, 2013
Damages Phase On behalf of Free Conferencing Corp.
Expert Report — September 21, 2015

In the District Court of the Fourth Judicial District of the State of Idaho, County of Ada
Case No. CV OC 1103406
Cable One, Inc. v. Idaho State Tax Commission
On behalf of Defendant
Expert Report — September 23, 2011
Deposition — January 31, 2012
Trial — February 25-27, 2013

In the United States District Court for The Middle District of Florida, Jacksonville Division
Civil Action No. 3:07-CV-598-TJC-MCR
James D. Hinson Electrical Contracting Co., Inc. and Jensen Civil Construction, Inc., Individually and On Behalf Of All Others Similarly Situated, Plaintiffs, v. BellSouth Telecommunications, Inc., Defendant
On behalf of Plaintiffs
Declaration — September 18, 2007
Expert Report — August 1, 2008
Deposition — August 20, 2008
Declaration for Class Certification — June 15, 2010
Supplemental Expert Report — June 30, 2011

United States District Court, Northern District of Illinois Eastern Division
Case No. 05-C-6250
Cingular Wireless, LLC, a Delaware Limited Liability Company V Omar Ahmad
On behalf of Omar Ahmad.
Report on Disputes and Business Losses Caused by Cingular Wireless, LLC — June 22, 2006

Federal Communications Commission Cases

Before the Federal Communications Commission
File No. EB-11-MD-006
In the matter of the formal complaint of Sprint Communications Company L.P. v. Tekstar Communications, Inc.
On behalf of Tekstar Communications, Inc.
Declaration — August 19, 2011
Amended Declaration — September 7, 2011

Before the Federal Communications Commission
File Nos. EB-01-MD-001 and EB-01-MD-002
In the matter of the formal complaints of AT&T corp. and Sprint Communications Company L.P., vs. Business Telecom, Inc.
On behalf of Business Telecom, Inc.
Affidavit — February 23, 2001
Deposition — March 7, 2001

State Public Utilities Commission Cases

Before the Public Utilities Commission of the State of Colorado
Docket No. 07A-211T
In the matter of Qwest Corporation's application, pursuant to Decision Nos. C06-1280 and C07-0423, requesting that the Commission consider testimony and evidence to set costing and pricing of certain network elements Qwest is required to provide pursuant to 47 U.S.C. §§ 251(b) and (c).
On behalf of CBeyond Communications, Comcast Phone of Colorado, LLC, DIECA Communications, Inc. d/b/a Covad Communications Company, Integra Telecom, Inc., McLeodUSA Telecommunications Services, Inc. d/b/a PAETEC Business Services, and XO Communications Services, Inc.
Rebuttal — October 30, 2009

Before the Public Utilities Commission of the State of Colorado
Docket No. 99A-161T
In the matter of the application of U S WEST Communications, Inc., to reduce business basic exchange and long-distance revenues upon receipt of the Colorado high-cost support mechanism in accordance with Decision No. C 99-222
On behalf of AT&T Communications of the Mountain States, Inc.
Direct — August 6, 1999

Before the Public Utilities Commission of the State of Colorado
Docket No. 98A-068T
In the matter of the application of U S WEST Communications, Inc., to restructure and reduce switched access rates pursuant to the stipulation in Docket No. 97A-540T
On behalf of AT&T Communications of the Mountain States, Inc.
Amended Direct — May 17, 1999
Supplemental — June 9, 1999

Before the Public Service Commission of the District of Columbia
Formal Case No. 1040
In the Matter of the Investigation into Verizon Washington, D.C. Inc.'s Universal Emergency Number 911 Services Rates in the District of Columbia.
Advisor to the Public Service Commission of the District of Columbia — 2008 - 2010

Before the Public Service Commission of Florida
Docket No. 041464-TP
Petition of Sprint–Florida, Inc. for Arbitration of an Interconnection Agreement with Florida Digital Network, Inc. Pursuant to Section 252 of the Telecommunications Act of 1996
On Behalf of Florida Digital Network, Inc. d/b/a FDN Communications
Direct — May 27, 2005

Before the Public Service Commission of Florida
Docket No. 990649B-TP
In re: investigation into pricing of unbundled network elements
On Behalf of AT&T Communications of the Southern States, Inc., MCImetro Access Transmission Services, LLC & MCI WorldCom Communications, Inc., and Florida Digital Network, Inc. (collectively called the "ALEC Coalition")
Rebuttal — January 30, 2002

Before the Illinois Commerce Commission
Docket No. 09-0315
Illinois Commerce Commission on its Own Motion vs McLeodUSA Telecommunications Services, Inc. d/b/a PAETEC Business Services: Investigation into Whether Intrastate Access Charges of McLeodUSA Telecommunications Service, Inc. d/b/a PAETEC Business Services are Just and Reasonable
On Behalf of McLeodUSA Telecommunications Services, Inc. d/b/a PAETEC Business Services
Rebuttal — April 6, 2010

Before the Illinois Commerce Commission
Docket No. 02-0864
Illinois Bell Telephone Company: Filing to increase unbundled loop and nonrecurring rates (tariffs filed December 24, 2002)
On Behalf of AT&T Communications of Illinois, Inc., WorldCom, Inc. ("MCI"), McLeodUSA Telecommunications Services, Inc., Covad Communications Company, TDS Metrocom, LLC, Allegiance Telecom of Illinois, Inc., RCN Telecom Services of Illinois, LLC, Globalcom, Inc., Z-Tel Communications, Inc., XO Illinois, Inc., Forte Communications, Inc., and CIMCO Communications, Inc.

Direct	May 6, 2003
Rebuttal	January 20, 2004
Surrebuttal	February 20, 2004
Supplemental Surrebuttal	May 5, 2004

Before the Indiana Utility Regulatory Commission
Cause No. 42393
In the matter of the commission investigation and generic proceeding of rates and unbundled network elements and collocation for Indiana Bell Telephone Company, Incorporated d/b/a SBC Indiana pursuant to the Telecommunications Act of 1996 and related Indiana statutes
On behalf of AT&T Communications of Indiana, G.P. and TCG Indianapolis ("AT&T), WorldCom, Inc. ("MCI"), McLeodUSA Telecommunications Services, Inc., Covad Communications Company, and Z-Tel Communications, Inc.

Response	August 15, 2003

Before the Maine Public Utilities Commission
Docket No. 2013-00340
NORTHERN NEW ENGLAND TELEPHONE OPERATIONS LLC d/b/a FAIRPOINT COMMUNICATIONS-NNE, Request for Increase in Rates and for Maine Universal Service Fund Support for Provider of Last Resort Service
Advisor to the Maine Public Utilities Commission

Examiner's Bench Analysis	May 13, 2014

Before the Maine Public Utilities Commission
Docket Nos. 2009-40 through 2009-44
CRC Communications of Maine, Inc. Investigation Pursuant to 47 U.S.C. § 251(f)(1) Regarding CRC Communication of Maine's Request of Lincolnville Telephone Company, Oxford Telephone Company, Oxford West Telephone Company, Tidewater Telecom, Inc., and UniTel, Inc.
On behalf of CRC Communications, Inc. d/b/a Pine Tree Networks

Direct	October 9, 2009
Rebuttal	March 10, 2010

Before the Maine Public Utilities Commission
Docket No. 2007-67
Verizon New England Inc., Northern New England Telephone Operations Inc., Enhanced Communications of Northern New England Inc., Northland Telephone Company of Maine, Inc., Sidney Telephone Company, Standish Telephone Company, China Telephone Company, Maine Telephone Company, and Community Service Telephone Co., Re: Joint Application for Approvals Related to Verizon's Transfer of Property and Customer Relations to Company to be Merged with and into FairPoint Communications, Inc.

Advisor to the Maine Public Utilities Commission	2007 - 2008

Before the Public Service Commission of Maryland
Case No. 8879
In the matter of the investigation into rates for unbundled network elements pursuant to the Telecommunications Act of 1996
On Behalf of the Staff of the Public Service Commission of Maryland

Rebuttal	September 5, 2001
Supplemental Rebuttal	October 4, 2001
Surrebuttal	October 15, 2001

Before the Massachusetts Department of Telecommunications and Cable
Docket DTC 10-2
Petition of Choice One Communications of Massachusetts, Inc., Conversent Communications of Massachusetts Inc., CTC Communications Corp. and Lightship Telecom LLC For Exemption from Price Cap on Intrastate Switched Access Rates as Established in D.T.C. 07-9
On Behalf of Choice One Communications of Massachusetts Inc., Conversent Communications of Massachusetts Inc., and CTC Communications Corp. and Lightship Telecom LLC

Direct	August 13, 2010
Rebuttal	December 15, 2010
Sur-Response	January 14, 2011

Before the Massachusetts Department of Telecommunications and Energy
Docket DTE 06-61
Investigation by the Department on its own motion as to the propriety of the rates and charges set forth in the following tariff: M.D.T.E. No. 14, filed with the Department on June 16, 2006, to become effective July 16, 2006, by Verizon New England, Inc. d/b/a Verizon Massachusetts
On Behalf of Broadview Networks, Inc.; DSCI Corporation; Eureka Telecom, Inc. d/b/a InfoHighway Communications; Metropolitan Telecommunications of Massachusetts, Inc., a/k/a MetTel; New Horizon Communications; and One Communications (collectively "CLEC Coalition")

Rebuttal Panel	September 12, 2006

Before the Massachusetts Department of Telecommunications and Energy
Docket DTE 01-20
Investigation by the department on its own motion into the appropriate pricing, based upon total element long-run incremental costs, for unbundled network elements and combinations of unbundled network elements, and the appropriate avoided cost discount for Verizon New England Inc., d/b/a Verizon Massachusetts' resale services
On Behalf of the CLEC Coalition

Rebuttal	July 17, 2001

Before the Michigan Public Service Commission
Case No. U-13531
In the matter, on the commission's own motion, to review the costs of telecommunications services provided by SBC Michigan
On behalf of AT&T Communications of Michigan, Inc., and TCG Detroit ("AT&T")

Initial	January 20, 2004
Final Reply	May 10, 2004

Before the Michigan Public Service Commission
Case No. U-11756
In the matter of the complaint of Michigan Pay Telephone Association et al. Against Ameritech Michigan and Verizon North Inc., f/k/a GTE North Incorporated
On behalf of Michigan Pay Telephone Association and the other payphone service provider Complainants

Direct	February 10, 2003

Before the Office of Administrative Hearings for the Minnesota Public Utilities Commission
MPUC P-5096, 5542/C-09-265, OAH Docket No. 12-2500-21151-2
In the matter of the Complaint by Qwest Communications Company, LLC against Tekstar Communications Inc. regarding Traffic Pumping.
On behalf of Tekstar Communications, Inc.
Direct October 3, 2011
Rebuttal March 30, 2012
Surrebuttal April 18, 2012

Before the Office of Administrative Hearings for the Minnesota Public Utilities Commission
MPUC Docket No. P-421/AM-06-713, OAH Docket No. 3-2500-17511-2
In the matter of Qwest Corporation's Application for Commission Review of TELRIC Rates Pursuant to 47 U.S.C. § 251
On behalf of Integra Telecom of Minnesota, Inc.; McLeodUSA Telecommunications Services, Inc.; POPP.com, Inc.; DIECA Communications, Inc., d/b/a Covad Communications Company; TDS Metrocom; and XO Communications of Minnesota, Inc., ("The CLEC Coalition")
Direct August 24, 2007

Before the Public Service Commission of the State of Montana
Docket No. D97.5.87
IN THE MATTER OF the Investigation into U S WEST Communications, Inc.'s Compliance with Section 271(c) of the Telecommunications Act of 1996
On behalf of AT&T Communications of the Mountain States
Direct June 1998
Rebuttal June 1998
Supplemental Rebuttal November 1998

Before the Public Service Commission of the State of Montana
Docket No. D96.12.220
IN THE MATTER of the Application of U S WEST Communications, Inc. to Restructure its Prices for Regulated Telecommunications Service.
On behalf of AT&T Communications of the Mountain States, Inc.
Direct October 1997

Before the Nebraska Public Service Commission
Application No. C-1628
In the matter of the Nebraska Public Service Commission, on its own motion, seeking to conduct an investigation into intrastate access charge reform and intrastate universal service fund
On behalf of AT&T Communications of the Midwest, Inc.
Direct October 20, 1998

Before the Nebraska Public Service Commission
Application No. C-1830
In the Matter of US West Communications, Inc., filing its notice of intention to file Section 271(c) application with the FCC and request for Commission to verify US West compliance with Section 271(c)
On behalf of AT&T Communications of the Midwest, Inc.
Direct and rebuttal August 1998

Before the Nebraska Public Service Commission
Docket No. C-1519
In the matter of the emergency petition of MCI Telecommunications Corporation and AT&T Communications of the Midwest, Inc. to investigate compliance of Nebraska LECs with FCC payphone orders
On behalf of AT&T Communications of the Midwest, Inc.
Direct January 20, 1998

Before the New Jersey Board of Public Utilities
Docket No. TX08090830
In the matter of the Board's investigation and review of local exchange carrier intrastate exchange access rates
On behalf of One Communications, PAETEC Communications, Inc., and US LEC of Pennsylvania, LLC
Panel Reply — April 20, 2009
Panel Rebuttal — June 22, 2009

Before the New Mexico Public Regulation Commission
Case No. 15-00058-UT
In the Matter of the Petition of Sacred Wind Communications, Inc. for Support from the New Mexico Rural Universal Service Fund
On behalf of The New Mexico Attorney General's Office
Direct — June 12, 2015
Rebuttal — June 30, 2015

Before the New Mexico Public Regulation Commission
Case No. 11-00340-UT
In the Matter of the Petition of Qwest Corporation d/b/a CenturyLink QC for a Determination that Telecommunications Services are Subject to Effective Competition in New Mexico
On behalf of The New Mexico Attorney General's Office
Direct — August 24, 2012
Supplemental — September 7, 2012

Before the New Mexico Public Regulation Commission
Case No. 11-00305-UT
In the Matter of the Joint Petition for Determination of MCI Communication Services, Inc. d/b/a Verizon Business Services; MCImetro Access Transmission Services LLC, d/b/a Verizon Access Transmission Services; Teleconnect Long Distance Services and Systems Company; TTI National, Inc. Verizon Long Distance LLC; Verizon Enterprise Solutions LLC; and Verizon Select Services, Inc., to Eliminate Certain Filing Requirements
On behalf of The New Mexico Attorney General's Office
Direct — June 28, 2012
Rebuttal — July 16, 2012

Before the New Mexico Public Regulation Commission
Case No. 10-00315-UT
In the matter of the application of Sacred Wind Communications, Inc. for approval of initial rates, terms and conditions of service and support from the New Mexico Universal Service Fund, and petition for variance from the New Mexico Universal Service Fund rules
On behalf of The New Mexico Attorney General's Office
Direct — February 2, 2011
Supplemental — April 6, 2011
Rebuttal — May 4, 2011

Before the New Mexico State Corporation Commission
Docket No. 96-310-TC and Docket No. 97-334-TC
In the matter of the consideration of the adoption of a rule concerning costing methodologies and In the matter of the implementation of new rules related to the rural, high-cost, and low-income components of the New Mexico universal service fund
On behalf of AT&T Communications of the Mountain States, Inc.
Direct — July 8, 1998
Rebuttal — August 5, 1998

Before the New Mexico State Corporation Commission
Docket No. 97-106-TC
In The Matter Of Qwest Corporation's Section 271 Application And Motion For Alternative Procedure To Manage The Section 271 Process
On behalf of AT&T Communications of the Mountain States, Inc.
Direct — July 1998
Rebuttal — July 1998
Reply — September 1998

Before the New Mexico State Corporation Commission
Docket No. 97-69-TC
On behalf of AT&T Communications of the Mountain States, Inc.
Direct — March 20, 1997

Before the North Carolina Utilities Commission
Docket No. P-100, Sub 133d, Phase I
In the matter of general proceeding to determine permanent pricing for unbundled network elements
On Behalf of New Entrants
Direct — August 11, 2000

Before the Public Service Commission of the State of North Dakota
Case No. PU-05-451
Midcontinent Communications, a South Dakota Partnership, Complainant vs. North Dakota Telephone Company, Respondent
On behalf of Midcontinent Communications
Direct — December 21, 2005
Rebuttal — January 16, 2006

Before the Public Service Commission of the State of North Dakota
Docket No. PU-314-97-465
In the matter of U S WEST Communications, Inc., universal service costs investigation
On behalf of AT&T Communications of the Midwest, Inc.
Rebuttal — February 27, 1998

Before the Public Utilities Commission of Ohio
Case No. 02-1280-TP-UNC, Phase II
In the matter of the Review of SBC Ohio's TELRIC Costs for Unbundled Network Elements
On behalf of MCIMetro Access Transmission Services, LLC, McLeodUSA Telecommunications Services, Inc., Covad Communications Company, NuVox Communications of Ohio, Inc., and XO Ohio, Inc.
Direct — August 8, 2005

Before the Public Service Commission of South Carolina
Docket Nos. 2008-325-C, 2008-326-C, 2008-327-C, 2008-328-C, and 2008-329-C
Application of Time Warner Cable Information Services (South Carolina) LLC, d/b/a Time Warner Cable to Amend its Certificate of Public Convenience and Necessity to Provide Telephone Services in the Service Area of Farmers Telephone Cooperative, Inc. and for Alternative Regulation
On behalf of Time Warner Cable Information Services (South Carolina) LLC
Direct — November 24, 2008

Before the State of South Dakota Public Utilities Commission
Docket No. TC07-117
In The Matter of the Petition Of Midcontinent Communications For Approval Of Its Intrastate Switched Access Tariff And For An Exemption From Developing Company-Specific Cost-Based Switched Access Rates
On behalf of Midcontinent Communications
Direct — July 15, 2008

Before the State Office of Administrative Hearings (Texas)
SOAH Docket No. 473-07-1365, PUC Docket No. 33545
Application of McLeodUSA Telecommunications Services, Inc. For Approval of Intrastate Switched Access Rates Pursuant To PURA Section 52.155 And PUC Subst. R. 26.223
On behalf of McLeodUSA Telecommunications Services, Inc.
Rebuttal May 24, 2007

Before the Public Service Commission of West Virginia
Case No. 10-0756-T-T
FiberNet, LLC Petition For Consent and Approval of Switched Access Rate and Exhibit No.1-FiberNet Network Usage Costs Assessment
On behalf of FiberNet, LLC
Direct September 1, 2010

Before the Public Service Commission of Wisconsin
Docket No. 6720-TI-187
Petition of SBC Wisconsin to determine rates and costs for unbundled network elements
On behalf of AT&T Communications of Wisconsin, L.P. and TCG Milwaukee ("AT&T"), and MCI, Inc.
Rebuttal June 15, 2004

Before the Wyoming Public Service Commission
Docket No. 70000-TA-98-442
In the matter of the second application of U S WEST Communications, Inc., for a finding that its interexchange telecommunications services are subject to competition
On behalf of AT&T Communications of the Mountain States, Inc.
Direct January 6, 1999

Before the Wyoming Public Service Commission
Docket No. 70000-TR-98-420
In the matter of the application of U S WEST Communications, Inc., for authority to implement price ceiling in conjunction with its proposed Wyoming price regulation plan for essential and noncompetitive telecommunication services
On behalf of AT&T Communications of the Mountain States, Inc.
Direct September 9, 1998

Before the Wyoming Public Service Commission
General Order No. 81
In the matter of the investigation by the Commission of the feasibility of developing its own costing model for use in determining federal universal service fund support obligations in Wyoming
On behalf of AT&T Communications of the Mountain States, Inc.
Direct November 1997
Amended Direct January 23, 1998
Rebuttal February 6, 1998

Before the Wyoming Public Service Commission
Docket No. 72000-TI-97-107 and Docket No. 70000 TI-97-352
In the matter of the petition of AT&T for the Commission to initiate investigation of U S WEST Communications, Inc.'s compliance with Section 271 of the Telecommunications Act of 1996
On behalf of AT&T Communications of the Mountain States, Inc.
Direct 1998

Before the Wyoming Public Service Commission
Docket No. 72000-TC-97-99
On behalf of AT&T Communications of the Mountain States, Inc.
Direct May 15, 1997

Before the Wyoming Public Service Commission
Docket No. 70007-TR-95-15
On behalf of AT&T Communications of the Mountain States, Inc.
Adopted Pre-filed Direct October 1996

Selected Reports, Presentations and Publications

"The Efficiency and Effectiveness of the Kansas Universal Service Fund"
Management audit report prepared on behalf of the Kansas Legislature addressing: (1) the adequacy of state statutes and administrative rules governing the operation of the Kansas Universal Service Fund ("KUSF"), (2) a detailed analysis of how monies distributed from the KUSF have been used by the telecommunications carriers for capital investment and operating expenses over a 17-year period, and (3) a detailed assessment of the economic benefit the KUSF has provided to the State of Kansas.
October 2014

"Assessment of the Vermont Universal Service Fund"
Management audit report on the administration of the Vermont Universal Service Fund prepared on behalf of the Vermont Department of Public Service.
May 2013

"Telecommunications Cooperatives: Cost of Capital Issues"
Whitepaper prepared on behalf of the Utah Office of Consumer Services to identify cost of capital and patronage capital issues that are unique to cooperative rural local exchange carriers and the impact of these issues on state universal service fund support requests made by these carriers.
April 2013

"Weighted Average Cost of Capital Issues and Recommendations"
Whitepaper prepared on behalf of the Utah Office of Consumer Services to examine Utah telecom cost of capital issues and to prepare a confidential white paper on the recommended cost of capital and capital structure for the rural incumbent local exchange carriers operating in Utah.
April 2013

"Status of Competition in CenturyLink QC's Certificated Areas in New Mexico"
Expert report prepared on behalf of the New Mexico Attorney General's Office evaluating the status of competition within CenturyLink QC's certificated area in New Mexico. The report was filed along with expert testimony in Case No. 11-00340-UT.
August 2012

"Chicago Clean Energy Coke/Coal Gasification to SNG Project - Analysis of Return on Equity per Section 9-220(h-3)(1)(B) of Public Act 97-96"
Whitepaper prepared on behalf of the Illinois Power Agency to recommend an appropriate return on equity for the Chicago clean energy coke/coal gasification to synthetic natural gas project proposed by Chicago Clean Energy, a subsidiary of Leucadia National Corporation.
October 2011

"In-Band Auction Cap: Promoting Sustainable Competition in the Canadian Mobile Wireless Industry Through An Equitable Auction Design."
Expert Report filed in Canada Gazette Notice No. SMSE-018-10 Consultation on a Policy and Technical Framework for the 700 MHz Band and Aspects Related to Commercial Mobile Spectrum, in support of the Comments of Videotron G.P., a wholly-owned subsidiary of Quebecor Media Inc. and Shaw Communications (filed April 6, 2011).
On behalf of Videotron G.P. and Shaw Communications
April 2011.

"Management Audit of the Connecticut Light & Power Company"
Audit Report prepared by Blue Ridge Consulting Services, Inc. (with QSI serving as independent contractors) on behalf of the Connecticut Department of Public Utility Control to (1) investigate and assess the utility's business processes, procedures, and policies relating to management operations and system of internal controls in place, and (2) an identification of areas of the utility that might require further investigation.
May 2009

QSI Final Report to the District of Columbia Public Service Commission. "Confidential Analysis and Recommendations Related to Case No. 1040."
In the Matter of the Investigation of Verizon Washington DC, Inc.'s Universal Emergency 911 Service Rates in the District of Columbia
March 2009

Report and Conclusions and Recommendations on the Financial Audit of the Columbia Gas of Ohio, Inc. in Regard to Case No. 08-0074-GA-AIR.
Audit Report prepared by Blue Ridge Consulting Services, Inc. (with QSI serving as independent contractors) in relation to Public Utilities Commission of Ohio Case No. 08-0074-GA-AIR In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service.
August 2008

Report and Conclusions and Recommendations on the Financial Audit of the East Ohio Gas Company d/b/a Dominion East Ohio in Regard to Case No. 07-0829-GA-AIR.
Audit Report prepared by Blue Ridge Consulting Services, Inc. (with QSI serving as independent contractors) in relation to Public Utilities Commission of Ohio Case No. 07-0829-GA-AIR In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Distribution Service
April 2008

Report of Conclusions and Recommendations on the Financial Audit of Duke Energy Ohio, Inc. in Regard to Case No. 07-0589-GA-AIR.
Audit Report prepared by Blue Ridge Consulting Services, Inc. (with QSI serving as independent contractors) in relation to Public Utilities Commission of Ohio Case No. 07-589-GA-AIR In the Matter of the Application of Duke Energy Ohio, Inc. for an Increase in Gas Rates.
November 2007

QSI Technical Report No. 052507A "The State of Wireless Technologies in Canada: A Comparison of Wireless Technologies in Canada and the United States of America."
Expert Report filed in Canada Gazette Notice No. DGTP-002-07 Consultation on a Framework to Auction Spectrum in the 2GHz Rage including Advanced Wireless Services, in support of Bell Canada's Reply Comments (filed June 27, 2007).
On behalf of Bell Canada Enterprises.
May 2007.

"Blue Ridge Consulting Services, Inc. Examination of NW Natural's Rate Base and Affiliated Interests Issues In Support of Oregon Public Utilities Commission Docket UM 1148"
Audit Report prepared by Blue Ridge Consulting Services, Inc. (with QSI serving as independent contractors) to assess the utility's rate base treatment and affiliated interest transactions to ensure they comply with orders, rules, and regulations of the Commission, with the utility's policies, and with Generally Accepted Accounting Principles.
December 2005.

QSI Final Report to the Hawaii Public Utilities Commission *"*Analysis and Recommendations Related to Docket No. 04-0140 *Merger Application Of Paradise Mergersub, Inc. (n/k/a Hawaiian telecom Mergersub, Inc.), Verizon Hawaii, Inc. and Related Companies*"
February 7, 2005

QSI Technical Report No. 012605A "IP-Enabled Voice Services: Impact of Applying Switched Access Charges to IP-PSTN Voice Services"
Ex Parte filing in FCC dockets WC Dockets No. 04-36 **(***In the Matter of IP-Enabled Services***),** *03-266* **(***In the Matter of Level 3 Communications LLC Petition for Forbearance Under 47 U.S.C. § 160(c) from Enforcement of 47 U.S.C. § 251(g), Rule 51.701(b)(1), and Rule 69.5(b); IP Enabled Services)*
Washington DC, January 27, 2005

QSI Report to the Wyoming Legislature "The Wyoming Universal Service Fund. *An Evaluation of the Basis and Qualifications for Funding*" December 3, 2004

QSI Management Audit Reports to the Wyoming Public Service Commission on the Wyoming Universal Service Fund:

1. For the period October 28, 1999 through December 31, 2001 (issued May 15, 2002)
2. For the period January 1, 2002 through December 31, 2004 (issued January 31, 2006)

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2703

PGE Exhibit 208 Rate Base Delta

PGE
UE 416
Exhibit 208
Rate Base Comparison
Scaled (Thousands)

Line No.	Line	UE 394 Approved Order No. 22-129	Test Year at GRC Rates	2024 Variance to Approved
1	Plant in Service	10,951,085	12,249,545	1,298,460
2	Less: Accumulated Depreciation/Amortization	(4,887,187)	(5,441,309)	(554,122)
3	Accumulated Deferred Taxes	(690,748)	(667,288)	23,460
4	Accumulated Deferred ITC			
5				
6	**Net Utility Plant**	5,373,150	6,140,947	767,798
7				
8	**Operating Materials and Fuel Stocks**	55,799	91,228	35,429
9				
10	**Deferred Debits**			
11	Glass Insulators	5,477	5,847	369
12	Major Maintenance Accruals	(3,163)	(1,871)	1,293
13	Cloud-Based License and Hosting Fees		8,227	8,227
14	Dispatchable Standby Generation	7,069	4,197	(2,872)
15	Wheatridge O&M Start-up Costs	1,517	1,429	(88)
16				
17	**Deferred Credits**		-	
18	Injuries & Damages	(8,813)	(8,240)	573
19	Customer Deposits	(11,737)	(10,973)	765
20	Incentive Adjustment (UE 283)	(6,333)	(5,500)	833
21	Post Retirement Liabilities	(46,213)	(29,804)	16,409
22	Misc. Other	(790)	(714)	76
23				
24				
25	**Working Capital**	65,995	95,817	29,821
26				
27	**Rate Base**	5,431,958	6,290,590	858,633

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2704

PGE Non-Confidential Responses to Data Requests

STAFF 2700 DRs - ISSUE 1
(PLANT ADDITIONS)

STAFF 2704
NON-CONFIDENTIAL
AWEC 39
STAFF 588
STAFF 626
STAFF 627
STAFF 628
STAFF 629
STAFF 630
STAFF 634
STAFF 635
STAFF 706
STAFF 707
STAFF 788
STAFF 789
STAFF 790
STAFF 791
STAFF 807
STAFF 808
STAFF 809
STAFF 813
STAFF 814
STAFF 817

March 27, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 039
Dated March 13, 2023

Request:

Please provide workpapers used to calculate and forecast depreciation expenses in the test period. Please provide this detail by FERC account and subaccount.

Response:

Attachment 039-A provides the requested information.

May 3, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 588
Dated April 19, 2023

Request:

For all capital transmission and distribution projects in excess of $1 million that are included in UE 416 rate base please provide the following information:

a. Project number and description including why it was necessary and how ratepayers will benefit;
b. Date the project was placed into service or is expected to be placed into service;
c. Final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service;
d. FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General);
e. Capital spending by month;
f. Date and amounts of transfers to plant;
g. Documents associated with project approval, including approval of any substantial changes (such as project justification forms);
h. One-line diagrams, as applicable; and
i. Reference the Company's direct testimony and exhibits in this case if applicable.

Response:

PGE objects to this request on the basis of being overly broad and unduly burdensome. Notwithstanding its objection, PGE provides the requested information for all capital transmission and distribution projects in excess of $3 million (excluding wildfire mitigation capital projects because they are included in an isolated revenue requirement):

a. Attachment 588-A provides the project number. PGE's response to OPUC Data Request No. 586 provides the project justification forms which describe the need for the project.
b. PGE's responses to OPUC Data Request Nos. 626 and 627 provide the requested information.
c. Attachment 588-A provides the requested information.

d. Attachment 588-A provides the requested information.
e. Attachment 588-B provides the requested information.
f. PGE's response to AWEC Data Request No. 047 provides the requested information for calendar year 2023. Attachment 588-B provides the requested information for May through December 2022.
g. PGE's response to OPUC Data Request No. 586 provides the project justification forms, which provide this information.
h. Highly Confidential Attachment 588-C provides the one-line diagrams, as applicable.
i. Attachment 588-A provides the requested information.

Attachment 588-C contains protected information and is subject to Modified Protective Order No. 23-138.

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 626
Dated April 24, 2023

Request:

Similar to OPUC Request Nos. 142 and 198 in Docket No. UE-394, please provide the following information supporting the Construction Work in Process balances on PGE's FERC Form 1, page 216, for the years ended December 31, 2021, and December 31, 2022, when it is filed, for each listed project (>$3 million).

a. The date the project was placed into service or is expected to be placed into service.
b. The final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service.
c. The FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General).
d. A brief narrative description of the nature of the project including why it was necessary and how ratepayers will benefit.
e. Complete Project Justification Forms for each project inclusive of project budgets and any change orders.
f. Please reference the Company's direct testimony and exhibits in this case if applicable.

Response:

a. Attachment 626-A provides the requested information.

b. Attachment 626-A provides the requested information.

c. Attachment 626-A provides the requested information.

d. PGE's response to OPUC Data Request No. 586 provides the requested information for transmission and distribution capital projects greater than $3 million included in UE 416 rate base. PGE's response to OPUC Data Request No. 628 provides the requested information for the other capital projects greater than $3 million included in UE 416 rate base.

e. Project justification forms are provided in in PGE's response to OPUC Data Request No. 586 and PGE's response to OPUC Data Request No. 628. As described in PGE's response to OPUC Data Request No. 593, part (b), the most comprehensive source of documentation of changes to a capital project's scope, budget, schedule, etc. is the project justification forms. "Change orders" provide an incomplete picture of PGE's spending and budget management given that they are only used to document changes with outside vendors/contractors.

f. Attachment 626-A provides the requested information.

Attachment 626-A, parts (a)-(c) and (f)
For Year: 2021

Line No.	FP Description (PP)	Funding Project	CWIP @ 12/31/2021	(a) In-Service Date(s)	(b) Final Project Cost	(c) FERC account category	(f) Reference to PGE's direct testimony, as applicable
1	FY: Repower Faraday Units 1-5	P36167	109,262,275	March 2017 January 2023	188,067,480	Hydro Production	PGE Exhibit 800, Section V
2	Brookwood Substation Conversion	P36680	43,360,316	July 2022 December 2022 September 2022	61,196,673	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, specifically on page 7
3	Shute Capacity Addition	P36868	15,463,078	June 2022 September 2022	20,468,316	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, specifically on page 8
4	Evergreen Property Land Purchase	P36666/P36422	14,709,877	May 2024	116,595,680	Transmission Plant	Not included in UE 416
5	Hydro Control System Upgrade	P36134	9,184,333	December 2018-October 2024	35,224,139	Hydro Production	Not explicitly referenced
6	P22449 Colstrip Capital Proj PPL	P22449	6,658,993	May 2004-May 2023	131,731,039	Steam Production	As described in PGE Exhibit 200, Section I, no Colstrip operations and maintenance (O&M) or plant-related costs are
7	North Portland Conversion	P36178	5,047,110	February 2022 April 2022 November 2022 March 2024 September 2024 December 2024 January 2025	10,854,046	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
8	Facilities Upgrades-EV Readiness	P37017	5,001,172	December 2022 February 2023 June 2023 August 2023 June 2024 February 2025 December 2025	16,137,739	General Plant	Not explicitly referenced
9	Canyon-Urban 115kV Reconductor	P36860	4,864,817	April 2022 May 2022	8,202,830	Transmission Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Reconductor/conversion" on page 6
10	WSH:Restore Facilities post-fire	P37118	4,651,309	July 2021 September 2021 May 2022 August 2022	10,133,526	Hydro Production	Not explicitly referenced
11	Harborton Reliability Project PH2	P36916	3,772,147	June 2023-December 2026	13,627,421	Transmission Plant	PGE Exhibit 700, Section II, "Substation" category, discussed
12	Memorial Substation Build	P36953	3,658,504	February 2023 December 2024	12,309,252	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
13	Blue Lake Phase II	P36373	3,341,052	February-December 2020 September 2023	3,946,769	Transmission Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
14	South Milliken Line Rebuild	P36617	3,264,915	November 2023 - June 2027	11,660,623	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category,

Attachment 626-A, parts (a)-(c) and (f)
For Year: 2022

Line No.	FP Description (PP)	Funding Project	CWIP @ 12/31/2022	(a) In-Service Date(s)	(b) Final Project Cost	(c) FERC account category	(f) Reference to PGE's direct testimony, as applicable
1	FY: Repower Faraday Units 1-5	P36167	168,332,602	March 2017 January 2023	188,067,480	Hydro Production	PGE Exhibit 800, Section V
2	powERPlay	P37346	22,953,607	August 2023	37,595,820	Intangible Plant	PGE Exhibit 600, Section III.B
3	Orenco Substation 115kV Rebuild	P36679	19,257,303	June 2020 April 2021 June 2021 July-Aug 2023	25,422,455	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, specifically on page 7
4	Oracle Utilities Upgrade	P37272	18,501,037	April 2023	23,208,486	Intangible Plant	PGE Exhibit 600, Section III.B
5	Hydro Control System Upgrade	P36134	13,928,197	December 2018-October 2024	35,224,139	Hydro Production	Not explicitly referenced
6	Build Evergreen Substation	P36666/P36422	22,236,911	May 2024	116,595,680	Transmission Plant	Not included in UE 416
7	Coffee Creek, Energy Storage	P36728	10,671,876	September 2024	22,132,082	Distribution Plant	Not included in UE 416
8	Helvetia Substation Phase 2	P37160	10,234,681	February 2023	10,879,955	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, specifically
9	Horizon-Keeler BPA #2 230kV Line	P37302	9,064,644	May 2024	9,609,171	Transmission Plant	Not included in UE 416
10	Facilities Upgrades-EV Readiness	P37017	8,314,688	December 2022 February 2023 June 2023 August 2023 June 2024 February 2025 December 2025	16,137,739	General Plant	Not explicitly referenced
11	Digital Channel Uplift 22	P37312	8,167,436	April 2023	10,774,324	Intangible Plant	PGE Exhibit 600, Section III.B
12	Substation Communication Upgrade	P36101	7,794,354	November-December 2020 July 2021 December 2026	47,011,909	General Plant	PGE Exhibit 700, Section IV, discussed generally on pages 21-27
13	RB: Replace Turbine Shut-off Valves	P36838	7,716,735	January 2023 December 2023 January 2025	35,130,724	Hydro Production	Not explicitly referenced
14	Harborton Reliabilty Ph2 - 115kV	P36916	6,342,012	June 2023-December 2026	13,627,421	Transmission Plant	Not included in UE 416
15	Reedville Substation Rebuild	P37266	5,910,841	June 2023-March 2025	17,648,143	Transmission Plant	PGE Exhibit 700, Section II, "Substation" category, discussed
16	Tech Refresh	P37344	5,265,320	May 2023	12,603,008	Intangible Plant	PGE Exhibit 600, Section III.B
17	Tonquin Substation Build	P36954	4,954,631	January-June 2024 June-July 2025	9,774,212	Distribution Plant	Not included in UE 416
18	South Milliken Line Rebuild	P36617	4,524,716	November 2023 - June 2027	11,660,623	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category,
19	Shute WJ1 and WJ2 Upgrade	P37366	4,273,056	October 2024	11,351,309	Distribution Plant	Not included in UE 416
20	Memorial Substation Build	P36953	3,898,617	February 2023 December 2024	12,309,252	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
21	BR: Beaver Modernization	P36836	3,897,887	July 2022 August 2023 April-December 2024 May-December 2025 January 2026	122,585,726	Other Production	PGE Exhibit 800, Section II, "PGE's Generation Resources" on pages 2-3.
22	Blue Lake Phase II	P36373	3,742,550	February-December 2020 September 2023	3,946,769	Transmission Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
23	Salem LC EIFS Replacement	P37240	3,594,301	August 2023	6,211,919	General Plant	Not explicitly referenced
24	Bethel to Round Butte Fiber	P36100	3,236,039	May 2024 January 2025	4,355,733	General Plant	Not included in UE 416
25	PW2: Top End Engine Parts and Insta	P37417	3,206,684	December 2024	12,578,000	Other Production	Not included in UE 416
26	Zero Trust	P37477	3,141,669	December 2024	5,118,022	Intangible Plant	Generally discussed in PGE Exhibit 600, Section III.B

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 627
Dated April 24, 2023

Request:

Similar to OPUC Request Nos. 143 and 198 in Docket No. UE-394, for 2023 plant additions not separately listed in CWIP at December 31, 2022, please provide the following:

a. A list of individual projects with an expected cost of $3 million or greater.
b. The date the project is expected to be placed into service.
c. The final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service.
d. The FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General).
e. A brief narrative description of the nature of the project including why it was necessary and how ratepayers will benefit.
f. Complete Project Justification Forms for each project inclusive of project budgets and any change orders.
g. Please reference the Company's direct testimony and exhibits in this case if applicable.

Response:

Excluding wildfire mitigation capital projects because they are included in an isolated revenue requirement, the following information is provided:

a. Attachment 627-A provides the requested information.

b. Attachment 627-A provides the requested information.

c. Attachment 627-A provides the requested information.

d. Attachment 627-A provides the requested information.

e. PGE's response to OPUC Data Request No. 586 provides the requested information for transmission and distribution capital projects greater than $3 million included in UE 416 rate base. PGE's response to OPUC Data Request No. 628 provides the requested information for the other capital projects greater than $3 million included in UE 416 rate base.

f. Project justification forms are provided in in PGE's response to OPUC Data Request No. 586 and PGE's response to OPUC Data Request No. 628. As described in PGE's response to OPUC Data Request No. 593, part (b), the most comprehensive source of documentation of changes to a capital project's scope, budget, schedule, etc. is the project justification forms. "Change orders" provide an incomplete picture of PGE's spending and budget management given that they are only used to document changes with outside vendors/contractors.

g. Attachment 627-A provides the requested information.

Attachment 627-A, parts (a)-(d) and (g)

(a) Funding Project	(b) In-Service Date(s)	(c) 2023 Forecasted Plant Additions	(d) FERC account category	(g) Reference to PGE's direct testimony, as applicable
P37218 - OH FITNES Distribution	Monthly	108,334,383	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
P36394 - Vintage Vehicle Replacement II	Monthly	18,777,608	General Plant	Not explicitly referenced in testimony
P36501 - Integrated Operations Center - IOC	March 2019 January 2021 February 2023 July 2023 December 2023	18,692,709	General Plant	PGE Exhibit 700, Section IV, "Grid Modernization"
P14628 - Replace Failed Underground Cables	Monthly	15,346,000	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Replace of upgrade underground cable" on page 6
P35924 - Distribution System Construction II	Monthly	14,169,775	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Customer needs" on page 5-6
P37048 - Outage or Emergency Replacement	Monthly	13,207,291	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Emergency distribution asset replacements" on page 6
P35890 - Purchase Distribution Transformers	Monthly	12,733,049	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Blanket T&D projects" on page 6
P36770 - Street and Area Light Construction	Monthly	11,148,325	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Customer needs" on page 5-6
P36522 - Distribution Automation	Monthly	10,142,329	Distribution Plant	PGE Exhibit 700, Section IV, "Grid Modernization"
P35925 - Dist. Customer Line Construction II	Monthly	8,666,102	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Customer needs" on page 5-6
P36845 - McLoughlin Sub Security Upgrades	December 2023	8,528,006	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
P37214 - Dist. Customer Line Construct III	Monthly	8,168,475	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Customer needs" on page 5-6
P37213 - Distribution System Construct III	Monthly	7,952,862	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Blanket T&D projects" on page 6
P37176 - Eastern Gen Admin Building-Carty	August 2023 October 2023	7,796,428	Other Production	Not explicitly referenced in testimony
P37509 - Biglow I Wind Enhancement Program	December 2023	7,297,603	Other Production	PGE Exhibit 800, Section II
P36913 - Trans. Line Clearance Mitigation	Monthly	6,765,352	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
P37314 - Project 360 Bundle 1	December 2023	6,486,805	Intangible Plant	Not explicitly referenced in testimony
P37061 - OH FITNES Transmission	Monthly	6,080,078	Transmission Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
P37331 - CMD Network Protector Replacements	October 2023	6,000,770	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
P37133 - CTO Network Fitness	Monthly	5,752,852	General Plant	Not explicitly referenced in testimony
P35995 - Downtown UG Core Cable Replacement	Monthly	5,496,996	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Replace of upgrade underground cable" on page 6
P37347 - Risk Technology Optimization	March 2023 May 2023	5,338,265	Intangible Plant	Not explicitly referenced in testimony

Attachment 627-A, parts (a)-(d) and (g)

(a) Funding Project	(b) In-Service Date(s)	(c) 2023 Forecasted Plant Additions	(d) FERC account category	(g) Reference to PGE's direct testimony, as applicable
P37379 - New Dist Feed to Buildings 2-5	September 2022 March-August 2023	5,338,021	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Customer needs" on page 5-6
P37364 - Newberg/Dundee Street Imprv/UG Conv	December 2023	5,100,786	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Road Widening" on page 6
P37046 - T&D Asset Relocation	Monthly	4,908,990	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
P36537 - Unjacketed Cable Replacement Prgrm	Monthly	4,494,720	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Replace of upgrade underground cable" on page 6
P37093 - Facilities Management Fitness	Monthly	4,453,731	General Plant	
P37333 - Upgrade Pleasant Valley-Moon	July 2023	4,320,796	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Reconductor/conversion" on page 6
P36417 - Replace/Rewind Failed Transformers	Monthly	4,305,178	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed on pages 6-7
P36582 - Substation FITNES 2019-2021	Monthly	4,154,612	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
P37211 - Substation Cap Rplcmts 2022-2024	Monthly	4,073,061	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
P37416 - PN: Rewind Unit 2 Generator	December 2023	4,055,939	Hydro Production	Not explicitly referenced in testimony
P37466 - EMS Upgrade Project	December 2023	4,033,690	General Plant	Not explicitly referenced in testimony
P37429 - PORTS - Package 1	February 2023 May 2023 December 2023	3,949,916	Intangible Plant	PGE Exhibit 600, Section III.B, "IT Capital Projects"
P37275 - Project Basie	January 2023 April 2023 November 2023	3,840,308	Distribution Plant	PGE Exhibit 700, Section II, "Substation" category, discussed generally on pages 6-7
P37459 - TR - Rebuild Tower I-10	July 2023	3,833,915	Other Production	Not explicitly referenced in testimony
P37382 - ADMS CVR VVO	December 2023	3,801,686	Distribution Plant	PGE Exhibit 700, Section IV, "Grid Modernization"
P37487 - Energy Tracker Replacement	July 2023	3,755,614	Intangible Plant	Not explicitly referenced in testimony
P37353 - CY: Purchase 2023 Outage Components	June 2023	3,750,800	Other Production	Not explicitly referenced in testimony
P35892 - Purchase Customer Meters	Monthly	3,632,781	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Customer needs" on page 5-6
P37047 - Joint Pole Construction	Monthly	3,609,213	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
P37135 - Server Storage Fitness	Monthly	3,529,440	General Plant	Not explicitly referenced in testimony
P37539 - CISCO Contact Center to Cloud	July 2023	3,311,082	Intangible Plant	Not explicitly referenced in testimony
P35834 - Round Butte Transmission Upgrades	October 2023	3,045,839	Transmission Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Reconductor/conversion" on page 6
P36723 - Field Area Network Project	Monthly	3,023,410	General Plant	PGE Exhibit 700, Section IV, "Grid Modernization"

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 628
Dated April 24, 2023

Request:

For all capital projects other than transmission and distribution in excess of $3 million constructed by PGE that that are included in the UE 416 rate base:

Please provide all briefings to PGE management on the status of all capital projects in excess of $3 million that PGE proposes to be included in the UE 416 rate base that reflects capitalized plant not included in current rates.

Response:

OPUC Data Request Nos. 628-633 ask PGE to delineate capital projects by those "constructed by PGE" and those "constructed by other companies for PGE." PGE objects to these data requests on the basis that they are unduly burdensome, vague and calls for speculation as the phrase "constructed by PGE" is undefined.

PGE often uses third-party contractors and vendors to perform work on capital projects. PGE does not track capital projects by the undefined categories of "constructed by PGE" and "constructed by other companies for PGE," making it unduly burdensome for PGE to attempt to categorize capital projects that way.

Notwithstanding its objections, PGE responds as follows:

PGE provides the project justification forms (PJF) for all capital projects other than transmission and distribution in excess of $3 million included in the UE 416 rate base (excludes P22449-P22449 Colstrip Capital Proj PPL) here:

- PGE's response to CUB Data Request No. 025 provides the PJF for P36167 - FY: Repower Faraday Units 1-5.
- Confidential Attachment 628-A provides the remaining PJFs.

PGE management (specifically, the Business Sponsor Group) receives a copy of the PJF for each in-flight project when the project manager submits a proposed budget revision.

Attachment 628-A contains protected information and is subject to General Protective Order No. 23-039.

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 629
Dated April 24, 2023

Request:

For all capital projects other than transmission and distribution in excess of $3 million constructed by PGE that that are included in the UE 416 rate base:

Please provide a copy of a resource loaded schedule for all completed capital projects at the beginning of the project, at the midpoint of the project and at the end of the project.

Response:

OPUC Data Request Nos. 628-633 ask PGE to delineate capital projects by those "constructed by PGE" and those "constructed by other companies for PGE." PGE objects to these data requests on the basis that they are unduly burdensome, vague and call for speculation on the definitions of "constructed by PGE" and "constructed by other companies for PGE."

PGE often uses third-party contractors and vendors to perform work on capital projects. PGE does not track capital projects by the undefined categories of "constructed by PGE" and "constructed by other companies for PGE," making it unduly burdensome for PGE to attempt to categorize capital projects that way.

Notwithstanding its objection, for capital projects other than transmission and distribution greater than $3 million that are managed within its Generation, Transmission, and Distribution Project Management Office (PMO) Department, PGE responds as follows:

PGE currently does not resource or cost load its schedules due to lack of system integration capabilities and labor constraints. However, PGE does utilize a project schedule to manage discrete capital projects for projects within its Generation, Transmission, and Distribution PMO Department. PGE does not utilize project schedules for repeated, programmatic work. Confidential Attachment 629-A provides the project schedules for the applicable capital projects within PGE's Generation, Transmission, and Distribution PMO Department at the beginning of the project, at the midpoint of the project, and at the end of the project.

Attachment 629-A contains protected information and is subject to General Protective Order No. 23-039.

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 630
Dated April 24, 2023

Request:

For all capital projects other than transmission and distribution in excess of $3 million constructed by PGE that that are included in the UE 416 rate base:

Please provide a copy of a resource loaded schedule for all in-progress capital projects at the beginning of the project, at the midpoint of the project and the most recent version of the resource-loaded schedule.

Response:

OPUC Data Request Nos. 628-633 ask PGE to delineate capital projects by those "constructed by PGE" and those "constructed by other companies for PGE." PGE objects to these data requests on the basis that they are unduly burdensome, vague and call for speculation on the definitions of "constructed by PGE" and "constructed by other companies for PGE."

PGE often uses third-party contractors and vendors to perform work on capital projects. PGE does not track capital projects by the undefined categories of "constructed by PGE" and "constructed by other companies for PGE," making it unduly burdensome for PGE to attempt to categorize capital projects that way.

Notwithstanding its objection, for capital projects other than transmission and distribution greater than $3 million that are managed within its Generation, Transmission, and Distribution Project Management Office (PMO) Department, PGE responds as follows:

PGE currently does not resource or cost load its schedules due to lack of system integration capabilities and labor constraints. However, PGE does utilize a project schedule to manage discrete capital projects for projects within its Generation, Transmission, and Distribution PMO Department. PGE does not utilize project schedules for repeated, programmatic work. Confidential Attachment 630-A provides the project schedules for the applicable capital projects within PGE's Generation, Transmission, and Distribution PMO Department at the beginning of the project and the most recent version.

Attachment 630-A contains protected information and is subject to General Protective Order No. 23-039.

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 634
Dated April 24, 2023

Request:

For the Beaver Emissions Reduction Program project on pages 2-3, please provide the following:

a. Confirm that this is project P36836-BR: Beaver Modernization in file UE 416_AWEC DR 048_Attachment A.xlsx.

b. If the answer to part a. above is yes, confirm that $21.1 million listed in the Attachment A represents amounts closed to plant as of December 31, 2022.

c. Confirm whether the $56.9 million noted on Exhibit 800, page 3, line 9, represents total costs expected to close to plant as of December 31, 2023, inclusive of those closed to plant as of December 31, 2022.

d. If the answer to part c. above is yes, identify how much of the $25.8 million in additional capital expenditures in 2023 have closed to plant as of the filing date of PGE's GRC application.

e. Referring to Exhibit 800, page 3, line 3, when is this project expected to be completed and how much additional cost does PGE expect to incur?

Response:

a. Confirmed.
b. Confirmed.
c. Confirmed.
d. As of the filing date of PGE's GRC, an additional $173,000 closed to plant in January of 2023, associated with the upgrade of Unit 6.
e. The entire project is expected to be completed in 2025 with additional trailing costs likely incurred into 2026. The current project budget and timing of projected plant closings post-2023 is as follows: $39.0M for 2024, $30.3M for 2025, and $0.9M for 2026.

May 8, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 635
Dated April 24, 2023

Request:

For the Biglow Phase I Wind Enhancement Program project on page 4, lines 3-5:

a. Provide all analyses and/or reports that PGE relied upon to conclude that its proposed plan resulted in lower customer cost impact, better economics (based on levelized costs per MWh), and reduced interruption to facility operations compared to repowering.

b. The estimated completion date.

c. The estimated project costs at completion.

Response:

a. Highly Confidential Attachment 635-A provides PGE's analysis of the capital enhancement option, and Highly Confidential Attachment 635-B provides PGE's analysis of the repowering option. These models were used to conclude that our currently proposed plan results in lower customer cost impact and better economics. As for reduced interruptions, a repowering would require shutting down entire strings of turbines at once while a capital enhancement program does not require this.
b. The estimated completion date for Biglow Phase I is 2028. PGE will evaluate if we can expedite this project after construction in 2023 for future years.
c. The estimated project costs at completion of Biglow Phase I is $70.2M, un-escalated and in 2023 dollars.

Attachments 635-A and 635-B are protected information subject to General Modified Protective Order No. 23-138.

May 12, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 706
Dated April 28, 2023

Request:

Provide copies of PGE's documentation supporting its standard capital process and/or its capitalization policy inclusive of the following in the Company's response.

a. Describe any changes in PGE's capital budget process that have occurred since PGE Exh. 1800 was filed in UE 394 on December 2, 2021.

b. Describe the composition of the Capital Review Group referenced in response to CUB Data Request 026 in this proceeding through a listing of the members by job title and/or board of director title.

c. The level of management and/or board of directors' approval for each dollar amount threshold by capital project or group of related projects.

d. The documentation required to support each capital project such as Project Justification Forms, Issued for Construction (IFC) Design Estimates, Authorization to Spend (ATS) documents, Accounting Work Orders (AWO), change orders, etc.

e. **Standing Data Request:** Please provide any post completion report for projects and other review of completed projects including any other analysis of project changes, corrections or remedies, and cost responsibility for same – as these reports are available.

f. The Company's procedures for tracking actual variances from budgeted project costs. Provide examples of monthly reports produced by PGE Project Managers as described in UE 394, Exh. 1800, page 9, lines 12-23.

g. Describe of how the Company determines when the capital project is officially in service and when the project costs are transferred from CWIP to Plant-in-Service.

h. Describe how existing plant-in-service that is to be retired after the capital project(s) being constructed or purchased to replace it are tied to or cross referenced to those capital additions to ensure that retired plant is promptly removed from plant-in-service.

i. Please reference the Company's direct testimony and exhibits in this case or UE 394 as applicable.

Response:

a. There have been no changes to the capital budgeting process described in PGE Exhibit 1800 filed in Docket No. UE 394 that would impact the capital projects included in the Docket No. UE 416 rate base.

b. The titles of the members of the Capital Review Group are:
   - Chief Financial Officer
   - Senior Vice President Advanced Energy Delivery
   - Vice President Strategy Regulation & Energy Supply
   - Senior Director Engineering Services
   - Manager Financial Analysis Planning & Reporting
   - The Chairs of the five Business Support Groups (BSG): Grid Modernization; Transmission and Distribution; Information Technology/Customer; Generation and Power Operations; and Services.

c. PGE has an annual process that must be followed before any money can be spent, called authorization to spend (ATS). This begins with PGE's annual budgeting process in May, when each project submits its annual spending plan for the following year for consideration by the BSG and, ultimately, the CRG. This is called "Capital Call." Between May and November, the Portfolio Manager analyzes the proposed spending requests and modifies the portfolio's three- to five-year roadmap. Based on this analysis, the Portfolio Manager recommends to the BSG approval of funding for projects. Once each BSG has approved its annual spending plan, these are brought to the CRG for review and approval.

   Once the CRG approves the spending plan, there is one more step before funds are available to be spent. This is the ATS process, which occurs in November. ATS is the confirmation of budgets submitted in May. Depending on the size of the project's budget, there are multiple layers of approval that are required before funds are authorized to be spent. In order to have funds released and allowed to be spent based on approved project funds, all projects require the approval of Corporate Planning, Asset Accounting, Environmental Services, the sponsoring department's manager, and the Project Process Administrator.

   Additional approvals are required as a project increases in cost. If a project is more than $350,000, it needs the additional approval of the sponsoring department's senior manager. If the project is more than $500,000, it needs the approval of the sponsoring department's director. If the project is more than $1 million, it needs the approval of the organization's vice president and lastly, if the project is more than $5 million, it needs the approval of the Chief Financial Officer. These approvals are sequential and cumulative. For example, if a project is more than $5 million, it will need approval from each layer of management prior to seeking approval from the next higher level of management. If any person in the authority chain rejects a project, the project does not progress up the chain and is sent back to the Project Manager for revision.

d. See response to part (c) above.

e. PGE objects to this request on the basis of being overly broad and unduly burdensome. Notwithstanding its objection, PGE provides the following information for transmission and distribution capital projects in excess of $3 million included in the UE 416 rate base:

   PGE's response to OPUC Data Request No. 593 provides the post completion reports for transmission and distribution projects greater than $3 million included in the UE 416 rate base.

f. While in the execution phase, on a monthly basis, the Project Manager reviews actual spend compared to budget; updates forecast of spend timing; reports and takes action on significant variances; and updates in-service dates. Confidential Attachment 706-A provides an example of a monthly report prepared by a Project Manager for a project in the Generation, Transmission and Distribution Project Management Office.

   Project Justification Forms, provided in PGE's responses to OPUC Data Request Nos. 586 and 628, are produced when Project Managers request approval to modify the budget of a project. The PJF provides documentation of the business justification, project schedule and approved budget.

g. PGE classifies capitalized construction costs as Closed to Plant when the project and associated capitalized costs are determined to be used and useful for utility services. With the completion of the installation, modification, or construction of the elements essential to the project and that they are ready for their intended use or assigned function, the project costs are transferred from construction work in progress (CWIP) to Plant-in-Service.

h. Upon completion of a capital work order, PGE will transfer the cost of the related assets from construction work in progress (CWIP) to utility plant in-service in utility plant, as appropriate. After a reasonable trailing charge period, PGE will unitize the related assets to their final utility accounts, units of property (retirement units), and asset locations. Related asset retirements are identified and recorded concurrently with the unitization process.

i. PGE objects to this request on the basis of it being vague and overly broad. Notwithstanding its objection, PGE responds as follows:

   Confidential Attachment 706-B provides PGE's detailed testimony on PGE's capital budgeting and management processes provided in PGE's last rate case, Docket No. UE 394.

   Attachments 706-A and 706-B contain protected information and are subject to General Protective Order No. 23-039.

May 12, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 707
Dated April 28, 2023

Request:

Referring to Exh. 1800 in UE 394, page 18, lines 15-20, page 32, lines 4-12, and PGE's attachments UE 416_AWEC DR 047_Attach A.xlsx and UE 416_AWEC DR 048_Attach A.xlsx filed in response to AWEC Data Requests 047 and 048 in UE 416, provide the following.

a. Identification of each project where the PGE Project Manager identified variances exceeding 10% of the projects budget in the execution phase and whether additional funding was rejected or approved by the Portfolio Manager and/or BSG and CRG personnel.

b. Copies of change orders issued for projects where actual external vendor costs incurred during the execution phase exceeded the 10% variance threshold that support the material changes noted on the related PJF for the project.

Response:

PGE objects to this request on the grounds that it is overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. There are several hundred capital projects listed in the referenced documents, many of which occurred over multiple years. Variances are tracked monthly, meaning there are thousands of records to review.

May 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 788
Dated May 15, 2023

Request:

For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, please provide a detailed line-item budget from the date the project was approved.

Response:

Confidential Attachment 788-A provides the detailed line-item budget for each of the 75 capital projects (excluding P36167 - FY: Repower Faraday Units 1-5; PGE provided the requested information in its response to AWEC Data Request No. 056) greater than $3 million included in UE 416 rate base at the time when UE 416 rate base plant additions were forecasted (e.g., December 2022).

Attachment 788-A contains protected information and is subject to General Protective Order No. 23-039.

May 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 789
Dated May 15, 2023

Request:

For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, please provide the Monthly Project Status Report quarterly, from the date the project was started until it was placed in service.

Response:

PGE objects to this request on the basis that it is unduly burdensome. Without waving its object, PGE responds as follow:

PGE proposed providing the information requested in DRs 788-790 for a sampling of 10-15 projects. Staff selected the following 15 projects as the sample:

- P37218 OH FITNES Distribution
- P36680 Brookwood Substation Conversion
- P36679 Orenco Substation 115kV Rebuild
- P37160 Helvetia Substation Phase 2
- P37218 OH FITNES Transmission
- P36417 Replace/Rewind Failed Transformers
- P35995 Downtown UG Core Cable Replacement
- P36373 Blue Lake Phase II
- P36953 Memorial Substation Build
- P36838 RB: Replace Turbine Shut-off Valves
- P37133 CTO Network Fitness
- P37176 Eastern Gen Admin Building-Carty
- P37314 Project 360 Bundle 1
- P37251 P37251-PACS 2.0
- P37533 P37533-2022 Microsoft Enterprise Agreement

Due to internal systems and transitions issues, PGE was unable to locate monthly project status reports for P36417-Replace/Rewind Failed Transformers, and instead is provide the monthly project status reports for P36913-Trans. Line Clearance Mitigation.

Confidential Attachment 789-A provides the monthly project status reports, on a quarterly basis, for the following projects:

- P37218 OH FITNES Distribution
- P36680 Brookwood Substation Conversion
- P36679 Orenco Substation 115kV Rebuild
- P37160 Helvetia Substation Phase 2
- P37218 OH FITNES Transmission
- P35995 Downtown UG Core Cable Replacement
- P36373 Blue Lake Phase II
- P36953 Memorial Substation Build
- P36838 RB: Replace Turbine Shut-off Valves
- P37133 CTO Network Fitness
- P37176 Eastern Gen Admin Building-Carty
- P37314 Project 360 Bundle 1
- P37251 P37251-PACS 2.0
- P37533 P37533-2022 Microsoft Enterprise Agreement[1]
- P36913 Trans. Line Clearance Mitigation

Attachment 789-A contains protected information and is subject to General Protective Order No. 23-039.

[1] Given that there are not monthly project status reports for P37533-2022 Microsoft Enterprise Agreement because the funding project is for software licensing, Confidential Attachment 789-A instead provides information about the project.

May 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 790
Dated May 15, 2023

Request:

For each capital project greater than $3 million that is not currently in PGE's rate base, that PGE plans to include in rate base in UE416, that is still under construction, please provide the Monthly Project Status Report quarterly, from the date the project was started until the most recent report available.

Response:

Please see PGE's response to OPUC Data Request No. 789.

May 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 791
Dated May 15, 2023

Request:

See the excerpt below from UE 416_OPUC DR 626_Attach A, projects in FERC Form 1 CWIP at 12/31/2022 and the two highlighted columns referencing Project Total amounts from PGE's New Construction Budget Report for the 2023 calendar year filed with the OPUC on April 3, 2023.

Line No.	FP Description (PP)	Funding Project	CWIP @ 12/31/2022	In-Service Date(s)	Final Project Cost	New Construction Budget Report 2023 (filed 4/3/2023)	New Construction Budget Report Project Total Greater (Less) Than Final Project Cost	FERC account category	Reference to PGE's direct testimony, as applicable
1	FY: Repower Faraday Units 1-5	P36167	168,332,602	March 2017 January 2023	188,067,480	173,838,281	(14,229,199)	Hydro Production	PGE Exhibit 800, Section V
2	powERPlay	P37346	22,953,607	August 2023	37,595,820	33,142,867	(4,452,953)	Intangible Plant	PGE Exhibit 600, Section III.B
5	Hydro Control System Upgrade	P36134	13,928,197	December 2018-October 2024	35,224,139	36,260,289	1,036,150	Hydro Production	Not explicitly referenced
6	Build Evergreen Substation	P36666/P36422	22,236,911	May 2024	116,595,680	34,903,843	(81,691,837)	Transmission Plant	Not included in UE 416
10	Facilities Upgrades-EV Readiness	P37017	8,314,688	December 2022 February 2023 June 2023 August 2023 June 2024 February 2025 December 2025	16,137,739	19,619,074	3,481,335	General Plant	Not explicitly referenced
12	Substation Communication Upgrade	P36101	7,794,354	November-December 2020 July 2021 December 2026	47,011,909	55,283,032	8,271,123	General Plant	PGE Exhibit 700, Section IV, discussed generally on pages 21-27
13	RB: Replace Turbine Shut-off Valves	P36838	7,716,735	January 2023 December 2023 January 2025	35,130,724	10,553,110	(24,577,614)	Hydro Production	Not explicitly referenced
18	South Milliken Line Rebuild	P36617	4,524,716	November 2023 - June 2027	11,660,623	14,093,496	2,432,873	Distribution Plant	PGE Exhibit 700, Section II, "Poles and Wires" category, included in "Poles/Towers/Fixtures" on page 5
21	BR: Beaver Modernization	P36836	3,897,887	July 2022 August 2023 April-December 2024 May-December 2025 January 2026	122,585,726	57,406,880	(65,178,846)	Other Production	PGE Exhibit 800, Section II, "PGE's Generation Resources" on pages 2-3.
25	PW2: Top End Engine Parts and Insta	P37417	3,206,684	December 2024	12,578,000	10,615,088	(1,962,912)	Other Production	Not included in UE 416

Provide the following information concerning the above table.

a. Explain why all projects listed in PGE's New Construction Budget Report for the 2023 calendar year with start dates of 2023 or earlier are not included in CWIP at 12/31/2022 if the project is not yet completed or is ongoing?

b. Explain what the Final Project Cost amount in UE 416_OPUC DR 626_Attach A represents.

c. Explain what the Project Total amount in PGE's New Construction Budget Report for the 2023 calendar year represents.

d. Explain what the variances between Final Project Cost and Project Total represent.

e. For each project listed in Schedule B: Electric Company New Construction Budget (System) in PGE's New Construction Budget Report for the 2023 calendar year, explain why the Total amount reflecting the sum of actual to date and all current and future budget years is different from the Project Total amount in the Project Narrative section of the report for those projects where a variance exists.

<u>Response:</u>

a. Attachment 626-A only includes projects that had a CWIP balance greater than or equal to $3 million at December 31, 2021 or December 31, 2022. Projects that started before 2023 which had a CWIP balance less than $3 million at those reporting periods and projects that close to plant on a monthly basis were not included in the response to DR 626.

b. For projects with in-service date(s) prior to 2023, the Final Project Cost includes actual 2022 plant additions. For projects with a 2023 in-service date, Final Project Cost includes forecasted 2023 plant additions. For projects with spanning multiple years, Final Project Cost includes totals per the related project justification form.

c.-e. The New Construction Budget Report represents project approvals at the time of the approval of PGE's annual capital plan by the Board. The "Project Total" column in the New Construction Budget Report shows project total spend, including incurred and overhead costs. In contrast, UE 416 includes actual and forecasted close to plant capital additions from May 2022 through December 2023 at the time of the initial filing in the UE 416 docket.

PGE files the New Construction Budget Report on an annual basis in accordance with Oregon Administrative Rule 860-027-0015. Questions specific to what is included in that report may best be addressed in the reporting docket.

June 5, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 807
Dated May 18, 2023

Request:

Referring to UE 394_OPUC DR 311_Attach A, provide a schedule of all UE 416 plant additions by project number from April 30, 2022 through December 31, 2023. Additions should be broken out in the same manner as UE 394_OPUC DR 311_Attach A such as Table 1 Grouping fields, By Function fields, and In Service Dates.

Response:

PGE objects to this request on the basis of ambiguity and lack of clarity given that PGE's response to OPUC Data Request No. 311 in UE 394 was specific only to transmission and distribution capital additions. Notwithstanding its objection, PGE responds as follows:

Attachment 807-A provides the following information for all transmission and distribution and grid modernization capital projects: Funding Project number, Funding Project Name, Capital Additions, Business Sponsor Group, and categorization as described in PGE Exhibit 700.

Attachment 807-A also provides the following information for all other capital projects greater than $3 million: Funding Project number, Funding Project Name, Capital Additions, and Business Sponsor Group.

PGE's responses to OPUC Data Request Nos. 588, 626, and 796, and AWEC Data Request No. 213 provide other information, such as in-service dates, FERC functional class, and FERC account.

FP	Funding Project	Capital Additions	BSG	T&D Classification (PGE Exh 700)
P36167	P36167 - FY: Repower Faraday Units 1-5	$ 188,067,480	Gen & PO	
P37218	P37218 - OH FITNES Distribution	$ 173,079,692	T&D	Poles/Towers/Fixtures
P36680	P36680 - Brookwood Substation Conversion	$ 61,196,673	T&D	Substation
P36836	P36836 - BR: Beaver Modernization	$ 56,857,381	Gen & PO	
P37346	P37346 - powERPlay	$ 37,595,820	Services	
P36394	P36394 - Vintage Vehicle Replacement II	$ 32,419,385	Services	
P35924	P35924 - Distribution System Construction II	$ 30,294,337	T&D	Blanket
P36679	P36679 - Orenco Substation 115kV Rebuild	$ 29,671,871	T&D	Substation
P14628	P14628 - Replace Failed Underground Cables	$ 29,374,403	T&D	Cable
P35925	P35925 - Dist. Customer Line Construction II	$ 28,546,406	T&D	Customer
P37048	P37048 - Outage or Emergency Replacement	$ 26,965,654	T&D	Outage / Emergency /Major Storm
P35890	P35890 - Purchase Distribution Transformers	$ 25,364,565	T&D	Blanket
P36868	P36868 - Shute Capacity Addition	$ 23,461,057	T&D	Substation
P37272	P37272 - Oracle Utilities Upgrade	$ 22,914,997	IT	
P36501	P36501 - Integrated Operations Center - IOC	$ 22,145,775	Grid Mod	Grid Mod
P37046	P37046 - T&D Asset Relocation	$ 19,365,388	T&D	Poles/Towers/Fixtures
P36770	P36770 - Street and Area Light Construction	$ 18,389,168	T&D	Customer
P36522	P36522 - Distribution Automation	$ 17,752,440	Grid Mod	Grid Mod
P37344	P37344 - Tech Refresh	$ 12,603,008	IT	
P36134	P36134 - Hydro Control System Upgrade	$ 11,879,347	Gen & PO	
P37314	P37314 - Project 360 Bundle 1	$ 11,766,500	IT	
P37160	P37160 - Helvetia Substation Phase 2	$ 10,879,955	T&D	Substation
P37312	P37312 - Digital Channel Uplift 22	$ 10,774,324	Customers	
P36913	P36913 - Trans. Line Clearance Mitigation	$ 10,336,459	T&D	Poles/Towers/Fixtures
P37214	P37214 - Dist. Customer Line Construct III	$ 10,267,405	T&D	Customer
P37118	P37118 - WSH:Restore Facilities post-fire	$ 10,131,661	Gen & PO	
P37133	P37133 - CTO Network Fitness	$ 9,873,465	IT	
P37213	P37213 - Distribution System Construct III	$ 9,783,079	T&D	Blanket
P37017	P37017 - Facilities Upgrades-EV Readiness	$ 9,521,405	Services	
P37061	P37061 - OH FITNES Transmission	$ 9,228,514	T&D	Poles/Towers/Fixtures
P36417	P36417 - Replace/Rewind Failed Transformers	$ 8,864,024	T&D	Substation
P36116	P36116 - Wind Generation Fitness Program	$ 8,699,629	Gen & PO	
P35892	P35892 - Purchase Customer Meters	$ 8,585,074	T&D	Customer
P36845	P36845 - McLoughlin Sub Security Upgrades	$ 8,528,006	T&D	Substation
P37176	P37176 - Eastern Gen Admin Building-Carty	$ 7,796,428	Gen & PO	
P37509	P37509 - Biglow I Wind Enhancement Program	$ 7,297,603	Gen & PO	
P37466	P37466 - EMS Upgrade Project	$ 7,178,221	Grid Mod	Grid Mod
P37093	P37093 - Facilities Management Fitness	$ 6,961,568	Services	
P35995	P35995 - Downtown UG Core Cable Replacement	$ 6,709,540	T&D	Cable
P36723	P36723 - Field Area Network Project	$ 6,521,968	Grid Mod	Grid Mod
P37336	P37336 - Operational Technology Visibility	$ 6,468,184	IT	
P37379	P37379 - QTS: New Dist Feed to Buildings 2-5	$ 6,331,442	T&D	Customer
P37135	P37135 - Server Storage Fitness	$ 6,276,540	IT	
P37240	P37240 - Salem LC EIFS Replacement	$ 6,211,919	Services	
P37162	P37162 - Bill Redesign	$ 6,159,484	Customers	
P36762	P36762 - Milliken Tower Reinforcement	$ 6,152,652	T&D	Poles/Towers/Fixtures
P37533	P37533-2022 Microsoft Enterprise Agreement	$ 6,136,400	IT	
P37331	P37331 - CMD Network Protector Replacements	$ 6,000,770	T&D	Substation
P37376	P37376-CS: Rewind Unit 1 CTG & STG	$ 5,898,411	Gen & PO	
P36537	P36537 - Unjacketed Cable Replacement Prgrm	$ 5,768,768	T&D	Cable
P36582	P36582 - Substation FITNES 2019-2021	$ 5,607,775	T&D	Substation
P37347	P37347 - Risk Technology Optimization	$ 5,338,265	IT	
P37211	P37211 - Substation Cap Rplcmts 2022-2024	$ 5,222,808	T&D	Substation
P37047	P37047 - Joint Pole Construction	$ 5,214,689	T&D	Poles/Towers/Fixtures
P37049	P37049 - Dist. Crews Truck Stock Materials	$ 5,137,357	T&D	Blanket
P37364	P37364 - Newberg/Dundee Street Imprv/UG Conv	$ 5,100,786	T&D	Road Widening
P36178	P36178 - North Portland Conversion	$ 4,409,825	T&D	Substation
P37251	P37251-PACS 2.0	$ 4,387,226	Services	
P37333	P37333 - Upgrade Pleasant Valley-Moon	$ 4,320,796	T&D	Reconductor/Conversion
P35172	P35172 - PSES - Generation Fitness Fund	$ 4,159,570	Gen & PO	

FP	Funding Project	Capital Additions		BSG	T&D Classification (PGE Exh 700)
P37416	P37416 - PN: Rewind Unit 2 Generator	$	4,055,939	Gen & PO	
P37275	P37275 - Project Basie	$	4,017,860	T&D	Substation
P37429	P37429 - PORTS - Package 1	$	3,949,916	IT	
P36645	P36645 - DPU Relay Replacement Program	$	3,946,592	T&D	Substation
P36373	P36373 - Blue Lake Phase II	$	3,925,092	T&D	Substation
P37459	P37459 - TR - Rebuild Tower I-10	$	3,833,915	Gen & PO	
P37382	P37382 - ADMS CVR VVO	$	3,801,686	Grid Mod	Grid Mod
P36953	P36953 - Memorial Substation Build	$	3,763,187	T&D	Substation
P37487	P37487 - Energy Tracker Replacement	$	3,755,614	Customers	
P37353	P37353 - CY: Purchase 2023 Outage Components	$	3,750,800	Gen & PO	
P35484	P35484 - Repl Trans Structures & Insulators	$	3,669,307	T&D	Poles/Towers/Fixtures
P36449	P36449 - PRB: Upgrade Governors & Exciters	$	3,539,198	Gen & PO	
P37539	P37539 - CISCO Contact Center to Cloud	$	3,311,082	IT	
P35834	P35834 - Round Butte Transmission Upgrades	$	3,237,919	T&D	Reconductor/Conversion
P36439	P36439 - Gresham Sub 115kV Rebuild	$	3,166,722	T&D	Substation
P23528	P23528 - Clackamas PME - Recreation, Aesthet	$	3,075,682	Gen & PO	
P37267	P37267 - Grid Operations Logging System	$	2,916,255	Grid Mod	Grid Mod
P36879	P36879-Advanced Dist Mgmt Sys(ADMS) Phs 1	$	2,852,358	Grid Mod	Grid Mod
P36564	P36564 - Stephens 11kV Conversion Project	$	2,721,979	T&D	Substation
P36543	P36543-PRC-002 Protection Upgrades	$	2,649,287	T&D	Substation
P36716	P36716 - Arleta-Holgate Ln Rebuild_SE PDX	$	2,640,166	T&D	Reconductor/Conversion
P37200	P37200 - Harmony Rd Reconductor	$	2,627,295	T&D	Reconductor/Conversion
P37404	P37404 - Bull Mt Reconductor	$	2,452,702	T&D	Reconductor/Conversion
P36341	P36341-St Marys System Protection Upgrade	$	2,336,614	T&D	Substation
P37128	P37128 - Tualatin Sherwood, phase 1-3	$	2,292,563	T&D	Road Widening
P37104	P37104 - SW 209th Hillsboro Road Widening	$	2,252,428	T&D	Road Widening
P37266	P37266 - Reedville Substation Rebuild	$	2,213,108	T&D	Substation
P16567	P16567 - UG FITNES	$	1,951,424	T&D	Cable
P36285	P36285 - PurchaseT&D - Tools & Lab Equipment	$	1,933,099	T&D	Blanket
P37103	P37103 - ODOT OR213 Street Improvement	$	1,759,217	T&D	Road Widening
P37167	P37167 - Mitigate Overdutied Breakers	$	1,722,437	T&D	Substation
P37121	P37121 - Durham Substation Separation	$	1,713,899	T&D	Substation
P36089	P36089 - Transm Full Pole Inspct & Replace	$	1,689,830	T&D	Poles/Towers/Fixtures
P36617	P36617 - South Milliken Line Rebuild	$	1,606,730	T&D	Poles/Towers/Fixtures
P36727	P36727 - Energy Storage, Microgrid	$	1,535,547	Grid Mod	Grid Mod
P36545	P36545-Tree Wire Installment Program	$	1,534,607	T&D	Reconductor/Conversion
P36740	P36740 - Energy Storage Controls	$	1,358,320	Grid Mod	Grid Mod
P37427	P37427 - Expeto Wireless Platform & Service	$	1,292,135	Grid Mod	Grid Mod
P37406	P37406 - Critical Customer List (CCL)	$	1,263,863	Grid Mod	Grid Mod
P36641	P36641 - Oil Spill Containment Modifications	$	1,244,607	T&D	Substation
P37504	P37504 - Smart Grid Chips Initial Deployment	$	1,240,810	Grid Mod	Grid Mod
P37112	P37112 - Kelley Point Reconfiguration	$	1,221,153	T&D	Reconductor/Conversion
P36101	P36101 - Substation Communication Upgrade	$	1,208,515	Grid Mod	Grid Mod
P37548	P37548 - Grand Ronde - Sheridan 57kV Upgrade	$	1,176,373	T&D	Customer
P37178	P37178-ADMS Phase 2	$	1,122,676	Grid Mod	Grid Mod
P35846	P35846 - CPP Switch Replacement	$	1,108,222	T&D	Cable
P17443	P17443 - T&D Major System Inspect, Replace	$	1,104,955	T&D	Poles/Towers/Fixtures
P36235	P36235 - Install Low OH Services Guarding	$	1,079,067	T&D	Other
P37204	P37204-AMI Improvement Project	$	1,052,706	Grid Mod	Grid Mod
P35149	P35149 - Colstrip Transmission NW Energy	$	1,045,870	T&D	Other
P35556	P35556 - Avian Protection Program	$	1,013,604	T&D	Poles/Towers/Fixtures
P37256	P37256 - Amity Transformer Replacement	$	997,208	T&D	Substation
P35349	P35349 - Dist Line Sys - Equip Replacement	$	952,635	T&D	Other
P37551	P37551 - Tualatin Sherwood, Phase 4	$	854,811	T&D	Road Widening
P37421	P37421 - Foreign Utility Blanket	$	814,872	T&D	Substation
P37020	P37020 - Marquam Fiber Project	$	712,512	T&D	Communications
P14757	P14757 - Underground Locating	$	706,622	T&D	Cable
P37521	P37521 - Distribution State Estimation	$	691,438	Grid Mod	Grid Mod
P37232	P37232 - Communications Fitness II	$	681,230	T&D	Communications
P37359	P37359 - Integrated Dist Planning Tools	$	519,031	Grid Mod	Grid Mod

FP	Funding Project	Capital Additions		BSG	T&D Classification (PGE Exh 700)
P36205	P36205-Metal Streetlight Grounding	$	426,053	T&D	Poles/Towers/Fixtures
P37519	P37519 - Solar QF Metering Integration	$	391,401	Grid Mod	Grid Mod
P37339	P37339 - Trojan Switchyard-Install Breaker	$	344,353	T&D	Substation
P36860	P36860-Canyon-Urban 115kV Reconductor	$	336,867	T&D	Reconductor/Conversion
P36151	P36151 - Eagle Take Permitting	$	321,605	T&D	Other
P36105	P36105 - 2016-2024 Dispatchable Standby Gen	$	275,948	Grid Mod	Grid Mod
P36391	P36391-Willbridge Station 11kV Conversion	$	255,151	T&D	Substation
P37494	P37494 - Livefront Switch Replacements	$	246,506	T&D	Other
P37370	P37370 - Salem Smart Power Center Repower	$	194,930	Grid Mod	Grid Mod
P37537	P37537 - Microchip Prelim Scope/Survey	$	166,384	T&D	Substation
P36861	P36861-Division Transit Project (DTP)	$	139,168	T&D	Road Widening
P36563	P36563-Battery Safety Improvements	$	127,722	T&D	Substation
P36170	P36170 - OHSU Infrastructure Upgrades	$	114,036	T&D	Customer
P37107	P37107-PBT Transmission Line Relocation	$	99,664	T&D	Poles/Towers/Fixtures
P36209	P36209 - Silverton Capacity Addition	$	73,872	T&D	Substation
P35650	P35650 - Emergent Radio Equipment	$	73,348	T&D	Communications
P18834	P18834 - Station E: River District Infrastr	$	73,213	T&D	Cable
P37352	P37352 - Customer Reliability Improvement	$	71,755	T&D	Other
P37337	P37337 - TD Utility Standards Eng. Redbook	$	50,682	T&D	Other
P36039	P36039 - Harborton Reliability Project PH1	$	48,789	T&D	Substation
P37143	P37143-Credit Remote Connect Meters	$	47,293	T&D	Customer
P36708	P36708-Butler Substation Construction	$	41,554	T&D	Substation
P36867	P36867-Remote Disconnect Project	$	29,989	T&D	Customer
P35894	P35894-Communications Fitness	$	16,469	T&D	Communications
P36714	P36714 - Dayton-Gr Ronde Conv Segment 2	$	14,109	T&D	Reconductor/Conversion
P37109	P37109-Customer Data Centers	$	13,549	T&D	Customer
P36527	P36527-TRIP (TripSaver II) Implementation	$	9,564	Grid Mod	Grid Mod
P36907	P36907-Reconductor Murrayhill-St Marys	$	8,942	T&D	Reconductor/Conversion
P36270	P36270-Roseway Substation Expansion	$	6,886	T&D	Substation
P35096	P35096 - Dist Customer Line Construction	$	6,349	T&D	Customer
P35938	P35938-Field Voice Communications System	$	5,357	T&D	Communications
P36454	P36454-Substation Rerock - multiple sites	$	4,628	T&D	Substation
P23970	P23970-Corporate Strategic Fiber Project	$	4,214	Grid Mod	Grid Mod
P36693	P36693-Build Helvetia Substation	$	2,969	T&D	Substation
P35980	P35980-PCB Transformer Replacement	$	2,332	T&D	Other
P35351	P35351-Major Event Tracking	$	1,234	T&D	Outage / Emergency /Major Storm
P35918	P35918-Purchase Vacuum Truck	$	755	T&D	Other
P35914	P35914-Substation Fitness 2015-2018	$	712	T&D	Substation
P36932	P36932 - Marquam Cap Addn - Terwilliger	$	397	T&D	Customer
P36656	P36656-Energy Storage - PW2 Project	$	202	Grid Mod	Grid Mod
P23077	P23077-Horizon 230kV - Phase 1 Constructio	$	52	T&D	Substation
P36856	P36856-Malin Substation - Security	$	9	T&D	Substation
P37114	P37114-Project BaT	$	1	T&D	Customer
P37368	P37368 - Virtual Power Plant (VPP)	$	-	Grid Mod	Grid Mod
P37532	P37532 - WTC to IOC Move	$	-	Grid Mod	Grid Mod
P36901	P36901 - Minimum Load Agreement -MLA Reserve	$	-	T&D	Customer
P37126	P37126 - Walker Rd Beaverton-Road Widening	$	-	T&D	Road Widening
P36954	P36954 - Tonquin Substation Build	$	-	T&D	Substation
P37350	P37350-Waconda Substation Expand	$	(1)	T&D	Substation
P36324	P36324-Garden Home Substation Upgrade	$	(3)	T&D	Substation
P36322	P36322-King City - Substation Upgrades	$	(19)	T&D	Substation
P35679	P35679-Construct Marquam Project	$	(66)	T&D	Substation
P36722	P36722-Stephens Substation Demo	$	(127)	T&D	Substation
P36730	P36730-Harrison Sub Temp H Install_SE PDX	$	(193)	T&D	Substation
P35820	P35820-Estacada Capacity Addition	$	(321)	T&D	Substation
P35572	P35572-Build New Rock Creek Substation	$	(349)	T&D	Substation
P36036	P36036-Canemah-Sullivan 57kV Project	$	(365)	T&D	Substation
P35095	P35095-Dist System Line Construction	$	(614)	T&D	Blanket
P36710	P36710-Fairview Substation Upgrades	$	(1,568)	T&D	Substation
P36485	P36485-Intel D1X Add and Replace Cables	$	(3,450)	T&D	Customer

FP	Funding Project	Capital Additions		BSG	T&D Classification (PGE Exh 700)
P24723	P24723-Substation Arc Flash Mitigation	$	(6,212)	T&D	Substation
P36763	P36763-Install Horizon VWR3 Transformer	$	(6,351)	T&D	Substation
P36550	P36550 - Small Gen/QF/NM Interconnect Costs	$	(25,189)	T&D	Customer
P37168	P37168 - 2021-2022 QF Projects	$	(263,863)	T&D	Customer
P36859	P36859 - ODOT Outer Powell Ph2-Road Improv.	$	(954,749)	T&D	Road Widening

June 5, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 808
Dated May 18, 2023

Request:

Refer to PGE's response to UE 416 OPUC DR 628, Confidential Attachment A, containing Project Justification Forms for capital projects other than transmission and distribution greater than $3 million. Produce the Project Justification Forms for the following projects listed in PGE's response to UE 416 OPUC DR 626, Attachment A, that were not produced in response to UE 416 OPUC DR 628.

a. P36101 – Substation Communication Upgrade;

b. P36838 – RB: Replace Turbine Shut-Off Valves; and

c. P37477 – Zero Trust

Response:

Confidential Attachment 808-A provides the requested information.

Attachment 808-A contains protected information and is subject to General Protective Order No. 23-039.

June 5, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 809
Dated May 18, 2023

Request:

Refer to PGE's response to UE 416 OPUC DR 628, Confidential Attachment A, containing Project Justification Forms for capital projects other than transmission and distribution greater than $3 million. Also, refer to the Attachment A workbooks produced in response to UE 416 OPUC DRs 626 and 627. Confirm whether each project listed below has an amount representing the cost being included in the UE 416 rate base that was part of either 2021 CWIP, 2022 CWIP, or 2023 Forecasted Capital Additions in UE 416 OPUC DRs 626 and 627. If the answer is yes, provide the amount. If the answer is no, explain why not.

a. P23528 - Clackamas PME - Recreation, Aesthet.pdf;
b. P35172 - PSES - Generation Fitness Fund.pdf;
c. P36116 - Wind Generation Fitness Program.pdf;
d. P36394 - Vintage Vehicle Replacement II.pdf;
e. P36449 - PRB Upgrade Governors & Exciters.pdf;
f. P36501 - Integrated Operations Center - IOC.pdf;
g. P37162 - Bill Redesign.pdf;
h. P37176 - Eastern Gen Admin Building-Carty.pdf;
i. P37251-PACS 2.0.pdf;
j. P37314 - Project 360 Bundle 1_Redacted.pdf;
k. P37336 - Operational Technology Visibility_Redacted.pdf;
l. P37347 - Risk Technology Optimization.pdf;
m. P37376-CS Rewind Unit 1 CTG & STG.pdf;
n. P37509 - Biglow I Wind Enhancement Program.pdf; and
o. P37533-2022 Microsoft Enterprise Agreement_Redacted.pdf

Response:

Attachment 809-A provides the requested information.

OPUC DR 809, Attachment 809-A

	CWIP Balances at		Plant Additions		
	12/31/2021	12/31/2022	May 2022- December 2022 (Actual)	2023 Plant additions (Forecast)	Notes:
P23528 - Clackamas PME - Recreation, Aesthet.pdf	$ 119,422	$ 1,606,604	$ 119,622	$ 2,956,060	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P35172 - PSES - Generation Fitness Fund.pdf;	$ 429,906	$ 728,852	$ 2,980,678	$ 1,178,892	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P36116 - Wind Generation Fitness Program.pdf	$ 657,588	$ 864,340	$ 7,982,649	$ 716,980	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P36394 - Vintage Vehicle Replacement II.pdf	$ -	$ -	$ 13,641,776	$ 18,777,608	Not included in DR 626 as CWIP not greater than $3M. Included in DR 627
P36449 - PRB Upgrade Governors & Exciters.pdf	$ 1,536,410	$ 832,900	$ 2,401,040	$ 1,138,158	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P36501 - Integrated Operations Center - IOC.pdf	$ 148,946	$ 2,073,325	$ 3,453,066	$ 18,692,709	Not included in DR 626 as CWIP not greater than $3M. Included in DR 627
P37162 - Bill Redesign.pdf	$ 1,721,499	$ 644,420	$ 3,792,441	$ 2,367,043	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P37176 - Eastern Gen Admin Building-Carty.pdf	$ -	$ 1,885,497	$ -	$ 7,796,428	Not included in DR 626 as CWIP not greater than $3M. Included in DR 627
P37251-PACS 2.0.pdf	$ -	$ -	$ 4,387,226	$ -	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P37314 - Project 360 Bundle 1_Redacted.pdf	$ -	$ -	$ 5,279,695	$ 6,486,805	Not included in DR 626 as CWIP not greater than $3M. Included in DR 627
P37336 - Operational Technology Visibility_Redacted.pdf	$ -	$ 1,954,122	$ 3,529,036	$ 2,939,148	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P37347 - Risk Technology Optimization.pdf	$ -	$ 2,940,488	$ -	$ 5,338,265	Not included in DR 626 as CWIP not greater than $3M. Included in DR 627
P37376-CS Rewind Unit 1 CTG & STG.pdf	$ -	$ -	$ 5,898,411	$ -	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M
P37509 - Biglow I Wind Enhancement Program.pdf	$ -	$ -	$ -	$ 7,297,603	Not included in DR 626 as CWIP not greater than $3M. Included in DR 627
P37533-2022 Microsoft Enterprise Agreement_Redacted	$ -	$ -	$ 6,136,400	$ -	Not included in DR 626 as CWIP not greater than $3M. Not included in DR 627 as 2023 Forecasted Additions are less than $3M

June 6, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 813
Dated May 23, 2023

Request:

Referring to *UE 416-21-23 Exhibit Support_2024_Errata.xlsx*, Ex 208 Rate Base Delta, provide the following linked Microsoft Excel workbooks referenced on this sheet:

a. *Integrated PGE RevReq_4-25-22_Final Order_net Colstrip.xlsx* referenced in cells C9-C11, C16, and C20.

b. Exhibit Support 2022_Errata.xlsx referenced in cells C19-C20, C22-C23, and C26-C30.

Response:

Attachments 813-A and 813-B provide the requested files.

June 6, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 814
Dated May 23, 2023

Request:

Referring to *UE 416-21-23 Exhibit Support_2024_Errata.xlsx*, Ex 208 Rate Base Delta, provide a reconciliation between the amounts in column UE 394 Approved Order No. 22-129, Lines 1-27 and the amounts in the stipulated integrated revenue requirement schedule for rate base in UE 394 Order No. 22-129, Appendix C, Stipulating Parties/302/2. Provide all of the reasons for the differences.

Response:

There are two differences that account for the delta between Order No. 22-129, Appendix C, Stipulating Parties/302/2 (Appendix C) and PGE Exhibit 200 work paper Exhibit Support_2024_Errata.xlsx, Ex 208 Rate Base Delta, Column C.

1. Colstrip is included in Appendix C but not in Ex 208. The amounts attributed to Colstrip can be found in PGE's response to OPUC Data Request No. 813, Attachment 813-A.
2. Appendix C reflects settled amounts prior to PGE's final November 15, 2021 net variable power cost (NVPC) update for 2022. This update reduced PGE's 2022 NVPC by approximately $375,000, which had a corresponding impact to PGE's working cash amount included in rate base. The final NVPC amount and corresponding changes to PGE's revenue sensitive amounts, including working cash, can be found in PGE's response to OPUC Data Request No. 813, Attachment 813-A.

June 6, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 817
Dated May 23, 2023

Request:

Refer to *UE 416_AWEC DR 039_Attach A.xlsx*, tabs Unbundling Source Data, Net Plant Recon Detailed and CPR Controls. Revise these schedules to add PGE's plant balances as of May 1, 2022 by the same FERC account categories as the starting point and then showing actual additions, retirements, and other adjustments to get to the actual December 31, 2022 plant balances that currently serve as the starting point for each schedule.

Response:

Attachment 817-A provides the requested information.

OPUC DR 817

Gross Plant

		May 2022-December 2022 Activity							
Functional Class	**FERC Balance - Actuals 4/30/22**	**Additions**	**Additions (ARC)**	**Retirements**	**Transfers**	**Lease Activity (Accounts 1011%)**	**Remove Colstrip Steam & General**	**Actuals 12/31/2022**	
Hydro	*723,090,966*	*11,606,657*	*-*	*(526,320)*	*(29,922)*	*(6,196,105)*	*-*	*727,945,276*	[redacted]
Other Production	*3,384,597,478*	*32,635,201*	*1,459,436*	*(12,913,151)*	*-*	*(7,131,904)*	*-*	*3,398,647,060*	[redacted]
Steam Production [1]	*536,785,321*	*9,553,296*	*-*	*(12,746,525)*	*-*	*-*	*(533,592,092)*	[redacted]	[redacted]
Generation	4,644,473,764	53,795,154	1,459,436	(26,185,996)	(29,922)	(13,328,009)	(533,592,092)	[redacted]	4,126,592,336
Distribution	4,563,260,983	259,444,915	-	(10,065,759)	-	-	-	[redacted]	4,812,640,139
General Plant	922,494,019	54,558,855	-	(26,498,744)	29,922	(367,302)	(4,717,174)	[redacted]	945,499,575
Intangible - Software	598,467,051	33,879,609	-	-	-	-	-	[redacted]	632,346,660
Intangible - Other	197,802,202	98,955	-	-	-	-	-	[redacted]	197,901,158
Transmission	1,021,774,422	95,644,178	-	(1,390,757)	-	-	-	[redacted]	1,116,027,843
Ending Balance	**11,948,272,441**	**497,421,665**	**1,459,436**	**(64,141,256)**	**-**	**(13,695,311)**	**(538,309,266)**		**11,831,007,710**

OPUC DR 817

Gross Plant

Functional Class	Remove Leases in Accounts 1011%	ARO Adjustment to Rate Base	Adjusted 12/31/22 Balance	Forecasted Additions	Forecasted Retirements	[Not in Use]	ARO Adjustment to Rate Base	12/31/2023 Forecasted Ending Balance
Hydro	*(167,294,823)*		[redacted]	*217,613,039*	*(1,134,021)*			[redacted]
Other Production	*(179,524,545)*		[redacted]	*66,278,555*	*-*			[redacted]
Steam Production [1]			[redacted]	[redacted]	[redacted]			[redacted]
Generation	(346,819,368)	(27,383,533)	3,752,389,435	283,891,594	(1,134,021)	-	-	4,035,147,007
Distribution	-	-	4,812,640,139	374,930,777	(35,114,675)	-	-	5,152,456,241
General Plant	(3,768,388)	-	941,731,187	91,031,589	(75,266,486)	-	-	957,496,290
Intangible - Software	-	-	632,346,660	137,445,160	-	-	-	769,791,819
Intangible - Other	-	-	197,901,158	824,011	-	-	-	198,725,169
Transmission	-	-	1,116,027,843	28,619,196	(5,143,022)	-	-	1,139,504,017
Ending Balance	**(350,587,756)**	**(27,383,533)**	**11,453,036,421**	**916,742,327**	**(116,658,204)**	**-**	**-**	**12,253,120,544**

STAFF 2700 DRs - ISSUE 2
(MMAs)

STAFF 2704
NON-CONFIDENTIAL
STAFF 611
STAFF 615
STAFF 617
STAFF 775
AWEC 113

May 12, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE's *Supplemental* Response to OPUC Data Request 611
Dated April 20, 2023

Request:

Refer to Exhibit 800 Workpaper "2024 GRC MMA Work Paper Final for initial filing," Tab "Assumptions," table "LTSA Contract Assumptions" (cell range J1:U30), please provide:

a. Actual vendor service agreements / contract documents / quotes / other sources (whichever are applicable) supporting the hard-coded dollar values and assumed annual escalations contained in this table.

b. Please make sure the provided vendor documents include vendor name, effective dates, pricing payment terms/ fee schedules, as well as the description of services to be provided.

Initial Response (dated May 4, 2023):

The contract assumptions from our MMA workbook are created using the LTSA contracts. PGE is currently unable to provide the requested information due to contractual obligations with third parties. PGE will supplement this response if authorized by third parties to provide unredacted versions of the agreements.

Highly Confidential Attachment 611-A provides our Carty LTSA contract as approved by PGE's legal counsel.

Attachment 611-A is highly confidential information subject to Modified Protective Order No. 23-138.

Supplemental Response (dated May 12, 2023):

Highly Confidential Attachment 611-B provides our Coyote Springs LTSA contract, which is the basis for PGE's Coyote Springs LTSA contract assumptions. This contract also supports the vendor information requested in OPUC DR 612.

Highly Confidential Attachment 611-C provides our Carty LTSA contract, which is the basis for PGE's Carty LTSA contract assumptions. This contract also supports the vendor information requested in OPUC DR 612.

Highly Confidential Attachment 611-D provides our Port Westward LTSA contract, which is the basis for PGE's Port Westward LTSA contract assumptions. This contract also supports the vendor information requested in OPUC DR 612.

Attachments 611-B through 611-D are highly confidential information subject to Modified Protective Order No. 23-138.

May 4, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 615
Dated April 20, 2023

Request:

Please compare two tables: (i) an image of a table entitled "PW1 MMA Accrual & Deferral" found in Exhibit 800 Workpaper "2024 GRC MMA Work Paper Final for initial filing, Tab "Summary," and, (ii) a table in "PW1 2022 JPR67P_202212_PWW LTSA", Tab "1. PW1 MMA Rollforward," provided in data response to AWEC Data Request 113. These two tables appear to be very similar, with one major difference being entries for December 2022.

a. Which version of this table is more accurate?
b. Which version of this table flows into PGE's proposed MMA adjustments?

Response:

a. The table included in PGE's response to AWEC Data Request No. 113 is more accurate, as it has newer numbers than the numbers included in PGE's Exhibit 800 MMA work paper. The Exhibit 800 MMA work paper is created as a snapshot in time during the development of PGE's General Rate Case filing.
b. The version included in PGE's Exhibit 800 work paper, "2024 GRC MMA Work Paper Final for initial filing," is what PGE used to develop the 2024 MMA collection amount.

May 4, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 617
Dated April 20, 2023

Request:

Referring to PGE non-confidential workpaper to Exhibit 200 entitled "Exhibit Support_2024" Tab "Rate Base Data," line numbers 17 through 20 (Rate Base, Major Maintenance):

a. How are these amounts derived? Please explain and provide supporting workpapers.

b. Regarding line 20 "Carty Major Maintenance (AWO 7000000322); excluded from base:" Please explain whether this item is excluded from rate base in this case as this note appears to indicate.

Response:

a. The referenced amounts are calculated by PGE's financial forecasting department. For the December 31, 2023 balances included in this case, actual October 2022 month-ending balances were used as the starting point. From there, PGE's financial forecasting model assumes a net monthly change in balance based on an estimated collection (amortization) amount and spend (additions) amount. Attachment 617-A provides this data.

b. No. This appears to be extraneous data and is not relevant to the referenced line.

May 24, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 775
Dated May 10, 2023

Request:

Refer to Exhibit 800 Workpaper "2024 GRC MMA Work Paper_Final for initial filing," Tab "Summary:"

a. Confirm or deny that value in cell D34 (year 2023 Amortization for PW2) should be negative, rather than positive. To the extent you deny this observation, please explain why.
b. To the extent you confirm (a), please (i) explain whether and how the correction would change the proposed MMA adjustment, as well as overall proposed revenue requirements and (ii) provide the updated workbook(s).
c. To the extent you deny (b), please explain why.

Response:

a. PGE confirms that the value in cell D34 should be negative, rather than positive.
b. This correction would reduce the proposed MMA amount from $1,160,459 to $773,805 for PW2. PGE will provide an updated workbook in its reply to Staff's opening testimony.
c. Not applicable.

April 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 113
Dated March 30, 2023

Request:

Reference Exhibit 800 Workpaper "2024 GRC MMA Work Paper_Final for initial filing," Tab "Summary":

a. Please provide accounting workpapers detailing the December 31, 2022 balancing account balances for each of PGE's power plants or facilities identified in the referenced workpaper. Please provide the balance on a monthly basis, detailing all additions and amortizations to the respective accounts since the accounts were initiated.

b. Please provide transaction-level detail supporting all major maintenance expenses recorded to the balancing accounts identified in the referenced workpaper since the respective accounts were initiated through the most recent month available.

c. Please explain how the adjustments in the referenced worksheet are included in revenue requirement in workpaper "Exhibit Support_2024"

d. Please provide the workpapers from UE 394 that were used to establish the current amortization rate.

Response:

a. PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Subject to and without waving its objection, PGE responds as follows:
Confidential Attachments 113-A through 113-F provide accounting workpapers for each of PGE's power plants referenced in the major maintenance accrual (MMA) workpaper, from 2019 to 2022. Please note that for Carty and Port Westward I from 2019-2020 and Port Westward II from 2019-2021, accounting workpapers allocated the MMA balance by invoice instead of by month. To provide more detail, PGE is providing Confidential Attachment 113-G which contains the monthly accrual for the previously mentioned plants and years.
b. PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Subject to and without waving its objection, PGE responds as follows:

Confidential Attachment 113-H contains transaction-level detail from 2019 through 2022 for all major maintenance expenses as shown in the “YTD EXP” columns from the screenshots on the “Summary” tab of the referenced Exhibit 800 Workpaper: “2024 GRC MMA Work Paper_Final for initial filing.” These major maintenance expenses contain all expenses recorded to generation account 5530001, for each plant’s MMA accounting work order.

c. The MMA adjustment in cell E19 of tab “2020-2022 MMA Adjustment” is included in the PGE Exhibit 200 work paper, “Exhibit Support_2024,” tab “Generation” as part of the total amount for account 5530001. The total amount included in “Exhibit Support_2024,” tab “Generation” matches the sum of 5530001 provided in the PGE Exhibit 800 work paper “GRC Production Workpaper 2022-2024 Variance,” tab “Core Data.”
d. Confidential Attachment 113-I contains the workpaper from UE 394 that was used to establish the current amortization rate.

Attachments 113-A through 113-I provide protected information subject to General Protective Order No. 23-039.

**STAFF 2700 DRs - ISSUE 3
(FUEL STOCK)**

STAFF 2704
NON-CONFIDENTIAL
UE 394 STAFF 779
STAFF 340
STAFF 341
STAFF 342
STAFF 344
STAFF 639
STAFF 640
STAFF 642
STAFF 647
STAFF 648
STAFF 650
STAFF 653

September 29, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 779
Dated September 15, 2021

Request:

With regard to the Company's historic "fuel stock":

a. Please provide the forecasted value of the Company's fuel stock in each year from 2016 to 2021.
b. Please provide the actual value the Company fuel stock in each year from 2016 to 2020.
c. Please provide a breakdown of the value provided in response to section "a," showing each fuel type separately, providing both the US dollar value of the fuel stock, and its quantity and unit of measure (e.g. gallons or other).
d. Please provide a narrative explanation of how the values provided in response to sections "a" and "b" were calculated. Include a copy of the Company's calculation with this response in electronic workbook format, with all cells and formulas intact.
e. Where fuel stock has been assigned to a specific generator, please provide" a breakdown showing:
    i. The fuel types assigned to each generator.
    ii. The quantity of each fuel type (including the unit of measurement) assigned to each generator
    iii. The US dollar value of each fuel type assigned to each generator.

Response:

a. PGE objects to this request on the basis that it is vague, unduly burdensome, and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:
PGE maintains a rolling forecast of fuel stock that changes monthly based on recorded actuals for the previous month. Additionally, PGE typically reviews, and updates forecast parameters on an annual basis. This forecast is maintained within a logic-based software system and PGE does not maintain historical forecast scenarios beyond a few years. Attachment 779-A provides forecast 2017 and 2018 year-end balances as filed in PGE's last two general rate cases (Docket Nos. UE 319 and UE 335) and a forecast 2021 year-end balance consistent with the forecast used in PGE's current general rate case. Additionally, as PGE did not file a general rate case between UE 335 and UE 394,

Attachment 779-A provides a year-end 2019 forecast balance, based on a March 2019 forecast, with actuals through February 2019 and a year-end 2020 forecast balance, based on a March 2020 forecast, with actuals through February 2020.

b. Attachment 779-B provides actual year-end quantity and value of PGE's fuel stock for 2016 to 2020.

c. PGE forecasts fuel stock based on the value and not based on quantity. See PGE's response to OPUC Data Request No. 778 for additional detail.

d. PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:

   Values for part (a.) come from PGE's historical general rate case records and from historical forecast information. PGE no longer has the calculations used at that point in time. PGE's response to OPUC Data Request No. 778 provides a narrative explanation and data in support on how PGE currently forecasts fuel inventories. Values for part (b.) come from PGE's accounting records. Inventory values are calculated based on ending balances and the weighted average cost of the commodity at that point in time.

e. All current gas inventories are stored at North Mist, which is used to fuel PGE's Port Westward 1, Port Westward 2, and Beaver plants. All current coal inventory is for Colstrip. Oil inventories are currently used for Colstrip and Beaver. CO2 allowance inventories are not assigned to a specific generator. Attachment 779-B provides the historical breakout of these amounts.

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 340
Dated March 16, 2023

Request:

Regarding the Company's fuel stock:

a. Please provide a narrative explanation of the purpose of fuel stock.

b. Please provide a narrative explanation of how existing fuel stock is valued in the Company's filing.

c. If fuel stock is not valued at the lower of average cost or net realizable value in this filing, please explain why not.

d. If the calculation of fuel stock as included in the Company's filing differs from the calculation of fuel stock recorded on the Company's FERC Form 1 filing, please provide a narrative explanation of this difference.

e. Please specify the value of fuel stock that the Company's is requesting recovery for in this filing in US dollars. Include a reference to where this value is reflected in the Company's work papers and indicate whether and when this value will be updated during the course of this filing.

Response:

a. The purpose of fuel stock is to allow immediate availability of fuels needed to run PGE's generating plants to meet load demand.
b. For the MONET model, existing natural gas volumes at the North Mist storage facility are used to forecast the January 2024 storage volume and weighted average cost of gas (WACOG) based on anticipated gas injections and withdrawals at North Mist. The value of stored gas is based on the forecasted WACOG for the month that PGE anticipates the stored fuel will be burned. PGE's oil stock is valued at the lower of cost or market (LCM). PGE calculates the value of coal purchased that Talen reports, using the weighted average cost method.
c. Regarding natural gas, North Mist stored gas is valued at the WACOG. There is no physical access from North Mist to the Williams NW Pipeline due to the uni-directional nature of the Kelso-Beaver pipeline, and thus, there is no realizable value for stored gas as it can

only be used to fuel Port Westward, Port Westward II, and Beaver 1-7.

d. The calculation of PGE’s actual fuel stock does not differ.
e. The value of fuel stock included in PGE’s filing is $31,484,573. This is included as part of PGE’s Operating Materials & Fuel balance, as provided in PGE Exhibit 200. This amount can be isolated in the PGE Exhibit 200 work paper, “2024 Unbundled ROO,” tab “Unbundled” by filtering on account 1510001.

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 341
Dated March 16, 2023

Request:

Please provide a narrative explanation of how the Company determines the most efficient and effective inventory levels for fuel stock. In addition to this response, please provide the following information:

a. References to any relevant internal policies in response to the question above.
b. A copy of any relevant internal policies with this response, and whether the Company is in compliance with its policies. Please explain.
c. Indicate whether the optimal inventory levels depend on the price of the fuel. If yes, please provide an explanation of this.
d. Explain how the Company accounts for potential supply disruptions when planning its fuel stock.

Response:

PGE maintains adequate fuel stock levels for the primary purpose of helping to facilitate the reliable operations of PGE's generation fleet. A secondary purpose, which pertains to PGE's gas inventories at North Mist, is to facilitate the most economic dispatch of PGE's Port Westward 1, Port Westward 2, and Beaver plants (Westside Thermal Plants).

North Mist, PGE's sole source of gas storage, coupled with 111,805 dekatherms (dth) of daily Northwest Pipeline transport is the portfolio solution for fueling PGE's Westside Thermal Plants. With a total combined daily demand of approximately 220,000 dth PGE must rely on stored gas to operate these plants at full capacity.

Based on current forward price curve information and to meet reliability needs during heavier usage seasons, North Mist, which has approximately 4,100,000 dth of capacity, is intended to be full June 30th and November 30th. If a structural change occurs to the current forward price curve the storage optimization will be adjusted, resulting in a different North Mist inventory level throughout the year. For reliability purposes, North Mist inventory is maintained at a minimum storage level of 1,200,000 dth.

As it pertains to PGE's coal supply for its ownership share in Colstrip Units 3 and 4, the co-owners of the Colstrip plant have a coal supply agreement with Westmorland, covering the period of January 1, 2020 through December 31, 2025. The terms of the agreement have a minimum take provision for tons of coal annually and tiered pricing. Coal is delivered directly from the mine to the plant for immediate consumption. Due to the proximity of the plant to the mine, a minimum amount of coal is on site at the plant. To determine the annual quantity of coal that will be utilized, the price of the delivered coal is used to determine the dispatch cost for the plant. Please note that all costs associated with Colstrip have been placed in a separate schedule (Schedule 146) and are not included in this general rate case.

a. Not applicable.

b. Not applicable.

c. Optimal inventory levels do not depend on the price of fuel. For gas at North Mist, it depends on the value derived from PGE's gas storage modeling in MONET, coupled with maintaining approximately 1.2 billion cubic feet (BCF), to ensure the Port Westward thermal plant can be dispatched for seven days exclusively on storage gas should a gas pipeline disruption occur.

   Colstrip is a mine mouth plant.[1] On site, a small quantity of coal is on hand to help regulate the volume of coal entering the plant and to manage issues that arise at the plant or the mine. For example, the plant may go off-line for a few hours or few days and coal from the mine would be held on site to be burned when the plant resumes operation. Conversely if there is an issue with the mine, the coal on hand could be utilized to keep the plant running while the mine issues are resolved. In addition, the on-site coal can be blended with coal coming directly from the mine to ensure that quality meets the standard needed for the units. The coal on hand at the plant can vary from a few days' supply up to several days' supply for both units 3 and 4 at full operation.

   Oil inventory levels are based on the amount required to fuel PGE's Beaver Plant operations at full load for approximately four to five days during heavy load hours. Oil (diesel) is used at Colstrip to start the units. Typically, Colstrip will store sufficient diesel on site to support three to five starts per year for each unit.

d. See PGE's response to part (c.).

[1] Colstrip is located directly next to a coal mine.

March 30, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 342
Dated March 16, 2023

Request:

Regarding the Company's fuel stock requirements:

a. Please provide a narrative explanation of any applicable Company policies or procedures and provide a copy of same.

b. Please specify the number of days/hours of plant operation at full capacity the fuel stock represents for each of the Company's applicable generating facilities. Include references to, and copies of, any applicable policies or procedures which guide this.

c. Please indicate whether the Company has undertaken any cost benefit, risk management, and/or other analyses to inform its fuel stock requirements. If yes, please provide a copy of any such analyses.

d. In general, how is fuel stock related to average historic operation, or interruptions in fuel supply deliveries?

e. Please provide a narrative explanation of the change in PGE's fuel stock requirements following its entry into the Energy Imbalance Market. Include comparisons with December 31st coal fuel stocks held in prior years.

Response:

a. PGE does not have a company policy regarding fuel stock requirements. See PGE's response to OPUC Data Request Nos. 340, 341, and 344 for additional information.
b. See PGE's response to OPUC Data Request No. 341.
c. Not applicable.
d. Colstrip's fuel stock has remained relatively consistent year over year. Beaver's oil stock also remains relatively consistent year over year. North Mist is based on PGE's seasonal injection and withdrawal cycles and consistent with amounts forecast in PGE's net variable power costs. Additionally, PGE stores gas in the lower-price times of year to ensure sufficient gas supply in the periods when the prices for power and gas will be higher. This operation is forecasted based on historical operation and power and gas prices. The actual operations will vary based on information that is available within the operating year. See

PGE’s response to OPUC Data Request Nos. 340, 341, and 344 for additional information.

e. Entry into the EIM has not affected PGE’s fuel stock requirements. See PGE’s response to OPUC Data Request Nos. 340, 341, and 344 for additional information.

April 11, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 344
Dated March 16, 2023

Request:

With regard to the Company's historic "fuel stock":

a. Please provide the forecasted value of the Company's fuel stock in each year from 2015 to 2024 at the time a forecast was made for that respective year for Company operating purposes.

b. Please provide the actual value the Company fuel stock in each year from 2015 to 2022.

c. Please provide a breakdown of the value provided in response to section "a," showing each fuel type separately, providing both the US dollar value of the fuel stock, and its quantity and unit of measure (e.g. gallons or other).

d. Please provide a narrative explanation of how the values provided in response to sections "a" and "b" were calculated. Include a copy of the Company's calculation with this response in electronic workbook format, with all cells and formulas intact.

e. Where fuel stock has been assigned to a specific generator, please provide" a breakdown showing:

   i. The fuel types assigned to each generator.

   ii. The quantity of each fuel type (including the unit of measurement) assigned to each generator.

Response:

a. PGE objects to this request on the basis that it is vague, unduly burdensome, and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:
Attachment 344-A provides forecasted values that pull from PGE's UI Financial Model data. Forecasted values exist starting with 2016.
b. Attachment 344-B provides actual year-end quantity and value of PGE's fuel stock for 2015 to 2022

c. PGE forecasts oil and gas inventories as one amount and coal and CO2 allowance inventories as one amount and these amounts of fuel stock are forecast based on value and not on quantity.
d. PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows: Values for part (a.) come from PGE's UI Planner Financial Model. Attachment 344-A provides the UI calculation used to arrive at these values, on the "Data source-methodology" tab. On this tab, the calculation is described with a step by step formula for January 2023, as an example of how a forecast value gets created. Values for part (b.) come from PGE's accounting records. Inventory values are calculated based on ending balances and the weighted average cost of the commodity at that point in time.
e. All current gas inventories are stored at North Mist, which is used to fuel PGE's Port Westward 1, Port Westward 2, and Beaver plants. All current coal inventory is for Colstrip. Oil inventories are currently used for Colstrip and Beaver. CO2 allowance inventories are not assigned to a specific generator. Attachment 344-B provides the historical breakout of these amounts.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 639
Dated April 25, 2023

Request:

In PGE Response to OPUC Data Request 340 (e), PGE states: "The value of fuel stock included in PGE's filing is $31,484,573. This is included as part of PGE's Operating Materials & Fuel balance, as provided in PGE Exhibit 200. This amount can be isolated in the PGE Exhibit 200 work paper, "2024 Unbundled ROO," tab "Unbundled" by filtering on account 1510001." With respect to this fuel *hardcoded* stock figure of $31,484,573 in said work paper, please answer the following questions:

a. Please provide a full explanation for how $31,484,573 is derived/calculated, including all assumptions and calculations. Please also provide all supporting workpapers.
b. Please identify how much of $31,484,573 is associated with each fuel stock by plant as well as CO2 allowances. Please indicate where this information is found in the work papers, and provide all workpapers and supporting calculations.

Response:

a. The account and amount referenced above is derived from PGE's financial forecasting modeling software, which summarizes fuel inventory into two primary categories (i.e., oil & gas and coal) for reporting and forecasting purposes. The account referenced above is the combination of accounts 1510001(Fuel Stock-Purchase & Transport Oil) and 1510008 (Fuel Stock-Store Natural Gas), which are rolled up into one line item for reporting purposes, specified as Fuel Oil & Gas. The $31,484,573 above was forecast using the starting point of actual October 31, 2022 ending balances for accounts 1510001 and 1510008. From this point, no changes were made to the oil balance other than removing $304,146 associated with Colstrip oil. For gas inventories, actual period ending inventory is used as the starting basis, which is then adjusted on a monthly forecast basis using a forecast percent change in inventory multiplied against a forecast weighted average cost of gas to adjust the monthly balance. Confidential Attachment 639-A provides this calculation.
b. No amounts are associated with CO2 allowances.

Attachment 639-A is protected information and subject to Protective Order No. 23-039

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 640
Dated April 25, 2023

Request:

In its testimony, the Company states "PGE has removed all identifiable costs for the Colstrip generating plant from base rates and included them within Schedule 146. Consequently, no Colstrip operations and maintenance (O&M) or plant-Related costs are included in PGE's 2024 revenue requirement." (UE 416 / PGE / 200 / Batzler - Ferchland / 3.) The Company goes on to note: "Similar to Colstrip, all Boardman-related costs have been removed from both actual and forecasted results." (*Id.*)

a. Please discuss whether these statements hold with respect to fuel stocks for Colstrip. To the extent that there are non-zero fuel stock costs for Colstrip in PGE's 2024 revenue requirement, please identify how much and where in PGE's workpapers the figure is found and derived.
b. Please confirm that there are zero fuel stock costs for Boardman in PGE's 2024 revenue requirement.

Response:

a. Yes. All fuel stock assigned to Colstrip (coal and oil) have been removed from PGE's request in this case.
b. Confirmed.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 642
Dated April 25, 2023

Request:

In Docket No: UE 394, Staff stated: "As for the Company's determination of CO2 allowance stock, Staff believes that the forecasted CO2 allowance stock provides no value to customers and should be excluded in its entirety for the reasons explained below." (Docket No: UE 394, Staff/1000 / Enright/3.) With respect to this issue, please answer the following questions:

a. How was this issue resolved in the Stipulation in UE 394?
b. With respect to the CO2 allowance stock in the instant proceeding, is it PGE's position that the allowances are used and useful? Please explain.
c. Please provide a discussion of PGE's policies and practices with respect to CO2 allowance stocks. Please provide all internal documents detailing such policies and practices.
d. Please identify the total dollar value of CO2 allowance stock included in the rate base in the instant proceeding, where that figure is found in the work papers and how it was calculated.
e. Per UE 416_OPUC DR 344_Attach B, the dollar value of CO2 allowance stocks has fluctuated dramatically. Please explain the fluctuations. Also, in view of the fluctuations, please explain how PGE determines an optimal CO2 allowance stock. Please provide all policy analyses and work papers supporting the answer.

Response:

a. The above referenced issue was a part of a bundled settlement listed as item 12 in Docket No. UE 394's Second Partial Stipulation between PGE, Staff, CUB, AWEC, Kroger, and Walmart. PGE's willingness to include this item in the bundled settlement should not be interpreted as an agreement to Staff's arguments.
b. Yes. PGE has a compliance obligation under California's cap and trade program for GHG emissions associated with imported electricity into the state of California. Imported electricity into the state of California results in sales benefits in PGE's net variable power costs from both a forecast perspective within MONET (e.g., EIM benefit methodology)

and an actuals perspective as ultimately reflected within customer prices via PGE's PCAM.

c. Confidential Attachment 642-A provides PGE's accounting & reporting white paper regarding PGE's accounting for carbon (i.e., CO2) allowances. PGE notes that the white paper has not yet been updated to reflect Washington State's cap-and-invest program and PGE does not currently hold any Washington carbon allowances within its fuel inventories.

d. PGE's fuel inventory test year forecast is derived from PGE's financial forecasting modeling software, which summarizes fuel inventory into two primary categories (i.e., oil & gas and coal) for reporting and forecasting purposes. Because PGE's carbon allowances are rolled up under coal in this software, they were inadvertently excluded from PGE's test period revenue requirement forecast. PGE's normal method of forecasting carbon allowances simply carries forward the most recent actual period ending balance. No additional assumptions are made. PGE will update its revenue requirement within reply testimony to correctly reflect the current balance of carbon allowances in inventory. As of March 31, 2023 the current inventory balance was $3,020,973.

e. PGE objects to this request on the basis that it is vague and ambiguous. It is unclear what Staff considers "fluctuated dramatically." Notwithstanding its objection, PGE responds as follows:

   If the focus on fluctuation is the increase in allowances beginning year end 2019 (relative to year end 2018) and then a fall in allowances in year end 2020 and year end 2021, the changes in CO2 allowance stock result from PGE's purchases of allowances throughout a compliance period but retirements of allowances predominantly in November of the year after the end of a compliance period.

   For example, the third California Air Resources Board (CARB) compliance period began January 1, 2018 and ended December 31, 2020. To meet requirements for the third compliance period, PGE purchased compliance instruments in 2018 and 2019, and retired compliance instruments equivalent to the following schedule:

   - 30 percent of its 2018 obligation on November 1, 2019,
   - 30 percent of its 2019 obligation on November 1, 2020, and
   - All remaining compliance period obligation (i.e., 70 percent of 2018, 70 percent of 2019 and 100 percent of 2020) on November 1, 2021.

   PGE monitors compliance obligations throughout the year to ensure year-to-date obligations incurred are consistent with PGE's anticipated obligations based on prior year(s) results.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 647
Dated April 25, 2023

Request:

In UE 394, PGE Response to OPUC Data Request 780, Dated September 15, 2021, states: "For reliability purposes, North Mist inventory is maintained at a minimum storage level of 1,200,000dth."

a. Please explain what is meant by "reliability purposes." Reliability of what? Is it the reliability of the North Mist storage facility or the operations of PGE's gas facilities (e.g., PW2)? If it is the latter, please explain why 1,200,000dth is the minimal storage level needed to maintain/ensure "reliability." Please provide supporting documentation for your answer.

Response:

The North Mist minimum storage level of 1.2 billion cubic feet (BCF) ensures generation reliability at PGE's Port Westward / Beaver complex as it is designed to support seven days of continuous operations at PW1 with North Mist as the sole source of fuel.

The 1.2 BCF minimum storage level ensures that the North Mist capacity remains above the minimum capacity of 18% and meets expected gas supply demand at PW1 for seven days, based on expected 2024 summer and winter plant MONET output and heat rate. Attachment 647-A, tab "PW1 Gas Demand", provides monthly gas supply demand forecast to support PW1 operations in 2024 based on March 31, 2023 MONET update plant output and heat rate. As provided in the attachment, gas supply demand fluctuates between approximately 62,000 dth/day and 66,000 dth/day in summer (i.e., July, August, September) and winter months (December, January, February).

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 648
Dated April 25, 2023

Request:

In UE 394, PGE Response to OPUC Data Request 780, Dated September 15, 2021, states: "*Optimal inventory levels* do not depend on the price of fuel. For gas at North Mist, it depends on the value derived from PGE's gas storage modeling in MONET, coupled with maintaining approximately *1.2 billion cubic feet (BCF)*, to ensure the Port Westward thermal plant can be dispatched for seven days exclusively on storage gas should a *gas pipeline disruption* occur."

a. Please explain and demonstrate how MONET determines the *optimal fuel stock* at North Mist? In this explanation, please distinguish between (i) the optimal level of fuel inventory/stock at North Mist, and (ii) the optimal dispatch of Westside Thermal Plants. Also, please identify where in the work papers this analysis is found.

b. What is the basis for the requirement to be able to run Port Westward for "seven days" on stored gas. Please provide supporting documentation.

c. Please provide all instances in the last ten years in which such "gas pipeline disruptions" have occurred.

d. Please provide support for the statement that Port Westward requires "1.2 billion cubic feet (BCF)" to run for seven days.

Response:

PGE objects to this request on the basis that it is vague and overly broad. Subject to and without waiving this objection, PGE responds as follows:

a. MONET does not determine the optimal fuel stock at North Mist. The stored gas balance in the MONET model is based on storage cycle plan, which is dependent on a number of considerations. Please see PGE's response to OPUC Data Request No. 645 part (b). In addition, PGE modifies the storage cycle plan input into the model based on discussion with its Power Operations traders to confirm maintenance operations and storage requirements.

b. PGE uses the seven days assumption consistent with actual operational practices.

c. Because there is no business need or requirement, PGE did not maintain records of all instances in the last ten years when there were gas pipeline disruptions. However, one example is the October 2018 gas pipeline rupture near Prince George in Canada, British Columbia, that caused natural gas supply shortages in the Pacific Northwest region. Additionally, as described in PGE Exhibit 300, Section III.F, natural gas prices in Western US have soared in Q4 of 2022 due to several factors, including pipeline constraints and reduced natural gas flows, according to the U.S. Energy Information Administration.

d. See PGE’s response to OPUC Data Request No. 647.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 650
Dated April 25, 2023

Request:

In UE 394, PGE Response to OPUC Data Request 780, Dated September 15, 2021, states: "Oil inventory levels are based on the amount required to fuel PGE's Beaver Plant operations at full load for approximately *four to five* days during heavy load hours." But the Company in same response stated that it is "maintaining approximately *1.2 billion cubic feet (BCF)*, to ensure the Port Westward thermal plant can be dispatched for *seven days* exclusively on storage gas should a *gas pipeline disruption* occur."

a. Please explain how the two provisions — (i) the oil inventory for "four to five days" and (ii) the gas fuel stock for "seven days" — are not duplicative to the same purpose of covering for potential contingencies.

Response:

Beaver fuel oil and North Mist gas storage reserves for Port Westward 1 (PW1) are not duplicative. PGE's west side thermal generation consists of three generating facilities (i.e., PW1, PW2, and Beaver) totaling roughly 1100MWa of generation, depending on ambient conditions.

Natural gas supply for the west side thermal plants is delivered via a single interstate natural gas pipeline, Northwest Pipeline. Therefore, any natural gas supply disruption could significantly impact west side thermal plant reliability.

The Beaver fuel oil and the North Mist gas storage reserves for PW1 currently provide fuel redundancy for 51% of the west side generating facilities in the on-peak hours.[1] However, as part of the multi-year Beaver Emission Reduction Program (see PGE Exhibit 800), PGE is removing fuel oil firing capability at the Beaver plant. In 2024, fuel oil firing capability will be removed from an additional two Beaver turbines, resulting in four of the six Beaver turbines unable to consume fuel oil. Fuel oil firing capability will be removed from the final two Beaver turbines in 2025.

[1] 51% represents the average capacity of PW1 (i.e., approximately 400 MW) and two Beaver units (i.e., approximately 160MW)

During a contingency event, like a pipeline disruption that reduces or eliminates gas supply from the regional pipeline infrastructure, fuel oil inventory would support operations of two Beaver turbines while gas storage reserves would support full operations of PW1 for 7 days. In this type of a contingency event, some portions of the generation (e.g., all of PW2 and up to four Beaver turbines) would need to be replaced with power purchases at potentially high market prices, because there would be no fuel supply available.

May 9, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 653
Dated April 25, 2023

Request:

Please explain how PGE weighs/balances (i) the *permanent* cost of maintaining a fuel stock for "reliability purposes" against (ii) the *incidental* cost of power purchases, to accommodate contingencies. Please also explain the extent to which the Company views fuel stocks and power purchases as two alternatives for maintaining reliability. What are the Company's policies in this regard? Has the Company conducted financial analysis to this effect? If yes, please provide those analyses and supporting policy documents.

Response:

PGE does not view relying on market purchases (as a replacement to a considerable amount of PGE's westside generation) as sound operational strategy to ensure reliability during potential supply disruptions, when market prices can increase dramatically and expose PGE and customers to large power costs and even power outages if there is no capacity available in the market. Therefore, PGE did not conduct specific financial analyses to compare maintaining storage reserves at North Mist that support PW1 plant dispatch during potential supply disruption events with the cost of equivalent market energy purchases.

Reference PGE's response to OPUC Data Request No. 650: North Mist gas storage reserves maintained for reliability purposes ensures fuel supply for seven days of operation at Port Westward 1 (PW1). If the gas storage reserve for reliability purposes is no longer maintained, PGE and its customers would be exposed to the risk of market energy purchases at potentially prohibitive prices to cover the capacity that PW1 provides (i.e., approximately 400 MWa) during supply disruption events or peak demand, when market prices are expected to be extremely high.

For reference, the total North Mist gas storage inventory included in PGE's 2024 forecast rate base is approximately $22.2 million (see PGE's response to OPUC Data Request No. 639), which translates to an annual revenue requirement (i.e., cost of including this fuel inventory in rate base) of approximately $2.0 million.

STAFF 2700 DRs - ISSUE 4 (CO_2 ALLOWANCES)

STAFF 2704
NON-CONFIDENTIAL
STAFF 344
STAFF 732
STAFF 738
STAFF 744

UE 416
PGE's Response to OPUC DR 344
Attachment A

$000

Forecast	Dec 2016	Dec 2017	Dec 2018	Dec 2019	Dec 2020	Dec 2021	Dec 2022	Dec 2023	Dec 2024
X:[Materials & Supplies:]									
Y:[Fuel Oil & Gas]	11,526	9,217	9,575	16,171	11,330	11,058	18,289	17,386	12,397
Z:[Coal]	19,175	21,163	20,425	17,016	3,421	8,569	4,877	6,519	6,519
AA:[Materials]	45,168	50,357	53,219	54,369	56,761	50,044	51,981	64,616	66,655
AB:[Total]	**75,869**	**80,737**	**83,219**	**87,555**	**71,512**	**69,671**	**75,147**	**88,521**	**85,570**

Year-End Fuel Inventory
By Fuel and Year 2015-2022

	2015		2016		2017		2018	
Coal	**Tons/Units**	**$**	**Tons/Units**	**$**	**Tons/Units**	**$**	**Tons/Units**	**$**
Boardman	601,100	$ 24,330,780	422,612	$ 16,783,297	283,876	$ 11,422,971	294,919	$ 11,760,874
Colstrip	135,405	$ 2,753,044	133,525	$ 2,801,449	130,090	$ 2,678,764	132,955	$ 2,923,234
CO2 Allowances	94,926	$ 1,162,155	160,004	$ 1,967,963	188,754	$ 2,331,408	222,741	$ 3,120,107
Total Coal		**28,245,979**		**21,552,710**		**16,433,143**		**17,804,215**
	2015		**2016**		**2017**		**2018**	
Oil	**Barrels**	**$**	**Barrels**	**$**	**Barrels**	**$**	**Barrels**	**$**
Beaver	70,913	$ 7,568,278	70,346	$ 7,507,774	69,600	$ 7,428,145	74,201	$ 7,880,281
Boardman	8,743	$ 633,270	4,055	$ 289,620	6,529	$ 549,065	7,550	$ 729,472
Colstrip	2,156	$ 207,310	2,363	$ 167,892	2,297	$ 192,318	2,314	$ 241,636
	2015		**2016**		**2017**		**2018**	
Natural Gas	**Decatherms**	**$**	**Decatherms**	**$**	**Decatherms**	**$**	**Decatherms**	**$**
Mist	908,645	$ 2,251,001	1,219,144	$ 2,335,699	1,091,722	$ 1,896,668	722,758	$ 1,554,022
N Mist	-	$ -	-	$ -	-	$ -	797,315	$ 2,573,377
Total Oil & NG		**$ 10,659,860**		**$ 10,300,984**		**$ 10,066,196**		**$ 12,978,788**
Total:		**$ 38,905,838**		**$ 31,853,694**		**$ 26,499,339**		**$ 30,783,003**

Year-End Fuel Inventory
By Fuel and Year 2015-2022

	2019		2020		2021		2022	
Coal	**Tons/Units**	**$**	**Tons/Units**	**$**	**Tons/Units**	**$**	**Tons/Units**	**$**
Boardman	398,945	$ 17,280,888	-	$ -	-	$ -	-	$ -
Colstrip	132,372	$ 4,034,401	130,928	$ 3,565,188	133,174	$ 3,346,523	126,813	$ 3,494,977
CO2 Allowances	415,993	$ 6,121,955	333,414	$ 5,004,122	101,622	$ 1,525,215	146,683	$ 3,020,985
Total Coal		**27,437,244**		**8,569,310**		**4,871,738**		**6,515,961**
	2019		**2020**		**2021**		**2022**	
Oil	**Barrels**	**$**	**Barrels**	**$**	**Barrels**	**$**	**Barrels**	**$**
Beaver	73,735	$ 7,717,332	73,382	$ 7,680,473	73,250	$ 7,666,653	71,006	$ 7,456,472
Boardman	6,264	$ 543,866	-	$ -	-	$ -	-	$ -
Colstrip	2,386	$ 221,460	1,612	$ 119,116	2,109	$ 202,211	1,981	$ 303,533
	2019		**2020**		**2021**		**2022**	
Natural Gas	**Decatherms**	**$**	**Decatherms**	**$**	**Decatherms**	**$**	**Decatherms**	**$**
Mist	-	$ -	-	$ -	-	$ -	-	$ -
N Mist	1,671,868	$ 4,393,586	3,249,664	$ 6,522,163	3,544,746	$ 14,252,258	2,637,030	$ 17,143,446
Total Oil & NG		**$ 12,876,244**		**$ 14,321,752**		**$ 22,121,122**		**$ 24,903,450**
Total:		**$ 40,313,488**		**$ 22,891,062**		**$ 26,992,860**		**$ 31,419,411**

May 19, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 732
Dated May 5, 2023

Request:

In its Form 10-K (page 82) for the fiscal year ended December 31, 2022, PGE states:

> PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities, *as well as fuel, which includes natural gas, coal, and oil for use in the Company's generating plants*. Periodically, the Company assesses inventory for purposes of determining that inventories are recorded at the lower of average cost or net realizable value. (Emphasis added.)

With respect to this statement, please answer the following questions:

a) This statement about PGE's inventories fails to mention CO2 / emission / carbon allowances. Is the omission because PGE has none, or are they included elsewhere? Please explain and provide references.

b) To the extent PGE does own CO2 / emission / carbon allowances, where in its Form 10-K are they reflected?

c) To the extent that PGE anticipates being a covered entity under the Washington Cap-and-Invest Program (as noted in its GRC filing) in 2023, please indicate *where* in its Form 10-K for fiscal year 2023 the Company will book the required CO2 / emission / carbon allowances to cover its obligations?

d) Please provide PGE's *best estimate* of the dollar value of its CO2 / emission / carbon allowances and obligations for 2023 under the Washington Cap-and-Invest Program as the Company anticipates reporting in its Form 10-K for 2023. To the extent this best estimate of the dollar value differs from that reported in its instant GRC filing, please explain the difference.

Response:

a) This language is included within PGE's Note 2: Summary of Significant Accounting Policies section of the 2022 10-K. While PGE does have carbon allowances, they do not make up a significant portion of PGE's inventory balance, as such, they are omitted from Note 2.

b) As described in PGE's Accounting for Carbon Allowances Whitepaper memo, provided in PGE's response to OPUC Data Request No. 642, Attachment 642-A, within section IV. Conclusion, "Financial Statement Classification - carbon allowances will be recorded in inventory. The revenue and expense associated with carbon allowance transactions will be recorded in Net Variable Power costs for SEC reporting purposes." The balance associated with PGE's owned carbon allowances is included within the Fuel line item within the Inventories, at average cost financial statement line item (page 75 of the 2022 10-K).

c) PGE anticipates accounting for allowances to cover obligations under the Washington Cap-and-Invest Program under the same methodology that allowances under the CARB cap-and-trade program are accounted for, which would result in carbon allowances being recorded in inventory and the revenue and expense associated with carbon allowance transactions being recorded in Net Variable Power costs for SEC reporting purposes. Refer to PGE's response to OPUC Data Request No. 642, Attachment 642-A.

d) Staff's request is premature. Actual carbon allowance and obligations for 2023 volumes will be included in the 2023 10-K, which will be issued in the first quarter of 2024. Additionally, PGE has yet to purchase any Washington Cap-and-Invest Program allowances, there are no amounts recorded within PGE's actual inventory balances, nor any amounts forecast within PGE's test year rate base.

May 19, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 738
Dated May 5, 2023

Request:

According to the accounting firm KPMG, "there are currently no accounting requirements under IFRS Accounting Standards (or US GAAP) specific to carbon offsets or credits." (See, Carbon offsets and credits under IFRS® Accounting Standards (kpmg.us))

With respect to this statement, please answer the following questions:

a) Please state whether PGE agrees or disagrees with this statement.

b) Please provide a discussion of PGE's accounting treatment of compliance instruments (e.g., emission/carbon allowances, carbon offsets and carbon credit.) Please provide supporting documents and Company policy documents/statements.

Response:

a. PGE objects to this request on the basis that it calls for speculation. Subject to and without waiving this objection, PGE responds as follows:
   To the best of our knowledge, there are currently no standards under US GAAP that are specific to carbon offsets or credits. PGE does not report under IFRS Accounting Standards and, therefore, has no opinion regarding this statement as it relates to IFRS.
b. See PGE's response to OPUC Data Request No. 642, Attachment 642-A.

May 19, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to OPUC Data Request 744
Dated May 5, 2023

<u>Request:</u>

At UE 416 / PGE / 300 / Schwartz – Outama – Cristea / 31, the Company describes aspects of the Washington's Cap-and-Invest program as follows:

> These allowances can be obtained through *quarterly auctions* or bought and sold on a *secondary market*. (Emphasis added.)

With respect to this testimony, please answer the following questions:

a) Please identify all *auctions* and *secondary* markets that PGE considers to be available to it for meeting its carbon obligations under the WA Cap-and-Invest program.

b) Has PGE explored international carbon markets? If yes, please discuss.

c) Please generally discuss PGE's experience with carbon markets in the United States. Also, please discuss how liquid these markets are and whether PGE would be / is readily able to obtain compliance instruments. Please provide all relevant documents (e.g., policy discussions, memos, PowerPoint presentations) discussing such markets.

d) For the last ten years, please identify all instances in which PGE has traded (bought or sold) compliance instruments (of any sort) and/or participated in auctions or secondary markets. Please provide details, such as dates, auctions, allowances sold and purchased, quantities and prices.

e) If PGE can readily purchase CO2 allowances, then generally explain why the Company needs to hold a fuel <u>*stock*</u> of CO2 allowances on which it proposes to earn a rate-of-return (see, e.g., UE 416 / PGE / 208 / Batzler-Ferchland / 1).

f) If there are *time delays, timing issues or any other market imperfection*, dictating that PGE hold a "stock" of CO2 allowances, please explain. For example, explain why PGE would (could) not simply purchase the necessary compliance instruments at the end of each compliance period, or at any other point when they are needed to avoid penalties under the WA Cap-and-Invest program?

g) If there are *pricing considerations* that dictate the timing of CO2 allowance purchases, please explain and show how holding a stock of CO2 allowances is financially more advantageous to (i) PGE and/or (ii) PGE's ratepayers.

h) Please provide and explain in detail PGE's financial calculations to determine the *optimal* stock of CO2 allowances in the instant GRC? Please provide supporting documentation.

Response:

PGE objects to this request on the basis that it is overly broad. Notwithstanding its objection, PGE responds as follows regarding CO2 allowances:

a) Auctions available to PGE are presently the auctions initiated by the Washington Department of Ecology. Secondary markets available to PGE would include brokers, bilateral trading partners, and exchanges (e.g., PGE anticipates the Intercontinental Exchange will facilitate trading of Washington allowances at a future date).

b) No, PGE has not explored international carbon markets.

c) PGE's experience with carbon markets in the United States is based on its obligations under California's cap and trade program. PGE has a compliance obligation under California's cap and trade program for GHG emissions associated with imported electricity into the state of California. To meet its compliance obligation, PGE can procure California compliance instruments through secondary markets or California allowance auctions. PGE is not presently encountering challenges with liquidity in the California carbon market.

d) See Confidential Attachment 734-A in PGE's Response to OPUC Data Request No. 734.

e) Should PGE only purchase compliance instruments at the point in which PGE is required to retire allowances to meet a compliance obligation, PGE and customers would be subject to the current prevailing market price, with no alternative. If PGE creates or maintains an inventory balance due to purchases throughout a compliance period (i.e., not just the end of a period) PGE maintains some flexibility in procurement decisions as it monitors obligation balances and prevailing market prices for allowances. Using PGE's inventory balance as of May 3, 2023, and PGE's currently requested weighted average cost of capital, PGE customers will incur a cost of approximately $215,000 in the test year for the allowance balance that PGE currently holds. Based on allowances outstanding, this is a cost of $1.90 per unit (i.e., $/balance of allowances).

f) See PGE's response to OPUC Data Request No. 733, part f. PGE does not currently have a stock of allowances that can be used for the WA Cap-and-Invest program, but as noted in part e, a stock of allowances allows PGE to maintain some flexibility in procurement decisions.

g) See part e.

h) PGE does not have financial calculations used to determine an optimal stock of CO2 allowances.

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2705

PGE Confidential Responses to Data Requests

REDACTED

Subject to General Protective Order No. 23-039

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2706

PGE Highly Confidential Responses to Data Requests

REDACTED

Subject to Modified Protective Order No. 23-138

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2707

Summary of PGE Plant Additions in UE 416 Rate Base

SUMMARY OF PGE PLANT ADDITIONS IN UE 416
5/1/2022 - 12/31/2023

LINE #	CAPITAL ADDITION CATEGORIES	FULLY LOADED COSTS ($ MILLIONS)	REFERENCE
1	TRANSMISSION, DISTRIBUTION AND GRID MODERNIZATION	$ 754.8	PGE 700/4, Table 1
2	CORPORATE IT	$ 87.5	PGE 600/25, Table 5 and
3	OTHER IT NOT EXPLICTLY REFERENCED IN TESTIMONY	$ 28.5	
4	PRODUCTION		
5	BEAVER EMISSIONS REDUCTION PROGRAM	$ 56.9	PGE 800/3/LINE 9
6	BIGLOW PHASE I WIND ENHANCEMENT PROGRAM	$ 7.3	PGE 800/4/LINE 6
7	TUCANNON WIND ENHANCEMENT PROGRAM	$ 1.7	PGE 800/4/LINE 20
8	FARADAY REPOWERING PROJECT	$ 189.7	PGE 800/47/LINES 7-21
9	ALL OTHER CAPITAL ADDITIONS IN UE 416 RATE BASE > $3 MILLION	$ 161.1	STAFF DR NO. 807, ATTACHMENT A
10	ALL OTHER CAPITAL ADDITIONS IN UE 416 RATE BASE < $3 MILLION	$ 11.1	DIFFERENCE BETWEEN TOTAL ADDITIONS ON LINE 11 AND THE SUM OF LINES 1 - 9
11	TOTAL UE 416 CAPITAL ADDITIONS	$ 1,298.5	

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2708

Summary of PGE Capital Projects in UE 416 by FERC Category

SUMMARY OF PGE CAPITAL PROJECTS BY FERC CATEGORY IN UE 416
(OTHER THAN TRANSMISSION, DISTRIBUTION, FARADAY REPOWERING, & IT PROJECTS)
5/1/2022 - 12/31/2023

			ESTIMATED FULLY LOADED UE 416 COSTS ($ MILLIONS)						
LINE #	PROJECT NAME	PROJECT NUMBER	HYDRO PRODUCTION	STEAM PRODUCTION	GENERAL PLANT	OTHER PRODUCTION	INTANGIBLE PLANT	TOTAL	SOURCE
1	Hydro Control System Upgrade	P36134	$ 11.9	$ -	$ -	$ -	$ -	$ 11.9	STAFF DR 807 ATTACHMENT A
2	Vintage Vehicle Replacement II	P36394	$ -	$ -	$ 32.4	$ -	$ -	$ 32.4	STAFF DR 807 ATTACHMENT A
3	Field Area Network Project	P36723	$ -	$ -	$ 6.5	$ -	$ -	$ 6.5	STAFF DR 807 ATTACHMENT A
4	BR: Beaver Modernization	P36836	$ -	$ -	$ -	$ 56.9	$ -	$ 56.9	PGE 800/3/LINE 9 AND STAFF DR 807 ATTACHMENT A
5	Facilities Upgrades-EV Readiness	P37017	$ -	$ -	$ 9.5	$ -	$ -	$ 9.5	STAFF DR 807 ATTACHMENT A
6	Facilities Management Fitness	P37093	$ -	$ -	$ 7.0	$ -	$ -	$ 7.0	STAFF DR 807 ATTACHMENT A
7	WSH:Restore Facilities post-fire	P37118	$ 10.1	$ -	$ -	$ -	$ -	$ 10.1	STAFF DR 807 ATTACHMENT A
8	Eastern Gen Admin Building-Carty	P37176	$ -	$ -	$ -	$ 7.8	$ -	$ 7.8	STAFF DR 807 ATTACHMENT A
9	Salem LC EIFS Replacement	P37240	$ -	$ -	$ 6.2	$ -	$ -	$ 6.2	STAFF DR 807 ATTACHMENT A
10	CY: Purchase 2023 Outage Components	P37353	$ -	$ -	$ -	$ 3.8	$ -	$ 3.8	STAFF DR 807 ATTACHMENT A
11	PN: Rewind Unit 2 Generator	P37416	$ 4.1	$ -	$ -	$ -	$ -	$ 4.1	STAFF DR 807 ATTACHMENT A
12	TR - Rebuild Tower I-10	P37459	$ -	$ -	$ -	$ 3.8	$ -	$ 3.8	STAFF DR 807 ATTACHMENT A
13	Energy Tracker Replacement	P37487	$ -	$ -	$ -	$ -	$ 3.8	$ 3.8	STAFF DR 807 ATTACHMENT A
14	Biglow I Wind Enhancement Program	P37509	$ -	$ -	$ -	$ 7.3	$ -	$ 7.3	PGE 800/4/LINE 6 AND STAFF DR 807 ATTACHMENT A
15	P23528 - Clackamas PME - Recreation, Aesthet	P23528	$ -	$ -	$ 3.1	$ -	$ -	$ 3.1	STAFF DR 807 ATTACHMENT A
16	P35172 - PSES - Generation Fitness Fund	P35172	$ -	$ -	$ 4.2	$ -	$ -	$ 4.2	STAFF DR 807 ATTACHMENT A
17	P36116 - Wind Generation Fitness Program	P36116	$ -	$ -	$ 8.7	$ -	$ -	$ 8.7	STAFF DR 807 ATTACHMENT A
18	P36449 - PRB Upgrade Governors & Exciters	P36449	$ -	$ -	$ 3.5	$ -	$ -	$ 3.5	STAFF DR 807 ATTACHMENT A
19	P37162 - Bill Redesign	P37162	$ -	$ -	$ 6.2	$ -	$ -	$ 6.2	STAFF DR 807 ATTACHMENT A
20	P37251-PACS 2.0	P37251	$ -	$ -	$ 4.4	$ -	$ -	$ 4.4	STAFF DR 807 ATTACHMENT A
21	P37376-CS Rewind Unit 1 CTG & STG	P37376	$ -	$ -	$ 5.9	$ -	$ -	$ 5.9	STAFF DR 807 ATTACHMENT A
	TOTAL CAPITAL ADDITIONS		$ 26.1	$ -	$ 97.6	$ 79.5	$ 3.8	$ 206.9	

SUMMARY OF PGE CAPITAL PROJECTS BY FERC CATEGORY IN UE 416
(OTHER THAN TRANSMISSION, DISTRIBUTION, FARADAY REPOWERING, & IT PROJECTS)
5/1/2022 - 12/31/2023

	ESTIMATED FULLY LOADED UE 416 COSTS ($ MILLIONS) FROM CWIP OR FORECASTED 2023 BALANCES (OTHER THAN T&D, FARADAY REPOWERING, & IT PROJECTS)					
# OF PROJECTS	HYDRO PRODUCTION	STEAM PRODUCTION	GENERAL PLANT	OTHER PRODUCTION	INTANGIBLE PLANT	TOTAL
3	$ 26.1					$ 26.1
0		$ -				$ -
12			$ 97.6			$ 97.6
5				$ 79.5		$ 79.5
1					$ 3.8	$ 3.8
21	$ 26.1	$ -	$ 97.6	$ 79.5	$ 3.8	$ 206.9

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2709

PGE Project Justification Form Evaluation Tables

REDACTED

Subject to General Protective Order No. 23-039

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2710

Summary of PGE Project Justification Form Review

SUMMARY OF PJF REVIEW

	CAPITAL ADDITIONS AT ISSUE IF FLAG IS "YES" (MILLIONS)	COUNT OF PROJECTS WHERE CRITERIA ARE MET / NOT MET			
Criteria of Review		**YES**	**NO**	**UNCLEAR**	**TOTAL**
Approximate Actual or Expected Capital Addition (may exclude loadings, overheads, and AFUDC)		N/A	N/A	N/A	N/A
Criterion #1 – In service by 12/31/2023?	$ 90.9	11	0	10	21
Criterion #1A – Officer Attestation Required	$ 192.4	19	2	0	21
Criterion #2 – Evidence of Cost Overruns?	$ 22.8	3	18	0	21
Criterion #3 - Are there costs PGE is getting reimbursed for by insurance or warranties?	$ 14.0	2	19	0	21
Criterion #4 – Evidence of any project failures?	$ 14.0	2	19	0	21
Criterion #5 – Possibility of deferral to future years with jeopardizing safety or reliability?	$ 35.5	2	18	1	21

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2711

Sample of Monthly Reports Monitoring PGE Capital Projects

REDACTED

Subject to General Protective Order No. 23-039

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2712

SUMMARY OF RESTATED MMA ADJUSTMENT

Plant	2022 actuals	UE 394 Approved MMAs	2024 FILE	2024 GRC revised	Variance (2022 Actuals-2024 revised)	Annualized Variance (2022 GRC-2024 GRC)	Variance 2022 FILE vs 2024 Revised
Carty	6,398,086	6,850,948	6,850,947	7,170,646	772,559	319,697	319,698
Coyote	3,188,850	3,464,004	3,464,005	1,875,942	(1,312,909)	(1,588,062)	(1,588,064)
PW1	4,980,351	4,453,956	3,710,378	6,228,562	1,248,211	1,774,606	2,518,184
PW2	791,488	773,805	773,803	850,937	59,449	77,132	77,134
Colstrip					-	-	-
KB Pipeline Pigging	(38,422)	143,100	(104,558)	26,764	65,187	(116,336)	131,323
Total	15,320,354	15,685,812	14,694,576	16,152,850	832,497	467,038	1,458,275

Plant	2022 GRC revised
Carty	6,850,948
Coyote	3,464,004
PW1	4,453,956
PW2	773,805
Colstrip	637,960
KB Pipeline Pigging	143,100
Total	16,323,773

PGE Accounts	2022 actuals	2024 FILE	2024 GRC revised	Variance (2024 Actuals-2024 revised)	Variance 2022 FILE vs 2024 Revised
MMAs in Account 4560002	1,962,199	(1,461,881)	(1,461,881)	(3,424,080)	-
MMAs in Generation O&M Accounts	13,358,155	16,156,456	17,614,731.10	4,256,577	1,458,275
check	-	-	-	-	-

PGE Exhibit 200 (Revenue Requirement) MMA Adjustment in[1]		
2024 FILE	2024 REVISED	Adjustment
14,694,576	16,152,850	1,458,275

1. Total MMA amounts in Generation O&M Accounts and Account 4560002 (Other Revenue)

PGE Exhibit 700 (Generation O&M) MMA Adjustment[2]		
2024 FILE	2024 REVISED	Adjustment
16,156,456	17,614,731	1,458,275

2. Includes only Generation O&M Accounts

COLSTRIP

	2022 actuals	UE 394 Approved MMAs	2024 FILE	2024 GRC revised	Variance (2022 Actuals-2024 revised)	Annualized Variance (2022 GRC-2024 GRC)	Variance 2022 FILE vs 2024 Revised
Colstrip	$ 625,616	$ 637,960	$ 637,960	$ 975,672	$ 350,057	$ 337,712	$ 337,713

O&M / Oth Revenue Split					
MMAs in Account 4560002	625,616	334,400	334,400	(291,216)	-
MMAs in Generation O&M Accounts	-	303,560	303,559.57	303,560	(0)

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 416

WITNESSES: August Ankum, Ph.D., and Warren Fischer, C.P.A.

STAFF EXHIBIT 2713

RESTATED GRC MMA WORKPAPER

Highly CONFIDENTIAL

Subject to Modified Protective Order No. 23-138

Provided in Electronic Format Only