

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 457

In the Matter of

PORTLAND GENERAL ELECTRIC
COMPANY,

2024 Annual Power Cost Adjustment
Mechanism.

ORDER

DISPOSITION: SCHEDULE 126 APPROVED AS REVISED

I. SUMMARY

In this order, we authorize Portland General Electric Company (PGE) to recover Reliability Contingency Event (RCE) costs based on its requested \$80.3 million, as reduced by the two modifications we direct below, through Schedule 126. This amount is to be amortized over two years. We decline to extend the RCE mechanism an additional year beyond its stated sunset date.

II. PROCEDURAL HISTORY AND BACKGROUND

On July 1, 2025, PGE filed its 2024 annual power cost adjustment mechanism (PCAM) update. Schedule 126 is designed to recognize in rates the difference between actual net variable power costs and the net variable power cost forecast under Schedule 125, subject to certain thresholds. Schedule 126 defines how the power cost variance is calculated, including deadbands that are applied to either a positive or negative power cost variance, and sharing of any variance outside the applicable deadband between PGE ratepayers and shareholders. An earnings test permits collecting or refunding power costs only to the extent that PGE's actual earnings are more than 100 basis points lower or higher than PGE's authorized ROE.

The forecast for power costs in the 2024 calendar year was adopted in Order No. 23-386 in the 2024 Annual Update Tariff (AUT) docket UE 416. The adjusted 2024 baseline NVPC is \$928.5 million. Pursuant to a stipulation executed by PGE, the Staff of the Public Utility Commission of Oregon, the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) and adopted by the Commission

in PGE's 2024 general rate case proceeding (part of UE 416) concerning ratemaking treatment of costs incurred during RCEs, some 2024 costs are removed from the calculation of actual NVPC and handled through a separate RCE mechanism. The sixth partial stipulation in docket UE 416, implemented in PGE's Schedule 126, allowed PGE to recover 80 percent of actual RCE costs above the RCE costs forecast in the 2024 AUT, without application of the deadbands or earnings test; the remaining 20 percent of RCE costs flow through the existing PCAM.

PGE requests recovery of \$80.3 million associated with four 2024 RCEs: the January 2024 winter storm and events in July, August, and September of 2024. This amount constitutes 80 percent of the overall 2024 RCE cost variance. PGE acknowledges a negative variance of approximately \$69 million in non-RCE NVPC after adjusting for its updated recovery request, but states that after application of the deadband and earnings test, no refunds are due on that amount because PGE's 2024 adjusted actual ROE (assuming RCE cost recovery) would have been below the 10.5 percent that would trigger refunds under the earnings test.¹

Staff, CUB, and AWEC all participated as parties to this proceeding and filed written testimony. The parties did not identify any witnesses for cross-examination, and no evidentiary hearing was held in this matter. PGE, CUB, and AWEC filed opening briefs on February 11, 2026; Staff filed its opening brief on February 12, 2026 with a motion for extension of time, which the Administrative Law Judge granted on February 19, 2026. Staff, CUB, and AWEC each filed closing briefs on February 25, 2026, and PGE filed its closing brief on March 11, 2026.

III. CONTESTED ISSUES

A. Reliability Contingency Mechanism Costs

1. Introduction

In docket UE 416, the Commission adopted multiple stipulations among the parties to PGE's 2023 request for a general rate revision.² As relevant here, the sixth partial stipulation as adopted in Order No. 23-386 provides:

- a. Parties agree that 80% of actual Reliability Contingency Events (RCE) costs above the RCE forecast from PGE's Annual Update

¹ PGE Opening Brief at 5-6; PGE Closing Brief at 8-9.

² *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 416, Order No. 23-386 (Oct. 30, 2023).

Tariff (AUT) will be recovered through rates in Schedule 126 and not be subject to the earnings test or deadbands for the annual power cost variance.

- b. Parties agree that the remaining RCE costs not recovered will flow through the existing PCAM.
- c. This mechanism will sunset after 12/31/2025.³

The definition of Reliability Contingency Event in Schedule 126 included in PGE's Initial Filing in docket UE 416⁴ is:

An event qualifies as a Reliability Contingency Event (RCE) for cost recovery when 2 out of the 3 criteria are met:

- 1. The Day-ahead Mid-Columbia index prices exceed \$150/MWh.
- 2. PGE is eligible to request or acquire resource adequacy (RA) assistance through a regional RA program in which it participates.
- 3. A neighboring Balancing Authority has publicly declared an event that indicates potential supply or actual supply constraints.

Currently-effective Schedule 126 provides, with respect to the RCE mechanism:⁵:

Reliability Contingency Event (RCE) power costs are the amount of annual actual power costs prudently incurred during RCEs. Through an RCE Power Cost Mechanism, RCE Power Costs, adjusted by any amount of RCE forecast included within Schedule 125 for the associated calendar year, qualify for 80% cost recovery or refund. The remaining RCE costs not recovered through the RCE Power Cost Mechanism will flow through the Annual Power Cost Variance, subject to deadbands and 90% sharing.

The RCE power costs recoverable through the RCE Power Cost Mechanism will not be subject to the earnings test or deadbands for the Annual Power Cost Variance.

³ *Id* at Sixth Partial Stipulation at 47-48 (also citing n 1 (Reliability Contingency Events “[t]o be consistent with the definition provided in the proposed revisions to Schedule 126 included in PGE’s Initial Filing”).).

⁴ Docket No. UE 416, Initial Utility Filing, Schedule 126, Original Sheet No. 126-4, (Feb. 15, 2023). The definition of RCE in the currently effective Schedule 126 is nearly identical to the version included in PGE’s Initial Filing in docket UE 416, except that the words “at least” have been inserted before “2 out of the 3” in the first sentence. Schedule 126, First Revision of Sheet 126-4.

⁵ Schedule 126, Original Sheet No. 126-1.

Pursuant to Commission Order No. 23-386, the RCE Power Cost Mechanism will be in effect for PGE’s filings under this schedule submitted on or around July 1, 2025 for 2024 power costs and submitted on or around July 1, 2026 for 2025 power costs and shall not apply thereafter unless otherwise ordered by the Commission.

According to Schedule 126, “[s]ubject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90 [percent] of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.”⁶ Schedule 126 defines “Annual Variance” as “the dollar amount calculated annually based on the following formula: (Actual Unit NVPC – Adjusted Base Unit NVPC) * (Actual Loads – RCE Loads).”⁷ The “Actual Unit NVPC,” in turn, “is calculated based on the following formula: (Actual NVPC – 80% RCE costs) / (Actual Loads – 80% RCE Loads).”⁸

The third partial stipulation in UE 416, also adopted in Order No. 23-386, provides in pertinent part, “[f]or settlement purposes in this docket, Parties agree to reduce the RCE cost included in the 2024 NVPC forecast by \$1.6 million.”

In Order 23-424, the Commission adopted the seventh partial stipulation in UE 416, which includes the parties’ agreement for settlement purposes that “inclusive of the \$1.6 million reduction in Reliability Contingency Events (RCE) cost described in the Third Partial Stipulation, PGE’s 2024 NVPC forecast will include an RCE forecast of no more than \$2 million.”⁹

As part of its 2024 PCAM, PGE originally requested to recover \$86,323,578 in 2024 RCE costs. PGE states that this amount is 80 percent of the 2024 RCE costs, net “\$2 million that was contemplated in customer rates.”¹⁰ In reply testimony, PGE reduced its request to \$80.3 million, which PGE states equates to \$96.5 million including interest and the revenue sensitive factor. The parties have raised issues with PGE’s proposed costs and RCE cost calculations, as well as PGE’s interpretation of what constitutes an RCE. Staff requests that the Commission remove \$15.58 million from PGE’s originally claimed total RCE costs, 80 percent of which equates to a \$12.46 million reduction from PGE’s

⁶ Schedule 126, Original Sheet 126-1.

⁷ Schedule 126, Original Sheet 126-3.

⁸ Schedule 126, First Revision of Sheet 126-2.

⁹ Docket No. UE 416, Order No. 23-424 App. A at 2.

¹⁰ PGE/100, Outama-Pedersen-Schwartz/15.

originally requested \$86.3 million.¹¹ AWEC and CUB each assert that PGE’s recovery, including RCE costs, should be capped at the overall net 2024 power cost variance of \$6,011,441. CUB requests that the Commission determine that the 2024 power cost variance is \$6 million due to RCE costs, with a final PCAM rate of \$5.4 million after applying the 90 percent customer sharing to the applicable costs. AWEC requests that the Commission deny recovery of all PGE’s RCE costs.

2. *Positions of the Parties*

a. *PGE*

PGE requests that the Commission approve its requested recovery of \$80.3 million of prudently incurred costs under the RCE mechanism. PGE states that it identified all days that qualified as an RCE using the definition of an RCE provided in PGE Schedule 126. PGE notes that the RCE mechanism allows it to recover 80 percent of the costs that are incurred during an RCE event, and states that the request for recovery of \$80.3 million represents 80 percent of total RCE costs incurred during 2024. According to PGE, it has reduced its request by \$6 million in response to Staff’s recommendations;¹² it requests that the Commission reject Staff’s other adjustments as unsupported.

PGE asserts that the RCE mechanism does not require PGE to call a “No Touch” event internally for an event to qualify as an RCE, noting that there is no such requirement in the Schedule 126 definition or the sixth partial stipulation. PGE argues that the PGE testimony Staff cites in support of requiring PGE to call a No Touch event is not relevant because that testimony predated the sixth partial stipulation which, PGE says, ultimately adopted an RCE mechanism that differed from PGE’s original proposal.

In response to Staff’s position that PGE imprudently over-procured in the day-ahead for certain RCE days, PGE argues that Staff’s proposal applies perfect hindsight, but prudence must be evaluated based on the information available to PGE at the time. PGE states that if it assumed wind generation in the day-ahead forecast and the wind

¹¹ See PGE Closing Brief at 3 n 6, publicly quoting the unredacted version of Staff/200 Zhao/26, and noting that Staff’s Position Statement recommendation of a \$15.48 million reduction appears to be a typographical error meant to say \$15.58 million).

¹² PGE accepts Staff’s proposed adjustment shifting \$5.17 million (80 percent of \$6.46 million) of cost associated with CAISO curtailments and PGEM real-time load balancing deviations to the standard PCAM process, effectively reducing the total cost for recovery in this docket by the same amount. PGE also agrees with Staff that the methodology for hydro costs should be updated to align with the approach used to calculate wind costs in this docket, but does not agree with Staff’s calculation, which PGE states omits the day-ahead step. PGE states that updating the RCE calculation methodology to align with wind costs results in a reduction of \$846 thousand. PGE/300, Outama–Pedersen–Ferchland/18.

generation did not occur in the real time window, PGE could have hourly energy shortfalls in real time.

Noting that there is no specific RCE calculation methodology from UE 416, where the RCE mechanism was first adopted, and that this is the first time the RCE mechanism is being applied, PGE requests that the Commission adopt its proposed RCE calculation methodology in this docket. PGE states that its seven-step calculation compares key elements of actual costs incurred during all RCEs against the AUT baseline forecast of RCE costs. PGE adds that its methodology to calculate the RCE costs was the only methodology put forth by the parties. In response to AWEC's recommendation that the Commission allow zero dollars of recovery for RCE costs prudently incurred, based on AWEC's assertion that PGE's RCE calculations are unsupported, PGE states that adopting AWEC's recommendation would result in PGE's return on equity (ROE) being 6.39 percent, which is 311 basis points below authorized ROE, and accordingly asks the Commission to reject AWEC's recommendation. PGE states that recovering \$80.3 million in RCE costs would result in a regulated ROE of 8.29 percent, which PGE notes is below both PGE's 2024 authorized ROE of 9.5 percent and the 10.5 percent ROE that triggers a refund under the PCAM earnings test.

PGE argues that CUB's recommendation for recovery of only \$5.4 million dollars and AWEC's assertion that any amount for recovery should be limited by the positive NVPC variance are inconsistent with the tariff language and the tariff's explicit mathematical formulas regarding the recovery of RCE costs and should not be adopted. According to PGE, Schedule 126 clearly excludes 80 percent of RCE costs from the annual variance calculation and PGE is allowed to recover 80 percent of RCE costs before the PCAM deadbands, sharing, and earnings test are applied to the remaining net variable power costs. PGE states that its negative power cost variance, which is attributable to the baseline NVPC exceeding the actual NVPC, is entirely disconnected from its under-recovery of RCE costs, as RCE costs were excluded from baseline and actual NVPC at the outset.¹³

PGE claims that CUB's argument that RCE mechanism costs are subject to the PCAM's 90/10 sharing is in direct conflict with the tariff as written. PGE states that per the plain language of the tariff, PGE is allowed to recover 80 percent of the RCE costs, which are then removed from Actual NVPC as shown in the tariff definitional formulas. According to PGE, the 90 percent sharing is only applied to the Annual Variance after asymmetrical deadbands are applied. PGE argues in addition that the sixth partial stipulation does not reference the 90/10 sharing because sharing of the RCE costs is already addressed by

¹³ PGE Closing Brief at 8 (citing PGE's Advice No. 23-40, Schedule 126).

what PGE terms “application of the 80/20 sharing.”¹⁴ PGE proffers an alternative interpretation, based on its initial proposal in docket UE 416, which it states requested to recover 100 percent of RCE costs “outside of the PCAM,” and, in addition, proposed to remove the earnings test and deadbands from the original PCAM structure. PGE thus argues that RCE costs are intended to be entirely outside of the PCAM, and that the stipulation’s explicit mention of the earnings test and deadbands is in response to PGE’s concern about those elements of the PCAM.

b. Staff

Staff does not believe that the Commission should adopt PGE’s proposed RCE calculation methodology. Staff notes that all parties have proposed adjustments to PGE’s calculation of RCE costs eligible for recovery, and states that the Commission should at minimum adopt Staff’s proposed adjustments. Staff recommends removing \$12.46 million from PGE’s originally proposed \$86.3 million in claimed RCE mechanism costs on the basis that some such costs are mischaracterized; others are imprudent; Staff disagrees with the calculation of hydro costs attributable to RCEs; and Staff questions the inclusion of certain market disruption costs.¹⁵

With respect to the characterization of RCEs, Staff asserts that RCEs are limited to situations in which PGE has called a “No Touch” event, and states that PGE’s position to the contrary is inconsistent with its initial UE 416 testimony and subsequent UE 416 stipulation, which, according to Staff, points back to PGE’s testimony. Staff notes in addition that the Schedule 126 definition refers to “an event,” which Staff interprets as meaning a “No Touch” event called by PGE.

Staff argues moreover that PGE incurred higher than necessary energy costs on several days due to discretionary over-procurement in the day-ahead planning window. Staff states that per PGE’s winter and summer contingency protocols for 2024, if there is a potential for a 1-in-5 load event in the winter (or a 1-in-10 in the summer) and the temperature across all of Western Electricity Coordinating Council (WECC) is well below (or above, in the summer) normal, PGE must reserve one half (107 MW) of the Port Westward 2 units and replace all, or a probability-adjusted value, of the day-ahead wind generation forecast. Staff adds that the contingency protocols also specify that, when a No Touch event is declared, PGE *may* elect to purchase physical energy in the day-ahead window equivalent to all, or a probability adjusted value, of the day-ahead wind generation forecast, one half of the Port Westward 2 units, or both. Staff concludes

¹⁴ PGE/400 Outama–Pedersen–Ferchland/20.

¹⁵ As noted above, PGE has accepted Staff’s adjustment related to the calculation of market disruption costs, and accepted the premise but not the calculation of Staff’s adjustment related to hydro costs.

that taken together, for No Touch events that are *not* approaching a 1-in-5 load event in the winter or a 1-in-10 in the summer, or when the temperature across all of WECC is not well below (in winter) or above (in summer) normal, PGE's decision to implement these reservation protocols is discretionary.¹⁶

Staff argues that PGE decisions to purchase energy in the day-ahead window to replace one half of the Port Westward 2 as well as 100 percent of the day-ahead wind generation forecast were not prudent on several days. Staff notes that based on peak load forecasts, PGE was required to implement both capacity reservation protocols for only four out of ten days analyzed by Staff. On these four days, the peak load forecasts were approaching the applicable threshold outlined in the protocols. Staff believes that implementing both protocols on the other six days Staff examined was imprudent. Additionally, with respect to PGE's protocol of purchasing energy in the day-ahead window equivalent to 100 percent of the day-ahead wind generation forecast, Staff notes that it has stated in past dockets including UE 416 and UE 452 that this assumption is unreasonable, corroborated by Staff analysis indicating that day-ahead hourly wind generation forecasts are very reliable in predicting actual hourly wind generation.

c. CUB

CUB notes that the variance between the actual 2024 NVPC—which CUB states amount to \$934.5 million¹⁷—compared with the forecasted 2024 NVPC of \$928.5 million, was \$6 million, or less than 1 percent, which CUB argues means that the higher costs of the RCEs were offset by periods of lower-than-normal power costs in the remainder of the year. CUB asserts that PGE has thus already recovered \$80 million of the RCE event costs, and that granting PGE's request would inappropriately allow it double recovery of this amount.

Pointing out that, while the stipulation says that 80 percent of RCE costs are not subject to the earnings test and the deadband, it is silent with respect to the PCAM's 90/10 sharing between ratepayers and shareholders, CUB argues that any RCE variance that will be applied to rates is still subject to the 90/10 sharing.

CUB recommends that the Commission determine that the power cost variance in the PCAM is \$6 million and that this is due to RCE costs, which are not subject to the deadband and earnings test. According to CUB, these costs, after applying the PCAM 90/10 sharing, amount to \$5.4 million.

¹⁶ Staff/200 Zhao/9-10 (citing confidential Staff/205, PGE's 2023-2024 Winter Contingency Plan and 2024 Summer Contingency Plan); *see also* confidential PGE/303, Summer and Winter Contingency Plans.

¹⁷ CUB/100 Jenks/5 (citing PGE/100 Outama – Pedersen – Schwartz/25 Table 3).

d. AWEC

AWEC argues that PGE should not recover any dollar amount pursuant to its RCE mechanism. AWEC disputes that PGE has demonstrated that it has actually incurred the RCE-related costs as calculated by PGE, stating that PGE's calculations of RCE-related costs are unsupported and do not represent a principled calculation of actual costs that PGE incurred in connection with deploying its RCE power operations strategy. AWEC states that rather than identify actual RCE-related costs, PGE multiplies the hourly MONET model variances for load, wind, and hydro by day-ahead market prices, a calculation which does not represent any actual costs PGE incurred.

AWEC asserts moreover that the RCE adjustment should be limited to only those amounts that exceed PGE's recovery through Schedule 126 rates on an annual basis, such that the RCE adjustment is limited to the positive total power cost variance of \$6,011,441 including RCE-related costs. According to AWEC, this treatment is consistent with the stipulation authorizing the RCE mechanism in Docket UE 416, which allows for 80 percent of actual RCE costs in excess of those included in PGE's forecasted NVPC rates to be exempt from the PCAM deadbands and earnings test.

3. Resolution

Following its acceptance of some of Staff's proposed adjustments, PGE asks to recover \$80.3 million in RCE costs. Coincidentally, the negative non-RCE mechanism NVPC variance originally cited in these proceedings was roughly \$80.3 million; after acceptance of the Staff adjustments, however, the negative non-RCE mechanism NVPC variance is approximately \$69 million. Given the close alignment between the original NVPC variance and PGE's revised requested RCE cost variance recovery, as well as the unexpected magnitude of the positive RCE cost variance, we understand the appeal of an approach that would allow the positive and negative variances to cancel one another out. Such an approach, however, is not supported by either the terms of sixth partial stipulation or the language of Schedule 126. The two variances are processed through differing mechanisms that lead to distinctly different results.

The interpretation of the sixth partial stipulation proposed by AWEC and CUB, in which the RCE variance is netted against any negative NVPC variance, is inconsistent with the plain words of the stipulation, as well as with the currently-effective text of Schedule 126 that PGE filed in compliance with the stipulation, and that we accepted. The sixth partial stipulation provides that "80 [percent] of actual [RCE] costs above the RCE forecast from PGE's [AUT] will be recovered through rates in Schedule 126 and not be subject to the

earnings test or deadbands for the annual power cost variance.” In other words, there is a separate RCE forecast in the AUT that is to be subtracted from actual RCE costs to determine the RCE variance, 80 percent of which is recovered through the RCE mechanism. The stipulating parties in UE 416 did not provide for any further netting of the RCE variance against the NVPC variance. And the calculations set out in Schedule 126 clearly remove 80 percent of RCE costs from actual NVPC before the remaining amount flows through the usual PCAM mechanism and is collected or refunded in rates.

As we stated in Docket UE 416, “[a] practice of changing stipulations that we have concluded are in the public interest in ways that alter the benefits and burdens accepted by other stipulating parties may undermine the benefits we seek in encouraging settlement, including conserving litigation resources, avoiding litigated outcomes and associated risks, and prioritization of efforts.”¹⁸

CUB is correct, however, that costs to be recovered through the RCE mechanism are subject to the PCAM’s 90/10 sharing. The sixth partial stipulation exempts 80 percent of RCE costs from the earnings test and deadbands; it does not exempt those costs from 90/10 sharing between ratepayers and shareholders. If the stipulating parties had intended to exempt 80 percent of RCE costs from all three PCAM elements, they would have listed all three elements. PGE’s alternative interpretation based on its original proposal in docket UE 416 is unavailing: as PGE has noted elsewhere, its earlier “testimony [in Docket UE 416] occurred before and not in connection with or support of the Sixth Stipulation that ultimately adopted an RCE mechanism that differed from PGE’s original proposal for full recovery of RCE costs and additional PCAM reform. Therefore, this testimony is not relevant to the Sixth Stipulation.”¹⁹ We agree. The sixth partial stipulation did not adopt PGE’s original proposal (other than the definition of Reliability Contingency Event), and that original proposal is irrelevant to the sixth partial stipulation. Nor is the tariff’s inclusion of an equation applying 90/10 sharing to non-RCE mechanism costs but not to RCE mechanism costs dispositive; as PGE has pointed out, “[b]ecause docket UE 416 did not provide a specific calculation methodology, this is the first opportunity for parties to develop a RCE cost calculation methodology that is consistent with the plain language of the Sixth Stipulation and Schedule 126.”²⁰ In other words, Schedule 126 does not include *any* equations implementing the RCE mechanism, beyond removing 80 percent of RCE variance from NVPC. And, like the stipulation, Schedule 126 itself explicitly exempts RCE mechanism costs from the deadbands and earnings test, but not from 90/10 sharing: “The RCE power costs recoverable through the RCE Power Cost Mechanism will not be subject to the earnings test or deadbands for the

¹⁸ Docket No. UE 416, Order No. 23-476 at 10-11 (Oct. 6, 2023) (citation omitted).

¹⁹ PGE Opening Brief at 20.

²⁰ PGE Opening Brief at 23.

Annual Power Cost Variance.” The recovery of 80 percent of RCE costs through the RCE mechanism and the remaining 20 percent through the PCAM is not, as PGE would have it, “80/20 sharing” analogous to the PCAM’s allocation of 90 percent of NPVC variance to ratepayers and 10 percent to shareholders; it divides RCE cost variance between two mechanisms, each of which is subject to 90/10 sharing between ratepayers and shareholders. In its compliance filing, PGE should apply 90/10 sharing to the 80 percent of RCE costs, net of the RCE forecast, that we find prudent and properly included as RCE costs.

AWEC’s concern that PGE’s request is not based on actual RCE costs is misplaced. Unchallenged evidence in the record states that it is not possible, under current standard utility accounting practices, to perfectly isolate the costs of each hour of an event from the utility’s accounting records and compare them to the AUT baseline.²¹ If the RCE mechanism is not to be a nullity, then, some form of approximation or assumptions about the portion of generation costs associated with the scale of the event is evidently required.

We turn next to Staff’s proposed adjustments to PGE’s requested RCE costs.

Staff’s position that an RCE entails an internal PGE declaration of a “No Touch” event is inconsistent with the sixth partial stipulation, which incorporates the definition of “Reliability Contingency Event” in PGE’s initial filing of Schedule 126 in Docket No. UE 416. That definition does not refer to “No Touch” declarations. The stipulation references only PGE’s initial filing of Schedule 126; it does not incorporate PGE’s testimony. Nor does the currently-effective Schedule 126 include a requirement that PGE have called a “No Touch” event.

Staff’s concern regarding the prudence of PGE’s day-ahead procurement decisions has merit. PGE did not explain the reasonableness of its decisions to go beyond the measures set out in its protocols by reserving excessive capacity in the day-ahead window on days that were not approaching the relevant peak load forecast thresholds. It is true that, as PGE states, if it assumed wind generation in the day-ahead forecast and the wind generation did not materialize in the real time window, PGE could have hourly energy shortfalls in real time. That a risk *exists*, however, tells us nothing of the risk’s magnitude, and thus nothing about whether PGE’s choices to insure against that risk are prudent. Staff has presented evidence that day-ahead forecasts of hourly wind generation are quite reliable, which PGE has also not refuted, and which Staff has demonstrated was available to PGE prior to the events at issue. In its compliance filing, PGE should remove from its RCE costs the power costs indicated at Staff/200 Zhao/21, lines 11 to 16.

²¹ PGE/300 Outama–Pedersen–Ferchland/16.

With the two modifications required herein to PGE's requested recovery of \$80.3 million in RCE costs—application of 90/10 sharing and removal of certain power costs—we find that the rates resulting from this order will be fair, just, and reasonable.

B. Amortization Period

1. Introduction

PGE proposes to amortize its proposed costs over a two-year period. Staff concurs with PGE's two-year amortization period. CUB proposes that PGE amortize the costs over a four-year period. AWEC proposes no amortization period, because it recommends that PGE recover no costs.

2. Positions of the Parties

a. PGE

PGE argues that the costs approved for recovery should be amortized over a two-year period beginning on April 1, 2026. PGE states that the Commission approved modified blended treasury rate is the applicable interest rate for the recovery period. PGE asks the Commission to reject CUB's recommendation to amortize the approved costs over a four-year period, noting that customers would be paying more overall if costs were amortized over a four-year period with interest accruing for twice as long.

b. Staff

Staff recommends amortization over a period of no more than two years.

c. CUB

CUB recommends that the amount that the Commission determines is eligible for recovery from customers be collected starting April 1, 2026, spread over a four-year period, with the appropriate risk-free interest rate, which CUB states is the modified blended treasury rate.

d. AWEC

Because AWEC recommends the RCE adjustment be set to zero and eliminated from the PCAM recovery, AWEC further recommends setting the deferral period to zero because the remaining power cost variance falls within the deadband limits. If the Commission

determines that PGE should recover some or all of its RCE-related costs, AWEC states that the Commission should balance rate impacts to customers with additional costs incurred from interest accruing on deferred amounts; AWEC agrees with Staff and PGE that a two-year amortization period may be reasonable.

3. Resolution

We find that a two-year amortization period, at the modified blended treasury rate, best balances limitation of short-term rate impacts against the overall higher cost to ratepayers of extending the amortization period.

C. Reliability Contingency Mechanism Extension

1. Introduction

PGE proposes to extend the RCE recovery mechanism established by stipulation in docket UE 416 by an additional year. Staff, CUB, and AWEC oppose PGE's proposal to extend the RCE mechanism, and CUB requests that the Commission remove the mechanism from Schedule 126 prior to PGE's filing to recover such costs. CUB proposes that the power cost threshold for an event be raised to \$250/MWh if the Commission does not eliminate the RCE recovery mechanism.

2. Positions of the Parties

a. PGE

PGE requests that the RCE mechanism (in a simplified form) be extended one year, describing the mechanism as allowing the utility to preserve reliability without facing financial disincentives for taking prudent reliability focused actions under extraordinary stress conditions. PGE asserts that the stress conditions that created the need for the RCE mechanism have persisted. PGE believes that the RCE mechanism is a lower cost, more targeted, and more transparent means of addressing RCE events compared to hedging alternatives. Finally, PGE notes that the one-year extension aligns with PGE's move into the California Independent System Operator's Extended Day-Ahead Market.

b. Staff

Staff asserts that the RCE mechanism is significantly flawed and has failed to serve the purpose for which it was intended, and that it therefore should not be extended.

c. CUB

CUB recommends elimination of the RCE mechanism from future PCAM calculations. In addition, CUB notes that PGE's 2024 residential rates were 18.2 cents/kWh, or \$182/MWh, which is higher than the current dollars per MWh trigger. CUB recommends that if the Commission chooses to keep the RCE mechanism, the power cost threshold for an event be increased to \$250/MWh, which CUB states would ensure that the trigger is related to PGE seeing power costs that are higher than its retail revenues while providing a buffer for further PGE rate increases.

d. AWEC

AWEC argues against extension of the RCE mechanism, noting that it was agreed to as part of a larger stipulation in PGE's 2023 general rate case. AWEC describes extension of the RCE mechanism as a substantial policy decision and one that is not appropriate for consideration in a PCAM. AWEC believes that any extension of the RCE mechanism beyond the sunset date agreed upon in the 2023 general rate case should be reserved for a future rate case proceeding where the entirety of the risks and benefits to be shared by customers and ratepayers can be considered.

3. Resolution

This case demonstrates how challenging decision making is in this time of rapid change in the energy sector. We have previously determined that the existing ratemaking mechanism strikes the right balance of risk and competing policy priorities.²² PGE articulates its view that the existing mechanism increases costs to customers and, in light of changing power market dynamics, sharing the risks differently would reduce customer costs overall. This record does not develop analytical support for that hypothesis and the premise is disputed by other parties. However, those parties agreed to adjust the mechanism in a limited fashion in UE 416. Commission and party time and resources, as well as repeated shocks to the energy system, limit full visibility into the scale of the risks on both sides of a proposed change. It cannot be assumed that the status quo is lower risk or cost and will not generate unexpected outcomes. It is similarly difficult to ensure that changes to existing approaches do not create unanticipated outcomes. Whether changes are crafted through negotiated stipulations or the Commission's fully litigated processes, whether in a general rate case or in a single-issue proceeding, unanticipated outcomes, as this case seems to raise, may emerge.

²² See, e.g., Order No. 15-408, Docket No. UM 1662 (describing PGE and PacifiCorp PCAMs as "designed to promote various regulatory policies and to operate in the long-term interests of the utility shareholders and ratepayers," and declining to adopt separate ratemaking treatment for variable costs associated with renewable resources).

Stipulations are an important tool in this era of rapid change, so it remains important to uphold adopted stipulations, as discussed above. The stipulating parties in Docket No. UE 416 agreed to, and we adopted, a sunset date of December 31, 2025 for the RCE mechanism. The sunset date was one element of a broad stipulation that addressed many issues beyond the RCE mechanism, and the stipulation was adopted in the course of a general rate case. We will not extend the agreed-upon sunset date as PGE requests, expanding the scope of this exception to the PCAM, nor will we alter the negotiated outcome by accelerating the mechanism's termination as CUB asks. For the same reason, we decline to alter the definition of a Reliability Contingency Event agreed to in the stipulation we adopted.

IV. ORDER

IT IS ORDERED that:

1. Advice No. 25-20, filed on July 1, 2025, is permanently suspended.
2. Portland General Electric Company must file a revised Schedule 126 consistent with this order to be effective April 1, 2026.

3. In its compliance filing, the company is directed to provide detailed rate impacts for the adjustment authorized in this order as well as the combined rate impacts for all rate adjustments to be effective on April 1, 2026. All rate impacts should be expressed relative to current overall rates, both in dollar and percentage terms. For the individual and combined rate impacts, the company is directed to provide average residential customer bill impacts, identifying the associated level of usage.

Made, entered, and effective Mar 18 2026.



Letha Tawney
Chair



Les Perkins
Commissioner



Karin Power
Commissioner



A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001- 0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.