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September 10, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
Request for a General Rate Revision.
Docket No. UE 435

Dear Filing Center:

Please find enclosed the Redacted Rebuttal Testimony and Exhibits of Bradley G. Mullins (AWEC/300 – 304) and Lance D. Kaufman (AWEC/400-402) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that Exhibit AWEC/304 of Bradley G. Mullins and the Testimony and Exhibits of Lance D. Kaufman, AWEC/400 and AWEC/401, contain confidential protected information that is being handled in accordance with General Protective Order No. 23-132. The Confidential version of the Rebuttal Testimony and Exhibits of Bradley G. Mullins and Lance D. Kaufman have been password protected and encrypted with 7-zip software which will be transmitted via electronically to the Commission and qualified persons on the service list.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Nannette M. Moller
Nannette M. Moller

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the enclosed **Rebuttal Testimony and Exhibits of Bradley G. Mullins and Lance D. Kaufman on behalf of the Alliance of Western Energy Consumers** upon the parties below by electronic mail.

DATED this 10th day of September 2024.

Davison Van Cleve, P.C.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

REBUTTAL TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

SEPTEMBER 10, 2024

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OF BRADLEY G. MULLINS**

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EXHIBIT LIST

Exhibit AWEC/103 – Revised Revenue Requirement Calculations

Exhibit AWEC/103 – PGE Responses to Data Requests

Exhibit AWEC/104 – Hybrid Rate Base Inconsistency Illustrations

Confidential Exhibit AWEC/105 – PGE Confidential Response to AWEC Data Request 177

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am the Principal Consultant of MW Analytics, a consulting firm that represents utility customers before state public utility commissions in the Northwest and Intermountain West.

Q. ARE YOU THE SAME WITNESS THAT PREVIOUSLY SUBMITTED OPENING TESTIMONY IN THIS DOCKET?

A. Yes. I previously caused to be filed Opening Testimony on behalf of the Alliance of Western Energy Consumers ("AWEC"), regarding the level of revenue requirement proposed by Portland General Electric Company ("PGE") in this docket, among other policy issues.

Q. WHAT IS THE PURPOSE OF YOUR RESPONSE TESTIMONY?

A. I respond to the Reply Testimony of PGE on revenue requirement issues.

Q. PLEASE SUMMARIZE YOUR RESPONSE.

A. PGE has not presented a coherent revenue requirement calculation that is supported with necessary evidence required for the Commission to find that the rate increase it has proposed is just, reasonable, and in the public interest as required by ORS 757.210(1)(a). Accordingly, I recommend the Commission reject this rate filing based on a finding that PGE has not satisfied its evidentiary burden of proof. Foremost, PGE's revenue requirement is not justified based on evidence it has submitted in this docket. Rather, it has justified its rate increase based on a budget that it submitted in Docket No. UE 416, the 2023 General Rate Case ("GRC"). PGE asserts that contesting this evidence is akin to "re-litigat[ing] the results of UE 416 …."[1]

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[1] *See* e.g. PGE/1300, Batzler-Meeks/8:8-9.

Taking aside the many facts discrediting this assertion—namely, that the 2023 GRC was resolved through a settlement stipulation and that the Commission does not approve budgets—the rates that PGE is proposing to implement in this docket must be based on evidence submitted in this docket, including PGE's actual costs. As I demonstrate again below, the form of PGE's revenue requirement calculation is incoherent, relying on arbitrary assumptions regarding the timing of new capital additions and dissonant rate base and depreciation expense calculations.

Q. HAVE YOU REVISED YOUR REVENUE REQUIREMENT RECOMMENDATION?

A. Yes. In the alternative to my primary recommendation that the Commission reject PGE's rate filing for the reasons set forth herein, **Table 1-Reb** provides a revised revenue requirement recommendation.

Table 1-REB
AWEC Rebuttal Revenue Requirement Recommendation ($000)

1		**PGE Initial Proposal (Incl. Constable, Excl. NVPC)**	**204,299**
2		*% Increase*	*6.8%*
3		Impact of Adjustments	
4		Cost of Capital	(53,049)
5	*A1*	AMA Rate Base Valuation	(60,249)
6	*A2*	Cost of Removal Depr.	-
7	*A4*	Non-Labor O&M	(23,323)
8	*A5*	Labor Expense	(35,461)
9	*A6*	Revolver Fees	(2,234)
10	*A7*	Margin Net Interest	(1,264)
11	*A8*	Broker Fees	(138)
12	*A9*	Directors' Fees	(3,393)
13	*A10*	Stock Incentives	(3,085)
14	*A11*	Incentives Overhead	(4,199)
15	*A12*	PTC Carryforward	(10,184)
16	*A13*	Boardman C.O.R.	(600)
17	*A14*	Emergency Deferrals	(2,474)
18	*A15*	Accrued Incetnives	(501)
19	*A16*	Or. Corp. Activity Tax	(1,935)
20	*A17*	Anderson Readiness Ctr. ITCs	(122)
21	*A18*	Constable ITCs	(24,742)
22	*A19*	Key Cust.Mngr (Kaufman)	(725)
24		Interest Coordination	12,076
25		**Total Adjustments**	**(215,602)**
26		**Adjusted Revenue Requirement**	**(11,303)**
27		*Adjusted % Increase*	*-0.4%*

II. PGE'S REVENUE REQUIREMENT JUSTIFICATION

Q. WHY DOES PGE BELIEVE THAT ITS 2024 O&M BUDGET IS SUFFICIENT EVIDENCE TO JUSTIFY A RATE INCREASE IN THIS DOCKET?

A. PGE has basically taken the position that the Commission must accept its 2025 budget as reasonable based on its 2024 budget, regardless of whether it has justified the 2025 budget in relation to its actual costs or any other factors. My general understanding of PGE's logic is as follows. First, PGE supposes that if the Commission found its 2024 budget to be reasonable, then the Commission must also find its 2025 budget to be reasonable. This of course is not accurate. PGE also presumes that, when the Commission approved the settlement stipulation in the 2023 GRC, it found PGE's 2024 budget to be reasonable. The Commission did not. Finally, PGE appears to reason that if a budget is found to be reasonable in a prior GRC, then the Commission must continue find the budget to be reasonable in a subsequent GRC. This is not the case. It should be plainly obvious, that PGE's arguments in this regard are not sound and that its conclusion is invalid. Revenue requirement in a regulatory proceeding must be justified in relation to evidence submitted in that proceeding, not the results of another.

Q. WHEN THE COMMISSION APPROVED THE SETTLEMENT STIPULATIONS IN THE 2023 GRC, DID IT APPROVE PGE'S BUDGET FOR 2024?

A. No. The Commission never found PGE's 2024 budget to be reasonable. As a general principle, the Commission approves the reasonableness of rates, not the specific budgetary assumptions that were made in developing those rates. Further, the revenue requirement from the 2023 GRC was the result of multiple partial stipulations, including several black-box adjustments. When the Commission adopted these stipulations, it did not endorse any part of PGE's 2024 budget. The Second Partial Stipulation, for example, states that "[b]y entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation."[2]

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2 Docket No. UE 416, Second Partial Stipulation at ¶ 18 (Aug. 21, 2023).

Q. IF THE 2024 BUDGET WERE FOUND TO BE REASONABLE, DOES IT FOLLOW THAT THE 2025 BUDGET IS ALSO REASONABLE?

A. No. Even if PGE's 2024 budget were reasonable that does not necessarily mean that the 2025 budget is reasonable. Effectively, PGE is asking the Commission to conclude that the reasonableness of the 2025 budget is not distinct from the 2024 budget because the process used to develop those budgets is similar and continuous. Such a conclusion, however, cannot be made. Under this theory, any budget that PGE were to submit in this docket must be found to be reasonable simply because it was developed through PGE's budgetary process.

Q. WHAT EVIDENCE IS TRADITIONALLY REQUIRED TO EVALUATE THE REASONABLENESS OF A REVENUE REQUIREMENT CALCULATION?

A. The evidence needs to be objective and verifiable, which inherently requires a reconciliation to PGE's actual costs. The traditional way that this is done is through a pro forma study, which I discussed in my Opening Testimony. This does not necessitate the use of a historical test period but requires evidence and documentation supporting all pro forma adjustments made in developing the revenue requirement in the test period, future or otherwise, starting with actual costs. A black box budget of costs, as PGE submitted in this case, does not conform with this traditional approach because there are no concrete reconciliations or explanations for why the forecasts differ from actual, known and measurable costs.

Q. DID PGE PRESENT A PRO FORMA STUDY IN ITS REPLY TESTIMONY?

A. No. While AWEC recommended PGE present a pro forma study to support its budget, PGE refused to do so. Failing that, I do not believe adequate evidence has been submitted to justify the major rate increase PGE is seeking in this case.

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION REGARDING A PRO FORMA STUDY?

A. PGE identified two objections to my recommendation. First PGE states that "AWEC neglects to mention that PGE provided historical actuals to compare against its 2025 test year through the standard data request process and as work paper support included with each piece of testimony provided."[3] Second, PGE states that "AWEC appears to be describing the use of a historical test year, while Oregon has standardized the use of a forward test year for many decades."[4] Both of these statements are false and/or irrelevant to the need to reconcile PGE's proposed revenue requirement to its actual costs.

Q. DID YOU "NEGLECT TO MENTION" THAT PGE PROVIDED HISTORICAL DATA IN RESPONSE TO DATA REQUESTS?

A. No. That assertion is plainly untrue. On the contrary, I cited and used that very information in my revenue requirement analysis.[5] Further, a traditional pro forma study requires more than just a comparison back to the historical data. A pro forma study is a sequential analysis that is designed to document each and every pro forma assumption that the utility made to support its test period revenue requirement. This contrasts with PGE's method in this proceeding of simply placing the actual and budgeted results side-by-side, with no explanation for why the budgeted results are different from the actuals. From this perspective, the budget is effectively a black box amount, without sufficient evidence to ascertain why there are differences between the actual amounts and budgeted amounts.

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3 PGE/1300, Batzler-Meeks/7:20-22.

4 *Id.* at 7:22-8:2.

5 *See, e.g.,* AWEC/100, Mullins/27 (Table 4); AWEC/100, Mullins/38 (Table 10).

Q. IS A PRO FORMA STUDY A HISTORICAL TEST PERIOD?

A. No. While a pro forma study starts with actual costs, it applies sequential adjustments to those costs, which can be used in the context of both historical test periods and future test periods. The difference between the budget that PGE has proposed, and the use of a pro forma study is that in a pro forma study all of the pro forma adjustments to the actual costs must be justified with concrete evidence, as opposed to merely asserting that the overall budget is reasonable. This is the approach PacifiCorp took in its ongoing rate case, as I noted in my Opening Testimony.[6] In asserting that my testimony describes an historical test period, PGE does not appear to have reviewed the pro forma study PacifiCorp submitted in its ongoing rate case, which was used in the context of a forward test period.

Q. HAS PGE SUBMITTED SUFFICIENT EVIDENCE TO JUSTIFY ITS PROPOSED REVENUE REQUIREMENT INCREASE?

A. No. PGE has refused to provide any concrete documentation that reconciles back to its actual known and measurable costs. It continues to recommend that its revenue requirement be found to be reasonable based on a comparison to its 2024 budget. The Commission, however, has never approved the 2024 budget, and PGE has provided no evidence in the context of this case that the 2024 budget was independently reasonable. Moreover, the reasonableness of the 2024 budget in no way proves the reasonableness of the 2025 budget used in this case. Accordingly, my principal recommendation is that the Commission find that, with respect to revenue requirement, PGE has failed to meet its burden of proof and that the Commission reject the rate increase PGE is proposing.

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[6] AWEC/100, Mullins/9:15-18.

Q. HAVE OTHER UTILITY COMMISSIONS REJECTED A UTILITY RATE FILING ON THE BASIS THAT IT LACKED SUFFICIENT EVIDENCE TO BE APPROVED?

A. Yes. In 2016, following a fully developed evidentiary record, the Washington Utilities and Transportation Commission ("WUTC") rejected Avista Corp.'s general rate case, finding that "Avista, in this case, has failed to carry its burden to show that its existing rates 'are unjust, unreasonable, [or] insufficient to yield a reasonable compensation for the service rendered.'"[7]

Q. WERE YOU A WITNESS IN THAT CASE?

A. Yes. I filed testimony on behalf of AWEC in Avista's 2016 general rate case in Washington.

Q. WHAT WERE THE CIRCUMSTANCES OF THAT CASE?

A. Like PGE, Avista's 2016 case was filed on the heels of a previous rate case, just six weeks after the WUTC had approved new rates for the utility. While Washington relies on a historical test year to set rates, Avista used an "attrition adjustment" to support its rate increase.

Q. WHAT IS AN ATTRITION ADJUSTMENT?

A. An attrition adjustment increases a utility's revenue requirement based on a study provided by the utility that allegedly demonstrates that the level of investment the utility intends to make in the rate year will result in earnings "attrition", thus making it impossible for the utility to earn its authorized return. In essence, then, the attrition adjustment modifies the historical test period by introducing investments and expenses that are projected to occur after rates are set.

Q. ARE THERE SIMILARITIES BETWEEN AVISTA'S 2016 WASHINGTON RATE CASE AND THIS CASE?

A. Yes. In its order rejecting Avista's rate filing, the WUTC noted that Avista did not follow an "appropriate methodology" for developing an attrition study.[8] Whereas Avista should have

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7 WUTC Docket Nos. UE-160228/UG-160229, Order 06 at ¶ 61 (Dec. 15, 2016) (quoting RCW 80.28.020).
8 *Id.* at ¶ 62.

developed a modified historical test year with pro forma plant additions and then performed the attrition study on these results, Avista's case instead "begins and ends with its attrition study."[9] This is similar to PGE's filing, in which its revenue requirement request begins and ends with its 2025 budget.

III. CAPITAL

a. Rate Base Valuation

Q. IS PGE'S INVALID RATE BASE VALUATION TECHNIQUE FURTHER REASON TO REJECT PGE'S FILING?

A. Yes. In my Opening Testimony, I noted that PGE was proposing an unaccepted and invalid rate base valuation technique. In its filing, PGE measured the rate base balances over the 12 months ending December 31, 2024. However, PGE made a false modeling assumption that all capital in 2024 was to be transferred to plant on January 1, 2024. I demonstrated that the actual transfers to plant PGE was forecasting occur ratably over the course of the year and that its assumption that all transfers to plant occur on January 1, 2024 lead to an incongruous and inaccurate rate base valuation.[10] This technique represents a jumble of rate base valuation assumptions, depending on when the plant is assumed to be placed into service. Considering the invalidity of this approach, PGE has not adequately justified the rate base included in revenue requirement. Intervenors do not have access to the outboard computer programs, including the tax normalization software, necessary to fully correct for this erroneous calculation. Since PGE has been unable to present a coherent rate base calculation, there is not

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9 *Id.*

10 AWEC/100, Mullins/12:16-13:7.

sufficient evidence to determine what PGE's rate base should be, nor to determine the appropriate revenue requirement impact thereof.

Q. WHAT RATE BASE VALUATION METHOD DID YOU RECOMMEND IN OPENING TESTIMONY?

A. I recommended using PGE's rate base model to develop a consistently stated Average of Monthly Averages rate base calculated over the 12-months ending December 31, 2024.

Q. HOW DID PGE RESPOND TO YOUR CRITICISMS OF ITS APPROACH?

A. PGE stated that AWEC's assertion that it had included all of the 2024 plant additions in its rate base model with a January 1, 2024 rate effective date was factually inaccurate. PGE stated that AWEC "incorrectly asserts that PGE assumes plant balances were placed into service January 1, 2024."[11] PGE cited PGE's Exhibit 200 "GRC Plant Additions Detail" as evidence that it did not assume plant balances were placed into service January 1, 2024.[12]

Q. DID PGE'S RATE BASE MODEL ASSUME THAT ALL 2024 PLANT ADDITIONS WERE PLACED INTO SERVICE ON JANUARY 1, 2024?

A. Yes. I attached as an exhibit to my Opening Testimony the specific workpaper in PGE's rate base model where this assumption was made, and PGE confirmed in its Reply Testimony "[t]he use of a January 1, 2024 date"[13] for 2024 plant additions in that model. Accordingly, it is not clear how PGE can truthfully state that the 2024 plant additions were modeled consistently with the in-service dates forecast in Exhibit 200 "GRC Plant Additions Detail." To be clear, the in-service dates forecast in Exhibit 200 "GRC Plant Additions Detail," were not used in PGE's rate base modeling. That was the very point of AWEC's testimony and

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11 PGE/1300, Batzler-Meeks/19:18-19.

12 *Id.* at 19:20:20:1.

13 *Id.* at 20:1-2.

concerns with respect to this matter. Therefore, PGE's assertion that its Exhibit 200 provides evidence that it molded the plant additions correctly in its rate base model is not accurate since the dates in that Exhibit were not used.

Q. WHAT RATIONALE DID PGE GIVE FOR MODELING THE PLANT ADDITIONS ON JANUARY 1, 2024?

A. PGE stated that this assumption was necessary to "provide customers a full year of accumulated depreciation benefit for new 2024 assets."[14] PGE further explains that "[t]his date is only a proxy used in the calculation of annualized depreciation for new plant additions."[15]

Q. IS IT NECESSARY TO PROVIDE A FULL YEAR OF ACCUMULATED DEPRECIATION BENEFITS FOR NEW 2024 ASSETS?

A. No. Consistency is a primary consideration in establishing rate base. It requires that all of the rate base assumptions, including gross plant, accumulated depreciation, and deferred taxes be evaluated over the same period of time. Correspondingly, it is also necessary for there to be consistency between the accumulated depreciation values used in a rate base calculation and the accumulated depreciation accrued with respect to the depreciation expenses. Depreciation expense is an additional cost to ratepayers, while the corresponding accumulated depreciation is a benefit because it reduces rate base. Thus, measuring depreciation expenses in a manner that is different than accumulated depreciation is inconsistent with the principle that costs and benefits match in a revenue requirement calculation. PGE's assertion that its proposal "*reduces* PGE's December 31, 2024 rate base request"[16] obfuscates the fact that the approach

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14 PGE/1300, Batzler - Meeks/20:2-3.
15 *Id*. at 21:7-8.
16 *Id.* at 20:3-4 (emphasis in original).

systematically *increases* revenue requirement after considering the effects on depreciation expense. By constructing its rate base in this way, PGE's proposal includes incremental depreciation expenses and accumulated depreciation after the December 31, 2024 valuation date for some plant but not all. While this approach results in a hypothetical rate base that is lower than the expected December 31, 2024 value, it also results in a higher depreciation expense, which has approximately 10 times the impact to revenue requirement as the incremental accumulated depreciation.

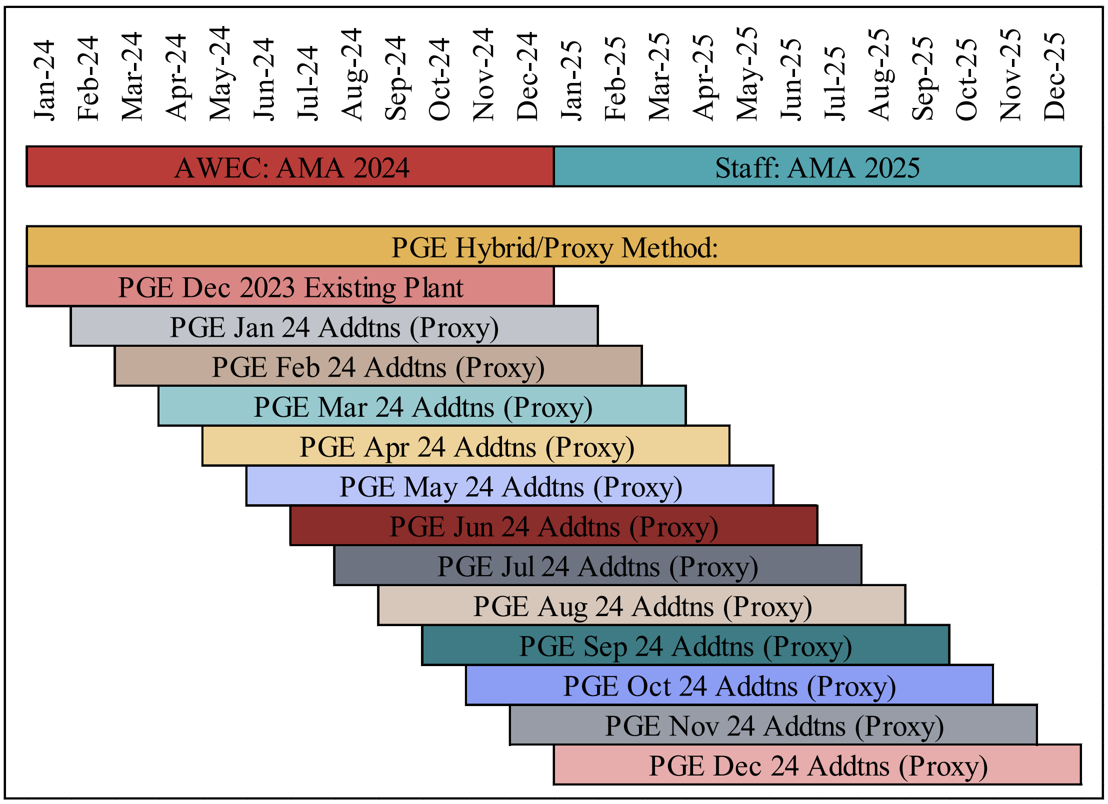
Q. CAN YOU PROVIDE AN EXAMPLE OF THIS?

A. Yes. Exhibit AWEC/302, Mullins/1 provides a numerical example using hypothetical numbers demonstrating that the incremental accumulated depreciation associated with the poxy rate base addition date is offset dollar for dollar by increased depreciation expenses. Since the incremental depreciation expenses have a higher revenue requirement value than the increase in accumulated depreciation, PGE's proposal systematically inflates revenue requirement. In the example, I evaluated the impact of a single capital addition being added on July 1, 2024 using PGE's proxy method versus the actual plant balances in both 2024 and 2025. The analysis shows that not only does PGE's proxy approach increase revenue requirement relative to actual 2024 balances, but it also increases revenue requirement relative to the 2025 balances. Thus, PGE's approach overstates revenue requirement, and therefore is not an acceptable method for valuing rate base.

Q. IS THERE SUCH THING AS A PROXY RATE BASE CALCULATION?

A. No. A proxy rate base calculation is a term that PGE invented, whereas I referred to it as a hybrid calculation. Regardless of the name applied to the method, it is not a standard rate base valuation method. When PGE states that it is using the January 1, 2024 in-service date as a proxy, it is not clear what that date is a proxy for. Notwithstanding, the practical effect of changing the modeled in-service date for new capital is that the rate base valuation period is different depending on when the plant is placed into service. In **Figure REB-1**, below, I compare the rate base valuation periods PGE is proposing with those recommended by AWEC and Staff.

Figure REB-1
Comparison of Proposed Rate Base Valuation Periods



By changing the in-service date for all plant in-service, plant placed in-service in each month of 2024 will have a different effective rate base valuation period. Consider for example, plant placed in-service in December 2024. PGE's proxy approach, which models the plant to be placed in-service on January 1, 2024, will have the effect of calculating the expected depreciation expenses from those additions over the 12 months ending December 2025. The result is a rate base valuation as of December 2025. This valuation period, however, is not consistent with the treatment of existing plant-in-service as of December 31, 2023. For the existing plant-in-service, depreciation expenses are calculated over the 12 months ending December 2024 and the rate base valuation is made as of December 31, 2024. This is unreasonable accounting because both the rate base and the depreciation expense of the existing plant will decline if measured over the same period as the December plant additions—i.e. January 2025 through December 2025.

Q. HOW DOES PGE'S HYBRID/PROXY APPROACH OVERSTATE REVENUE REQUIREMENT?

A. If the existing plant depreciation expense and rate base were measured over the 12 months ending December 2025 in a manner consistent with the December 2024 plant additions, it would produce a materially lower rate base and depreciation expense. More accumulated depreciation would accrue on the existing plant over the 12 months ending December 2025, resulting in a reduction to net plant and a reduction to rate base. Further, since PGE uses net plant balances instead of gross plant balances, calculating the depreciation expenses for existing plant over the 12 months ending December 2025 will also produce a reduction to depreciation expenses. Thus, by measuring plant balances over inconsistent periods using the proxy/hybrid approach, PGE is able to get the best possible revenue requirement outcome. PGE gets higher depreciation expense on new plant additions, without recognizing the lower depreciation expense and lower rate base valuation for the existing plant. This is not a reasonable outcome.

Q. IS PGE'S METHOD MEASURING A 2025 RATE BASE?

A. No. Later in testimony, PGE attempts to justify this inconsistent treatment by stating that its method is attempting to measure test year (calendar year 2025) rate base.[17] This is a somewhat curious assertion since PGE has explicitly rejected Staff's recommendation to calculate the plant balances consistently over the 2025 test year. PGE criticizes Staff's approach and defends the inflated proxy/hybrid method on the basis that its revenue requirement does not consider capital additions in 2025. Yet, it is not valid to justify the use of an inflated and inconsistent rate base on the basis that it is a workaround to avoid the effects of the Oregon used and useful requirement. If the only reason for using an inconsistent rate base is that it results in a rate base that captures some of the revenue requirement impacts of plant that will not be used and useful by the rate effective date, then the approach is not consistent with the used and useful standard.

Q. DO YOU SUPPORT STAFF'S 2025 AMA APPROACH?

A. No. While it is more consistent than PGE's hybrid approach, I do not agree with Staff's approach because Staff did not consider the reduction to depreciation expenses that will result from the incremental depreciation that it calculated over the 2025 period. Since PGE uses the unique approach of calculating depreciation expenses using net plant balances, Staff's incremental accumulated depreciation calculation will have a materially downward impact on PGE's depreciation expenses. Calculating that depreciation expense would require the use of PGE's depreciation software which is something that is not available to the parties.

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17 *Id.* at 23:6-8.

Accordingly, I continue to support the use of the 2024 AMA rate base calculation because it is more consistent with the rate base model that PGE submitted with its filing.

b. <u>Cost of Removal</u>

Q. WHAT RECOMMENDATION DID YOU MAKE REGARDING COST OF REMOVAL IN YOUR OPENING TESTIMONY?

A. I raised a concern that PGE's cost of removal accounting is resulting in overstated depreciation expenses.

Q. HOW DID PGE RESPOND?

A. PGE responded that its method "is consistent with the parameters adopted within PGE's depreciation study (Docket No. UM 2152) through Commission Order No. 21-463."[18] PGE also provided numerical examples demonstrating the way that it was intending to calculate cost of removal expenditures.[19]

Q. DID THE COMMISSION ORDER 21-243 IN DOCKET UM 2152 SPECIFY HOW COST OF REMOVAL EXPENDITURES ARE TO BE CONSIDERED?

A. No. Fundamental to this issue is the fact that PGE calculates depreciation expenses using the *net* plant balance as the depreciation base, rather than the *gross* plant balances. PGE's unique method, however, was not clearly specified in Commission Order 21-243. The net plant depreciation rates that PGE calculated use "future accruals" as the denominator for the depreciation rate calculation and those future accrual rates do include a provision for negative net salvage and cost of removal expenditures. This was not disputed in my testimony. My concern was that the rate base computer program used to develop depreciation expense was not giving credit for reserves accumulated with respect to cost of removal expenses. The cost of

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18 *Id. at* 26:11-12.
19 *Id.* at 27, Table 4

removal parameters were hidden in the report that PGE provided to support its depreciation expense, and it appeared from my calculation that the reserves were not being considered.

Q. DID YOU ASK PGE TO PROVIDE THE HIDDEN DATA USED TO CALCULATE THE COST OF REMOVAL DEPRECATION EXPENSE?

A. Yes. In AWEC Data Request 156, PGE provided the hidden cost of removal parameters used in its model, and I was able to confirm that the reserves were being deducted in the calculation of the cost of removal depreciation base. Therefore, I am withdrawing this recommendation in this case.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. PGE's calculation of depreciation expense using the net plant balances, as opposed to the gross plant balances, is problematic. It results in unstable depreciation expense levels and requires a number of opaque assumptions regarding parameters such as cost of removal and salvage. In the future, I recommend that PGE transition to using gross plant as the deprecation base for depreciation expense, which is the approach used by every other utility that I am aware of. This will avoid the complicated gymnastics and computer modeling that go into PGE's depreciation calculations.

c. <u>Capital Attestation</u>

Q. DID PGE AGREE TO PERFORM A CAPITAL ATTESTATION IN THIS CASE?

A. Yes. PGE stated "[w]hile PGE does not agree with the necessity of an attestation process, PGE is amenable to discussing a fair and balanced attestation process for a subset of its capital additions in this docket."[20]

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20 *Id.* at 64:4-6.

Q. WHAT PARAMETERS DID YOU PROPOSE?

A. With the exception of those projects having a capital cost of less than $1,000,000, I recommend the capital attestation be performed on a project-by-project basis. I recommended that two attestations occur. First, I recommended a provisional capital attestation filing occur approximately 15 days before the rate effective date, although this may depend on the timing of the Commission's final order. That filing would incorporate all plant additions up to that date and, based on the best information available to PGE at that time, would evaluate the actual capital expected to be placed into service as of the January 1, 2025 rate effective date. Second, I recommended a final capital attestation occur 45 days after the rate effective date. The second filing would be made after PGE has finalized its transfers to plant accounting for 2025 and would explain any variances between its provisional capital attestation filing and the actual plant placed into service.

Q. DID PGE AGREE WITH THESE ATTESTATION PARAMETERS?

A. No. PGE provided an alternative proposal, although it is apparent that the alternative is not workable. The parameters PGE provided are as follows:

- Include capital projects and amounts included in PGE's May 2024 rate case filing update and reviewed in the evidentiary process.
- Only include projects placed in service between October 1 and December 31, 2024.
- Include a $5 million forecast project cost threshold on a project-by-project basis for inclusion in the process.

- Include a one-time attestation filing and rate adjustment 45 days after the rate. effective date.
- The attestation be performed on a portfolio basis with the ability to net over spending on a one project with underspending on another.[21]

Q. DO YOU SUPPORT BASING THE ATTESTATION ON THE MAY 2024 UPDATE?

A. Since PGE quantified the impacts of this capital forecast in its Reply Testimony, AWEC does not oppose this aspect of its proposal. Notwithstanding, AWEC opposes further updates to the capital forecast, as parties will not have the opportunity to review or respond to the reasonableness of future updates.

Q. IS IT REASONABLE TO ONLY INCLUDE PROJECTS PLACED IN SERVICE BETWEEN OCTOBER 1 AND DECEMBER 31, 2024?

A. No. PGE provides no support for this recommendation other than its conclusory assertion that it would constitute a " fair and balanced attestation approach."[22] Yet, there is nothing fair or balanced with excluding projects placed into service prior to October 1, 2024, from the capital attestation process. The purpose of the attestation is to ensure, consistent with Oregon policy, that all plant included in rates is used and useful and meets the standard of prudence. These policies apply equally whether the plant is placed into service prior to October 1, 2024, or after.

Q. IS IT REASONABLE TO ONLY INCLUDE PROJECTS WITH A CAPITAL BUDGET IN EXCESS OF $5 MILLION IN THE ATTESTATION?

A. No. This will subject only a portion of the capital included in PGE's filing to a project specific capital review. AWEC believes that if forecasts are to be used in ratemaking, utilities need to

[21] *Id.* at 65:6-14.
[22] *Id.* at 64:7-14.

be accountable for their forecast assumptions, and this includes projects with a capital budget of less than $5 million.

Q. WAS PGE ACTUALLY PROPOSING A PROJECT-BY-PROJECT REVIEW FOR CAPITAL PROJECTS EXCEEDING $5 MILLION?

A. PGE's testimony on this point is contradictory. First it states that it is willing to perform a project-by-project review for projects exceeding $5 million.[23] A few sentences later it states that the review would "include both over and under budget amounts."[24] While the precise meaning of this second provision is not entirely clear, PGE appears to be suggesting that it should be allowed to use underspending on one project to offset overspending on another. If this understanding is correct, PGE is not proposing a project-by-project review at all. If PGE is proposing to net over and underspending between projects, that is not a project-by-project review. Such a proposal is a portfolio review. Thus, PGE's testimony on this point is unclear.

Q. DO YOU SUPPORT A PORTFOLIO REVIEW?

A. For small projects, with capital budgets less than $1 million, a portfolio review is the only practicable way to review these projects. For other projects, such as a substation or other major investments, PGE needs to be held accountable for its budget estimates. Consider the following example. Say PGE were to spend $20 million on a substation, Substation A, that was originally supposed to cost only $4 million. Under my recommended approach, PGE would only be able to include the $4 million in rates for Substation A in this case regardless of its actual spending on other projects. PGE would not, however, be precluded from including the $16 million in overspending in a later rate case. Correspondingly, say there was also a $16

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23 *Id.* at 65:9-10.
24 *Id.* at 65:13-14.

million substation, Substation B, which PGE was unable to place in service by the rate effective date. If a portfolio review were to be used, PGE would still be able to recover on the combined $20 million of capital costs budgeted for Substation A and Substation B, even though PGE dramatically overspent on Substation A and did not place Substation B into service. This is not a reasonable outcome. Underspending or under-execution of one project does not justify overspending on another. Accordingly, a project-by-project review is the most equitable way to do a capital attestation, with a focus on the greatest number of projects possible.

Q. IS IT REASONABLE TO PERFORM THE ATTESTATION 45 DAYS AFTER THE RATE EFFECTIVE DATE?

A. No. My approach would require PGE to provide two attestations, a provisional attestation immediately prior to the rate effective date and a final attestation after its books have closed. PGE's proposal to perform just a single attestation 45 days after the rate effective date is problematic because it is possible that rates will include projects that were not used and useful for the 45 days between the rate effective date and the final attestation. Under my approach, the likelihood that rates will include projects that were not used and useful will be minimized because PGE will have a good idea of the capital that will be transferred to plant around the time of the rate effective date, even though the accounting will not be finalized until a few weeks later.

IV. OPERATING EXPENSES

a. Non-Labor O&M Expense

Q. WHAT DID YOU RECOMMEND IN OPENING TESTIMONY WITH RESPECT TO NON-LABOR O&M EXPENSE?

A. In Opening Testimony, I reviewed PGE's actual non-labor O&M expense incurred in 2023. I compared those expenses to PGE's budgeted expenses for 2025. I demonstrated that, relative to its actual costs, PGE was proposing a 31% increase to non-labor O&M expense through its 2025 budget. I reviewed PGE's proposal with respect to each of the functional categories of O&M expense and, based on the information PGE provided in testimony and discovery, I found that much of this variance was unexplained and unjustified. Accordingly, when developing my revenue requirement recommendation, I reduced non-labor O&M expense by $22,540,807 relative to the levels PGE had included in its filing.

Q. HOW DID PGE RESPOND?

A. In general PGE found that it was inappropriate for AWEC to consider PGE's actual non-labor O&M at all. PGE alleged that AWEC was bound to form its recommendation in this case starting with the budget it used in Docket No. UE 416, stating the following:

> As a party and signatory to applicable settlement agreements in UE 416, AWEC is aware of the amounts approved for recovery in 2024. By asking PGE to use 2023 as the basis for rate making in this case, instead of 2024 amounts already established through a rate making process, AWEC is relitigating 2024 and the results of UE 416.[25]

As discussed above, the resolution of UE 416 through settlement in no way resulted in Commission approval of PGE's 2024 budget as just and reasonable. Similarly, nothing that was agreed in the 2023 GRC stipulations prevents AWEC from reviewing PGE's actual costs

[25] PGE/1400, Mersereau–Van Oostrum–Batzler/28:17-21.

and making recommendations based on its review in this proceeding. Indeed, I made similar observations about PGE's budget in the 2023 rate case,[26] and PGE's revenue requirement was decreased in the stipulations resolving that case, in which no party agreed to the reasonableness of any methodology to get to the final results.

Q. DID PGE PROVIDE ACTUAL COST DATA IN ITS OPENING TESTIMONY?

A. PGE's Opening Testimony did include some of the actual cost data from 2021-2023.[27] There was no explanation, however, as to why there were major differences between the actual costs and the proposed 2025 budget. This was the type of analysis that I attempted to do in my Opening Testimony, though an outside reviewer is always at a disadvantage because they have limited information. Compounding this informational asymmetry, when I conducted discovery on these amounts, the data PGE provided in response "inadvertently contained incorrect information."[28] I would probably characterize it as being entirely erroneous. It is necessary to point this out because it is infinitely more challenging for intervenors to determine and explain why costs are changing relative to PGE's actual costs given that intervenors do not have access to the relevant data, other than through the discovery processes, and the data that was provided contained inconsistencies and errors. This is why it is necessary for PGE, not ratepayers, to provide evidence to support its cases, rather than merely pointing back to the settled results of its prior case and providing erroneous information through the discovery process.

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26 Docket UE 416, AWEC/200, Mullins/12.
27 *See* PGE/1400, Mersereau–Van Oostrum–Batzler/28:8-10
28 *Id*. at 28:11.

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION ON DISTRIBUTION NON-LABOR O&M EXPENSE?

A. In my Opening Testimony, I noted the major increase to distribution non-labor O&M expense. Much of this increase could be explained by heightened routine vegetation management ("RVM") expense. I recommended that PGE hold non-labor RVM expense flat between 2024 and 2025, or if not possible, find areas to prioritize spending in order to achieve those reductions. In response, PGE states that "AWEC was part of and signatory to the settlement agreement that set the 2024 level of RVM spending and recognized the need for that work."[29] PGE appears to believe that AWEC is bound to support its 2025 level of RVM spending because of the settlement that was reached in the 2023 GRC.

Q. IS THE SETTLEMENT IN THE 2023 GRC RELEVANT TO THE RVM EXPENSE INCLUDED IN THIS DOCKET?

A. No. The RVM expense in the 2023 GRC was resolved through a black box adjustment, which reduced PGE's O&M expense relative to its filed case. AWEC made no representation to the reasonableness of the settled RVM expenses in the 2023 GRC. Further, PGE's response misses the point. I had also recommended PGE find areas to prioritize its spending considering the higher expense. PGE's RVM spending has increased, but that does not mean PGE should not be searching for opportunities to prioritize other expenditures to offset those major increases. In the face of such dramatic increases to distribution non-labor O&M, it is reasonable for PGE to identify further areas to reduce its budget.

[29] PGE/1600, Cloud–Albi–Putnam/18:19-20.

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATIONS ON GENERATIONS AND POWER OPERATIONS NON-LABOR O&M?

A. In my Opening Testimony, I noted that non-labor O&M expenses for generation and power operations increased collectively by approximately 24.9% relative to 2023 levels. Some of this increase was explained by Clearwater O&M expenses and changes to the major maintenance accrual, while the remainder was not. Accordingly, I recommended applying inflationary escalation to the remainder. PGE states that AWEC did not "challenge any specific increase to generation O&M non-labor."[30] PGE continues, stating that "AWEC makes no specific adjustments or decreases to generation O&M non-labor but rather recommends a general, unsupported adjustment that does not consider that PGE's 2024 budget is based upon the Commission approved outcome of UE 416."[31]

Q. DID PGE MAKE SPECIFIC ADJUSTMENTS TO GENERATION NON-LABOR O&M?

A. No. PGE's assertion that AWEC did not challenge any specific adjustments is confuted by the fact that PGE did not propose any specific adjustments to its 2023 actual costs. PGE's proposal was based on its budget, not based on adjustments to the 2023 actual costs. Asserting that AWEC's approach, which relies on actual historical costs, is an unsupported adjustment, implies that PGE's approach, which does not consider its actual costs at all, is even less reasonable. In reality, it is PGE's approach that is unsupported by evidence.

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[30] PGE/1700, Powell–Clark/8:3-6.

[31] *Id.*

Q. DID PGE IDENTIFY ANY ERRORS IN YOUR CALCULATED ESCALATION?

A. Yes. PGE notes that my analysis included inflated MMA expenses[32] and based on my review of their response, I agree. In addition, the calculation of the 2025 Clearwater non-labor expense inadvertently excluded certain line items. These changes result in an approximate $21,738 reduction of my recommendation. The corrected calculation is detailed in **Table REB-2**, below. I have considered this change in my revised revenue requirement calculation in Exhibit AWEC/301.

Table REB-2
Corrected Generation and Power Operations Non-Labor O&M Increase – Whole Dollars

	2023	2025	Delta	%
Power Ops & Gen	67,621,032	84,423,119	16,802,088	24.8%
Clearwater		(5,466,348)	(5,466,348)	NMF
Maj. Maint	(18,589,778)	(21,683,043)	(3,093,265)	16.6%
Remaining	49,031,254	57,273,728	8,242,474	16.8%
Proposed w/ Inflation	49,031,254	51,482,817	2,451,563	5.0%
		Difference	**5,790,911**	

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATIONS ON CUSTOMER SERVICES AND ACCOUNTS?

A. PGE acknowledges that it "did not submit Customer Service opening testimony in this proceeding."[33] Notwithstanding, PGE's view was that it did not need to submit any evidence regarding the reasonableness of those costs because of "the essentially flat nature of Customer Service O&M and no material or notable new requests."[34]

32 PGE/1700, Powell–Clark/9:4-10.
33 PGE/1500, McFarland-Lawrence/7:12-14.
34 *Id.* at 7:13-14

Q. WERE PGE'S CUSTOMER SERVICE AND CUSTOMER ACCOUNTS COSTS "ESSENTIALLY FLAT"?

A. No. PGE forecasts a major increase to the non-labor O&M expense for these accounts relative to 2023 levels. By its own numbers, the non-labor O&M for customer accounts and customer services increased by $7.9 million, or 43%.[35] Regardless of what PGE had assumed in its prior rate case, this increase requires a detailed explanation. However, PGE's only explanation for the variance is "normal cost escalations."[36] This is not an adequate explanation for the major increase PGE is proposing. If it were, PGE would find AWEC's recommendation, which did assume normal cost escalation, to be reasonable.

Q. DID PGE PROVIDE ANY MEANINGFUL RESPONSE TO YOUR RECOMMENDATION REGARDING ADMINISTRATIVE AND GENERAL NON-LABOR O&M EXPENSES?

A. No. Other than reiterating its position that the 2024 budget included in the 2023 rate case is reasonable, addressed above, PGE does not provide any meaningful response on my recommendation for administrative and general non-labor O&M expense.

b. <u>Labor Expense</u>

Q. WHAT WAS YOUR RECOMMENDATION WITH RESPECT TO LABOR EXPENSES?

A. I recommended using the 2023 actual FTE levels, with known and measurable wage rate increases through 2025. This resulted in an overall 7% increase to the 2023 wages and salaries levels incurred in 2023, compared to the 20% increase PGE had proposed in its filing. Relative to PGE's proposed budget, this recommendation resulted in a $34,238,543 reduction in labor expense.

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[35] *Id.* at 7, Table 1.
[36] *Id.* at 10:3.

Q. HOW DID PGE RESPOND?

A. PGE stated that my approach holds PGE "to a single point in time, with no consideration for new and incremental work PGE encounters to support safety, compliance, and customer needs that result in an increased reliance on contract labor."[37]

Q. IS THAT STATEMENT ACCURATE?

A. No. First, AWEC did apply wage rate escalation to the labor expense amount. Second, while PGE has been budgeting for higher headcounts, those budgets have been inaccurate. As I demonstrated in Table 10 of my Opening Testimony, PGE's headcount actually declined in 2023, even though the budget in the 2024 GRC had forecast a 220 full-time equivalent increase. My analysis also considers the higher historical level of contract labor incurred in 2023. Thus, if it were necessary for PGE to hire more in-house employees and reduce contract labor, that would be captured in my analysis.

Q. IS PGE ONLY PROPOSING A 4.3% GROWTH TO LABOR OPERATING EXPENSES?

A. PGE states that its labor expense proposal results in "4.3% compound annual growth rate from 2023 to 2025."[38] This statement is misleading, however, because it appears to include both labor O&M expense, as well as capitalized labor expense. My analysis, however, focused solely on the O&M portion of labor expenses, which demonstrated that the increase PGE is proposing is significantly higher than what it implies in its reply.

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37 PGE/1400, Mersereau–Van Oostrum–Batzler/10:10-12

38 *Id.* at 5:13-14.

c. <u>Revolver Fees</u>

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION TO REMOVE REVOLVER FEES FROM REVENUE REQUIREMENT?

A. PGE states that "[r]evolver fees are appropriately included in PGE's revenue requirement, pursuant to a stipulated agreement adopted as part of Commission Order No. 10-410."[39] PGE states that the costs are already "within PGE's results of operations."[40] Finally, PGE believes that the costs are appropriate because the "allow PGE long-term access to a revolving line of credit,"[41] even though "[a]ny actual debt and interest from this facility, just like any other types of short-term debt, is not included in PGE's revenue requirement."[42]

Q. DID COMMISSION ORDER NO. 10-410 ADDRESS REVOLVER FEES?

A. No. In AWEC Data Request 170, PGE was requested to identify where in Commission Order 10-410 revolver fees, margin net interest, and broker fees were addressed. In response, PGE stated "[t]he specific provision of the stipulation resolving the treatment of revolver fees, margin net interest, and broker fees can be viewed in Commission Order No. 10-410, Appendix A at Term III."[43] Order 10-410 was issued in Docket UE 215, PGE's 2010 Annual Update Tariff ("AUT") proceeding, and the referenced term relates to the reclassification of certain chemical costs from base rates to the AUT. I have also been unable to identify any docket where the going forward treatment of these items has been explicitly addressed. Thus, PGE's assertion that these items have been resolved as a part of a settlement stipulation is misleading at best.

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39 PGE/1400, Mersereau–Van Oostrum–Batzler/43:18-19.

40 *Id.* at 43:20.

41 *Id*. at 45:19

42 *Id.* at 45:14-15.

43 AWEC/302 (PGE's Resp. to AWEC DR 170)

Q. WHAT INTEREST RATES DOES PGE RECEIVE FOR SHORT-TERM DEBT INSTRUMENTS THAT ARE NOT INCLUDED IN REVENUE REQUIREMENT?

A. PGE provided the interest rates in response to AWEC Data Request 176. As can be seen in that response, the interest rates on the revolver lines of credit are very low, ranging from 0.0% to 1.5%. Ratepayers don't receive the benefit of short-term debt in base rates, and therefore should not have to pay for the fees associated with the debt. The revolver fees themselves are akin to interest on the instruments, and in fact, PGE accounts for the revolver fees as short-term interest expense. Interest is a cost of capital item. It is not accurate or appropriate to include additional short term interest expense in revenue requirement in addition to the rate of return earned on rate base.

Q. ARE THESE FEES ALREADY CAPTURED IN INTEREST EXPENSE?

A. Yes. In response to AWEC Data Request 175, PGE provided the transactional data supporting its revolver fees over the period 2020 through 2023. From that response, it can be observed that PGE follows the FERC method which records revolver fees in account 186 as a deferred debit, and then amortizes the cost of the revolver fees to short-term interest expense in FERC account 431, other interest expense. The cost of this interest expense, however, is already recovered through Allowance for Funds Used During Construction ("AFUDC"). PGE uses average interest expense to calculate the interest on short-term debt for purposes of its AFUDC calculation. Ratepayers do not receive the benefit of short-term debt in general base rates, and therefore, including the interest expense associated with revolver fees in revenue requirement is not appropriate.

d. Margin Net Interest

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION TO EXCLUDE ITS MARGIN NET INTEREST ADJUSTMENT FROM REVENUE REQUIREMENT?

A. Similar to revolver fees, PGE cited to the same Commission Order No. 10-410 from the 2010 AUT as its reasoning for including Margin Net Interest in revenue requirement. As noted, that Order had nothing to do with margin net interest and is therefore irrelevant. PGE also stated that "PGE must maintain immediate liquidity of amounts and cannot use these funds for any other purpose,"[44] and therefore, including a provision for interest on the margin balances is appropriate.

Q. ARE THE ALLEGED MARGIN NET INTEREST BALANCES ACTUALLY BEING HELD IN A LIQUIDITY CONSTRAINED ACCOUNT?

A. No. In AWEC Data Request 177, AWEC requested that PGE provide the account statements supporting the interest expense incurred with respect to these alleged funds. In its response, PGE was unable to provide any account statements because there are no such accounts. PGE is not actually holding these alleged funds in a liquidity restricted account as it has represented. Its statements regarding the liquidity of the funds are therefore false.

Q. IS PGE ACTUALLY INCURRING INTEREST EXPENSE WITH RESPECT TO ITS COMMODITY MARGIN POSITIONS?

A. No. In Confidential Attachment 177-B, PGE provided all interest income and expense associated with margin funds over the period December 2020 through June 2024. I have attached that response as **Confidential Exhibit AWEC/104**. In 2023 and 2024 (to date) margin net interest resulted in overall interest revenues to ratepayers. Thus, PGE's assertion that this represents a cost to include in revenue requirement is concerning. As can be seen

[44] PGE/1400, Mersereau–Van Oostrum–Batzler/46:19-20

from the response, the interest expense and income represent accounting entries associated with payments to, and from, energy commodity counterparties. They are not based on restricted funds held in a specific account. Accordingly, to the extent that PGE is holding these funds, it is receiving a cash benefit from holding the funds.

Q. HOW THEN DID PGE CALCULATE ITS ESTIMATE OF MARGIN NET INTEREST?

A. PGE's calculation was provided in Confidential Attachment A in response to AWEC Data Request 177. While detail behind the balances was not provided, it appears that the balance is based on letters of credit outstanding in 2023. A letter of credit is not a financing obligation, however. It is an instrument issued by a bank, guaranteeing a payment in lieu of posting collateral with the counter party. Generally, interest expense is not paid on a letter of credit. Notwithstanding, PGE imputed an interest expense on the balances using its authorized rate of return. In other words, PGE is attempting to earn its rate of return on letters of credit. This, however, is inappropriate as a letter of credit does not represent a cash outlay, nor the type of used and useful utility asset on which PGE is authorized to earn its rate of return.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Not only does PGE's calculation violate the used and useful principle by proposing to earn its return on letters of credit, but it is inconsistent with the fact that PGE has actually received net interest income with respect to its commodity margins. Accordingly, I continue to recommend this charge be removed from revenue requirement.

e. Broker Fees

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION TO REMOVE ITS BROKER FEES ADJUSTMENT FROM REVENUE REQUIREMENT?

A. PGE clarified that these amounts represent fees paid by "power operations organization as well as fees from clearing brokers and exchanges that facilitate trades."[45] It explained that these fees "benefit customers by helping to lower PGE's net variable power costs."[46]

Q. IS IT NECESSARY TO INCLUDE THESE AMOUNTS AS A SEPARATE ADJUSTMENT TO REVENUE REQUIREMENT?

A. No. In response to AWEC Data Request 178, PGE confirmed that these amounts are recorded to Account 557. My confusion with respect to these fees was due to the fact that PGE is already recovering the costs associated with broker fees in Account 557. In its revenue requirement calculation, PGE applied the $133,318 adjustment as an increase to its administrative and general expenses, even though based on PGE's Reply Testimony, these amounts are related to power operations expense and have nothing to do with administrative and general expenses.

Q. ARE THE BROKER FEES ALREADY CONSIDERED IN ACCOUNT 557?

A. Yes. PGE provided the transactional data supporting the amounts in response to AWEC Data Request 177. From that response, PGE records broker fees as an outside services expense. My recommended non-labor O&M expense for power operations already includes these outside service expenses. Accordingly, a separate revenue requirement adjustment is not necessary for broker fees. Similarly, PGE's own budget for 2025 included a provision in Account 557 for outside services expenses, which is where the cost of broker fees is recorded.

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45 *Id.* at 47:12-13

46 *Id.* at 48:8-9.

Thus, broker fees are already included in PGE's proposed budget as well, requiring no separate revenue requirement adjustment to its own budget.

f. Directors' Fees and Expense

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO DIRECTORS' FEES AND EXPENSE?

A. Recognizing directors' fiduciary duty to shareholders, I recommended that directors' fees be split 90/10 between shareholders and ratepayers. Further, I recommend that no directors' stock compensation be considered in revenue requirement.

Q. HOW DID PGE RESPOND?

A. PGE stated that "Board members bring customer value through oversight and governance, strategic direction, and their wealth of expertise and experience that they bring to decision making."[47] PGE also stated that this adjustment is "duplicative" of the non-labor O&M adjustment detailed above.[48]

Q. DO YOU DISPUTE THE QUALIFICATIONS OF PGE'S DIRECTORS?

A. No. The qualifications of PGE's directors are not in dispute. The issue I raised concerns the interest of shareholders versus the interest of ratepayers. Directors are fiduciarily obligated to act in stockholders' best interests. Accordingly, it is appropriate for shareholders to bear some of the costs associated with retaining directors. PGE does not dispute that directors have a fiduciary duty to shareholders. It is an accepted regulatory framework to split the cost of directors' fees and expenses between shareholders and ratepayers, one that has been used for

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47 *Id*. at 29:5-7.

48 *Id*. at 29:10-14.

many decades in other states, such as Washington. Accordingly, I continue to support my recommendation.

Q. IS THIS RECOMMENDATION DUPLICATIVE OF YOUR NON-LABOR O&M ADJUSTMENT?

A. No. My non-labor O&M adjustment only considers rate escalation on costs that were incurred in calendar year 2023. I did not separately remove the director's fees and expense when making that adjustment. The adjustment removing the shareholder portion of directors' fees and expenses is in addition to my non-labor O&M adjustment.

g. <u>Stock Incentives</u>

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO STOCK INCENTIVES?

A. I recommended that all stock incentives be removed from revenue requirement. Stock incentives are not an expenditure to the utility but reflect the issuance of new stock instruments to employees. Therefore, they do not represent a cost of providing utility services that is appropriate to include in revenue requirement. From a financial accounting perspective, the accrual associated with stock incentives is a form of equity dilution, which is not a cost of providing utility service. Further, because stock incentives are specifically designed to align the interest of employees with the interest of shareholders, it is doubly necessary to exclude them from utility rates.

Q. HOW DID PGE RESPOND?

A. PGE did not specifically address whether it is appropriate to include the cost of equity dilution from the issuance of stock compensation in a revenue requirement calculation. Notably, the accounting for many items is different in a revenue requirement calculation than it is under Generally Accepted Accounting Principles ("GAAP"). Consider, for example, mark-to-market calculations associated with power and gas commodities or contingent liabilities. These types of accrual adjustments, which do not represent cash outlays, are included in GAAP financial statements but are not considered in a revenue requirement calculation. The treatment of stock compensation is no exception. Namely, GAAP is designed to determine the periodic income and/or loss to shareholders, not the cost of providing utility services. The dilution of shareholders' shareholdings from the issuance of stock to directors and employees reduces the value of their stock, and therefore, is a viable cost from a GAAP perspective. The purpose of revenue requirement, however, is different. It is designed to ensure that the utility has sufficient revenues to recover its costs and earn a reasonable return on its investment. When a utility issues stock to employees, no additional revenues are required to cover the costs of issuing the stock. PGE just issues the stock. If revenues were recovered for stock issued to employees, PGE would be recovering the cost of an expenditure that it does not make.

Q. HOW DID PGE RESPOND TO THE CONCERN REGARDING THE INCENTIVES PROMOTED THROUGH STOCK COMPENSATION?

A. PGE stated that it "reject[s] the idea that the interests of PGE shareholders and our customers are diametrically opposed."[49] In terms of revenue requirement, however, which is the subject at issue in this case, the interest *are* diametrically opposed. Shareholders are interested in more revenues; ratepayers are interested in less. It is up to the Commission to strike the balance. If the interest were the same, then PGE's shareholders would have no misgivings about removing the stock compensation from revenue requirement. While having a financially healthy company is certainly a valid employee interest, stock compensation is not necessary to meet

[49] *Id.* at 17:5-6.

that goal. Annual monetary incentives with specific goals tied to financial health would provide a greater incentive in that regard, without misaligning the interest of employees and ratepayers.

h. Incentive Overheads

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO PGE'S ADJUSTMENT FOR INCENTIVES OVERHEADS?

A. I noted that PGE reduces the allocation credit associated with incentives overheads, but did not reduce the incentive overheads themselves. Therefore, I recommended the reduction to the allocation credit amount be removed from revenue requirement.

Q. HOW DID PGE RESPOND?

A. PGE stated that it is not capitalizing incentives, and that therefore, the adjustment to the allocation credit should remain.[50]

Q. DO YOU AGREE?

A. No. There is a material amount of departmental incentives overheads, which were not allocated to capital or considered below the line. PGE admits this.[51] Through its adjustment, PGE is increasing revenue requirement for to one side of the equation—which it refers to as the accounting transfer department—but not reducing it for the other, the incentive overheads allocated to the departments. Further, while PGE states that it has allocated these amounts to capital, it correspondingly states that it has, consistent with the agreement in UE 283, not capitalized these amounts. Since the amounts are not being capitalized, there can be no costs being allocated to capital to begin with. Thus, I continue to support my original adjustment.

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50 *Id.* at 18:17-22.
51 *Id.* at 18:5-11.

V. TAXES

Q. ARE THERE ANY TAX RECOMMENDATIONS THAT PGE ACCEPTED IN ITS REPLY TESTIMONY?

A. Yes. PGE accepted my recommendations related to the Boardman Cost of Removal ADIT and Accrued Incentives ADIT. PGE did not, however, accept my other tax recommendations, which I discuss below.

a. Production Tax Credit Carryforwards

Q. WHAT DID YOU RECOMMEND IN OPENING TESTIMONY WITH RESPECT TO PRODUCTION TAX CREDIT CARRY FORWARDS?

A. I recommended that all production tax credit ("PTC") carryforwards be removed from revenue requirement. I noted that PGE has adopted a policy of selling all new PTC carryforwards, which, over time, will reduce PGE's PTC carryforward balance to zero. When PTCs are sold, they are sold at a discount and ratepayers are paying the cost of the discount through Schedule 105. The reason for making the sales, however, is that there is a corresponding benefit through the reduction to the ongoing PTC carryforward balance included in rate base. If ratepayers are to fund the cost of selling PTC carryforwards, it is imperative that they also receive the benefit of the reduction to rate base.

Q. HOW DID PGE RESPOND?

A. In Reply Testimony, PGE agreed that because of the ongoing PTC sales, the balance will decline materially. Accordingly, it proposed to reduce the balance from $89.1 million to $35.7 million based on its estimated balance as of December 31, 2024.[52]

[52] PGE/1300, Batzler-Meeks/37, Table 6.

Q. DO YOU AGREE WITH THE INCLUSION OF THE AMOUNTS PGE HAS PROPOSED?

A. No. I continue to recommend that PTC carryforwards be removed in their entirety from revenue requirement. Since PGE is passing through the cost of selling PTCs on a dollar-for - dollar basis, without recognizing the reduction in the PTC carryforward balance that results from the sales in between rate cases, including any balance in base rate revenue requirement is unfair to ratepayers. While only new credits can be sold, these sales free up existing credits that can be used to offset taxable income in the rate effective period, and PGE demonstrated that it expected the balance to decline to zero in 2025.

Q. ARE THERE OTHER WAYS TO PROVIDE RATEPAYERS THE BENEFIT OF THE DECLINING PTC CARRYFORWARD BALANCE BETWEEN RATE CASES?

A. Yes. If the Commission does not accept my recommended approach, an alternative recommendation would be to suspend the collection of the discount on monetized PTCs through Schedule 105. Ratepayers should not have to pay for the discount on PTCs if they are not receiving the corresponding rate base reduction associated with the sales. Correspondingly, if PGE is recognizing the benefit of the declining PTC carryforward balance between rate cases, it should pay the cost of the discount. The rate base impacts are generally greater than the discounts, which is why these sales are being pursued. Therefore, it is reasonable for PGE to bear the cost of the sales transactions if it is also recognizing the savings in terms of rate base. Finally, another alternative approach would be to defer the benefit of the PTC carryforward reductions associated with PTC sales between rate cases.

b. Emergency Wildfire and Storm Deferrals

Q. WHAT TAX ISSUE DID YOU IDENTIFY RELATED TO THE EMERGENCY WILDFIRE AND STORM DEFERRALS IN OPENING TESTIMONY?

A. Because PGE was able to deduct the costs associated with the emergency wildfire and storm deferrals at the time the expenditures were made, they represented a major tax benefit to PGE. When these expenses were deducted, they reduced PGE's tax liability materially and correspondingly increased its ongoing carryforward balances. I recommended that the ADIT associated with these expenditures, which PGE recognizes on its books, be considered in rate base.

Q. HOW DID PGE RESPOND?

A. PGE merely points out that these valid tax benefits are not considered in revenue requirement and states that considering the tax benefits would be inconsistent with the amounts deferred and amortization of amounts has been previously ruled upon by the Commission.[53]

Q. WERE THE ADIT IMPACTS ASSOCIATED WITH THE DEFERRAL ADDRESSED IN COMMISSION ORDER NO. 22-435?

A. No. Notably, PGE does not dispute that there were tax benefits associated with the expenditures that were deferred. The tax benefits are recorded as line items in the tax provision and included in their financial statements. Yet, PGE reaches the conclusion that these tax benefits should not be reflected in ADIT because the Commission order approving the deferral of the expenditures never addressed ADIT.

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[53] *Id.* at 38:1-39:22.

Q. WAS IT NECESSARY FOR THE ADIT IMPACTS TO BE ADDRESSED IN ORDER NO. 22-435?

A. No. On the contrary, absent a Commission order that requires the ADIT impacts of the deferral to be excluded from revenue requirement, one must assume that the impacts would be included. PGE did not, for example, file testimony requesting to exclude the ADIT benefits of the deferred expenditures from future revenue requirement calculations. Absent that, PGE's argument has no merit. In fact, it was the Commission's decision to defer the costs, which gave rise to the ADIT benefits to begin with. Absent the deferral, PGE would have been able to keep 100% of the tax benefits associated with the expenditures, although it would have also had to pay 100% of the costs. Considering that ratepayers are agreeing to pay for 100% of the costs PGE incurred, it is also appropriate for them to receive 100% of the tax benefits through ADIT.

c. <u>Corporate Activity Tax</u>

Q. WHAT DID YOU RECOMMEND IN OPENING TESTIMONY WITH RESPECT TO THE CORPORATE ACTIVITY TAX ("CAT")?

A. Recognizing that the amount of CAT expense that PGE had included in revenue requirement was materially higher than the historical CAT expense amounts, I recommended a $3,796,491 reduction to the CAT expense amount.

Q. HOW DID PGE RESPOND?

A. In response PGE modified its calculation of CAT expense to be $11.1 million, a reduction of $1.8 million from its initial filing.

Q. DO YOU SUPPORT PGE'S CALCULATION?

A. While the amount is still higher than the historical amounts, I found PGE's estimate to be reasonable for the purposes of this testimony. Further analysis of this calculation, however, should be undertaken in future proceedings.

d. Anderson Readiness Center ITCs

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO THE ANDERSON READINESS CENTER ITCS?

A. I recommended that $497,448 in ITCs associated with the Anderson Readiness Center be considered in revenue requirement. I also recommended that PGE affirm that it would opt out of ITC normalization for these credits.

Q. DID PGE AFFIRM THAT IT WOULD OPT OUT OF ITC NORMALIZATION?

A. Yes.

Q. DID PGE CONSIDER THE REVENUE REQUIREMENT BENEFITS OF THE ANDERSON READINESS CENTER ITCS IN REVENUE REQUIREMENT?

A. No. PGE asserted that it would not utilize the credits and that therefore, there would be no revenue requirement effect associated with the credits.

Q. DO YOU AGREE?

A. No. Because PGE is selling its PTCs, it will be able to utilize tax credits associated with the Anderson Readiness Center in 2025. Further, the Commission has full authority to begin amortization of these ITCs because PGE agreed to opt out of normalization. Accordingly, I continue to recommend that both the rate base and the amortization benefit of these ITCs be considered in revenue requirement.

VI. CONSTABLE AND SEASIDE BATTERY SYSTEMS

a. Resource Trackers

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO THE CONSTABLE AND SEASIDE BATTER SYSTEM TRACKERS?

A. In my Opening Testimony, I recommended that the proposed trackers for the Constable and Seaside Battery Storage systems be rejected as unfair single-issue ratemaking and inconsistent with Oregon's used and useful requirements.

Q. WHAT DID STAFF RECOMMEND?

A. Staff recommended the Commission approve a tracker only for the Constable Battery System, so long as the project meets commercial operations by January 31, 2025, and that the gross plant is less than or equal to the amount included in PGE's filing.[54]

Q. DO YOU AGREE WITH STAFF?

A. No. PGE's proposal for a tracker is a workaround for the Oregon used and useful requirement. PGE had the opportunity to file its case in a manner that would have provided a sufficient buffer with respect to the in-service date of Constable. PGE could have filed with a rate effective date of January 31, 2025, or later, to provide this buffer. PGE chose not to do so, and it is appropriate for PGE to bear the risk of that decision. Providing tracker recovery for major plant additions that might occur after the rate effective date provides the wrong regulatory incentive for utilities to file rate cases with in-service dates that are accelerated relative to the possible plant closing dates, knowing that recovery for a major plant addition can be assured to be recovered in rates regardless of whether it is used and useful by the rate effective date. Accordingly, I continue to disagree with the approval of any resource trackers in this case.

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[54] Staff/1700, Dlouhy/22:5-19.

Q. HOW DID PGE RESPOND?

A. PGE responded that it was generally agreeable to Staff's recommendation on Constable, so long as the in-service cutoff date was moved to February 28, 2025. This delay is telling. If PGE believes that it is probable that Constable will not be in service until February 28, 2025, that is an indication that PGE does not believe that Constable will be in-service by the rate effective date. In response to AWEC's opposition to the tracker, PGE stated that "[w]hile PGE expects Constable to be completed prior to December 31, 2024, some general construction risk inevitably remains."[55]

Q. DO YOU AGREE THAT THERE IS CONSTRUCTION RISK?

A. Yes. That is the very point. By filing its case in this manner, with Constable forecast to go into service on the very day prior to the rate effective date, PGE's tracker proposal would confer all of that construction risk onto ratepayers. PGE will be able to include Constable in rates regardless of whether it is in service by the rate effective date. Thus, I continue to believe that a tracker tariff is both inappropriate and unnecessary. Had PGE chosen to file with a rate effective date that is two months later, none of this discussion would have been necessary.

a. <u>ITC Normalization</u>

Q. DID PGE AFFIRM THAT IT WOULD OPT-OUT OF ITC NORMALIZATION FOR THE CONSTABLE AND SEASIDE BATTERIES?

A. No. In Opening Testimony, I explained the differences between ITC normalization and ordinary tax normalization and demonstrated why the legacy ITC normalization rules are punitive to ratepayers—namely that they do not allow for the return of both the rate base and the tax expense benefits of the ITC. I recommended that PGE's action be determined to be

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55 PGE/1700, Powell–Clark/17:8-10.

imprudent if it does not affirmatively agree to opt out of ITC normalization for both Constable and Seaside, which PGE affirmed in discovery was permitted. In its reply, PGE did not affirmatively state that it would opt-out of ITC normalization, although its revenue requirement proposal appears to assume that it will do so. However, in response to AWEC Data Request 163, PGE affirmatively stated that "PGE agrees to opt out of ITC normalization as described at PGE/1300, Batzler-Meeks/31 line 19 – 32 line 2." The referenced testimony, however, did not state that PGE would opt-out of normalization. Therefore, I continue to recommend that PGE's action be determined to be imprudent if it does not opt-out of normalization for the Constable and Seaside Battery Systems.

b. <u>ITC Accounting</u>

Q. HAS PGE AGREED TO WITHDRAW ITS ITC TRACKER PROPOSAL?

A. Yes. PGE has withdrawn its ITC tracker proposal and agreed with parties to include ITCs in base rates.[56]

Q. HAS PGE MADE ANY OTHER CHANGES WITH RESPECT TO ITS PROPOSAL?

A. Yes. Other than eliminating the ITC tracker tariff, PGE has made two new proposals. First, PGE proposes to extend the amortization period for the ITCs relative to the period assumed in its initial filing. Second, PGE has proposed to discount the ITCs by 10%, reflecting the expected cost of selling the ITCs.

Q. DO YOU AGREE WITH PGE'S PROPOSAL TO EXTEND THE AMORTIZATION PERIOD?

A. No. I recommend that the amortization period included in PGE's initial filing be retained. Provided that the ITCs are not subject to normalization, the Commission can decide to

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[56] PGE/1300, Batzler-Meeks/31:19-32:2.

amortize them over whatever period it finds to be most reasonable. In this case, accelerating the ITCs over the period that PGE included in its initial filing strikes a reasonable balance, considering the massive rate pressures being faced by ratepayers in this proceeding.

Q. DO YOU AGREE WITH PGE'S PROPOSAL TO DISCOUNT THE ITCS BY 10%?

A. This proposal was not supported by any substantive testimony, and to the extent that PGE is required to monetize the ITCs, the discount on the sale and the associated accounting should be determined at the time the sale is made. Notably, no discounting was assumed with PGE making the decision to pursue these investments, and PGE's ability to recover the cost of a potential discount on a sale of the ITCs can be scrutinized only after a sale is made.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/301

REVISED REVENUE REQUIREMENT CALCULATIONS

Electric Revenue Requirement Summary ($000)

			Revenue Requirement			Impact of AWEC Adjustments			
Line	**Adj. No.**	**Description**	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)	Pre-Tax Net Oper. Income	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)
1		**Filed Revenue Requirement**	**$331,807**	**$7,349,355**	**278,395**				
2		Less: UE 416 Adj.	$334,958	$7,349,355	273,932	4,309	3,151	-	(4,463)
3		Add: Constable	$335,202	$7,496,153	288,534	(3,750)	244	146,798	14,602
4		**Margin Rev. Req. (Less: NVPC)**	**$394,670**	**$7,496,153**	**204,299**	**81,330**	**59,467**	**-**	**(69,633)**
		AWEC Adjustments							
5		Cost of Capital	$394,670	$7,496,153	151,250	-	-	-	(53,049)
6	A1	AMA Rate Base Valuation	$415,884	$7,177,449	91,001	29,014	21,215	(318,703)	(60,249)
7	A2	Cost of Removal Depr.	$415,884	$7,177,449	91,001	-	-	-	-
8	A4	Non-Labor O&M	$432,350	$7,177,449	67,678	22,519	16,466	-	(23,323)
9	A5	Labor Expense	$457,384	$7,177,449	32,216	34,239	25,035	-	(35,461)
10	A6	Revolver Fees	$458,962	$7,177,449	29,982	2,157	1,577	-	(2,234)
11	A7	Margin Net Interest	$459,854	$7,177,449	28,718	1,221	893	-	(1,264)
12	A8	Broker Fees	$459,952	$7,177,449	28,580	133	97	-	(138)
13	A9	Directors' Fees	$462,347	$7,177,449	25,187	3,276	2,395	-	(3,393)
14	A10	Stock Incentives	$464,525	$7,177,449	22,102	2,979	2,178	-	(3,085)
15	A11	Incentives Overhead	$467,490	$7,177,449	17,903	4,054	2,964	-	(4,199)
16	A12	PTC Carryforward	$467,490	$7,069,973	7,719		-	(107,476)	(10,184)
17	A13	Boardman C.O.R.	$467,490	$7,063,645	7,119	-	-	(6,328)	(600)
18	A14	Emergency Deferrals	$467,490	$7,037,535	4,645	-	-	(26,110)	(2,474)
19	A15	Accrued Incetnives	$467,490	$7,032,252	4,145	-	-	(5,283)	(501)
20	A16	Or. Corp. Activity Tax	$468,856	$7,032,252	2,209	1,869	1,366	-	(1,935)
21	A17	Anderson Readiness Ctr. ITCs	$468,906	$7,031,705	2,087	68	50	(547)	(122)
22	A18	Constable ITCs	$483,570	$6,989,807	(22,655)	15,311	14,664	(41,898)	(24,742)
23	A19	Key Cust.Mngr (Kaufman)	$484,082	$6,989,807	(23,380)	700	512		(725)
25		Interest Coordination	$475,556	$6,989,807	(11,303)		(8,525)		12,076
26		**Adjusted Results**	**$475,556**	**$6,989,807**	(11,303)	**199,428**	**143,749**	**(359,548)**	**(275,096)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/302

PGE RESPONSES TO DATA REQUESTS

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 156
Dated August 21, 2024

Request:

Please provide an updated version of the attachment provided in response to Staff Data Request 124 based on the capital forecast included in PGE's Reply Testimony revenue requirement. With respect to the responsive workpaper, for each line included in the deprecation expense forecast, please provide the following hidden parameters:

a. The Cost of Removal Base
b. Cost of Removal Percent
c. Gross Salvage Percent
d. Any other hidden parameter or value necessary to recalculate the values in the study.

Response:

PGE understands this request as asking for an updated version of Attachment 124 with respect to the tabs relevant to depreciation expense. With this understanding, PGE responds as follows:

a. PGE disagrees that the referenced parameter is "hidden," but rather required calculation based on the presented information. PGE has provided shortcuts to these calculations in Attachment 156-A, tab "Depr Query – 2025 GRC". Please note that this response only includes tangible utility depreciation expenses included in revenue requirement as cost of removal and salvage are not relevant to intangible amortization.
b. See response to a.
c. See response to a.
d. There are no hidden parameters nor values necessary to recalculate the values in the study.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 163
Dated August 21, 2024

Request:

Reference PGE/1300, Baltzer-Meeks/31:9-18: Is PGE agreeing with AWEC's recommendation that it will opt-out of ITC normalization? If no, please explain.

Response:

PGE agrees to opt out of ITC normalization as described at PGE/1300, Batzler-Meeks/31 line 19 – 32 line 2.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 170
Dated August 21, 2024

Request:

Reference PGE/1400, Mersereau–Van Oostrum–Batzler/42:12-18: Please identify the specific provision of the stipulation adopted in Commission Order No. 10-410 where the treatment of revolver fees, margin net interest and broker fees was resolved.

Response:

The specific provision of the stipulation resolving the treatment of revolver fees, margin net interest, and broker fees can be viewed in Commission Order No. 10-410, Appendix A at Term III.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 175
Dated August 21, 2024

Request:

Please provide transaction level detail of all revolver fees recorded over the period January 1, 2020, through June 30, 2014.

Response:

Confidential Attachment 175-A provides the requested information.

Attachment 175-A contains protected information subject to General Protective Order 23-132.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 176
Dated August 21, 2024

Request:

For each revolver line of credit outstanding, please state the current interest rate.

Response:

All of PGE's revolving credit follows the interest rate scheme below.

PRICING	**LEVEL I STATUS ≥ A+/A1**	**LEVEL II STATUS A/A2**	**LEVEL III STATUS A-/A3**	**LEVEL IV STATUS BBB+/BAA 1**	**LEVEL V STATUS ≤ BBB/BAA2 OR UNRATED**
Applicable Eurodollar Margin	*0.875%*	*1.000%*	*1.125%*	*1.250%*	*1.500%*
Applicable ABR Margin	*0.000%*	*0.000%*	*0.125%*	*0.250%*	*0.500%*
Commitment Fee Rate	*0.075%*	*0.100%*	*0.125%*	*0.175%*	*0.225%*
Letter of Credit Fee	*0.875%*	*1.000%*	*1.125%*	*1.250%*	*1.500%*

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 177
Dated August 21, 2024

Request:

Reference PGE/1400, Mersereau–Van Oostrum–Batzler/46:1-47:4:

a. Does PGE deposit the margin funds in a particular bank account(s)? If yes, please provide the bank account statements over the period January 1, 2020, through June 30, 2024.
b. Please provide workpapers supporting the margin net interest amounts PGE is forecasting in revenue requirement.
c. Please provide the monthly margin net interest expenses over the period January 1, 2020, through June 30, 2024.
d. Do any of PGE's counterparties maintain margin funds payable to PGE? If yes, please identify all interest earned with respect to such margin funds held by counterparties over the period January 1, 2020, through June 30, 2024.
e. Do the amounts at issue represent actual interest payments or imputed interest on the funds PGE has deposited?
f. Please provide transaction level details supporting all interest payments associated with margin funds over the period January 1, 2020, through June 30, 2024.

Response:

a. PGE objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence.
b. Confidential Attachment 177-A provides the requested information.
c. Confidential Attachment 177-B provides the requested information.
d. Yes. Confidential Attachment 177-B provides the requested information.
e. Amounts at issue represent actual interest payments received.
f. Confidential Attachment 177-B provides the requested information.

Attachments 177-A and 177-B contain protected information subject to General Protective Order No. 23-132.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 178
Dated August 21, 2024

Request:

Reference PGE/1400, Mersereau–Van Oostrum–Batzler/47:5-48:9:

a. Please identify the FERC account where the broker fees are recorded.
b. Please explain why the Broker Fee amounts are not already considered in PGE's budget for FERC Account 557.
c. Please provide details of the amount of broker fees incurred by month over the period January 1, 2020, through July 31, 2024.
d. Please provide transactional details supporting the amount of broker fees incurred over the period January 1, 2023, through December 31, 2023.

Response:

a. Broker fees are recorded in FERC account 557.
b. Broker fees are not budgeted for in FERC Account 557 because PGE includes them in GRCs as a part of A&G expense in accordance with Commission Order No. 10-410.
c. Confidential Attachment 178-A provides the requested information.
d. Confidential Attachment 178-A provides the requested information.

Attachment 178-A contains protected information subject to General Protective Order 23-132.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/303

HYBRID RATE BASE INCONSISTENCY ILLUSTRATIONS

Parameters

Depr/Mo	0.21%
RoR	7%
Conv. Fact.	0.706

Proxy Method:

	Existing Plant				Plant Addition (January 1 Proxy)						
	Gross	A/D	Net	Depr	Gross	A/D	Net	Depr	Rate Base	Depr	Rev. Req.
Jan-24	1,000	(100)	900	1.9	200	-	200	0.4	1,100	2.3	
Feb-24	1,000	(102)	898	1.9	200	(0)	200	0.4	1,098	2.3	
Mar-24	1,000	(104)	896	1.9	200	(1)	199	0.4	1,095	2.3	
Apr-24	1,000	(106)	894	1.9	200	(1)	199	0.4	1,093	2.3	
May-24	1,000	(107)	893	1.9	200	(2)	198	0.4	1,091	2.3	
Jun-24	1,000	(109)	891	1.9	200	(2)	198	0.4	1,089	2.3	
Jul-24	1,000	(111)	889	1.9	200	(2)	198	0.4	1,086	2.3	
Aug-24	1,000	(113)	887	1.8	200	(3)	197	0.4	1,084	2.3	
Sep-24	1,000	(115)	885	1.8	200	(3)	197	0.4	1,082	2.3	
Oct-24	1,000	(117)	883	1.8	200	(4)	196	0.4	1,080	2.2	
Nov-24	1,000	(119)	881	1.8	200	(4)	196	0.4	1,077	2.2	
Dec-24	1,000	(120)	880	1.8	200	(5)	195	0.4	1,075	2.2	
Y/E	1,000	(122)	878	22.2	200	(5)	195	4.9	1,073	27.2	136.4

Actual Rate Base 2024:

	Existing Plant				Plant Addition (July 1 Actual)						Annual
	Gross	A/D	Net	Depr	Gross	A/D	Net	Depr	Rate Base	Depr	Rev. Req.
Jan-24	1,000	(100)	900	1.9	0	-	-	-	900	1.9	
Feb-24	1,000	(102)	898	1.9	0	-	-	-	898	1.9	
Mar-24	1,000	(104)	896	1.9	0	-	-	-	896	1.9	
Apr-24	1,000	(106)	894	1.9	0	-	-	-	894	1.9	
May-24	1,000	(107)	893	1.9	0	-	-	-	893	1.9	
Jun-24	1,000	(109)	891	1.9	0	-	-	-	891	1.9	
Jul-24	1,000	(111)	889	1.9	200	-	200	0.4	1,089	2.3	
Aug-24	1,000	(113)	887	1.8	200	(0)	200	0.4	1,087	2.3	
Sep-24	1,000	(115)	885	1.8	200	(1)	199	0.4	1,084	2.3	
Oct-24	1,000	(117)	883	1.8	200	(1)	199	0.4	1,082	2.3	
Nov-24	1,000	(119)	881	1.8	200	(2)	198	0.4	1,080	2.2	
Dec-24	1,000	(120)	880	1.8	200	(2)	198	0.4	1,078	2.2	
Y/E	1,000	(122)	878	22.2	200	(2)	198	2.5	1,075	24.7	134.2
Delta From Proxy Method	**-**	**-**	**-**	**-**	**-**	**2**	**2**	**(2.5)**	**2**	**(2.5)**	**(2.2)**

Actual Rate Base 2025:

	Existing Plant				Plant Addition (July 1 Actual)						
	Gross	A/D	Net	Depr	Gross	A/D	Net	Depr	Rate Base	Depr	
Jan-25	1,000	(122)	878	1.8	200	(2)	198	0.4	1,075	2.2	
Feb-25	1,000	(124)	876	1.8	200	(3)	197	0.4	1,073	2.2	
Mar-25	1,000	(126)	874	1.8	200	(3)	197	0.4	1,071	2.2	
Apr-25	1,000	(128)	872	1.8	200	(4)	196	0.4	1,069	2.2	
May-25	1,000	(130)	870	1.8	200	(4)	196	0.4	1,066	2.2	
Jun-25	1,000	(131)	869	1.8	200	(5)	195	0.4	1,064	2.2	
Jul-25	1,000	(133)	867	1.8	200	(5)	195	0.4	1,062	2.2	
Aug-25	1,000	(135)	865	1.8	200	(5)	195	0.4	1,060	2.2	
Sep-25	1,000	(137)	863	1.8	200	(6)	194	0.4	1,057	2.2	
Oct-25	1,000	(139)	861	1.8	200	(6)	194	0.4	1,055	2.2	
Nov-25	1,000	(140)	860	1.8	200	(7)	193	0.4	1,053	2.2	
Dec-25	1,000	(142)	858	1.8	200	(7)	193	0.4	1,051	2.2	
Y/E	1,000	(144)	856	21.7	200	(7)	193	4.9	1,049	26.6	133.4
Delta From Proxy Method	**-**	**(22)**	**(22)**	**(0.5)**	**-**	**(2)**	**(2)**	**(0.1)**	**(24)**	**(0.6)**	**(3.1)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)

EXHIBIT AWEC/304

PGE CONFIDENTIAL RESPONSE TO AWEC DATA REQUEST 177

(REDACTED VERSION)

PROTECTED INFORMATION SUBJECT TO
GENERAL PROTECTIVE ORDER NO. 23-132

Confidential Exhibit AWEC/304 contains

Protected Information Subject to the

General Protective Order No. 23-132 in this proceeding

and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision .	)
	)

REBUTTAL TESTIMONY OF LANCE D. KAUFMAN

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

September 10, 2024

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Confidential AWEC/401 – Responses to Data Requests

AWEC/402 – Cost of Capital Articles

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS CASE?

A. Yes, I submitted Opening Testimony on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including electric service customers of Portland General Electric Company ("PGE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide testimony in response to parties on PGE's cost of service, rate spread, and rate design. I also testify on PGE's cost of capital and low income bill discount program.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

1. Maintain all recommendations made in Exhibit AWEC/200.
2. As an alternative allocation for Schedule 118 costs, allocate costs based on each schedule's share of uncollectibles.

II. COST OF SERVICE STUDY: COST OF GENERATION

a. Capacity Value of Energy Resources

Q. WHAT RECOMMENDATION DID YOU MAKE REGARDING THE CAPACITY VALUE OF ENERGY RESOURCES?

A. In my Opening Testimony I recommended removing capacity value from the cost of wind and solar resources when estimating the cost of energy. I also recommended not removing the capacity value of wind and solar from battery resources. I made this recommendation for the following reasons:

1. It is consistent with the standard marginal cost of generation methodology.[1]
2. PGE's model is flawed because modeling energy resources with high effective load carrying capability ("ELCC"), such as hydro, hybrid solar and battery, hybrid wind and battery, and geothermal resources, results in a finding that capacity costs are zero.
3. PGE's model mismatches the cost of capacity with the amount of capacity served.[2]

Q. HOW DID PGE RESPOND TO YOUR CLAIM THAT PGE'S MODEL IS ILLOGICAL BECAUSE IT CAN RESULT IN ZERO CAPACITY COSTS?

A. PGE agreed that when high ELCC resources are modeled under its methodology, it results in estimating capacity costs to be zero.[3] PGE also admits that under such a scenario PGE's model would not apply.[4]

Q. WHY IS PGE'S MODEL INAPPLICABLE WHEN MODELING RESOURCES WITH HIGH ELCC?

A. Resources with higher ELCC are more costly than resources with low ELCC. For example, hybrid solar and wind are more expensive than standalone solar and wind. From a resource cost perspective, then, it is clearly absurd to argue that capacity costs are zero. Market outcomes also indicate that capacity costs are greater than energy costs. This is because hourly market prices during high load periods, such as summer heat waves or winter cold snaps, are greater than average energy prices. If capacity costs were not material, hourly market prices would be relatively flat across all hours in the year.

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1 AWEC/200 Kaufman/11:7-10.
2 *Id.* at 10-11.
3 PGE / 1900 Macfarlane-Manley/5:9-11.
4 *Id.*

Q. HOW DID PGE RESPOND TO YOUR ARGUMENT THAT PGE'S COST OF CAPACITY IS MISMATCHED TO THE QUANTITY OF CAPACITY BEING SERVED?

A. In my Opening Testimony, I argued that PGE's model only identifies the cost of serving a share of capacity:

> For example, a 1 kW wind resource with 30 percent ELCC would leave 0.7 kW of capacity that needs to be served by the battery, thus the cost of the battery is scaled down from 1 kW to 0.7 kW. However, PGE fails to account for the fact that the smaller battery resource is now serving a smaller demand. As a result, PGE's model does not measure the cost of serving 1 kW of capacity, but rather the cost of serving 0.7 kW of capacity.[5]

PGE responds that, under this example, while the battery is only serving 0.7 kW of capacity, the proxy energy resource is serving the remaining 0.3 kW of capacity.[6] The problem with this approach is that PGE assumes the 0.3 kW of capacity is provided at no cost. PGE appears to make this assumption because "PGE still needs to procure the same amount of renewable energy regardless of the capacity contribution of the resource."[7] This logic is flawed, however, because there are many different types of energy resources, and PGE has modeled high cost energy resources that provide resource diversity and capacity, rather than low cost energy resources with little capacity value. For example, PGE does not adopt my recommendation to use Gorge Wind, which was selected in the 2023 IRP and avoids costly transmission.[8]

Q. WHY DOES PGE FAVOR MONTANA WIND OVER GORGE WIND?

A. PGE asserts that Montana wind should be modeled to reflect resources with less correlation with existing resources to boost capacity benefits.[9]

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5 AWEC/200, Kaufman /10:14-11:3.
6 PGE/1900 Macfarlane-Manley/6:13-15.
7 *Id.* at 6:18-19.
8 AWEC/200 Kaufman/14:9-16.
9 PGE/1900 Macfarlane-Manley/10:8-11.

Q. IF PGE IS MODELING MORE EXPENSIVE RESOURCES IN ORDER TO BOOST CAPACITY BENEFITS, IS IT REASONABLE TO ASSUME THAT THESE CAPACITY BENEFITS HAVE ZERO COST?

A. No, this is not reasonable. A more appropriate approach is to acknowledge that a portion of the energy resources' costs are attributable to capacity needs, as done in AWEC's model.

Q. HOW DOES PGE RESPOND TO YOUR ARGUMENT THAT PGE SHOULD IMPLEMENT ITS HISTORICAL TREATMENT OF CAPACITY COSTS?

A. PGE responds that PGE's historical model used a Combined Cycle Combustion Turbine ("CCCT") as the energy resource, which provides 100 percent of energy and capacity needs.[10] PGE notes that past generation cost models divide the cost of the energy resource between energy and capacity using a proxy capacity resource. PGE does not explain why this approach is inapplicable when the energy resource provides less than 100 percent of energy and capacity needs.[11]

Q. IS IT REASONABLE TO APPLY PGE'S HISTORICAL MODEL WHEN ENERGY RESOURCES DO NOT SERVE 100 PERCENT OF CAPACITY NEEDS?

A. Yes. This can be illustrated by considering incremental changes from resources that serve 100 percent of energy needs. Consider the appropriate treatment of an energy resource that serves 99 percent of capacity needs and 100 percent of energy needs. It is inappropriate to argue that 100 percent of the cost of this resource is an energy cost, simply because additional resources must be acquired to serve the remaining 1 percent of capacity. If PGE's new model is applied to an energy resource serving 99 percent of capacity needs, none of the cost of the energy resource would be attributed to serving capacity, despite the fact that the resource serves nearly all capacity needs. Furthermore, PGE's new model would find that only 1 percent of needs

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[10] *Id.* at 7:10-16.

[11] *Id.* at 7- 8.

must be served by the capacity resource (i.e. the 4-hour storage resource), and thus would find capacity costs to be negligible. However, the appropriate approach is to allocate the cost of the energy resource between energy and capacity while accounting for the reduced capacity value, while also accounting for the fact that additional resources are needed to serve the remaining 1 percent of capacity needs. This is the method I applied in my Opening Testimony. Therefore, if PGE's historical method is appropriate for an energy resource with 100 percent capacity service, it is also appropriate for an energy resource with 99 percent capacity service. Through inductive logic, it is therefore appropriate to apply the historical marginal cost method when evaluating energy resources with any level of capacity service.

b. Resource ELCC

Q. WHAT ELCC RECOMMENDATIONS DID YOU MAKE IN OPENING TESTIMONY?

A. I recommended that tuned ELCC under firm transmission be used for all resources in the marginal cost study.

Q. WHAT WAS PGE'S RESPONSE TO THIS RECOMMENDATION?

A. PGE did not provide a clear response. PGE argued that it is appropriate to use conditional firm transmission despite modeling owned transmission costs because incremental resources may still use BPA's transmission system, and thus there is an unquantified risk that PGE uses conditional firm rather than firm transmission from BPA. However, PGE does not explicitly oppose AWEC's proposal and agrees to modeling tuned ELCC and firm transmission for the solar resource.

Q. IS CONDITIONAL FIRM TRANSMISSION THE DEFAULT ASSUMPTION IN PGE'S IRP

A. No. PGE's 2023 IRP models do not use conditional firm ELCC when modeling resources that use PGE-owned transmission.[12]

Q. WHAT OTHER ELCC ISSUES DID YOU RAISE?

A. In Opening Testimony I noted that PGE's 2023 IRP pairs Wyoming wind and Nevada solar with "market access" that offers 100 percent ELCC.[13] PGE responds that 100 percent ELCC should not be used because the paired energy resources cannot provide 100 percent of capacity needs, and that PGE's models separately account for market access in the calculation of the cost of energy.[14] However, the transmission enabling Mead solar and Wyoming wind is paired with a 100 percent ELCC. Thus, PGE's model cannot procure Mead solar without also acquiring a resource with 100 percent ELCC. In addition, the costly transmission required to procure Mead solar is not economic without the associated capacity.

PGE's model, which includes the full transmission cost of accessing Mead and Wyoming energy markets, but excludes the associated capacity contributions, is absurd and represents an action that would never be functionally implemented.

Q. WHAT IS YOUR RESPONSE TO PGE'S OBSERVATION THAT ENERGY COSTS ARE INCLUDED SEPARATELY IN THE IRP MODELS?

A. PGE's observation that the cost of market energy is included in its IRP but not in its generation cost model is only relevant if market energy prices are assumed to have capacity costs embedded in them. For example, it could be reasonable to assume the difference between on-

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12 PGE declined to provide workpapers necessary to confirm this. Exhibit AWEC/401 (PGE Response to AWEC Data Request 202).

13 AWEC/200, Kaufman/15:5-8.

14 PGE/1900, Macfarlane-Manley/9:10-13.

peak market prices and off-peak market prices represent capacity value.[15] This assumption is reasonable but has an immaterial impact in the model and is inconsistent with other assumptions in PGE's model. For example, if peak prices are $100 per MWh and off-peak prices are $60 per MWh, there is a $40 per MWh premium that could reasonably be attributed to meeting capacity needs. If PGE accesses markets 100 hours per year to meet peak capacity needs, the cost would be $4 per kW-year. This is immaterial when compared to the $275 per kW-yr cost that PGE assumes for Mead transmission costs. Moreover, arbitrage opportunities enabled by Mead transmission can reasonably be assumed to fully offset these costs. To see this, suppose that PGE uses Mead transmission to capture $10 per MWh in price differences between Mead and Mid-C in 400 hours per year. This would fully offset the capacity premiums required to leverage Mead transmission into a capacity resource.

Q. DO PGE'S CONCERNS WITH APPLYING 100 PERCENT ELCC TO WYOMING AND MEAD TRANSMISSION SUPPORT YOUR PRIMARY RECOMMENDATION?

A. Yes, my primary recommendation was to model local energy resources. This avoids disputes regarding both transmission-related ELCC and estimated transmission costs and reduces the potential impact of capacity contribution of energy resources because local energy resources have lower capacity contributions.

Q. HOW DID PGE RESPOND TO YOUR CONCERNS REGARDING TRANSMISSION COSTS?

A. In my Opening Testimony I noted that PGE was using Wyoming transmission costs when paired with Montana wind. PGE uses parameters for Clearwater wind for wind costs in its generation cost model but uses IRP cost for Wyoming market access rather than Clearwater

[15] This may be a bit more complicated when considering accessing markets outside of PGE's native load. For example, because PGE's peak occurs in winter and Mead's peak prices occur in summer, there may not be a capacity premium in the hours that contribute to PGE's capacity needs.

transmission costs.[16] PGE responded that it cannot procure additional transmission at the rates used for Clearwater because there is no additional transmission currently available.[17] This appears to ignore the fact that PGE will soon stop transmitting energy from Colstrip. It also lends further support for my recommendation to model local wind resources.

Q. IS PGE'S ESTIMATE OF WYOMING TRANSMISSION COSTS ACCURATE?

A. No. PGE's estimate appears to be a very high-level estimate and uses the same cost per MW-mile parameters for 23 different transmission projects.[18] It is more reasonable to use actual transmission costs than these high-level estimates.

c. <u>Mid-C Prices and Purchases</u>

Q. WHAT OUTSTANDING ISSUE DO YOU HAVE REGARDING MARKET PURCHASES IN THE GENERATION COST MODEL?

A. PGE uses inflated market prices when determining energy costs. PGE's model has two critical errors. First, PGE's cost model uses prices inconsistent with the model used to quantify market purchases. Second, PGE's cost model uses Mid-C prices during high-priced hours, which arguably reflect capacity constraints. Third, PGE's marginal cost model escalates 2025 costs at the inflation rate, while PGE's forward price curve shows Mid-C market prices are expected to decrease substantially over time.

Q. HOW DOES PGE RESPOND TO YOUR CONCERN THAT PRICES ARE INCONSISTENT BETWEEN PGE'S IRP MODELS AND MARGINAL COST MODEL?

A. PGE states that prices do not affect market quantities.[19]

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16 AWEC/200, Kaufman/14:17-15:3.

17 PGE/1900, Macfarlane-Manley/11:2-3.

18 Costs are based on a generic cost per mile multiplied by number of miles on the path. *See* AWEC/401 (UE 435_AWEC DR 090_Attach A_CONF.xlsx "Input" rows 156 and 157).

19 PGE/1900, Macfarlane-Manley/11:17-19.

Q. IS IT REASONABLE TO ASSUME THAT MARKET PRICES DON'T AFFECT MARKET PURCHASES?

A. No. It is highly dubious to assume that market prices don't affect market purchases, particularly in a paradigm of resource planning, where resources are acquired and dispatched in a least-cost manner. If PGE's market purchase estimates are so seriously flawed, they should be excluded entirely from PGE's cost-of-service model. However, given the depth and skill of PGE's workforce, it seems more likely that market purchases are impacted by market prices, but that the impact exists outside the greenhouse gas ("GHG") model. For example, Aurora results appear to be an input to the GHG model, and it may be that resource dispatch, market prices, and market purchases are jointly established in the Aurora model prior to being inputted to the GHG model.

Q. HOW DOES PGE RESPOND TO YOUR CONCERN THAT THE MID-C PRICES USED IN THE MARGINAL COST MODEL REFLECT CAPACITY VALUE RATHER THAN ENERGY VALUE?

A. PGE does not dispute that PGE's prices reflect capacity costs. Instead, PGE asserts that PGE's method reflects a more accurate cost of market purchases. However, PGE provides no direct evidence supporting this assertion and PGE declined to provide IRP workpapers necessary to support PGE's assertion.[20] Regardless of whether PGE's method accurately estimates the cost of purchased energy, it does not address AWEC's primary concern, which is that the estimate reflects capacity costs rather than energy costs. Thus, AWEC's approach of using flat energy prices is more appropriate when estimating energy costs.

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[20] AWEC/401 (PGE Resp. to AWEC DR 202).

Q. HOW DOES PGE RESPOND TO YOUR CONCERN THAT PGE ESCALATES MARKET PRICES USING INFLATION RATHER THAN PGE'S FORWARD PRICE CURVE?

A. PGE did not address this issue.

Q. DO YOU CONTINUE TO RECOMMEND USING THE GHG FLAT MID-C PRICE FORECAST?

A. Yes.

d. Flexibility Value of Storage

Q. WHAT ISSUE DID YOU RAISE REGARDING FLEXIBILITY VALUE?

A. I noted that PGE's flexibility study determined that flexibility value is highly correlated with capacity needs and recommended that capacity costs not be reduced by flexibility value.[21]

Q. WHAT WAS PGE'S RESPONSE TO THIS ISSUE?

A. PGE responded by noting that "flexibility value 'represents a benefit value stream that fast-acting dispatchable resources … should receive for addressing flexibility adequacy'" rather than capacity needs.[22]

Q. DID PGE ADDRESS YOUR OBSERVATION THAT FLEXIBILITY VALUE IS CORRELATED WITH CAPACITY NEEDS?

A. No.

Q. DID PGE'S HISTORIC COST OF GENERATION MODEL, WHICH INCLUDED FAST-ACTING DISPATCHABLE SIMPLE-CYCLE COMBUSTION TURBINES ("SCCTS") RATHER THAN BATTERY STORAGE FOR THE PROXY CAPACITY RESOURCE, ADJUST CAPACITY COST FOR FLEXIBILITY VALUE?

A. No.

[21] AWEC/200 Kaufman/20-21.

[22] PGE/1900, Macfarlane–Manley/12:19-21.

Q. HOW DID PGE MEASURE FLEXIBILITY VALUE?

A. PGE measured flexibility value by comparing simulations of PGE's system costs under two scenarios, one where capacity needs are served with an expensive day ahead on-peak block of market purchases, and a second scenario where 100 MW of this capacity is replaced by a storage resource.[23] PGE evaluated flexibility in 2026 and 2030, finding a flexibility value of $9.77 and $18.75 per kW-year respectively. However, PGE also notes that flexibility value declines with each additional resource addition, meaning that the second 100 MW of batteries has lower flexibility value than the first 100 MW. The numeric values that PGE arrived at rest on two critical assumptions: how "expensive" day ahead market capacity resources are, and the amount of 4-hour battery capacity added to PGE's system. This makes the flexibility value highly speculative.

Q. WHAT DOES THE FLEXIBILITY VALUE REPRESENT?

A. The flexibility value represents savings associated with avoiding the use of an "expensive day ahead on-peak capacity product."[24]

Q. DOES PGE'S GENERATION COST MODEL INCLUDE THE COST OF A DAY AHEAD CAPACITY PRODUCT?

A. No, these costs are not included in PGE's cost model. Thus, the alleged flexibility value stream does not need to be removed from PGE's generation cost model.

Q. WHAT IS THE RESULT OF REMOVING THESE NON-EXISTENT COSTS?

A. The result is a less than 100 percent allocation of costs. Because the alleged flexibility value does not actually correspond to a real reduction in generation costs, PGE effectively splits the

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23 Blue Marble Analytics, Flexibility Studies, at 3 and 13 (Nov 2022) available at: https://www.google.com/url?sa=t&source=web&rct=j&opi=89978449&url=https://assets.ctfassets.net/416ywc1laqmd/35EOAGYH4823pDrjzURp6F/ee3b94846ab455395ea6171c3f036329/PGE_Flexibility_Studies_.pdf

24 *Id.*

cost of generation into three components, capacity, energy, and flexibility. The flexibility component is then discarded because it is not used in allocating generation revenue requirement.

Q. CAN YOU CLARIFY WHY YOU DISMISS FLEXIBILITY COSTS AFTER OBSERVING THAT FLEXIBILITY AND CAPACITY COSTS ARE CORRELATED?

A. As I mentioned above, when flexibility costs are removed from capacity, the generation cost model does not estimate 100 percent of generation costs because the flexibility value is not actually a realized cash benefit. This means that, to achieve an allocation of 100 percent of the marginal cost of generation, the flexibility costs should be allocated in addition to capacity and energy costs. PGE's flexibility study found that flexibility needs are concentrated in winter evening hours and summer net load peak hours. This means that if flexibility costs are allocated, a 4-coincident peak allocation is appropriate. However, capacity costs are also allocated using a 4-coincident peak allocator. Thus, the separation of these costs is irrelevant in the final allocation of generation costs.

e. <u>Marginal Cost of Generation Summary</u>

Q. HAS PGE'S REPLY AFFECTED YOUR RECOMMENDATIONS REGARDING MARGINAL COST OF GENERATION?

A. No, I continue to support the recommendations presented in my Opening testimony.

III. RATE SPREAD AND RATE DESIGN

Q. WHAT RATE SPREAD RECOMMENDATION DID YOU MAKE IN OPENING TESTIMONY?

A. In Opening Testimony I recommended not implementing PGE's proposed Customer Impact Offset ("CIO") adjustments. However, this recommendation was worded to highlight adjustments to Schedules 15, 91, and 95, which were reported in PGE's description of deviations from the marginal cost study.[25]

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION?

A. PGE noted that the Schedule 90 CIO impacts are not driven by the Schedule 15, 91, and 95 CIO adjustment.[26] PGE does not dispute AWEC's assertion that PGE's rate design objectives can be implemented without the use of a CIO.

Q. DID PARTIES PROPOSE RATE CAPS AND FLOORS?

A. Yes. In reply testimony PGE clarified that it implemented a 1.5 times average rate cap and allocated the capped revenue requirement to Schedule 90.[27] Staff proposed a cap of 125 percent of average increase and a floor of 89.4 percent of average increase for non-residential customers.[28] Outside of Staff's rate spread testimony, Staff also proposed an overall limit on residential customers base rate revenue changes to 3 percent.[29]

Q. HOW DO YOU RESPOND TO THESE RECOMMENDATIONS?

A. PGE has not demonstrated a material need for a revenue requirement increase. In fact, AWEC recommended a revenue requirement decrease of 1.6 percent.[30] Given the limited overall revenue change necessary for PGE, there is no need to mitigate rate changes through caps and floors. AWEC clarifies that its initial recommendation was to institute no deviations from the cost of service model other than the transfers between Schedule 89 and 90 related to billing diversity. I continue to support this recommendation.[31]

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25 PGE/900, Macfarlane–Pleasant/14:15-15:2.
26 PGE/2000, Macfarlane-Pleasant/21:1-5.
27 *Id*. at 19:13-18.
28 Staff/900, Stevens/13:13-16.
29 Staff/200, Scala/6 at 13-15.
30 AWEC/100 Mullins/3, Table 1.
31 AWEC/200 Kaufman/28:4-29:19.

IV. SCHEDULE 90 LOAD FOLLOWING CREDIT

Q. WHAT ISSUE DOES STAFF RAISE REGARDING THE LOAD FOLLOWING CREDIT?

A. PGE's filed case includes an update to the load following credit to reflect PGE's most recent study of flexibility value. Staff recommends not updating the credit.[32]

Q. HOW DOES PGE RESPOND TO STAFF'S RECOMMENDATION?

A. PGE states that it is imperative to update the load following credit because it is more than 6 years out of date and does not reflect the realities of PGE's statutory obligations to reduce carbon emissions.[33]

Q. WHAT IS AWEC'S POSITION ON THE LOAD FOLLOWING CREDIT?

A. AWEC supports PGE's update to the load following credit. I discuss flexibility value in my testimony above regarding generation costs. Under both my proposed generation cost study and PGE's proposed generation cost study a substantial share of load following costs are allocated to Schedule 90. My cost model allocates load following costs based on demand because there is a high correlation between flexibility needs and peak demand. However, Schedule 90 customers with flat load have material load during peak demand, but do not cause load following costs in these hours due to their load shape.[34] Thus it is appropriate to apply the updated load following credit under either PGE or AWEC's generation cost model.

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32 Staff/900, Stevens/13:4-6.

33 PGE/2000, Macfarlane-Pleasant/17:10-16.

34 *Id.* at 18:2-5.

V. SCHEDULE 90 TIME OF USE RATES

Q. WHAT RECOMMENDATION DOES STAFF MAKE REGARDING TIME OF USE RATES?

A. Staff recommends that PGE offer time of use ("TOU") rates for Schedule 90.[35]

Q. DOES AWEC AGREE WITH STAFF'S RECOMMENDATION?

A. No. AWEC generally agrees with PGE that incentivizing Schedule 90 customers to maintain a flat load is preferrable to introducing a TOU rate.[36] In addition, it is not clear from the evidence that Schedule 90 customers have processes that would allow them to take advantage of a TOU rate. Moreover, there is no specific TOU design proposal for AWEC to comment on. Thus, AWEC cannot evaluate the validity of Staff's recommendation. To the extent that the Commission is interested in exploring a TOU rate, it should not be implemented until after AWEC has had the opportunity to review, analyze, and comment on the specific rate design, and after more is understood about the processes of Schedule 90 customers and their suitability for a TOU rate.

VI. INCOME-QUALIFIED BILL DISCOUNT ("IQBD") PROGRAM

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FROM YOUR OPENING TESTIMONY WITH RESPECT TO THE IQBD PROGRAM.

A. I made three recommendations in my Opening Testimony. First, I recommended that the existing 20 million kWh cap, if retained, be applied to Schedule 90 on a per-customer basis rather than a per-site basis. Second, I recommended that costs of the IQBD program be recovered based on revenue rather than as a kWh charge, similar to how the public purpose

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35 Staff/1700, Dlouhy/47:1-2.

36 *See* PGE/2000, Macfarlane-Pleasant/13:22-14:2.

charge and taxes are collected from customers. Third, I recommended that PGE implement a pre-enrollment verification process for IQBD program participants.

Q. WAS PGE SUPPORTIVE OF YOUR RECOMMENDATIONS?

A. No. With respect to the proposal to apply the 20 million kWh cap to Schedule 90 as a per-customer cap, PGE argued that implementing this recommendation would be administratively burdensome.[37] With respect to a revenue-based allocation, PGE noted that this would reduce the amount paid by direct access customers and the amount paid by large cost-of-service customers.[38] PGE also claims that my recommendations would have the potential for "significant cost shifting."[39] Finally, with respect to pre-enrollment verification, PGE asserted that the cost of administering a pre-enrollment process would outweigh the savings from preventing ineligible customers from receiving benefits.[40]

Q. DO PGE'S CONCERNS WITH A PER-CUSTOMER CAP HAVE MERIT?

A. No. In responding to my proposal to apply the current 20 million kWh cap to Schedule 90 on a per-customer basis, PGE appears to have misinterpreted my recommendation to apply to all rate schedules rather than just Schedule 90. Nevertheless, in discovery, PGE asserted that even applying a per-customer cap only to Schedule 90 would be "administratively burdensome."[41] In discovery in PGE's last general rate case, however, PGE admitted that it could customize its billing system to implement a per-customer cap and that doing so strictly for Schedule 90 would be "more straightforward to maintain."[42] Thus, PGE's complaints that implementing

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37 PGE/1200, Sheeran-Wise/15:1-9.
38 *Id.* at 15:12-17.
39 *Id.* at 6:1-2.
40 *Id.* at 13:13-19.
41 AWEC/401 (PGE Resp. to AWEC DR 184).
42 AWEC/205, Kaufman/20.

my proposal would be "administratively burdensome" lack any context and appear merely to assert that doing so would require some incremental work. This is not a sufficient justification to reject a proposal that the Commission itself found could be "reasonable and well-taken."[43]

Q. DOES PGE HAVE SYSTEMS IN PLACE TO MANAGE THE BURDEN ASSOCIATED WITH BILLING LARGE CUSTOMERS?

A. Yes. PGE's Key Customer Managers implement billing solutions for PGE's largest customers.[44] It is unreasonable for PGE to argue for administrative burden when the proposal will only affect a handful of customers, and these customers already have dedicated billing managers.

Q. DO PGE'S CONCERNS WITH A REVENUE-BASED ALLOCATION HAVE MERIT?

A. No. PGE's concern that direct access customers would pay less than they currently do under a revenue-based allocation is easily remedied. In the context of other programs furthering a public policy goal, like the Community Solar Program, the Commission has authorized rate recovery in a manner that treats direct access customers as if they were cost-of-service customers so that they pay an equivalent amount to cost-of-service customers.[45] AWEC would not oppose similar treatment of direct access in the context of the IQBD program. Under this treatment, the per-kWh rate for direct access customers would be equal to the rate of the corresponding bundled service schedule.

Q. WOULD A REVENUE-BASED ALLOCATION RESULT IN "SIGNIFICANT COST SHIFTING" AS PGE CLAIMS?

A. No. Again, PGE's statement is devoid of any context that would explain what it means by "significant cost shifting." A foundational point is that the IQBD program as a whole will shift

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43 Docket No. UE 416, Order No. 23-476 at 10 (Dec. 18, 2023)

44 PGE/1500 McFarland-Lawrence/14:16-15:2.

45 *See*, PGE Schedule 137.

$54 million from one subset of customers to all other customers in 2025 and, thus, itself results in cost shifting.[46] That this cost shifting is "significant" is demonstrated by PGE's IQBD workpaper, which shows Schedule 89 Primary customers paying over $11,000 per month for this program, equivalent to a 2.8% rate impact, and Schedule 90 paying over $54,000 per month. By contrast, moving to a revenue-based model would increase residential customer payments by 0.4%, or $0.60 per month. Small commercial customers would also see a 0.4% rate increase, or $0.82 per month. Especially as compared to the IQBD program's current cost shifting, the payment allocation of a revenue-based model is not "significant."

Q. HOW DOES AWEC'S REVENUE ALLOCATION PROPOSAL DIFFER FROM STAFF'S PERCENT OF BILL PROPOSAL?

A. AWEC's revenue allocation proposal allocates costs based on revenue, but continues to charge customers based on kWh, and continues to apply the monthly kWh cap ultimately approved by the Commission. AWEC's allocation and rate calculation is illustrated in the table below.

[46] PGE/1200, Sheeran-Wise/12:2-3.

Table 1: Schedule 118 Rate Spread

Rate Schedule	Rate Schedule	$ Millions	% of Revs	MWh	Rate ($/MWh)	MWh Subject to Sch 118	Capped Revenue
Residential	7	$ 29.2	1.8%	7,889,185	$ 3.701	7,889,185	$ 29.20
Outdoor Area Lighting	15	$ 0.1	1.8%	13,091	$ 6.116	13,091	$ 0.08
General Service <30 kW	32	$ 5.5	1.8%	1,550,351	$ 3.539	1,550,351	$ 5.49
Opt. Time-of-Day G.S. >30 kW	38	$ 0.1	1.8%	27,036	$ 3.773	27,036	$ 0.10
Irrig. & Drain Pump. < 30 kW	47	$ 0.1	1.8%	20,557	$ 5.117	20,557	$ 0.11
Irrig. & Drain Pump. > 30 kW	49	$ 0.3	1.8%	59,354	$ 4.461	59,354	$ 0.26
General Service 31-200 kW	83	$ 7.8	1.8%	2,867,544	$ 2.709	2,867,544	$ 7.77
General Service 201-4,000 kW							
Secondary	85-S	$ 4.6	1.8%	2,074,490	$ 2.216	2,074,490	$ 4.60
Primary	85-P	$ 1.3	1.8%	673,719	$ 1.919	673,719	$ 1.29
Schedule 89 > 4 MW							
Primary	89-P	$ 1.8	1.8%	1,024,681	$ 1.708	1,024,681	$ 1.75
Subtransmission	89-T/75-T	$ 0.1	1.8%	32,594	$ 2.025	32,594	$ 0.07
Schedule 90	90-P	$ 5.6	1.8%	3,685,313	$ 1.507	1,200,000	$ 1.81
Street & Highway Lighting	91/95	$ 0.3	1.8%	37,437	$ 6.781	37,437	$ 0.25
Traffic Signals	92	$ 0.0	1.8%	2,724	$ 1.936	2,724	$ 0.01
Direct Access 201-4,000 kW							
Secondary	485-S	$ 0.2	1.8%	433,088	$ 0.568	433,088	$ 0.25
Primary	485-P	$ 0.1	1.8%	304,716	$ 0.478	304,716	$ 0.15
Direct Access > 4 MW							
Primary	489-P	$ 0.2	1.8%	1,096,147	$ 0.204	1,096,147	$ 0.22
Subtransmission	489-T	$ 0.1	1.8%	249,687	$ 0.206	249,687	$ 0.05
New Load Direct Access > 10MW							
Primary	689-P	$ 0.1	1.8%	256,336	$ 0.220	256,336	$ 0.06
	Total	$ 57.2	1.8%	22,298,051		19,812,738	$ 53.5

Q. IS THERE AN ECONOMIC JUSTIFICATION FOR REDUCING THE COST OF THE IQBD PROGRAM FOR LARGE CUSTOMERS?

A. Yes. The Commission is primarily an economic regulator.[47] While there may be a number of policy rationales for providing discounts to low-income customers, an economic rationale for doing so is that it may reduce arrearages that PGE needs to write-off as uncollectible. Uncollectibles are recovered from customers and allocated to customer classes through the distribution function, which means that large customers pay proportionately less of this cost

47 *See* ORS 756.040.

than small customers.[48] This makes sense because uncollectible costs are predominately caused by residential and small commercial customers. Cost allocation for the IQBD program, however, is based on energy consumption and, thus, turns cost recovery on its head. In other words, costs incurred through the IQBD program are paid in greater proportion by large customers in part to reduce uncollectible costs borne primarily by small customers. This is a cost shift from small customers to large customers, which can be alleviated by reducing the amount large customers pay for IQBD costs.

Q. DOES THIS ANALYSIS SUGGEST AN ALTERNATIVE ALLOCATION FOR IQBD COSTS?

A. Yes. A reasonable allocation of IQBD costs would be to treat them similarly to uncollectible costs and assign them to the consumer function. AWEC would support this option as an alternative to its other recommendations.

Q. ARE PGE'S ARGUMENTS AGAINST PRE-ENROLLMENT VERIFICATION VALID?

A. Possibly, but not based on the evidence presented. PGE states that it "evaluated this option" and determined that the cost of pre-enrollment would be exceed the savings from barring ineligible participants.[49] However, PGE's "evaluat[ion]" of this option consisted solely of informal inquiries to the Community Action Partnership of Oregon, which provided estimates of evaluation costs.[50] It is unclear how these estimates were developed and, thus, it is difficult to assess whether they are accurate.

48 PGE/200, Batzler-Ferchland/34:15-16.
49 PGE/1200, Sheeran-Wise/13:15-19.
50 AWEC/401 (PGE Resp. to AWEC DR 183).

Q. DO YOU MAINTAIN YOUR RECOMMENDATION FOR PGE TO IMPLEMENT PRE-ENROLLMENT VERIFICATION?

A. Based on PGE's testimony, AWEC is willing to forgo its recommendation to institute pre-enrollment verification in this case. However, as the evaluation of PGE's IQBD program continues, PGE should perform a more thorough and evidence-based evaluation of the costs and benefits of a pre-enrollment verification process and should institute pre-enrollment verification if that evaluation demonstrates that it would reduce costs for non-participating customers.

Q. DOES PGE SUPPORT THE RECOMMENDATIONS OF OTHER PARTIES TO INCREASE THE DISCOUNTS PROVIDED BY THE IQBD PROGRAM?

A. Not exactly, although it does not necessarily oppose them either.[51] PGE instead recommends reviewing discount levels within the Energy Burden Assessment process and subsequent to a filing PGE intends to make this month.[52] However, PGE points out that party recommendations to increase the level of discounts could raise the overall cost of the IQBD program to between \$77 million and over \$100 million.[53]

Q. IS THIS LEVEL OF COST FOR THE IQBD PROGRAM REASONABLE?

A. No. This level of cost is excessive and would result in some customer classes, including Schedule 89, paying over 5% of their bill for this program. As PGE notes, there are also additional public policy programs that assist low-income customers, including the public purpose charge and Schedule 115.[54] The IQBD costs are incremental to these other programs, and so the total cost customers would pay for low-income assistance is even higher. As

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51 PGE/1200, Sheeran-Wise/11:9-12:19.
52 *Id.* at 12: 17-19.
53 *Id.* at 12: 10-14.
54 *Id.* at 12:2-7.

AWEC testified in PacifiCorp's ongoing general rate case, given the continued push to expand programs like the IQBD program, AWEC believes it is time for the Commission to issue policy guidance on what constitutes a reasonable cost for these programs given then need to balance their public policy objectives with the cost they impose on other customers.[55]

VII. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES PGE REQUEST?

A. PGE requests a capital structure with 50 percent debt and 50 percent common equity.[56]

Q. WHAT CONCERNS DO YOU HAVE WITH PGE'S REQUESTED CAPITAL STRUCTURE?

A. PGE is requesting a hypothetical capital structure that is unlikely to occur during the test year. PGE's actual equity ratio has been substantially below 50 percent since 2020.[57] While I agree that a 50 percent equity ratio is an appropriate target for PGE, I disagree that it is appropriate to use this ratio when PGE has consistently fallen below this target and has not plan to achieve the target equity ratio during the rate year.[58] In fact, PGE's five year capital plan shows PGE's equity ratio will be [redacted][59]

Confidential Table 2: PGE 5-year Capital Plan

[redacted]

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55 Docket No. UE 433, AWEC/400, Kaufman/39:1-19.
56 PGE/600 Figueroa-Liddle/2, Table 1.
57 AWEC/200, Kaufman/35.
58 PGE response to AWEC Data Request 188.
59 PGE Response to Staff DR 4 Confidential Attachment.

Combined with PGE's historic performance this indicates at least 9 years of actual or forecasted equity below the target ratio of 50 percent.

Q. HAS PGE EXPLAINED WHY IT IS FALLING SHORT OF IT'S TARGET CAPITAL RATIO?

A. No, PGE has not explained why it is planning to remain below its target capital structure in the long term.[60]

Q. WHAT MECHANISM DOES PGE USE TO RAISE EQUITY?

A. PGE issues stock to raise equity.

Q. WHY HAS PGE NOT ISSUED STOCK TO ACHIEVE IT'S TARGET EQUITY RATIO?

A. PGE's finance and investment plan focuses on the [redacted] when issuing equity.[61] For example, PGE has considered a self-imposed share price floor of 13 times price to earnings ratio. This floor would limit the amount of equity would consider issuing because issuing stock can lower share price. A lower share price negatively affects PGE's board because board members typically hold PGE stock and are elected by shareholders.

Q. TABLE 2 ABOVE INDICATES THAT PGE'S EQUITY RATIO WILL TEMPORARILY APPROACH [redacted] PERCENT IN 2026. IS THIS A RELIABLE FORECAST?

A. No. PGE's recent equity forecasts have failed to be realized. In 2021, PGE forecasted 2022 capital structure to be [redacted] percent in every quarter,[62] and a [redacted] percent equity ratio every year from 2021 to 2025.[63] In 2023 PGE forecasted a [redacted] percent equity ratio in every year from

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60 AWEC/401 (PGE Response to AWEC DR 190). PGE may have misinterpreted this request to explain the difference between average capital structure and SEC capital structure rather than a request to explain why PGE is not meeting capital structure targets.

61 AWEC/401 (PGE's Response to AWEC DR 189 Attachment A - CONF at 4, 5, and 8).

62 AWEC/401 (PGE's Response to AWEC DR 187 Confidential Attachment UE 394_OPUC SDR 004_Attach A_CONF.xlsx, tab "RROE").

63 AWEC/401 (PGE's Response to AWEC DR 187 Confidential Attachment UE 394_OPUC SDR 006_Attach A_CONF.xlsx, tab "RROE").

2023 to 2027.[64] However, PGE's actual equity ratio has fallen short of forecasted in 2021, 2022, 2023, and 2024. Based on this evidence there is little reason to believe that PGE's 2026 forecast will be achieved. Even if it is achieved, PGE expects the equity ratio to decline in 2027 and 2028.

Q. HOW DID PGE RESPOND TO YOUR ANALYSIS OF YEAR-END EQUITY RATIOS?

A. PGE noted that average equity ratio tends to differ from year-end equity ratios.

Q. HOW DO YOU RESPOND TO PGE'S OBSERVATION?

A. It is reasonable to set PGE's authorized equity ratio to an annual average rather than year-end average, particularly if there is strong seasonality in historic equity ratios. I requested data underlying PGE's annual average calculations but did not receive granularity sufficient to confirm that there is a seasonal pattern in PGE's equity ratio, however I acknowledge that it is possible. PGE's 2023 annual average equity ratio was 47.4 percent.[65] PGE also forecasts the 2025 equity ratio to be 47%. If PGE can demonstrate in surrebuttal testimony that it is making material progress towards the 2025 forecast, AWEC supports a capital structure of 47 percent. However, absent such a showing, and a demonstration of historic seasonality in monthly or quarterly capital structure, AWEC maintains the capital structure recommended in Opening Testimony, with 44.6 percent common equity and 55.4 percent debt.

VIII. RETURN ON EQUITY

Q. WHAT RETURN ON EQUITY DID INTERVENORS RECOMMEND?

A. AWEC recommended an ROE of 9.25 percent. Citizens Utility Board ("CUB") recommended an ROE of 9.2 percent. Staff recommended an ROE in the range of 8.96 to 9.41 percent.

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[64] PGE's Response to AWEC DR 187 Confidential Attachment UE 416_OPUC SDR 004_Attach A_CONF.xlsx, tab "RROE"

[65] PGE/1800 Figueroa-Liddle/62, Table 2.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING INTERVENOR'S ROE RECOMMENDATIONS?

A. While CUB and Staff used slightly different methods to arrive at ROE, all intervenors have similar recommendations, with CUB and Staff's recommendation being close to the midpoint of Staff's range.

Q. HAS PGE CHANGED IT'S REQUESTED ROE?

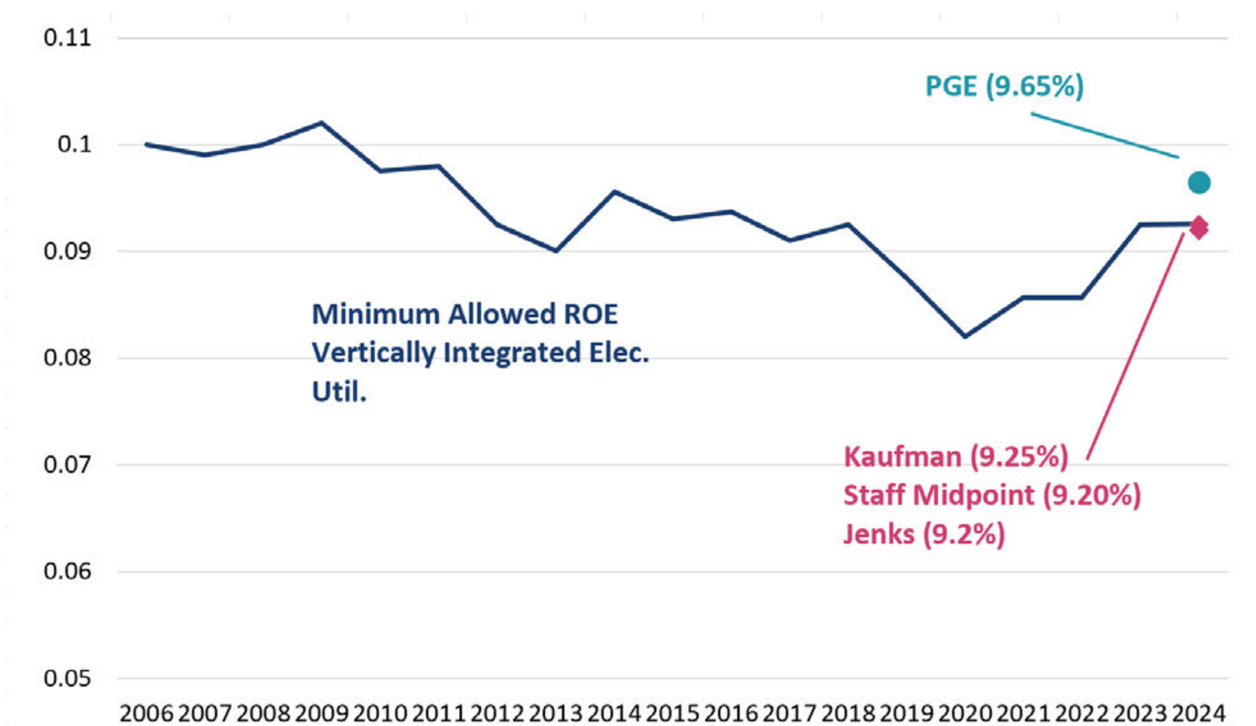
A. Yes, PGE has reduced its requested ROE from 9.75 to 9.65 percent.

Q. PGE OBSERVES THAT INTERVENORS RECOMMEND AN ROE THAT IS BELOW AVERAGE. IS THIS APPROPRIATE?

A. Yes. The Commission should authorize an ROE that is below average. Currently authorized ROEs are, in general, excessive, as illustrated by utility market to book ratios substantially exceeding 1. Furthermore, AWEC's recommendation is consistent with the lower range of ROEs authorized in other states, indicating that AWEC's recommendation is not inconsistent with other Commissions.[66]

66 Calculated from PGE/1800 workpaper Workpaper_Allowed ROEs CONFIDENTIAL.xlsx

Figure 1: Minimum Allowed ROE



Q. HOW DOES PGE RESPOND TO YOUR USE OF THE KROLL ERP?

A. PGE responds that the Kroll Equity Risk Premium ("ERP") is inconsistent with an alleged inverse relationship between the ERP and interest rates, by comparing average historical ERP and historical interest rates.[67]

Q. IS PGE'S ANALYSIS CORRECT?

A. No. PGE's analysis assumes that there is a fixed linear relationship between interest rates and ERP, and that this relationship has remained unchanged from 1926 to present. This assumption is unfounded. While interest rates may play a role in the ERP, it is not the sole determinant, and there is no reason to expect that all other determinants of the ERP have held constant over this period.

[67] PGE/1800, Figueroa-Liddle/46.

Q. WHAT OTHER CONCERNS DID PGE RAISE WITH YOUR ERP RECOMMENDATIONS?

A. PGE argues that most of my MRP estimates are results of survey data and argues that no weight be placed on survey data.[68] However, the research that PGE relies on to make this assertion presents a symposium of experts on the equity risk premium and finds that the consensus of experts is that the equity risk premium is expected to be around 4 percent.[69] Moreover, while I present many survey results, I also include many non-survey ERP estimates, such as Kroll's recommended ERP, historical average ERP, and implied ERPs, which are derived from discounted cash flow models.

Q. DO YOU PRESENT FORWARD LOOKING ESTIMATES OF THE ERP?

A. Yes. Survey results, the Kroll ERP, default spread estimates, and the implied risk premium are all forward looking estimates of the ERP.[70]

Q. IS PGE'S CRITICISM OF THE USE OF GEOMETRIC AVERAGES WHEN MEASURING HISTORIC ERP APPROPRIATE?

A. No. PGE relies on an article by Roger G. Ibbotson to criticize my ERP estimates.[71] However, that article states that "[i]nvestors typically use the Large Company Stock geometric mean return minus the Long-Term Government Bond return as their characterization of the historical ERP, which for 1926–2010 is 4.4 percent." [72]

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[68] *Id*. at 44:13-14.

[69] Roger G. Ibbotson, "The Equity Risk Premium," published in Rethinking the Equity Risk Premium, Research Foundation of CFA Institute, December 2011, p. 8.

[70] AWEC/200 Kaufman/67, Table 25.

[71] PGE/1800, Figueroa-Liddle/44:8-45:2.

[72] Roger G. Ibbotson, "The Equity Risk Premium," published in Rethinking the Equity Risk Premium, Research Foundation of CFA Institute, December 2011, at 20.

Q. HOW DOES PGE RESPOND TO YOUR RECOMMENDED BETA ADJUSTMENT?

A. PGE argues that adjusting to the industry average is problematic because it is unknown what the industry average beta is and that I do not attempt to analyze industry beta.[73] PGE also argues that academic evidence shows the Bloom adjustment, which adjusts betas to 1, is more accurate than raw betas[74] and that industry adjusted betas do not perform significantly better than the bloom adjustment.[75]

Q. IS PGE CORRECT THAT YOU DON'T ANALYZE INDUSTRY BETA?

A. No. In my Opening Testimony I presented an analysis of historic betas for a wide selection of comparable utilities.[76] I noted that betas do not converge towards 1, and, on average, are below 0.7. I also observed that betas were relatively flat from 2022 to present. Based on this pattern, I concluded that an industry average of 0.7 is a reasonable forecast of utility industry betas in 2025.

Q. IS PGE CORRECT THAT ACADEMIC EVIDENCE DOES NOT SUPPORT ADJUSTING TO THE INDUSTRY AVERAGE?

A. No.

Q. WHAT DOES ACADEMIC EVIDENCE INDICATE REGARDING ADJUSTMENT TO THE INDUSTRY AVERAGE?

A. Krysanowski and Jalilvand (1986)[77] estimates forecast error for utility betas using six different procedures. This analysis was performed on a sample of 50 utility stocks. The results are summarized below. Of the six procedures evaluated, all except the OLS procedure involve

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73 PGE/1800, Figueroa-Liddle/40-41.

74 *Id.* at 40:5-9.

75 *Id.* at 41:1-2. PGE did not provide a full citation to support this assertion and I was unable to identify an article written by Dimson and Marsh in 1983 related to industry adjusted betas.

76 AWEC/200, Kaufman/57- 58.

77 AWEC/402. Krysanowski and Jalilvand (1986). Statistical Tests of The Accuracy Of Alternative Forecasts: Some Results For U.S. Utility Betas.

some form of adjustment related to the sample. Thus all measures reflect an adjustment to the industry average, rather than the market. This supports betas over the Bloom adjustment.

Table 3: Reproduction of Krysanowski and Jalilvand (1986) Table 2

TABLE 2

AVERAGE MEAN SQUARE ERRORS (AMSEs) AND RELATIVE RANKINGS OF THE SIX BETA PREDICTORS FOR THE SAMPLE OF UTILITIES FOR THE FIVE FORECAST HORIZONS

Beta Predictor	Forecast Horizon				
	1 Year	2 Years	3 Years	4 Years	5 Years
Panel A: Average Mean Square Errors (AMSEs)					
OLS	.08459	.12106	.09767	.07545	.06650
E(Z)	.07295	.09166	.07236	.06120	.07238
VT	.09183	.10057	.07518	.05118	.03603
NI	.09419	.10292	.07745	.05245	.03547
NII	.20748	.21536	.18850	.15441	.11605
ML	.07148	.08527	.06313	.04534	.04331
Mean Beta	.64447	.63034	.63963	.66167	.70703
Panel B: Relative Rankings Based on the AMSEs					
OLS	3	5	5	5	4
E(Z)	2	2	2	4	5
VT	4	3	3	2	2
NI	5	4	4	3	1
NII	6	6	6	6	6
ML	1	1	1	1	3

Q. HOW DOES THE ML PREDICTOR COMPARE TO YOUR PREDICTOR?

A. The table below reproduces the ML predictor:

Table 4: Reproduction of Krysanowski and Jalilvand (1986) Table 1

TABLE 1 (Continued)

Method	Calculation Procedure
	$\hat{\beta}_{kt}^{OLS}$ is the predicted (forecast) beta for firm k in period t based on the OLS procedure.
Naive I (sample average)	$\hat{\beta}_{kt}^{NI} = \hat{\beta}_{st}^{OLS}$, where $\hat{\beta}_{st}^{OLS}$ is the mean (predicted) beta for sample s in period t based on the OLS procedure.
Naive II (beta equal to one)	$\hat{\beta}_{kt}^{NII} = 1.0 \quad \forall_{k,s}$
Naive Bayesian or ML (Merrill Lynch type)	$\hat{\beta}_{kt}^{ML} = 0.5\,\hat{\beta}_{kt}^{OLS} + 0.5\,\hat{\beta}_{st}^{OLS}$, where $\hat{\beta}_{kt}^{ML}$, is the predicted (forecast) beta for firm k in period t for the Merrill Lynch-type procedure; $\hat{\beta}_{kt}^{OLS}$ is the predicted (forecast) beta for firm k in period t based on the OLS procedure; and $\hat{\beta}_{st}^{OLS}$ is the mean predicted (forecast) beta for sample s in period t based on the OLS procedure.

The ML procedure weights the firm OLS beta by 50 percent and the industry group beta by 50 percent. This is very similar to my adjustment, which weights the individual beta by 66 percent and the industry group beta by 34 percent.[78]

[78] PGE characterizes my adjustment as a highly non-standard amalgamation of two different methods (PGE/1800, Figueroa-Liddle/41:7-9. This is incorrect, as my adjustment simply applies the most accurate method used in Krysanowski and Jalilvand (1986), with slightly lower weighting on the sample average.

Q. IS PGE CORRECT THAT ACADEMIC EVIDENCE INDICATES ADJUSTING UTILITY TO 1 IS NOT SIGNIFICANTLY DIFFERENT FROM ADJUSTING TO THE INDUSTRY AVERAGE?

A. No. Gombola and Kahl (1990)[79] conclude that betas revert to an underlying mean, but that the underlying mean is not 1, as assumed in the Bloom adjustment:

> Due to the preponderance of auto-regressive or random coefficient betas, the results of this study strongly support the use of Bayesian-type adjustment processes such as the one employed by Merrill Lynch. The results also suggest that the behavior of utility betas may differ from the behavior of large diversified samples of stocks. For example, since Blume [2] finds an underlying mean beta of 1.0 for a large sample of stocks, many Bayesian models will adjust the OLS beta estimate toward 1.0. The results of this study, however, indicate that 1.0 is too high an underlying mean for most utilities. Instead, they should be adjusted toward a value that is less than one. For Consolidated Edison, an underlying mean of 0.7 would be more appropriate.[80]

More recent academic research also argues against the Bloom adjustment, in favor of a qualitative analysis of utility betas over time:

> Therefore the Blume equation overpredicts utility betas and Blume-adjustments of utility betas are not appropriate. We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or public utility betas, or the specific utility's beta, not the trend in betas for all stocks in general. The time pattern of utility betas is obviously more complex than a smooth curvilinear adjustment, or for that matter, any adjustment toward one.[81]

My analysis is consistent with Michelfelder and Theodossiou (2013) in that I reviewed historic patterns in utility stocks and determined that the current industry average is consistent with recent trends.

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79 AWEC/402. Gombola, M. J., & Kahl, D. R. (1990). Time-series processes of utility betas: implications for forecasting systematic risk. *Financial Management*, 84-93.

80 *Id.*

81 AWEC/402. Michelfelder, R. A., & Theodossiou, P. (2013). Public utility beta adjustment and biased costs of capital in public utility rate proceedings. The Electricity Journal, 26(9).

Q. HOW DOES THE PROCEDURE RECOMMENDED BY GOMBOLA AND KAHL (1990) COMPARE TO THE METHOD YOU USED TO ESTIMATE BETAS?

A. My method is remarkably similar to Gombola and Kahl (1990). I adjust betas to the mean of the proxy group of 0.69, nearly identical to the 0.7 recommended by Gombola and Kahl for Consolidated Edison.

Q. HAVE YOU PROVIDED ACCESS TO THESE ARTICLES?

A. Yes. Exhibit AWEC/402 includes all three articles discussed in this testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision	)

REDACTED EXHIBIT AWEC/401

Responses to Data Requests

Protected Information is Subject to

General Protective Order No. 23-132

June 20, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 090
Dated June 5, 2024

Request:

Please refer to PGE Exhibit 800, page 4, lines 11 and 12:

a. Please explain why and how costs are weighted by capacity factor and indicate where in PGE's workpapers this weighting is performed.
b. Please identify the distance in miles that the transmission cost is intended to reflect.
c. Please provide all workpapers used to calculate transmission cost per kW-Year.

Response:

a. The "Real Levelized Annual Value ($/MWh)" of solar and wind (Cell P77 in tab 'Solar' and cell Q78 in tab 'Wind') are calculated by dividing their "Real Levelized Annual Value" by the average annual energy generation of each resource, and the annual energy generation of each resource is a function of its capacity factor.
b. The assumed distance of the WY transmission expansion resource is 1,293 miles.
c. 2023 IRP, Table 44 (annualized version of monthly proxy transmission costs). Confidential Attachment 090-A provides transmission cost workpapers.

Confidential Attachment 090-A contains protected information and is subject to General Protective Order No. 23-132.

PGE Response to AWEC Data Request 090
Confidential Attachment A
UE 435_AWEC DR 090_Attach A_CONF

PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

[redacted]

August 29, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 183
Dated August 21, 2024

Request:

Please refer to PGE/1200, Sheeran-Wise/13:13-19. Please provide the referenced evaluation and all supporting documents demonstrating that the costs to verify income eligibility would exceed the avoided cost of excluding ineligible customers.

Response:

PGE previously posted an RFP for post-enrollment verification but did not receive responses. Inquiries in 2022 with Community Action Partnership of Oregon (CAPO) showed estimates for the evaluation costs of $125 per customer. The amount paid for verification by utilities in Washington through low-income agencies is $75 per customer. Based on that guidance, PGE estimated the cost would be approximately $100 per customer. At the current enrollment rate, that would equate to approximately $8.5 million. As enrollments increase, so would the potential cost of verification. Not only would this increase the overall cost of the program and impact all customers, it would also create barriers and likely delay or reduce customer enrollments.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 184
Dated August 21, 2024

Request:

Please refer to PGE/1200, Sheeran-Wise/15:1-9 and also AWEC/200, Kaufman/32:5-8:

a. Does PGE agree that applying a per-customer cap only to Schedule 90, as proposed in the referenced AWEC testimony, would not create the administrative challenges PGE describes in the referenced PGE testimony? If PGE does not agree, please explain.
b. Does PGE oppose AWEC's proposal to apply the 20 million KWh Schedule 118 cap on a per-customer, rather than a per-site, basis only to Schedule 90? If so, please explain why.

Response:

a. Applying any per-customer cap is administratively burdensome.
b. A per-customer cap rather than a per-site cap is administratively burdensome. See PGE/1200 Sheeran-Wise/14 at 18 to /15 at 6.

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company

UE 435
PGE Response to AWEC Data Request 187
Dated August 21, 2024

Request:

Please provide PGE's response to OPUC Standard Data Request 38 from Docket No. UE 416, 394, and 335 ("Please provide, in electronic spreadsheet format, the Company's dollar value and percentage composition of capital structure on an actual basis as of December 31 of last year; on a pro forma basis as of December 31 of the current year; and on a pro forma basis as of March 31, June 30, September 30, and December 31 of the Test Year. Please provide, in electronic spreadsheet format, the actual and pro forma financial statements from which the information was derived for each period specified in the preceding.") If the response references any other discovery responses or documents, please provide the referenced discovery responses and documents.

Response:

Confidential Attachment 187-A provides copies of the indicated data requests.

Attachment 187-A contains protected information subject to General Protective Order 23-132.

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PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

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August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 188 - CONFIDENTIAL
Dated August 21, 2024

Request:

Please refer to PGE's response to Staff DR 38:

a. Please confirm that PGE's target equity ratio for first quarter 2025 is [Confidential] [redacted].
    a. If not confirmed, what is PGE's target equity ratio?
b. Please identify all steps PGE intends to take to achieve its target equity ratio.
c. What is PGE's current equity ratio?
d. Does PGE expect to achieve its target equity ratio in the first quarter of 2025?
e. What equity ratio does PGE expect to achieve on average in 2025?

Response:

a. PGE does not target a specific capital structure quarterly. As stated in testimony, PGE targets a long-term ratio of 50% equity, which will oscillate over time due to the size and timing of debt and equity issuances.
b. As shown in PGE's 5-year model provided in SDR 004, PGE will continue to issue more equity over the next several years to increase its equity percentage.
c. PGE's equity ratio as of quarter-ended June 30, 2024, provided by within PGE's SEC financial statements is 44.5%. PGE does not produce a regulated actual average equity percentage on a quarterly basis.
d. See part a.
e. PGE objects to this request on the basis that it calls for new analysis and speculation. PGE generally does not forecast a regulated "average of monthly averages" for equity.

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PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

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August 30, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 190
Dated August 21, 2024

Request:

For each rate year of Docket Nos. UE 416 and 394 please explain the basis for any discrepancies between pro-forma capital structure reported in OPUC standard data request 38 and the actual average capital structure for the corresponding rate year. For UE 416 please provide such information for any discrepancy between the pro forma capital structure reported in SDR 38 of UE 416 and the 2024 forecast average capital structure reported in SDR 38 of UE 435.

Response:

PGE understands this request to be asking how the pro-forma capital structure in PGE's financial statements filed with the SEC, as provided in OPUC SDR 38 is calculated differently from the average of actual averages as provided in PGE's annual results of operations reports to the OPUC.

Pro-forma capital structure from PGE's SEC Form 10-K filings, which is requested in SDR 38, is based solely on year-end equity relative to year-end debt. Actual average equity, as provided in PGE's annual results of operation (ROO) filings to the OPUC, averages the beginning and ending values of each month for a 13-month period and then averages the 12 monthly average values. The same is done for debt, and the capital structure is determined from the two average equity and debt values. The actual average equity is the value used to derive actual regulated return on equity.

For example, in 2023, as shown in PGE's ROO filing provided in AWEC Data Request No. 186, actual end-of-period common equity is 44.8%,[1] however, actual average equity is 47.4%.[2] The reason for this difference is due to PGE's equity rising early in the year, while debt was not issued until nearly the end of the year. As such, the average equity includes many months of equity at a higher value resulting in an average that is near to the year-end value. However, the average debt only includes a few months of higher debt resulting in an average debt that is far below the year-end debt. The timing of both equity increases, and debt issuances weighted throughout the year can and will drive significant differences between the actual average equity percentage and year-end equity percentage.

[1] 2023 SemiReport, Sheet "p12 – Cost of Cap – PULL", Cell E28
[2] *Id.*, Cell E21

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 202
Dated August 21, 2024

Request:

Please provide all inputs and outputs for each ROSE-E model run performed by PGE related to PGE's 2023 IRP, including any updates to the 2023 IRP.

Response:

PGE objects to this request as not being reasonably calculated to lead to the discovery of admissible evidence.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision	)

EXHIBIT AWEC/402

Cost of Capital Articles

Richard A. Michelfelder *is Clinical Associate Professor of Finance at Rutgers University, School of Business, Camden, New Jersey. He earlier held a number of entrepreneurial and executive positions in the public utility industry, some of them involving the application of renewable and energy efficiency resources in utility planning and regulation. He was CEO and chairperson of the board of Quantum Consulting, Inc., a national energy efficiency and utility consulting firm, and Quantum Energy Services and Technologies, LLC, an energy services company that he co-founded. He also helped to co-found and build Comverge, Inc., currently one of the largest demand-response firms in the world, which went public in 2006 on the NASDAQ exchange. He was also an executive at Atlantic Energy, Inc. and Chief Economist at Associated Utilities Services, where he testified on the cost of capital for public utilities in a number of state jurisdictions and before the Federal Energy Regulatory Commission. He holds a Ph.D. in Economics from Fordham University.*

Panayiotis Theodossiou *is Professor and Dean of Faculty of Management at the Cyprus University of Technology. Previously he was Professor of Finance at Rutgers University, School of Business, Camden. Dr. Thedossiou has also held a number of other faculty positions in finance at Catholic University and Clarkson University. He has also provided consulting advice to national governments. He holds a Ph.D. in Finance from the City University of New York.*

This article has benefitted from participant comments at the Rutgers University Center for Research in Regulated Industries Eastern Conference in May 2011. The authors would also acknowledge the Whitcomb Center for Financial Research for funding the data acquisition from the WRDS database.

Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings

The Capital Asset Pricing Model (CAPM) is commonly used in public utility rate proceedings to estimate the cost of capital and allowed rate of return. The beta in the CAPM associates risk with estimated return. However, an empirical analysis suggests that the commonly used Blume CAPM beta adjustment is not appropriate for electric and electric and gas public utility betas, and may bias the cost of common equity capital in public utility rate proceedings.

Richard A. Michelfelder and Panayiotis Theodossiou

I. Introduction

Regulators, public utilities, and other financial practitioners of utility rate setting in the United States and other countries often use the Capital Asset Pricing Model (CAPM) to estimate the rate of return on common equity (cost of common equity).[1] Typically, the ordinary least squares method (OLS) is the preferred estimation method for the CAPM betas of public utilities. Although the CAPM model has been widely criticized regarding its validity and predictability in the literature, as summarized by Professors Fama and French in 2005,[2] many firms and practitioners extensively use it to obtain cost of common equity estimates; e.g., such as shown by Bruser et al. in 1998, Graham and Harvey in 2001, and Gray, et al. in 2005.[3] Michelfelder, et al. in 2013[4] in this

 1040-6190/$–see front matter http://dx.doi.org/10.1016/j.tej.2013.09.017

journal presents a new model, i.e., the Predictive Risk Premium Model, to estimate the cost of common equity capital and compare and contrast the poor results of the CAPM to that model and the discounted cash flow model.

Major vendors of betas include, but are not limited to, Merrill Lynch, Value Line Investment Services (Value Line), and Bloomberg. These companies use Blume's 1971 and 1975[5] beta adjustment equation to adjust OLS betas to be used in the estimation of the cost of common equity for public utilities and other companies.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time; that is, betas greater or less than 1 are expected to revert to 1. There are various explanations for the phenomenon first discussed in Blume's pioneering papers. One explanation is that the tendency of betas toward one is a by-product of management's efforts to keep the level of firm's systematic risk close to that of the market. Another explanation relates to the diversification effect of projects undertaken by a firm.[6]

While this may be the case for non-regulated stocks, regulation affects the risk of public utility stocks and therefore the risk reflected in beta may not follow a time path toward one as suggested by Peltzman in 1976, Binder and Norton in 1999, Kolbe and Tye in 1990, Davidson, Rangan, and Rosenstein in 1997, and Nwaeze in 2000.[7] Being natural monopolies in their own geographic areas, public utilities have more influence on the prices of their product (gas and electricity) than other firms. The rate setting process provides public utilities with the opportunity to adjust prices of gas and electricity to recover the rising costs of fuel and other materials used in the transmission and distribution of electricity and gas. Companies operating in competitive markets do not have this ability. In this respect, the perceived systematic risk associated with the common stock of a public utility may be lower than that of a non-public utility. Therefore, forcing the beta of a utility stock toward one may not be appropriate, at least on a conceptual basis.

The premise behind the Blume adjustment is that estimated betas exhibit mean reversion toward one over time.

The explanations provided by Blume and others to justify the latter tendency are hardly applicable to public utilities. Unlike other companies, utilities can and do possess monopolistic power over the markets for their products. This power impacts the ''negotiation process'' for setting electric and gas prices. Furthermore, it provides them with the opportunity to raise prices to recover increases in operating costs without regard to competitive market pressure. Such price influence is rarely available to companies operating in competitive market environments for their products. In that respect, macroeconomic factors will have a greater impact on the earnings and stock prices of the non-utility companies resulting in larger systematic risk or betas.

The application of Blume's equation to public utility stocks generally results in larger betas, since most raw utility betas are less than 1. Therefore, applications of these betas to estimate the cost of capital and an allowed rate of return on common equity possibly biases the required rate of return or cost of common equity, leading to an over-investment of capital as predicted by Averch and Johnson in 1962,[8] which preceded the trend in prudency reviews that began to occur in the 1980s. Although reported public utility betas may have been biased upward by the vendors of beta that applied Blume's adjustment to public utility betas, ex post prudency reviews of ''used and useful'' assets defined and supported by the Duquesne 1989 US Supreme Court decision[9] resulted in an underinvestment of capital in generation and transmission assets, leading to electric brownouts and blackouts. This article examines the behavior of the betas of the population of publicly traded U.S. energy utilities. In

  http://dx.doi.org/10.1016/j.tej.2013.09.017

addition to evaluating the stability of these betas over the period from the January 1962 to December 2007, we also test whether or not public utility betas are stationary or mean reverting toward 1 or perhaps a different level.

II. Background

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity. Since the cost of common equity is not observable, it must be inferred from market valuation models of common equity. The differences in the recommended allowed rates of return resulting from necessary subjective judgments in the application of cost of common equity models can easily mean 500 basis points or more in the estimate. Therefore, both the impact on customer rates for utility service and the profits of the utilities are very sensitive to the methods used to estimate the cost of common equity and allowed rate of return. The two most commonly used models are the Dividend Discount Model (DDM) and the CAPM. We discuss the use of CAPM for estimating the cost of common equity for public utilities. Our focus is on the use of market-influential betas from the major vendors of betas: Merrill Lynch, Value Line, and Bloomberg. These vendors apply Blume's adjustment to raw betas to estimate forward-looking betas. Blume[10] performed an empirical investigation, finding that beta is non-stationary and has a tendency to converge to 1. Bey in 1983 and Gombola and Kahl in 1990[11] found that utility betas are non-stationary and concluded that each utility beta's non-stationarity must be viewed on an individual stock basis, unlike the recommendation of Blume which adjusts all betas for their tendency to approach 1. Similarly with

Investor-owned public utility regulatory proceedings to change rates for service almost always involve contentious litigation on the fair rate of return or cost of common equity.

Gombola and Kahl, we find that public utility betas have a tendency to be less than 1. They investigated the time series properties of public utility betas for their ability to be forecasted whereas we are concerned with the institutional reasons for the trends in beta, the bias instilled in cost of capital estimates assuming that utility betas converge to one and the widespread use and applicability of the Blume adjustment to public utility betas. McDonald, Michelfelder and Theodossiou in 2010[12] show that use of OLS is problematic itself for estimating betas as the nonnormal nature of stock returns result in beta estimates that are statistically inefficient and possibly biased.

Blume's equation is:

$$\beta_{t+1} = 0.343 + 0.677\beta_t \qquad (1)$$

where β_{t+1} is the foreasted or projected beta for stock *i* based on the most recent OLS estimate of firm's beta β_t. For example if β_t is estimated using historical returns from the most recent five years, then the projected β_{t+1} may be viewed as a forecast of the beta to prevail during the next five years. As mentioned earlier, Blume's equation implies a long-run mean reversion of betas toward 1. The long-run tendency of betas implied by Blume's equation can be computed using the equation:

$$\overline{\beta} = \frac{0.343}{1 - 0.677} = 1.0619 \approx 1 \qquad (2)$$

The same result can be obtained by recursively predicting beta until it converges to a final value. This can only be appropriate for stocks with average betas, as a group, close to one. This is, however, hardly the case for public utility betas that are generally less than 1 (as discussed in detail below).

The magnitude of adjustment for Blume's beta equation is initially large and declines dramatically as the adjusted beta approaches 1 either from below (for betas lower than 1) or from above (for betas greater than 1). In this respect, the beta adjustment step (size) will be larger for betas further away from 1.

As we will see in the next section, the median beta of the public utilities studied ranges between 0.08 and 0.74 over time,

  http://dx.doi.org/10.1016/j.tej.2013.09.017

depending upon the period used. Under the assumption that betas for public utilities are consistent with Blume's equation, the next period beta for a stock with a current beta of 0.5, will be $\beta_{t+1} = 0.343 + 0.677\ (0.5) = 0.6815$, implying a 36.3 percent (0.6815/0.5) upward adjustment. On the other hand a beta of 0.4 will be adjusted to $\beta_{t+1} = 0.343 + 0.677\ (0.4) = 0.6138$ which constitutes a 53.5 percent upward adjustment and a beta of 0.3 will be adjusted to 0.5461 or by 82.0 percent.

The beta adjustment method most widely disseminated by the major beta vendors is the Blume adjustment. Therefore, our focus is on the Blume adjustment for public utility betas and the public utility cost of common equity capital. Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings since these betas are not disseminated by influential stock analysts and presumed not to be reflected in the stock price. Section III discusses the data and empirical analysis of the Blume adjustment and its impact on the cost of common equity for public utilities.

III. Data and Empirical Analysis

The data include monthly holding period total returns for 57 publicly traded U.S. public utilities for the period from January 1962 to December 2007 obtained from the University of Chicago's Center for Research in Security Prices (CRSP) database. The sample includes all publicly traded electric and electric and gas combination public utilities with SIC codes 4911 and 4931 listed in the CRSP database. All non-U.S. public utilities traded in the U.S. and non-utility stocks were not included in the dataset. The monthly holding period total returns for each stock as calculated in the CRSP database were used for estimating betas of varying periods. The monthly market total return is the CRSP value-weighted total return.

Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings.

The computation of the betas is based on the single index model, also used in Blume:

$$R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}, \tag{3}$$

where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i are the intercept and beta for stock i and $e_{i,t}$ is a regression error term for stock i. As previously mentioned, OLS is the typical estimation method used by many vendors of beta and is used in this investigation.

Table 1 presents the mean and median OLS beta estimates for the 57 utilities using 60, 84, 96, and 108 monthly returns respectively over five different non-lapping periods between December 1962 and December 2007. We also performed the same empirical analysis for periods of 4, 6, 10, 11, 12 and 13 years and the results were similar; the results are not shown for brevity but available upon request. We used non-overlapping periods to avoid serial correlation and unit roots. If we take, for example, 360 months of time series of returns for a stock and estimate 60-month rolling betas moving one month forward for each beta, this would result in 300 betas. Since only two of 60 observations would be unique due to overlapping periods, the error term would be highly serially correlated. A Blume-type regression of these betas would have a unit root, a coefficient of one and an intercept near 0, and therefore appear to follow a random walk. Therefore, the empirical nature of beta requires that lags in the Blume equation involve no overlapping time periods.

The mean and median betas in Table 1 not only do not rise toward 1 as the time period moves forward; the betas generally decline. Table 2 includes OLS regressions of the Blume equation for the 5-, 7-, 8-, and 9-year betas. We estimated five sets of 4- through 13-year betas inclusively for each public utility then

  http://dx.doi.org/10.1016/j.tej.2013.09.017

Table 1: Mean and Median Betas for Varying Time Periods.

9-Year Periods	12/62–12/71	12/71–12/80	12/80–12/89	12/89–12/98	12/98–12/07
Mean	0.69	0.60	0.41	0.40	0.27
Median	0.68	0.57	0.40	0.36	0.22
8-Year Periods	**12/67–12/75**	**12/75–12/83**	**12/83–12/91**	**12/91–12/99**	**12/99–12/07**
Mean	0.76	0.39	0.45	0.27	0.33
Median	0.74	0.37	0.43	0.23	0.27
7-Year Periods	**12/72–12/79**	**12/79–12/86**	**12/86–12/93**	**12/93–12/00**	**12/00–12/07**
Mean	0.68	0.40	0.40	0.09	0.50
Median	0.65	0.39	0.38	0.06	0.47
5-Year Periods	**12/77–12/82**	**12/82–12/87**	**12/87–12/92**	**12/92–12/97**	**12/97–12/02**
Mean	0.36	0.38	0.53	0.49	0.12
Median	0.35	0.38	0.50	0.45	0.08

The following model was estimated for the sample of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the single index model: $R_{i,t} = \alpha_i + \beta_i R_{m,t} + e_{i,t}$
where $R_{i,t}$ and $R_{m,t}$ are total returns for stock i and the market during month t, α_i, and β_i is the intercept and capital asset pricing model beta for stock i, respectively, and $e_{i,t}$ is a regression error term for stock i. The entire data series ranges from December 1962 to December 2007. The stock returns are the monthly holding period total returns from the CRSP database. The market returns are the CRSP market value-weighted total returns.

regressed the latter beta on the previous period betas. The 5-, 7-, 8-, and 9-year equations are shown for brevity. The diagnostic statistics strongly refute the validity of the Blume equation for public utility stocks. Most of the R^2's are equal to or close to 0.00 and the largest is 0.09. Only one F-statistic (tests the significance of the equation estimation) is significant and all but two slopes are insignificant. Also shown is the long-run beta implied from each Blume model as shown in equation (2). They range from 0.08 to 0.59. Only one estimate, the first-period 9-year Blume equation, includes a positive and statistically significant slope and intercept. The implied long-term beta of that equation is 0.59, which is substantially below one and the largest value of all estimates. As a final and visual review of the trends in betas, we developed and plotted probability distribution box plots developed by Tukey in 1977[13] for the 4- through 13-year public utility betas. We have shown only the 4- and 5-year beta box plots as shown in Figures 1 and 2 for brevity (the 6- to 13-year plots are available upon request). Tukey box plots show the 25th and 75th percentiles (the box height), the 10th and 90th percentiles (the whiskers), the median (the line inside the box), and the dispersion of the outlying betas. The box plots should be viewed as looking down on the distributions of the betas. We developed 4- through 13-year beta box plots to review the trend in shorter-term versus longer-term betas. None of the 51 beta probability distributions display any tendency for betas to drift toward one. The 5-, 6- and 7-year betas have higher variances in the last period relative to all other periods. A few outlying betas are greater than 2.0. This pattern is consistent with the notion that utility holding companies are investing in risky ventures of affiliates that can retain excess returns should they be realized. Note that the mean beta in Figures 1 and 2 show the cyclical nature of short-term utility betas with a severe downturn in the late 1990s and a severe upswing in the early 2000s. Generally, the box plots show a long-term downward trend in public utility betas.

It is interesting to note that the drop in beta occurred just after

 1040-6190/$–see front matter http://dx.doi.org/10.1016/j.tej.2013.09.017

Table 2: Public Utility Blume Equation Estimates.

9-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.463***	0.318***	0.480***	0.235***
	(0.074)	(0.062)	(0.096)	(0.080)
γ_1	0.214**	0.153	−0.186	0.800
	(0.102)	(0.099)	(0.227)	(0.179)
Long Run β	0.59	0.38	0.41	0.26
R^2	0.09	0.04	0.01	0.00
F-Statistic	4.43**	2.36	0.67	0.20
p-Value	0.04	0.13	0.42	0.65
8-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.341***	0.464***	0.184**	0.321***
	(0.083)	(0.047)	(0.088)	(0.070)
γ_1	0.058	−0.034	0.193	0.035
	(0.106)	(0.115)	(0.189)	(0.220)
Long Run β	0.36	0.45	0.23	0.33
R^2	0.01	0.00	0.02	0.00
F-Statistic	0.30	0.09	1.04	0.02
p-Value	0.58	0.76	0.31	0.88
7-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.370***	0.375***	0.074	0.491***
	(0.081)	(0.052)	(0.075)	(0.049)
γ_1	0.048	0.059	0.036	0.128
	(0.115)	(0.122)	(0.179)	(0.259)
Long Run β	0.39	0.40	0.08	0.56
R^2	0.00	0.00	0.00	0.00
F-Statistic	0.17	0.23	0.04	0.24
p-Value	0.68	0.63	0.84	0.62
5-Year Betas	$\beta_2 = f(\beta_1)$	$\beta_3 = f(\beta_2)$	$\beta_4 = f(\beta_3)$	$\beta_5 = f(\beta_4)$
γ_0	0.329***	0.474***	0.321***	0.106*
	(0.047)	(0.086)	(0.088)	(0.061)
γ_1	0.151	0.137	0.316**	0.019
	(0.119)	(0.213)	(0.157)	(0.111)
Long Run β	0.39	0.55	0.47	0.11
R^2	0.03	0.01	0.07	0.00
F-Statistic				
p-Value	1.62	0.41	4.07	0.03
	0.21	0.52	0.05	0.87

The following Blume equation was estimated using the betas of public utility stocks for five 60-, 84-, 96-, and 108-month non-overlapping periods. The ordinary least squares method was used to estimate the parameters of the following model: $\beta_{i,t+1} = \gamma_0 + \gamma_1\beta_{i,t} + \varepsilon_{i,t}$.
where $\beta_{i,t+1}$ is the OLS estimated CAPM beta for stock *i*, $\beta_{i,t}$ is the previous period beta for stock *i*, γ_0 and γ_1 are the intercept and slope of the Blume equation, and ε_t is the regression error term. The time subscripts on the betas refer to the time periods of estimation from Table 1. For example, β_5 in the 9 year panel refers to the beta estimated for each stock using the returns data from December 1998 to December 2007. The long-run $\beta = \gamma_0/(1 - \gamma_1)$; it can also be found by solving recursively for the next period beta until it converges on a final value. Newey-West autocorrelation and heteroskedasticity consistent standard errors are in parentheses.
* Significance at 0.10 level.
** Significance at 0.05 level.
*** Significance at 0.01 level.

deregulation of the wholesale electricity market in April 1996. This is inconsistent with the buffering theory of Peltzman and Binder and Norton[14] who found that regulation buffers the volatility of cash flows of public utilities from the vicissitudes of competition and business cycles and therefore reduces their systematic risk. However, this is consistent with Koble and Tye's 1990[15] theory of asymmetric regulation and the empirical findings of Michelfelder and Theodossiou in 2008,[16] who found that asymmetric regulation is associated with down-market public utility betas greater than their up-market betas. Adverse asymmetric regulation began in the 1980s and resulted in an upper boundary for public utilities' allowed rates of return equal to the cost of capital. If public utilities were granted an opportunity to earn their cost of common equity, regulators frequently would disallow specific investments *ex post* from earning the allowed rate of return if they were deemed ''not used and useful,'' even though they were deemed to be prudent when the decision was made to make these investments. The result was that utilities were not truly granted the opportunity to earn their allowed rate of return. If they happened to over-earn their allowed rate of return due to higher than anticipated demand forecasts, ''excess'' returns were taken away. This became known as regulatory risk, quantified as a risk premium in the cost of

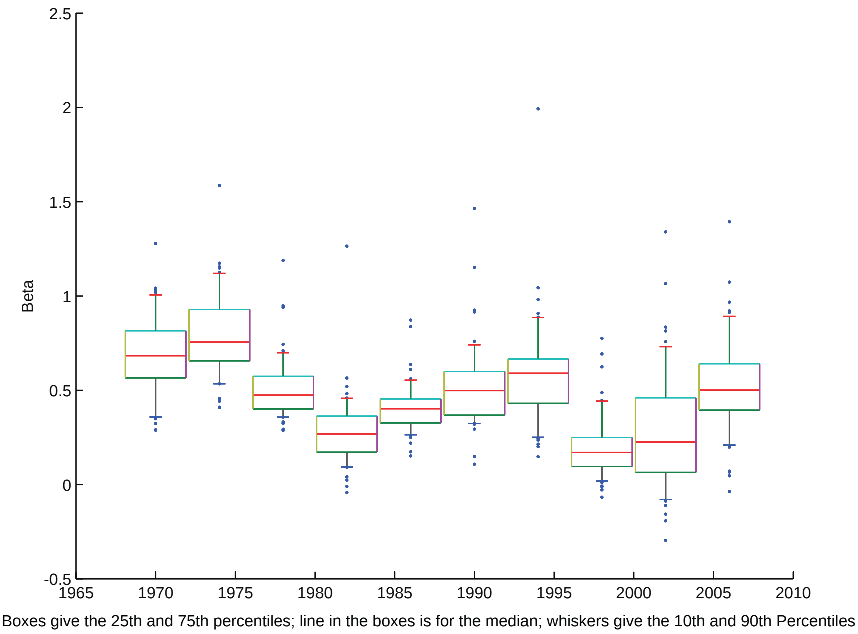

Figure 1: Boxplots of Utility Stock Betas Using 4 Year Periods Data

common equity. Michelfelder and Theodossiou in 2008[17] also concluded that public utility stocks are no longer defensive stocks dampening the downward behavior of otherwise less diversified portfolio returns in down markets.

Therefore, some suggest that *de*regulation may have ''buffered'' utility cash flows from regulatory risk, i.e., the chance that regulation would impose disappointing allowed rates of return in the manner described above. The advent of generation deregulation caused electric utilities with generating plants to no longer face regulatory risk on over 50 percent of their asset base. This is consistent with falling betas after deregulation of electric generation. The Brattle Group in 2004[18] found the same result in a research project for the Edison Electric Institute, an electric utility trade and lobbying organization. They found that electric utility betas fell after deregulation.

We suggest that it may be due to the relief of deregulation from asymmetric regulation. In any case, we find that the Blume adjustment toward 1 is not supported by our empirical results. This adjustment suggests that in the long run, all public utilities (and all firms) would gravitate toward the same risk and return. Our results herein suggest that the Blume adjustment is inappropriate for public utilities as it assumes that public utility betas are moving toward one in the long run as are non-utility company betas.

We perform a simple calculation to show the impact of a biased beta on public utility revenues. We calculate the common equity risk premium on the market as the annual total return for the CRSP market return from 1926 to 2007 to be approximately 12 percent and the average return on a three-month T-Bill to be about 4 percent. The long-term common equity risk premium is 8 percent. The difference between a beta of 0.50 and a Blume adjusted beta of .67 would result in a difference in cost of common equity

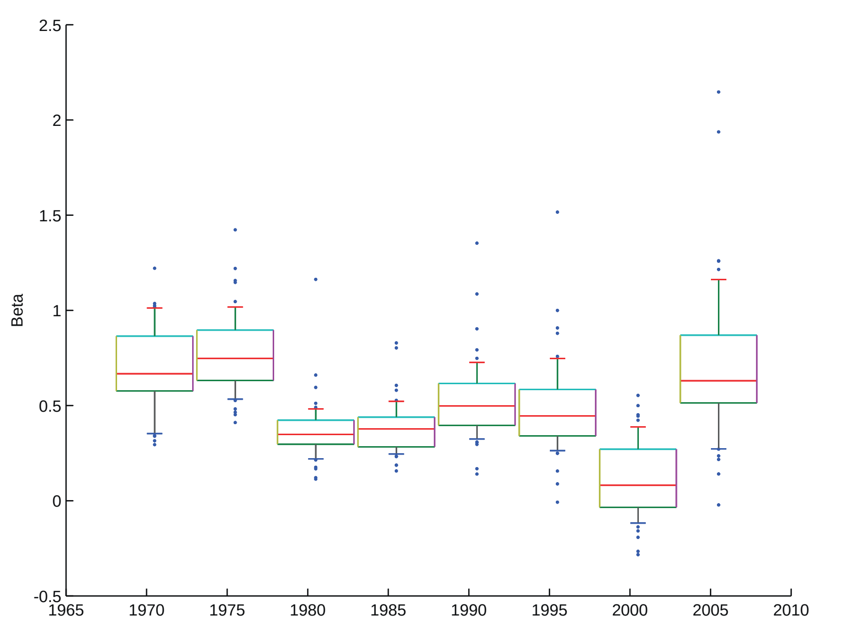

Figure 2: Boxplots of Utility Stock Betas Using 5 Year Periods Data

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of 136 basis points. Using a common equity ratio of 0.50, this would impact the weighted average rate of return by 68 points. Assuming a rate base of $5 billion (the level for a moderately large electric utility), the difference in ''allowed'' net income would be 0.0068 × $5 billion, or, $34 million. Assuming a 37.5 percent income tax rate, the increase in revenues required to earn the additional $34 million would be $54 million. This is obviously a substantial difference. It is important for us to stress in this example that we do not necessarily advocate these inputs for the recommended cost of common equity for a utility with a raw beta of 0.50. The deliberation in recommending the cost of common equity is performed with a careful and detailed analysis of the company and stock, referral to more than one valuation model of the cost of common equity estimation and expert judgment.

IV. Conclusion

Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume-adjusted betas to investors. We have shown empirically that public utility betas do not have a tendency to converge to 1. Short-term betas of public utilities follow a cyclical pattern with recent downward trends, then upward structural breaks with long-term betas following a downward trend. We estimate the Blume equation for electric and gas public utilities, finding that all but one equation is statistically insignificant. The single significant equation implies a long-term convergence of beta to approximately 0.59. During our nearly 45-year study period, the median beta ranged from 0.08 to 0.74. Therefore the Blume equation overpredicts utility betas and Blume-adjustments of utility betas are not appropriate.

We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or *public utility betas*, or the specific utility's beta, not the trend in betas for all stocks in general. The time pattern of utility betas is obviously more complex than a smooth curvilinear adjustment, or for that matter, any adjustment toward one. Nor do we suggest as an alternative the use of raw or unadjusted betas in an application of the CAPM to estimate a public utility's cost of common equity.■

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Major vendors of CAPM betas such as Merrill Lynch, Value Line, and Bloomberg distribute Blume adjusted betas to investors.

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STATISTICAL TESTS OF THE ACCURACY OF ALTERNATIVE FORECASTS: SOME RESULTS FOR U.S. UTILITY BETAS

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ABSTRACT

The common approach for assessing the relative forecast accuracy of various predictors is simply to compare their simple ranks based on some measure(s) of forecast accuracy (such as the mean square errors). However, conventional methodologies for conducting a *t*-test or *F*-test of forecast accuracy are inappropriate and unreliable. A statistical methodology is proposed in this paper that rectifies most of the problems involved with conducting such conventional tests of statistical significance. Using this statistical methodology on the mean square errors of six beta predictors for five forecast horizons for fifty utilities, it was found that there are statistically significant differences between the forecast accuracies of the beta predictors for each and every forecast horizon, that the statistical rankings of the beta predictors were significantly different from and more congruent than the simple rankings as the forecast horizon lengthened, and that the ordinary least squares predictor was consistently ranked as one of the poorest beta predictors for all of the forecast horizons.

INTRODUCTION

The Capital Asset Pricing Model (CAPM), which was developed by Sharpe [21], Lintner [16], and Mossin [18], has provided the basis for much of the research on capital markets during the past decade. Thus, the observed beta from the single factor market (SFM) model of Sharpe [21] is typically used as the best estimator of the true (unobservable) beta (systematic risk) of a security.[1] However, this beta predictor is only one of many different predictors that can be constructed. Others in-

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[1]The SFM model is given in Table 1.

clude the procedures of Vasicek [23], Blume [1, 2], and Merrill Lynch (see Klemkosky and Martin [14]). The accuracy of these alternative beta predictors has been investigated by a number of authors (including Klemkosky and Martin [14]; Eubank and Zumwalt [7]; Elgers, Haltiner, and Hawthorne [4]; Elton, Gruber, and Urich [6]; and Hawawini and Vora [11]). In general, these authors have found that the accuracy of simple no-change extrapolative beta forecasts can be improved by using a combination of the Bayesian (Vasicek) predictor and a reasonable portfolio size.

Estimating security betas has also received widespread attention among practitioners during the past decade. Investment analysts, portfolio managers, and corporate planners have increasingly used betas in evaluating securities, in optimizing investment portfolios, and in evaluating the performance of investment portfolios. Furthermore, since the mid 1970s, many economists, financial experts, and public service commissioners have placed a greater reliance on the use of beta as a risk measure when estimating the expected return of the equity component of the cost of capital for a given public utility.[2] Such beta usage has increased the demand for better beta forecasts. Several investment advisory services (such as Value Line, Barr Rosenberg and Assoc., and Merrill Lynch) have responded by providing various beta forecasts for a large number of securities. However, the accuracy of these commercially provided beta forecasts has been seriously questioned recently by Harrington [10]. Harrington compared the actual beta forecasts supplied by a number of these commercial services with their corresponding benchmark beta estimates for four forecast periods and found that the commercially provided betas appeared to have little predictive accuracy.

Although the quality of beta forecasts may be improved by incorporating some characteristics of the true beta's underlying distribution into the forecast procedure (see, for example, Vasicek [23] and Blume [2]), the ultimate test of a beta forecast is determined by observing its deviation from its true benchmark value in the ensuing period. Since the true values of many concepts that are commonly used in finance are unobservable (examples include risk, market value, and the return on the mar-

[2]Although Brigham and Crum [3] questioned the use of the CAPM during periods of economic instability, a number of authors (Peseau et al. [19]) have challenged Brigham and Crum's interpretation of how appropriate the CAPM is in utility rate hearings.

ket portfolio), these concepts must be both accurately proxied and measured. Thus, in an assessment of various beta forecasting techniques, it is important that the unobservable true benchmark beta be accurately measured (as has been recently shown by Jalilvand and Kryzanowski [13]). Although the determination of the true benchmark beta is important, an even more important issue is how to test whether one beta predictor is statistically different from, or superior to, another beta predictor, especially since some beta predictors are less or more cumbersome and (or) less or more costly to implement. Although it is tempting to employ a t-test or F-test for such purposes, Granger and Newbold [9, p 281] have dismissed this approach as generally being inappropriate for the following two reasons: ". . . First, it is not reasonable to assume in general that the errors produced by one procedure will be uncorrelated with those produced by another. Second, . . . the error series are not typically white noise even for optimal forecasts."

Given the shortcomings of conventional methodologies, the primary purpose of this paper is twofold: first, to develop a statistical approach that can be employed to test whether one forecasting procedure has performed significantly different than another forecasting procedure;[3] and second, to illustrate the differences that exist between statistical and simple rankings based on the mean square errors (MSEs) of various predictors.[4] To this end, the relative accuracy of six beta predictors for a sample of fifty utilities from 1969–1979 are tested statistically.

The remainder of this paper is organized as follows. In the next section, the sample and data collection are described. In the third and fourth sections, respectively, the methodology and a common approach for assessing relative forecast accuracy are discussed. In the fifth section, a statistical approach for testing relative forecast accuracy is first detailed and then used. In the sixth section, some concluding remarks are offered.

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[3]The statistical approach developed in this paper is quite general and can be used to test the statistical rankings of a variety of forecasts, such as exchange rates, earnings, and the correlation structure of asset returns.

[4]Other measures of forecast accuracy (such as the APE or MAD) or the three components of the MSE (namely, bias, efficiency, and random error) could have been used instead of the mean square error to illustrate the differences that exist between statistical and simple rankings of various beta predictors. Furthermore, as will be explained later in the paper, our proposed methodology is quite general since it uses forecast errors as opposed to any particular accuracy measure in its derivation.

THE SAMPLE AND DATA COLLECTION

The sample of firms used in this study consists of fifty public utilities (see the Appendix).[5] This sample was chosen because of its potential appeal for public utility rate-of-return analysts and investment practitioners. Monthly rates of return for each of the fifty firms, and for the value-weighted CRSP index were obtained from the CRSP tape for the 132-month period from January 1969 through December 1979. All security returns were adjusted for stock splits and stock dividends.

METHODOLOGY

Although the accurate measurement of the true and unobservable benchmark betas has been shown to be important by Jalilvand and Kryzanowski [13], only the ordinary least squares (OLS) estimates were used in this paper. Also, although the predictability of portfolio betas is both interesting and important, cost of capital (or rate-of-return) applications of the SFM model require forecasts of individual security betas. Thus, only the predictability of individual security betas is examined in this paper.

Beta Predictors

Six forecasting methods were used in this study, namely: (1) the OLS method; (2) the J-K E(Z) method;[6] (3) the Bayesian-adjusted (Vasicek) method; (4) the naive I (sample average) method; (5) the naive II (beta equal to one) method;[7] and (6) the naive Bayesian (Merrill Lynch-type) method. With the exception of the naive II method, these methods used five years of monthly returns for both the firms of interest and the CRSP value-weighted index. The specific calculation procedure used for each method is detailed in Table 1.

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[5]This sample is similar to that used by Harrington [10].

[6]The J-K measure, which Jalilvand and Kryzanowski [12] have derived from the moment-generating function of the joint probability density functions (jpdf) of the residuals, incorporates the contemporaneous relationships among the residual returns of different securities to provide more accurate betas. Numerous studies (for example, Fama [8] and Kryzanowski and To [15]) have demonstrated that the residuals for the SFM model are contemporaneously correlated.

[7]The Bayesian approach uses information obtained from the cross section distribution of betas to adjust sample betas in accordance with a minimum expected loss criterion. The procedure uses the prior or historical distribution of beta coefficients.

TABLE 1

CALCULATION PROCEDURE FOR EACH OF THE SIX BETA PREDICTORS

Method	Calculation Procedure
	The SFM model:
OLS	$R_k = \alpha_k + \beta_k R_m + e_k,$
	where
	R_k is the return on firm k; R_m is the return on the market (as proxied by the CRSP value-weighted index); α_k and β_k are the parameters of the linear regression; and e_k is the error term for firm k.
J-K E(Z)	$R_k = \alpha_k + \beta_k R_m + \gamma_k \mathrm{E(Z)} + e_k,$
	where
	γ_k is a parameter of the linear regression; E(Z) is the measure of the residual interrelationships, which is equal to the expected value of the product of the contemporaneous residuals of the first-pass OLS regressions of the security returns on the returns of the market index $[\text{i.e., } \mathrm{E(Z)} = \mathrm{E}(\prod_1^N e_i)];$ and all other terms are as defined earlier.
Bayesian (Vasicek) or VT	$\hat{\beta}_{kt}^{VT} = \frac{S^2(\hat{\beta}_{kt}^{OLS})}{\sigma_{st}^2 + S^2(\hat{\beta}_{kt}^{OLS})}\hat{\beta}_{st}^{OLS} + \frac{\sigma_{st}^2}{\sigma_{st}^2 + S^2(\hat{\beta}_{kt}^{OLS})}\hat{\beta}_{kt}^{OLS},$
	where t refers to the period of estimation (e.g., t = 1 refers to the period, January 1969 through December 1973);
	$S^2(\hat{\beta}_{kt}^{OLS})$ is the squared standard error of the estimate of the predicted (forecast) beta for firm k in period t based on the OLS procedure; σ_{st}^2 is the variance of the predicted (forecast) betas for the firms in sample s for period t based on the OLS procedure; $\hat{\beta}_{st}^{OLS}$ is the mean predicted (forecast) beta for sample s in period t based on the OLS procedure; and

TABLE 1 (Continued)

Method	Calculation Procedure
	$\hat{\beta}_{kt}^{OLS}$ is the predicted (forecast) beta for firm k in period t based on the OLS procedure.
Naive I (sample average)	$\hat{\beta}_{kt}^{NI} = \hat{\beta}_{st}^{OLS}$, where $\hat{\beta}_{st}^{OLS}$ is the mean (predicted) beta for sample s in period t based on the OLS procedure.
Naive II (beta equal to one)	$\hat{\beta}_{kt}^{NII} = 1.0 \quad \forall_{k,s}$
Naive Bayesian or ML (Merrill Lynch type)	$\hat{\beta}_{kt}^{ML} = 0.5\,\hat{\beta}_{kt}^{OLS} + 0.5\,\hat{\beta}_{st}^{OLS}$, where $\hat{\beta}_{kt}^{ML}$, is the predicted (forecast) beta for firm k in period t for the Merrill Lynch-type procedure; $\hat{\beta}_{kt}^{OLS}$ is the predicted (forecast) beta for firm k in period t based on the OLS procedure; and $\hat{\beta}_{st}^{OLS}$ is the mean predicted (forecast) beta for sample s in period t based on the OLS procedure.

With the exception of the fundamental betas provided by Barr Rosenberg Associates and Wilshire Associates, among others,[8] the beta predictors used in this paper capture the essence of most of the beta predictors used by commercial vendors of betas. More specifically, various types of OLS betas are provided by Barr Rosenberg Associates (based on sixty months of logarithmic return relatives and the S&P 500 stock index) and by Merrill, Lynch, Pierce, Fenner and Smith, Inc. (based on sixty months of price relatives and the S&P 500 stock index). Various types of Bayesian-adjusted betas are provided by Merrill-Lynch (based on an assumed population mean beta of 1.0); by Drexel, Burnham, Lambert, Inc. (based on data for eight market cycles); and by Value Line (based on five years of weekly price relatives, the New York Stock Exchange composite index, and periodic adjustment of the betas "for their long-term tendency towards 1.00"). In addition, the beta predictors used can be implemented easily by a practitioner using a sophisticated hand calculator or a microcomputer.

[8]In the Harrington [10] study, the fundamental beta predictors were among the middle-ranked predictors in terms of forecast accuracy for her sample of utilities.

Procedure for Generating the Forecasted and Benchmark Betas

The procedure used to generate the forecasted and benchmark betas was as follows. First, a matrix of beta forecasts was generated for the fifty securities for each of the six beta predictors. More specifically, sixty-one betas were estimated for each of the fifty securities for each of the beta predictors using a moving sixty-month regression, where the first regressions are for January 1969 through December 1973 and the last (sixty-first) regressions are for January 1974 through December 1978. Second, the returns for the one-, two-, three-, four-, and five-year forecast horizons were used to estimate the OLS benchmark betas for each of the fifty securities using twelve-, twenty-four-, thirty-six-, forty-eight-, and sixty-month moving regressions, respectively. For example, sixty-one benchmark betas for a one-year horizon were estimated for each of the fifty securities using a twelve-month moving regression, where the first regressions were for January 1974 through December 1974 and the last (sixty-first) regressions were for January 1979 through December 1979. Since progressively more data were required to estimate a benchmark beta for the two- to five-year forecast horizons, the number of benchmark betas decreased as the forecast horizon increased. For example, only thirteen benchmark betas could be estimated for each of the fifty securities for a five-year horizon, since the first regression required data for January 1974 through December 1978 and the last (thirteenth) regression required data for January 1975 through December 1979. Thus, for any given firm, the predictive accuracy of any given beta predictor was evaluated by comparing its beta forecast estimated over a given sixty-month period against the benchmark beta for the ensuing one-year horizon, for the ensuing two-year horizon, . . ., and finally for the ensuing five-year horizon. For example, as of the end of December 1973, the beta predictions calculated using the first sixty-month period from January 1969 through December 1973 were compared with the following: the benchmark betas for a one-year horizon which were estimated over the twelve-month period from January 1974 through December 1974, the benchmark betas for a two-year horizon which were estimated over the twenty-four-month period from January 1974 through December 1975, . . ., and finally the benchmark betas for a five-year horizon which were estimated over the sixty-month period from January 1974 through December 1978. The beta predictions based on the last sixty-month period from January 1974 through December 1978 were similarly taken as being the one-, two-, three-, four-, and five-year forecasts as of the end of December 1978. However, since only one year of data remained in the data set, these beta forecasts could only be evaluated against the benchmark betas for a one-year horizon (i.e., against the benchmark betas estimated over the twelve-month period from January 1979 through December 1979). Third, the average mean square error (AMSE)[9] was calculated for the sample of firms for the following: (1) the sixty-one forecasted and the sixty-one (twelve-month) benchmark betas; (2) the first forty-nine forecasted and all forty-nine (twenty-four-month) benchmark betas; (3) the first thirty-seven forecasted and all thirty-seven (thirty-six-month) benchmark betas; (4) the first twenty-five forecasted and all twenty-five (forty-eight-month) benchmark betas; and (5) the first thirteen forecasted and all thirteen (sixty-month) benchmark betas. This calculation was repeated for each of the six beta predictors.

SIMPLE RANKINGS OF FORECAST ACCURACY

A common approach for assessing the relative forecast accuracy of a number of different beta predictors is simply to compare their simple ranks based on one or a number of measures of forecast accuracy (such as their MSEs). The average

[9]The average mean square error (AMSE) is given by

$$\text{AMSE} = \frac{1}{N}\sum_{n=1}^{N} \text{MSE}_n,$$

where

N is the number of firms in the sample (i.e., 50);

$$\text{MSE}_n = \frac{1}{T}\sum_{t=1}^{T} (\hat{\beta}_{nt}^{F_i} - \hat{\beta}_{nt})^2, \; n = 1, \ldots, N;$$

T is the number of predictions for each forecast horizon (i.e., 61, 49, 37, 25, or 13);

n is the particular firm ($n = 1, \ldots, N$);

$\hat{\beta}_{nt}^{F_i}$ is the predicted (forecast) beta for firm n in period t based on forecast procedure $F_i (i = 1, \ldots, 6)$; and

$\hat{\beta}_{nt}$ is the benchmark beta for firm n in period t based on the OLS estimation procedure.

mean square errors (AMSEs) for the sample of utilities for the six beta predictors and the five forecast horizons are given in panel A of Table 2, and the relative simple rankings of the six beta predictors based on their AMSEs for the five forecast horizons are given in panel B of Table 2. Based on these simple rankings, for example, for the one year forecast horizon, the relative forecast accuracies of the six beta predictors would be classified as follows: the OLS predictor is average; the ML and E(Z) predictors are above average; and the VT, NI, and NII predictors are below average.

Unfortunately, since the conclusions based on these comparisons are devoid of any statistical content, they must be used with great caution. In other words, in the absence of a proper test of statistical significance, the rankings based on the magnitude of the AMSEs, or on any other measure of accuracy, can provide misleading and inconclusive information on the relative predictive superiority or inferiority of various beta predictors.

TABLE 2

AVERAGE MEAN SQUARE ERRORS (AMSEs) AND RELATIVE RANKINGS OF THE SIX BETA PREDICTORS FOR THE SAMPLE OF UTILITIES FOR THE FIVE FORECAST HORIZONS

Beta Predictor	Forecast Horizon				
	1 Year	2 Years	3 Years	4 Years	5 Years
	Panel A: Average Mean Square Errors (AMSEs)				
OLS	.08459	.12106	.09767	.07545	.06650
E(Z)	.07295	.09166	.07236	.06120	.07238
VT	.09183	.10057	.07518	.05118	.03603
NI	.09419	.10292	.07745	.05245	.03547
NII	.20748	.21536	.18850	.15441	.11605
ML	.07148	.08527	.06313	.04534	.04331
Mean Beta	.64447	.63034	.63963	.66167	.70703
	Panel B: Relative Rankings Based on the AMSEs				
OLS	3	5	5	5	4
E(Z)	2	2	2	4	5
VT	4	3	3	2	2
NI	5	4	4	3	1
NII	6	6	6	6	6
ML	1	1	1	1	3

Although it is tempting to use conventional statistical tests (e.g., t-tests or F-tests) in these circumstances, Granger and Newbold [9] state that these tests are inappropriate because the forecast errors for a specific predictor are generally seriously autocorrelated over time and the forecast errors across the different predictors are also usually correlated.[10] Such is the case for the predictors and the sample studied in this paper. An examination of the lag structure of the forecast errors for autoregressive patterns shows that the first twelve lag coefficients of the forecast errors for all of the six beta predictors for all of the five forecast horizons are significantly different from zero at the 1 percent level.[11] Based on the nonparametric Kendall Coefficient of Concordance test, the null hypothesis of no association among the rankings of forecast errors of different predictors (as proxied by their MSEs) is also systematically rejected at the 1 percent level of significance (or better) for all five forecast horizons.[12] Thus, the existence of within and between dependencies among the forecast errors of the different beta predictors can seriously diminish the reliability of the conventional tests of statistical significance by increasing the probability of committing type I and type II errors.

The appropriateness of using the conventional approach of conducting t-tests or F-tests to judge relative forecast accuracy for any measure of forecast accuracy (such as the MSE, APE,

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[10]In general, when the forecast errors or the sample observations are seriously correlated, the use of the standard t-test is inappropriate because the sample estimates of the population parameters are unreliable. More efficient estimates can be obtained by removing the autocorrelation from the forecast errors. For the use of a standard t-test under different but similar circumstances, see Eun and Resnick [5]. Also, see Rendleman and Carabini [20] for an adjusted t-test that attempts to account for any serial correlation in the time series of the differences between the forecast errors of any two predictors.

[11]These findings are available upon request from the authors of this paper.

[12]To implement this test, the sample firms were first ranked according to their MSEs, and then the relationships between their rankings were tested across all six beta predictors for each of the five forecast horizons using the Kendall Coefficient of Concordance, W. A nonparametric test is primarily chosen to avoid the statistical problems associated with the autoregressive nature of the forecast errors. This test statistic is given by: $W = S/[(1/12)K^2(N^3 - N)]$, where S is the sum of squares of the observed deviations from the mean of the sums of the ranks for the sample firms; K is the number of sets of rankings; N is the number of items ranked; and the denominator represents the maximum possible sum (S) which can occur with perfect agreement among K rankings. $0 \leq W \leq 1$, where $W = 0$ indicates no agreement in the rankings, $W = 1$ indicates perfect agreement, and $K(N - 1)W$ is distributed as χ_2 with $N - 1$ degrees of freedom. For more information on this test statistic, see Siegel ([22], pp. 229–239).

or MAD) is further compromised because the distributions of such measures are not only difficult to approximate but are in general not normal. Since normality of the underlying random variables is an important prerequisite assumption when conducting conventional tests of statistical significance, the ability to properly discriminate among various beta predictors is at best suspect in the absence of such normality. Thus, if a reliable and meaningful comparison among the forecast accuracy of various beta predictors is desired, a statistical methodology that alleviates most, if not all, of these potential problems is required.

STATISTICAL RANKINGS OF FORECAST ACCURACY

Let the squared value of the i-th random forecast error for the j-th forecasting technique, D_i^j, be denoted by

$$D_i^j = (e_i^j)^2, \text{ where } i = 1, 2, \ldots, NT; \; N = 50;$$

$$T = 61, 49, 37, 25, 13; \text{ and } j = 1, \ldots, 6.$$

For any given predictor and forecast horizon, the simple average of these D_i^j's is identical to the MSE of that predictor for that forecast horizon.[13] Under ideal conditions, a statistical test (e.g., t-test) of the difference between the means of the D_i^j's for the various predictors should provide the statistical basis for discriminating between the predictors. However, due to the autoregressive nature of the D_i^j's (resulting from the autocorrelation in the forecast errors) and the likelihood that the distribution of the D_i^j's is not normal, the reliability of any test performed on the D_i^j's in their present form would likely be low.[14]

These problems can be alleviated by selecting k (e.g., fifty) random samples of size p (e.g., 100) from all of the D_i^j observations for each forecasting technique for each forecast horizon.[15]

[13]The number of D_i^j observations for any given forecasting technique depends upon the forecast horizon chosen. There are 3050, 2450, 1850, 1250, and 650 observations for D_i^j for the one-, two-, three-, four-, and five-year forecast horizons, respectively.

[14]For example, if e_i^j is a standard normal random variable, then the D_i^j's will have a χ^2 distribution with one degree of freedom.

[15]The total number of samples (e.g., $k = 50$) and the size of each of these samples (e.g., $p = 100$) were primarily chosen so that the approach would satisfy the requirements of both the t distribution and the Central Limit Theorem.

In forming the random samples for each of the predictors for a given forecast horizon, a matched sampling procedure can be used, where for each observation in the k-th sample of the j-th predictor, matching observations are chosen for the k-th sample for each of the other predictors.[16]

The theoretical rationale for this proposed approach is reasonably straightforward. According to the Central Limit Theorem, and regardless of the distributions of the D_i^j's, the distributions of the resultant sample means will approach normality. Furthermore, the sample means are expected to have the same mean and a proportional (to sample size) variance of their respective populations (D_i^j) from which they have been drawn. Thus, by using this procedure, the sample means of any forecasting technique for any forecast horizon themselves form a random sample of fifty, which can be compared against the similarly drawn samples for the other forecasting techniques for the same forecast horizon. A matched test of the difference between the means of the D_i^j's for different predictors can then be performed by using a t-test on the matched differences of the resultant sample mean observations for any two predictors.[17]

The resulting statistical rankings of the six beta predictors, obtained by performing this proposed test procedure on all the possible pairs of the six beta predictors for each of the five forecast horizons, are reported in panel A of Table 3.[18] To facilitate comparison, the simple rankings based on the AMSEs have also been reported in panel B of Table 3. These findings can be summarized as follows. First, there are statistical differences between the forecast accuracies of the various beta predictors for each and every forecast horizon. Second, there are significant differences between the statistical and simple rankings of

[16]The use of a totally random procedure to select each of the samples may be preferable. In this study, its use had no effect on the results.

[17]Let M_i^{12} represent the i-th difference between the matched sample mean observations of the first and second predictors for a given forecast horizon. According to the Central Limit Theorem, the individual sample means and, therefore, the M_i^{12}'s should be normally distributed with mean equal to the difference between the means of the sample means of the first and second predictors and standard deviation of $S_{M_i}^{12} = [(1/49)(\Sigma(M_i^{12} - \bar{M}^{12})^2]^{1/2}$. The standard error of the estimate, $\bar{M}$, is $S_{\bar{M}} = S_M/\sqrt{50}$, and $(\bar{M} - \mu_M)/S_{\bar{M}} \sim t$, with 48 degrees of freedom.

[18]Using the proposed test procedure, we performed fifteen pairwise t-tests for each forecast horizon to determine the statistical rankings of the six beta predictors (as in Eun and Resnick [5]).

TABLE 3

A COMPARISON OF THE SIMPLE RANKINGS BASED ON THE AMSEs WITH THE STATISTICAL RANKINGS FOR THE SIX BETA PREDICTORS FOR THE FIVE FORECAST HORIZONS

Beta Predictor	Forecast Horizon				
	1 Year	2 Years	3 Years	4 Years	5 Years
	Panel A: Statistical rankings				
OLS	5	5	5	5	5
E(Z)	1	1	1	4	4
VT	2	2	4	3	3
NI	2	2	2	1	1
NII	6	6	6	6	6
ML	2	2	3	2	2
	Panel B: Simple rankings based on the AMSEs				
OLS	3	5	5	5	4
E(Z)	2	2	2	4	5
VT	4	3	3	2	2
NI	5	4	4	3	1
NII	6	6	6	6	6
ML	1	1	1	1	3

the beta predictors.[19] These differences are more pronounced for the one-, two-, and three-year forecast horizons, when the need for accuracy is probably the greatest. For instance, unlike the simple rankings for the one- to three-year forecast horizons, the E(Z) beta predictor is the most accurate, followed by the ML and NI beta predictors. For the four- and five-year forecast horizons, unlike the simple rankings, the NI beta predictor is the best, followed by the ML beta predictor. Also unlike the simple rankings, the OLS beta predictor is consistently ranked statistically as the second worst predictor over all forecast hori-

[19]Although the evidence unambiguously indicates that the conventional application of *t*-tests of the MSEs should not be used, such tests were nevertheless conducted. As expected, and unlike the statistical rankings reported here, the statistical rankings based on conventionally conducted *t*-tests were sometimes inconsistent. For example, for a one-year forecast horizon, the statistical rankings based on the conventional *t*-test results implied that although the E(Z) and NI beta predictors and the NI and ML beta predictors were not significantly different statistically, the ML beta predictor was significantly better statistically than the E(Z) beta predictor.

zons. Given that the majority of the utilities had betas less than one (and the means for all forecast horizons were always less than 0.71), it is not surprising that the NII beta predictor had the worst statistical and simple rankings for all forecast horizons. Finally, using the statistical rankings, the NI, ML, and VT beta predictors are all classified as either the same or in close proximity to each other. This result is intuitively appealing a priori, since these three predictors are only different weighted combinations of the average beta of the sample (see Table 1).

CONCLUDING REMARKS

The common approach for assessing the relative forecast accuracy of a number of different forecast techniques is to compare their simple ranks based on one or more of a number of measures of forecast accuracy (such as their MSEs). Although some researchers have used a *t*-test or *F*-test to determine whether any differences in the measure(s) of forecast accuracy are statistically significant, the conventional approach of conducting these tests is inappropriate and unreliable because of the following three reasons: (1) the forecast errors for many predictors are seriously autocorrelated over time; (2) the forecast errors across different predictors are generally correlated; and (3) the values of the chosen measure of forecast accuracy (e.g., the MSEs) are generally not normally distributed.

A statistical approach, which rectifies most, if not all, of these problems, was proposed in this paper. The procedure involves the selection of k (e.g., fifty) random samples of size p (e.g., 100) from the squared forecast error terms for a particular predictor so that, according to the Central Limit Theorem, the distribution of the resultant sample means approaches normality. Thus, a matched test of the difference between the means of the squared forecast error terms can be performed by using a *t*-test on the matched differences of the resultant sample mean observations for any two predictors.

Using this statistical methodology to assess the relative accuracy of six beta predictors for five forecast horizons for a sample of fifty utilities, it was found that there are statistically significant differences between the forecast accuracies of the beta predictors for each and every forecast horizon. Furthermore, the statistical rankings of the beta predictors were found to be not only significantly different from the simple rankings based on the MSEs, but the statistical rankings were more congruent as the forecast horizon lengthened. Interestingly, based on the statistical rankings the OLS beta predictor is consistently ranked as one of the poorest beta predictors for all of the forecast horizons. Finally, it is important to emphasize that the inferences made in this paper about the simple (and statistical) rankings of various beta predictors have only been established with respect to the studied sample, sample period, and the MSE measure of forecast accuracy and thus may not be generalizable to other samples of securities, other time periods, and other measures of forecast accuracy.

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APPENDIX

Firms in the Sample of Utilities

Allegheny Power
American Electric Power
Arizona Public Service Co.
Boston Edison
Central Hudson Gas & Electric Corp.
Central Illinois Lighting
Central Illinois Public Service
Columbia Gas
Consolidated Edison
Consumers Power
Dayton Power and Lighting
Delmarva Power and Light Co.
Detroit Edison
Eastern Utilities Assoc.
El Paso Co.
Florida Power and Lighting
Hawaiian Electric
Houston Industries Inc.

Internorth Inc.
Iowa Electric Lighting and Power
Kansas City Power and Lighting
Kansas Gas and Electric
Kansas Power & Lighting
Louisville Gas and Electric
Michigan Energy Resource Co.
Montana Dakota Utility
Montana Power
New England Telegraph and Telephone
New York State Gas and Electric
Northeast Utilities
Northern Industrial Public Service
Northern State Power
Oklahoma Gas and Electric
Oneok Inc.
Pacific Gas and Electric
Pacific Power and Lighting
Portland General Electric
St. Joseph Lighting and Power
San Diego Gas and Electric
Southern Calif. Edison
Southern Industrial Gas and Electric
Southwestern Public Service
Teco Energy Inc.
Texas Utility
Utah Power and Lighting
Virginia Electric & Power Co.
Washington Gas and Lighting
Washington Water and Power
Wisconsin Electric and Power
Wisconsin Public Service

Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk

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■ Brigham and Crum [5] describe difficulties with the Capital Asset Pricing Model (CAPM) in estimating utility cost of capital. This controversial article elicited six comments [7, 15, 17, 21, 22, 24], a reply [6], and one extension [11]. Examining the dividend omission by Consolidated Edison (Con Ed), Brigham and Crum note that this information release could confound estimation of Con Ed's beta. Although the Ordinary Least Squares (OLS) beta estimate decreased concurrent with the dividend omission, Brigham and Crum contend that Con Ed's risk had not decreased.

An OLS estimate of beta requires an estimation period during which the relationship between stock return and market return is stable. Without this stability, the forecaster needs alternatives for forecasting a time-varying relationship, such as the general Bayesian adjustment process [25] or its specific variations employed by Merrill Lynch [18]. The appropriateness of a given procedure depends on the particular time-series properties of the beta being forecast.

Information on the time-series properties of utility betas, including the variability of beta and the tendency of utility betas to auto-regress toward an underlying mean, is presented here. The degree of difficulty in forecasting beta depends on both of these properties. Since the basis of Bayesian adjustment lies in beta's tendency to return to an underlying mean, if betas follow a random walk process then Bayesian adjustment will be fruitless.

Collins, Ledolter, and Rayburn [10] explain that random variation in beta leads to severe forecasting difficulties, unlike variability due to auto-regression in beta. To the extent that beta instability is auto-correlated, an unstable beta can be forecasted accurately. Estimating that about 25% of beta variability in their sample is due to auto-correlated beta changes, Collins, Ledolter, and Rayburn suggest that recognition of auto-correlation can improve forecasting accuracy by 15%.

Auto-correlated beta changes allow use of beta adjustment models to improve beta forecasts. A general Bayesian adjustment model would adjust the short-term (transient) beta estimate towards a long-term underlying mean. An example of such an application is the Merrill Lynch [18] adjustment process:

$$B_t = 0.65(B_{t-1}) + 0.35(1.0)\,. \tag{1}$$

Here, the transient beta estimate obtained by OLS is presumed to return to an underlying mean of 1.0 slowly, since more weight is placed on the transient beta than on the underlying mean.

Studying the time-series properties of utility betas—including their tendency to return to an underlying mean, the speed of this return, and the underlying mean itself—should prove helpful in formulating Bayesian adjustments of beta forecasts. Carleton [7] suggests that Bayesian-adjusted beta forecasts have been applied, often inappropriately, to beta forecasts in regulatory proceedings. This study strives to determine whether such Bayesian adjustment processes are appropriate at all.

I. Beta Coefficient Instability and the Rate-Setting Process

Cooley [12] points out the widespread, albeit controversial, use of the Capital Asset Pricing Model in estimating required return for utility equity. Exchanges published by two journals dealing with the CAPM for rate setting ([7, 15, 17, 21, 22, 24] and [4, 19, 20]) center not on the validity of the theory but on the reliability and usefulness of beta estimates.

Concern over empirical estimates of systematic risk is based on a substantial body of empirical literature pointing to beta instability. From the early descriptive work of Blume [2] through later tests by Fabozzi and Francis [13] and Collins, Ledolter, and Rayburn [10], the evidence supports instability in security betas. Studying specifically the behavior of utility betas, Bey [1], Chen [8], and Pettway [23] all demonstrate instability.

Although the size of beta instability has been extensively investigated, comparatively little attention has been focused on the form of that instability, particularly for utilities. Beta instability does not necessarily preclude application of the CAPM unless combined with a random walk process for beta.

The simplest case, a constant coefficient process for beta, may be expressed as:

$$B_{it} = B_{i,t-1} = B_i^m \textit{ for all } t\,. \tag{2}$$

In Equation (2), the beta at any point in time remains equal to the previous beta and also to a constant underlying mean beta, B_i^m. This constant coefficient process is assumed in OLS estimation of a beta and serves as the null hypothesis in tests of beta variability [3, 13].

When the transient beta for a particular company (B_{it}) is distributed around an underlying mean beta for that company B_i^m, the resulting time-series process may be described as:

$$B_{it} = B_i^m + u_{it}\,. \tag{3}$$

Equation (3) describes the random coefficient model tested by Fabozzi and Francis [13] and assumed in a beta forecasting model by Chen and Keown [9]. Since the deviations of beta from its underlying mean (u_{it}) are limited to a single period and are serially uncorrelated, the transient beta (B_{it}) tends to return quickly to the underlying mean.

If the transient beta takes more than one period to return to its underlying mean, then an auto-regressive process describes the time-series behavior of beta:

$$B_{it} = a_i B_{i,t-1} + (1 - a_i)B_i^m + u_{it}\,. \tag{4}$$

This process is very similar to the random coefficient process, except for the strength of the tendency for mean-reversion. A value of 0.9 for $1 - a_i$ would cause the process to be classified as auto-regressive, whereas a value of 1.0 would label it random coefficient. Otherwise, there is little difference.

The auto-regressive model described in Equation (4) is the same one studied by Bos and Newbold [3] and Collins, Ledolter, and Rayburn [10]. The process considers a tendency to return to an underlying mean beta, where the tendency is measured by $1 - a_i$. The Merrill Lynch adjustment process [18] describes a special case in which the underlying mean beta (B_i^m) is 1.0 and the adjustment factor to the mean, also called the regression rate $(1 - a_i)$, is 0.35. Vasicek's adjustment model [25] is a less restrictive case in which the underlying mean beta is unity and no restriction is made on the adjustment rate toward the underlying mean.

If all beta variation is random, then there will be no tendency for beta to return to an underlying mean, resulting in a random walk process:

$$B_{it} = B_{i,t-1} + u_{it}. \tag{5}$$

This model has been suggested as a time-varying model for beta in a stability test described by Garbade and Rentzler [14]. Since there are no bounds on the value that beta can assume, the process is difficult to forecast, especially in the long run. If beta follows a random walk process then the best long-term forecast is the short-term beta, and a Bayesian adjustment process will not improve the forecast. Notably, Brigham and Crum's [6] original criticism of the CAPM was based on unadjusted OLS estimates of Con Ed's beta, which implicitly assumes that an unstable beta follows a random walk.

II. The Beta Coefficient as an Auto-Regressive Variable

Any of the four beta-generating processes can be represented as a special case of a general auto-regressive process. The general model has a measurement equation,

$$R_{it} = B_{it} R_{mt} + e_{it}, \tag{6}$$

and state equation,

$$B_{it} = a_i B_{i,t-1} + (1 - a_i)B_i^m + u_{it}, \tag{6'}$$

where R_{it} is the excess return on the ith security during time t, R_{mt} is the return on the market index during time t, B_i^m is the underlying mean beta for the ith stock, and B_{it} is the transient beta for the ith stock at time t.

Equation (6') specifies a first-order auto-regressive process for beta. If the value for $1 - a_i$ is 0.0, then (6') reverts to the random walk process described in Equation (5). If the value for $1 - a_i$ is 1.0, then (6') reverts to the random coefficient process described in Equation (3). If the residual variance is 0.0, then $1 - a_i$ becomes 0.0 and the underlying mean and error terms in Equation (6') drop out, leaving the constant beta process in Equation (2).

III. Estimating Parameters of the Model

The parameters of the model in Equations (6) and (6') were estimated using monthly stock return data from the Compustat PDE file for 109 utility companies, 61 electric and 48 electric and gas. The 15-year sample period is from January 1967–December 1981. The period contains both the dividend omission by Consolidated Edison [5] and the Three Mile Island incident.

The model in Equations (6) can be expressed in matrix format as:

$$R_{it} = \underline{h}_t \underline{B}_{mt} + \underline{e}_{it}, \tag{7}$$

$$\underline{B}_{it} = \underline{A}_i \underline{B}_{i,t-1} + \underline{U}_{it}, \tag{7'}$$

where

$\underline{h}_t = (R_{mt}, 0)$;
$\underline{B}'_{it} = (B_{it}, B_i^m)$;
$\underline{U}'_{it} = (u_{it}, 0)$ and is distributed as $N(0, W_i S_i^2)$,

$$\underline{W} = \begin{bmatrix} w_i & 0 \\ 0 & 0 \end{bmatrix}, \tag{8}$$

$$\underline{A} = \begin{bmatrix} a_i & 1 - a_i \\ 0 & 1 \end{bmatrix}. \tag{9}$$

The recursive Kalman filtering approach described by Kahl and Ledolter [16] is used to estimate simultaneously the three parameters of the market model in Equations (6). These parameters are: the underlying mean beta (B_i^m), the regression rate toward the underlying mean ($1 - a_i$), and the variance of beta over time.

Simultaneous estimation of three parameters requires considerable data and computer resources which might explain why studies using broad samples and large numbers of stocks formulate the problem somewhat differently. Bos and Newbold estimated a Kalman filtering model with a two-pass process. Decreasing the number of parameters from three to two reduces the computation time to only a fraction of that required for a full model. Collins, Ledolter, and Rayburn [10] suggest that the procedure followed by Bos and Newbold [3] creates a downward bias in the estimate of beta's regression rate. They were able to eliminate the estimate of the underlying mean beta in the model and focus on beta regression tendencies.

The model used in this study produces independent variance estimates like the model used by Collins, Ledolter, and Rayburn. In addition, this model estimates the underlying mean beta. Maximum likelihood estimates of elements in the transition matrix (a_i), the variance ratio (w_i), and the variance of the measurement equa-

Exhibit 1. Maximum Likelihood Estimates of Model Parameters

Regression Rate	Standard Deviation of Beta 0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
0.0			2[a]	3[a]	4[a]	6[a]	12[a]	5[a]	3[a]		
0.1				1	2	5	1				
0.2					1	7	2	5	2		
0.3				1	1	2	5	1	3		
0.4				1	2	1	3	1			
0.5											
0.6						1					
0.7						1					
0.8											
0.9		1	1								
1.0	6[b]	17[c]									

[a]These firms display characteristics of firms whose betas follow a random coefficient process.
[b]These firms display characteristics of firms whose betas are constant.
[c]These firms display characteristics of firms whose betas follow a random walk process.

tion (S_i^2), were all concurrently estimated using a grid search procedure.

IV. Results

The particular time-series process followed by a beta can be indicated by two parameters: the standard deviation of this beta over time, u_{it} in Equation (6'); and its adjustment rate to the mean, $(1 - a_i)$ in Equation (6'). Consequently, the cross-tabulation of these two parameters in Exhibit 1 is also a tabulation of the process followed by the beta. The most common process shown in Exhibit 1 is the auto-regressive process. Nearly half of the companies in the sample, 51 out of 109, show a nonzero standard deviation of beta together with a value for the regression rate between zero and unity.

The next most common process is the random coefficient process, indicated by a nonzero value for the standard deviation of beta together with an estimate of 1.0 for $1 - a_i$. These estimates are shown by 35 of the sample companies. The firms with auto-regressive betas and those with very similar random coefficient betas jointly comprise 86 of the 109 sample firms.

A nonzero estimate of the standard deviation of beta combined with a regression rate of zero indicates a beta following a random walk process. Parameter estimates consistent with a random walk process are shown for only 17 companies.

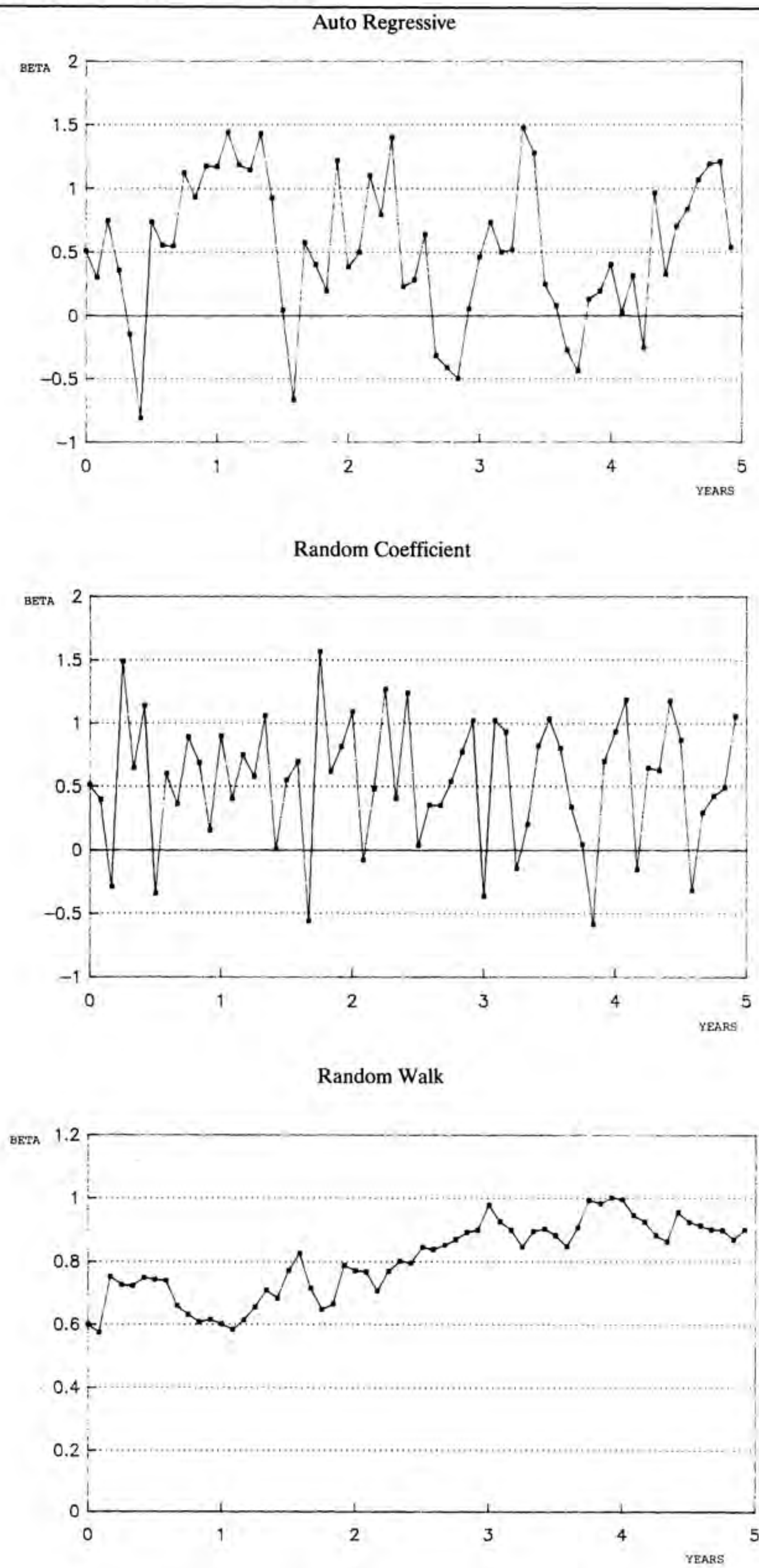
The least common process indicated by companies in the sample is the constant coefficient process, shown by only 6 companies. A constant beta coefficient is indicated by a zero estimate for the standard deviation of beta.

Since the estimation period covers 15 years (180 months), many companies could not maintain a constant beta coefficient. The long estimation period allows management, regulators, and the markets to react to any exogenous changes affecting systematic risk so as to bring risk back to reasonable levels. Such reaction is consistent with a beta that follows an auto-regressive process. Consequently, the preponderance of companies with auto-regressive betas in Exhibit 1 conforms to expected long-term behavior of management and markets.

Internal consistency of parameter estimates in Exhibit 1 is just as important as reasonableness. All companies having a zero estimate for the standard deviation of beta also show a value of 0.0 for the adjustment rate estimate. Any other estimate would be ambiguous for classifying the process. A positive association between the estimate of the standard deviation of beta and the estimate of $1 - a_i$ further points to the lack of ambiguity and helps in interpreting the process for all of the sample companies.

The positive association between beta variability and the regression rate is also consistent with boundaries upon beta values. Companies with high beta variability tend to have betas that return quickly to an underlying mean. Companies with low or zero return rates have low beta variability. High variability to-

Exhibit 2. Three Time-Series Processes for Beta



gether with a low or zero return rate would lead to extreme beta instability and preclude application of the CAPM. The results show no evidence of this type of beta instability.

A. Behavior of Transient Betas

To illustrate the implications of different processes and parameters, plots of betas following an auto-regressive process, a random coefficient process, and a random walk process are presented in Exhibit 2. Each of these processes behaves according to average coefficient values of companies with that process in Exhibit 1. For the auto-regressive process, the coefficients are an underlying mean of 0.51, a standard deviation of transient beta of 0.50, and a return rate toward the underlying mean of 0.52. For the random coefficient process, the underlying mean is 0.52 and its standard deviation is 0.53. For the random walk process the standard deviation of beta is 0.05.

The auto-regressive beta depicted in Exhibit 2 shows considerable variability and ranges between a minimum value of -0.8 and a maximum value of 1.50. Although the variability in the short run is rather large, the beta at no time takes longer than 9 months to return to its underlying mean, usually returning in three or four months. However, upon returning to its underlying mean it often strays on the opposite side, requiring several additional months to return.

Over the 60-month period shown for the auto-regressive process in Exhibit 2, only 36 of the transient beta values fall between a low of 0.0 and a high of 1.0. These bounds might be considered reasonable for a utility. Nine of the 60 beta observations lie below 0.0. The presence of such outliers might frustrate, but not obviate, application of OLS techniques for beta estimation. Although Exhibit 2 indicates that extreme beta values, such as those discussed by Brigham and Crum [5], might be common in the short run, the forecaster should not be deterred by the presence of short-run instability. In the long run, beta will return to its mean.

The similarity between the auto-regressive process and the random coefficient process, also shown in Exhibit 2, is obvious. Even if rather extreme values are encountered, the random coefficient beta reverts back to the mean within the next two observations. The upper and lower bounds on beta as well as the proportion of betas less than zero are very similar for the two processes.

Exhibit 2 also contains a plot of the time-series behavior of a beta following a random walk process. Although the beta behavior for the random walk process seems more stable than the auto-regressive or random coefficient process, such apparent short-run stability is misleading. Over the 60 months depicted in Exhibit 2, the beta wanders from a value of 0.6 to a value of about 0.9. Over the next 60 months, the beta could potentially rise by another 0.3, fall back to 0.6, or be anywhere in between. In the longer run, the beta becomes even more difficult to forecast, due to the lack of any tendency to revert to an underlying mean.

B. Focusing on the Consolidated Edison Dividend Omission

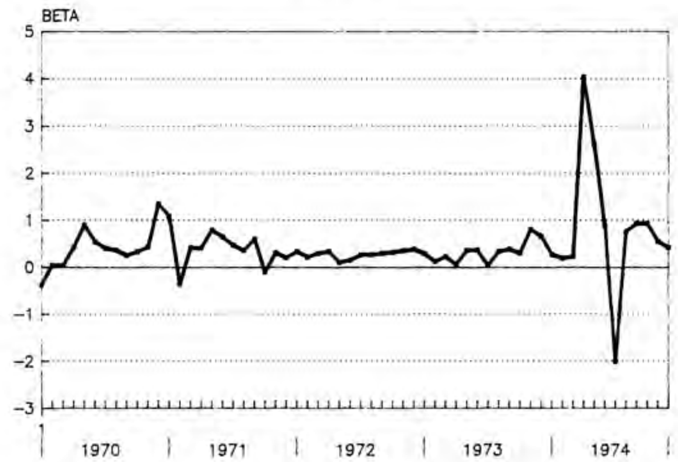
A plot during the period from January 1970–December 1984 of the behavior of the transient beta for Consolidated Edison is presented in Exhibit 3. The transient beta behaves much like the typical beta for any utility with an auto-regressive beta, except for the period immediately following the dividend omission. During this period, the transient beta becomes very erratic for about 9 months. Once it settles down, it continues to behave like any other utility with a typical auto-regressive beta. The plot of the transient beta for Con Ed over the last 60 months, if placed on the same scale as Exhibit 2, would be visually indistinguishable from the auto-regressive process depicted in that exhibit.

The plot of Con Ed's transient beta shown in Exhibit 3 depicts the transitory effect of economic disturbances on beta estimates. Even in this dramatic case of a dividend omission, the relationship between the stock and the market returned to normal within less than one year. This strong tendency to return to the mean beta gives empirical support to forecaster-supplied prior values in Bayesian adjustment models that place more weight on the underlying mean beta and less weight on the transient beta than the Merrill Lynch model would imply.

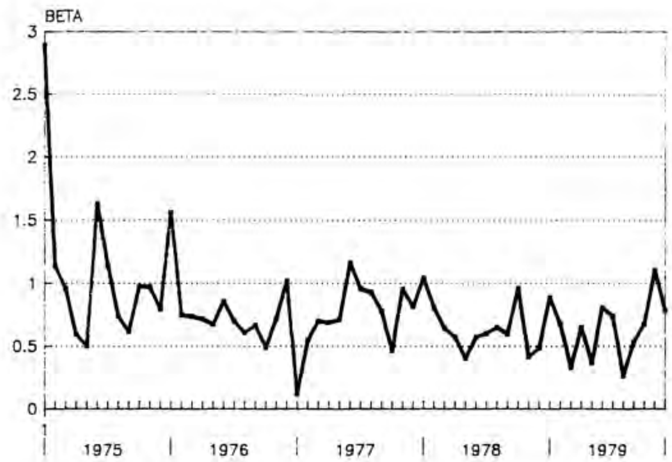
Some additional information on the behavior of Con Ed's beta is presented in Exhibit 4. During the overall period, which extends from January 1970–June 1984, its OLS beta estimate was 0.61 and the estimate of its underlying mean beta was 0.58. Since this overall period contains the dividend omission, a null hypothesis of a constant coefficient process for beta can be easily rejected. The regression rate of 0.70 toward the underlying mean indicates a strong mean-reversion tendency.

Exhibit 3. Transient Beta for Consolidated Edison, 1970–1984

1970–1974



1975–1979



1980–1984

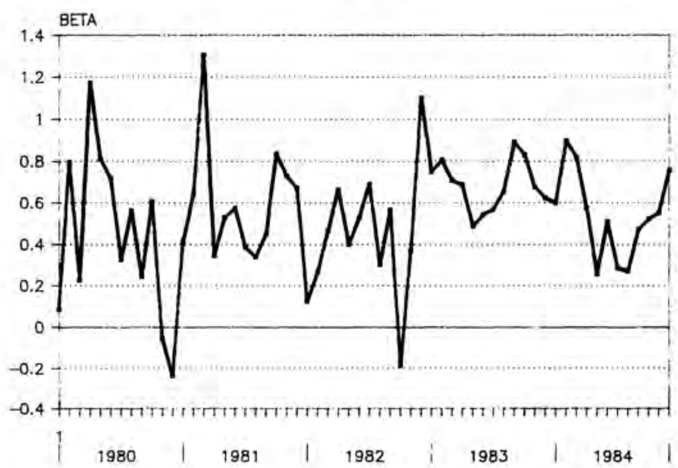


Exhibit 4. Parameter Estimates for Consolidated Edison Beta

Parameter	Overall Period 1970–1984	Before Dividend Omission 1970–1973	After Dividend Omission 1978–1981
Ordinary Least Squares Beta	0.61	0.39	0.62
Standard Error of OLS Beta	0.08	0.04	0.05
$K-F$ Underlying Mean Beta	0.58	0.34	0.47
$K-F$ Regression Rate to Mean	0.70	1.00	1.00
$K-F$ Standard Deviation of Beta	0.74	0.62	0.78
$K-F$ Residual Error in Market Model	0.05	0.03	0.04
$K-F$ Beta Stability Test	58.80*	20.30*	7.00*

*Significant at the 0.05 level.

Exhibit 4 also contains Kalman filtering and OLS estimates of beta for both a four-year period prior to the divided omission and a four-year period after the dividend omission. Forty-eight monthly observations is not sufficient to estimate reliably the underlying mean beta, since by nature this parameter reveals itself only over the long run. Likewise, the estimate of $1-a_i$ may also be unreliable when estimated by only a few observations over a short time period. However, the subperiods do depict the variability that is characteristic of short-term estimates, whether those estimates are obtained by OLS or by Kalman filtering.

Although these short-term estimates should be approached with caution, some effects of the dividend omission on Con Ed's risk might be inferred. First, estimates for the long-term period or either of the short-term periods do not appear contaminated by the dividend omission but appear quite reasonable for a utility. Second, no indication of a decline in the beta estimate due to inclusion of the dividend omission period is evident. The indication is to the contrary. The estimate of the underlying mean beta for the overall period is higher than either the four- year period prior to the omission or the four years following the omission.

V. Implications for Beta Forecasting and Rate Setting

A partial resolution to the beta measurement problem is outlined by Peseau and Zepp [22], who show that the effect of the dividend omission was transitory and could be diagnosed from examination of OLS statistics. Although the dividend omission produces beta estimation problems for Consolidated Edison, subsequent estimates using data after the omission become much more reasonable.

The primary difference between the Brigham and Crum [5] forecast using an OLS beta and the Peseau and Zepp comment lies in the assumption of the time-series process followed by beta. The OLS estimate for five years of return data is only a good beta forecast if beta follows a constant coefficient process. This assumption is untenable for an estimation period containing a major information release.

When beta is time-varying, a short-term unadjusted OLS estimate may not be the best estimate of beta. Instead, the forecaster, taking advantage of auto-regressive properties of beta, should adjust that short-term estimate toward an underlying mean beta. When beta is unstable but reverts to an underlying mean, beta instability would not preclude application of the CAPM, but might preclude use of an OLS beta.

Reliance on a short-term beta forecast, whether from an OLS estimate or the transient beta estimate in the Kalman filtering model, is appropriate only if the firm's beta follows a random walk process. This research shows little evidence suggesting the typical utility beta follows a random walk and no evidence that, specifically, Con Ed's beta follows a random walk.

Due to the preponderance of auto-regressive or random coefficient betas, the results of this study strongly support the use of Bayesian-type adjustment processes such as the one employed by Merrill Lynch. The results also suggest that the behavior of utility betas may differ from the behavior of large diversified samples of stocks. For example, since Blume [2] finds an underlying mean beta of 1.0 for a large sample of stocks, many Bayesian models will adjust the OLS beta estimate toward 1.0. The results of this study, however, indicate that 1.0 is too high an underlying mean for most utilities. Instead, they should be adjusted toward a value that is less than one. For Consolidated Edison, an underlying mean of 0.7 would be more appropriate.

VI. Conclusions

Understanding beta behavior requires more information than whether or not betas are stable. Development of statistical procedures admitting a continuously time-varying beta now allows forecasters to understand how beta may behave over the short run and how that short-run behavior can differ from long-run behavior. Measuring continuously time-varying betas also frees the forecaster from the limitations imposed by assuming a constant coefficient beta. Instead, like most economic variables, beta can be modeled as a coefficient that is always changing. From the time series process followed by betas, the forecaster also gains an understanding of the difficult problem of forecasting beta. The beta for the majority of utility companies in this sample follows either an auto-regressive process or a constant coefficient process. Very few appear to follow a random walk process, which would produce betas that are not only unstable but very difficult to forecast. On the other hand, with an auto-regressive process, a patient forecaster using relatively simple diagnostic procedures should be able to obtain a reasonable long-run estimate of systematic risk. A reasonable forecast of beta then admits application of the CAPM for utilities even if beta is time varying.

The strong evidence of auto-regressive tendencies in utility betas lends support to the application of adjustment procedures such as the Bayesian adjustment procedure presented by Vasicek [25]. This procedure depends upon beta following an auto-regressive process. In addition, the Kalman filtering methodology also provides objective prior estimates of the underlying mean beta and the adjustment rate toward that underlying mean.

Typical adjustment models use a prior estimate of about 0.35 for the adjustment rate toward the underlying mean and a prior estimate of 1.0 as the underlying mean. The results of this study indicate that an underlying mean of 1.0 is too high for most utilities and an adjustment rate of 0.35 is too low.

Although considerable variability in adjustment rates and underlying mean betas can be observed in the sample, it may not be necessary for a forecaster to apply the Kalman filtering approach in order to obtain these estimates. A reasonable estimate of the underlying mean may be obtained by OLS if applied to a very long time period. The prior estimate of the adjustment rate toward the mean can be obtained by considering the positive relationship between the adjustment rate and beta variability. Estimates of the prior adjustments in the Bayesian adjustment models could be applied without relying blindly on large-sample estimates that may not be applicable to utilities.

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