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March 16, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: AR 676--PacifiCorp's Comments on Multi-year Ratemaking and Performance-Based Ratemaking

PacifiCorp d/b/a Pacific Power respectfully submits the following comments in Docket No. AR 676. PacifiCorp appreciates the opportunity to comment on the Public Utility Commission of Oregon (Commission) Staff's questions circulated on March 5, 2026, and offers the comments below in the interest of continuing more in-depth discussions with Staff and other parties regarding the rules at issue in this rulemaking.

I. Introduction

Before responding to the questions below, PacifiCorp briefly summarizes the relevant statutory principles. As discussed during Workshop 3, the Department of Justice provided a clear articulation of these principles, several of which PacifiCorp reiterates in the table below.

Table 1: Statutory Principles for Rate Mechanisms

Statute	Principle
ORS 756.040	Rates must provide adequate revenue to cover a utility's operation expense and capital;
ORS 756.040	Rates must allow the utility to earn a return that is commensurate with the return on investments in other enterprises having corresponding risk;
ORS 757.335	Rates must be sufficient to ensure confidence in financial integrity of the utility, allowing the utility to maintain its credit and attract capital;
ORS 757.217	Requires adoption of rules for applicable utilities to establish multi-year rate plans; and
ORS 757.046	Authorizes the Commission to establish performance-based rates, with incentives and penalties, for electric utilities to achieve regulatory objectives listed in statute.

In sum, ratemaking mechanisms should allow a utility to recover operating and capital costs, earn a reasonable return, maintain financial integrity, and—within a multi-year rate plan—provide appropriate incentives to achieve statutory state policy objectives. These policy objectives are expressly defined in ORS 757.046.

Importantly, ORS 757.046 did not repeal the existing statutory framework. Rates must still be sufficient to recover prudently incurred costs, maintain financial integrity, and provide a reasonable opportunity to earn a rate of return adequate to attract capital. Indeed, rather than displacing these requirements, ORS 757.046 builds upon them by asking how utilities may be further incentivized to achieve additional state policy objectives.[1] Consistent with the Department of Justice presentation, PacifiCorp views ORS 757.046 as complementary to—not a departure from—ORS 756.040 and ORS 757.335.

When assessing existing regulatory frameworks, it is important to keep these statutory goals in mind. This is because many current structures—such as deferrals and automatic adjustment clauses—are likely to become more prevalent under performance-based ratemaking (PBR) and multi-year rate plan (MYRP) constructs. This is due both to the inherent limitations of the long-term forecasting underlying an MYRP,[2] and to the fact that these mechanisms represent an effective form of PBR. They appropriately establish proper incentives to utilities by ensuring that cost recovery, or the opportunity for cost recovery, align with the incurrence of costs necessary to implement Oregon's policy objectives.

By contrast, other structures—such as the deadbands associated with the Power Cost Adjustment Mechanism (PCAM)—operate in a punitive manner by imposing penalties associated with inherent forecast variances established through the Transition Adjustment Mechanism (TAM). For example, if the market price of natural gas exceeds the forecast embedded in the TAM, PacifiCorp may be penalized by up to $30 million for that variance, notwithstanding that the deviation is entirely driven by external market conditions beyond utility control. This penalty is automatically assessed without regard to utility performance or PBR principles. As discussed further in the response to Question 3, Oregon is one of only four jurisdictions in the United States that employs such a punitive mechanism for power costs, with Oregon having the largest deadbands in the country.

PacifiCorp will expand on concepts in response to the questions below:

Question 1: Of the ratemaking mechanisms you identified in Workshop #3 as working well today, please explain why they work well and what outcomes or protections they provide that should remain important as the Commission explores MRP and PBR design.

From a PBR perspective, the most effective incentive is to align cost recovery with the incurrence of prudent expenditures needed to achieve Oregon's policy objectives. Reducing regulatory lag for critical investments both incentivizes timely action and preserves the liquidity necessary for ongoing operations.

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[1] ORS 757.046 ("The commission may use performance-based regulation to provide incentives and penalties to induce electric companies to bring electric utility operations in line with the public interest as declared under subsection (2) of this section and . . . .").

[2] Please see Attachment B for a copy of PacifiCorp's most recent prior submitted comments, which provide a discussion of the inherent inaccuracy of rate plan forecasts.

This principle is already reflected in Oregon's regulatory framework and should be expanded within a PBR and MYRP construct. For example, automatic adjustment clauses for renewable investment and wildfire mitigation function as effective PBR mechanisms by reducing regulatory lag and aligning incentives with needed investment. Automatic adjustment clauses will become more critical in a PBR and MYRP construct as they allow utilities to promptly recover costs for priority investments, mitigating liquidity risks associated with non-forecasted expenditures. Without such mechanisms, utilities may have to wait until the approval of a new MYRP to make these critical and dynamic investments that may not have been reasonably anticipated—potentially delaying important state policy objectives such as renewable development and wildfire mitigation.

Deferrals should also play an increasingly important role under MYRPs given the inherent inaccuracy of multi-year forecasts.[3] For example, if a transportation electrification pilot is approved after a three-year rate plan is set, the associated costs—unforecastable at the time—would not be reflected in rates. A deferral allows those costs to be captured, and the program implemented thereby furthering Oregon's electrification policies without delay.

The alternative would require parties to speculate—when developing the rate forecast—whether a program would be proposed, approved, and at what budget, or effectively prohibit utilities from proposing programs during the pendency of a rate plan. Neither outcome is desirable, and the latter is plainly inconsistent with Oregon electrification policy. By contrast, deferred accounting is a well-established, reasonable means to record actual unforecastable costs incurred after a rate plan is set, align potential recovery with actual expenditures, and produce a more equitable PBR outcome that advances state policy. The Commission has taken this approach for a host of unavoidable compliance costs that further state policy, including but not limited to, programs that reduce energy burden, intervenor funding, advisory group costs, independent evaluator costs, and regulatory service fees. Without such mechanisms, these unquestionably prudent compliance costs—that have been ordered by the Commission after a rate plan is established—would be effectively unrecoverable if not accurately predicted in an MYRP forecast.

Accordingly, the most productive focus of this workshop should be on identifying additional areas where cost-recovery mechanisms can better align with the prudent incurrence of costs necessary to achieve the State's goals. This approach is undoubtedly the most effective way to provide utilities with the appropriate incentives to promptly further Oregon's policy objectives.

[3] PacifiCorp's last round of comments discussed the inherent inaccuracies and limitations of MYRP forecasts. These comments are included as Attachment B.

Question 2: In existing ratemaking structures in Oregon, what are the primary mechanisms or components that support balanced timing and risk sharing for cost recovery and why. In a possible MRP structure in the future, what mechanisms are most applicable for balancing timing and risk sharing for cost recovery?

Before addressing this issue, it is important to clarify what is meant by "risk sharing." In Oregon proceedings, some parties appear to define the relevant "risk" as customers paying the full and prudently incurred cost of service. For example, when actual net power costs exceed forecasts due to market conditions, parties argue that customers should not pay for that variance—resulting in a utility not recovering its cost of service.

But ORS 756.040 expressly contemplates that prudent expenditures are expenses that utilities should recover. The purpose of a PBR and MYRP framework should not be to shift risk from customers onto the utility. Rather, PBR should provide incentives for utilities to achieve high performance in providing safe, reliable and affordable service while meeting policy requirements. The goal of PBR should not be to restrict a utility's ability to recover its prudently incurred costs. Customers paying the full cost of service is not a "risk"; *it is the lawful intended outcome of ratemaking*. Treating such costs as a shared risk instead functions as a reduction in the authorized rate of return, undermining financial integrity and capital attraction in violation of ORS 756.040 and ORS 757.355.

Extending this form of "risk sharing" (i.e., cost disallowance) across additional cost-of-service components—such as employee compensation, pensions, wildfire mitigation, or insurance—would effectively erode a utility's authorized return. PacifiCorp supports prudence reviews as a legitimate form of PBR in rate setting—but opposes the systematic disallowance or "sharing" of the cost of service in contravention of ORS 756.040.

A goal of the ratemaking framework in Oregon should be to make the state an attractive destination for utility investment, particularly given its ambitious clean energy goals. Investors have choices, including alternatives such as equities or Treasury securities. When investors commit capital to utilities—often for assets with lives of 30 or more years—they reasonably expect rates to allow recovery of costs and a fair return. This is consistent with the longstanding *regulatory compact* between western states and private utilities.[4] Introducing punitive regulatory constructs, such as forcing utilities to "share" in prudently incurred costs through disallowances, undermine that expectation and deter capital investment. In such an environment, investors will rationally deploy their capital elsewhere.

[4] *See e.g., Western Electricity Emerging Market: State-Level Regulatory Analysis,* DUKE UNIVERSITY, Stephaine Lenhart & Lincoln Davies at 9 (March 27, 2023) ("Utilities and states participate in a mutually beneficial relationship known as a regulatory compact. Under this relationship, utilities traditionally have enjoyed exclusive service territories and the right to earn reasonable returns on their investments in exchange for providing efficient, reliable, universal service.").

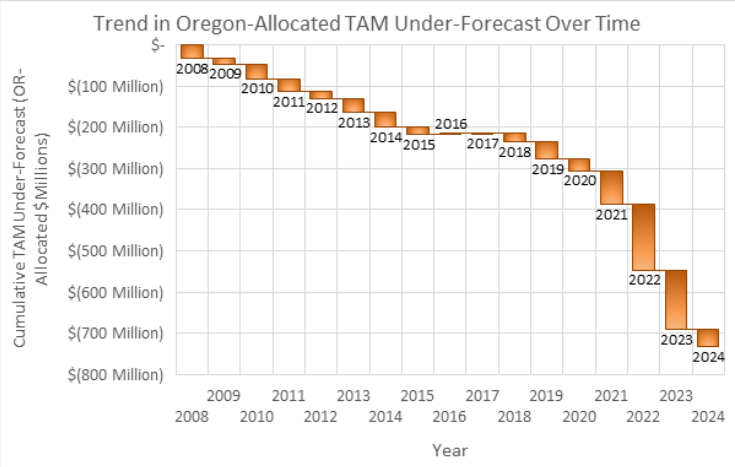
Accordingly, rather than focusing on the ill-defined concept of "risk sharing," which lacks statutory support, PacifiCorp submits that these workshops should focus on the objectives expressly set forth in statute. Those objectives include setting rates that recover prudently incurred costs, provide a reasonable opportunity to earn an authorized return, and create additional incentives to advance legislatively established policy goals. As noted above, ORS 757.046 builds on the existing statutory principles by asking how utilities can be further incentivized to achieve those goals.

The mechanisms discussed in response to Question 1 would advance these objectives by creating the proper incentives that align cost recovery with the actions necessary to meet Oregon policy goals. In addition, a portfolio-based review of provisional capital investments would further support these objectives by providing utilities with needed operational flexibility. This concept is discussed in greater detail in PacifiCorp's last round of comments, included as Attachment B.

Question 3: Of the ratemaking structures discussed in Workshop #3, identify which cost categories are most in need of attention or where improved outcomes are achievable? What regulatory mechanisms govern those, and how would they need to change? Please relate this to identified outcomes that your organization suggests for priority attention?

Of the current regulatory structures, the PCAM deadbands and sharing bands warrant the greatest concern. The TAM systematically produces understated power cost forecasts, resulting in disallowance of a substantial share of the variance between forecasted and actual costs in the PCAM. As shown in Figure 1, Oregon-specific TAM forecasts have largely been under-forecast for seventeen consecutive years, dating back to test period 2008.[5]

Figure 1: 17-Year TAM Performance



[5] With the one exception of test period 2016, the data incontrovertibly demonstrate the outcome of the prevailing dynamic within the Oregon TAM, wherein persistent downward adjustments proposed by parties do not achieve and are ultimately counter to the Commission's goal of accurate NPC forecasts.

The Commission has emphasized that accurate net power cost (NPC) forecasts are essential to setting fair, just, and reasonable rates.[6] Yet the TAM incentive structure encourages parties to push forecasts downward to achieve the lowest possible estimate, rather than the most accurate one. As a result, the PCAM deadbands and sharing bands operate as a systematic disallowance of prudent costs, not a legitimate PBR mechanism. In particular, the deadband functions as an automatic annual disallowance of up to $30 million in prudently incurred power costs—without any consideration of utility performance-based actions.

This is not an effective form of PBR; rather, it operates in a punitive manner toward utilities for TAM forecasting inaccuracies, which are often imposed by non-utility parties in the TAM proceedings. Power cost forecasting is inherently uncertain—even for sophisticated market participants—and utilities have limited control over key cost drivers, including weather-dependent renewable output, natural gas price volatility, and wholesale market conditions. These uncertainties will intensify as the West relies more on intermittent resources, experiences more extreme and unpredictable weather, and faces greater global geopolitical and trade-related instability. Consistent with this reality, past variances have generally not reflected any performance failures by PacifiCorp, but instead non-forecasted cost drivers not captured in the TAM forecast.

Utility control over power costs will be even more limited once PacifiCorp enters the Extended Day-Ahead Market (EDAM). EDAM will economically optimize most day-ahead, hour-ahead, and intra-hour generation and market transactions, leaving only pre–day-ahead hedging, long-term contracts, and reliability activities within the company's control. As a result, the economic operation of the system across these timeframes will be managed using centralized optimization, with oversight from a market monitor, to minimize costs for all participants. Under this structure, the majority of PacifiCorp's net power costs will be optimized—and largely outside of the utility's control.

These dynamics help explain why Oregon is one of only four jurisdictions that employ deadbands—with Oregon, in practice, having the largest deadband in the country at $30 million, compared to a jurisdiction such as Vermont, which employs a $0.3 million deadband (i.e., *one hundred times smaller*). In other words, 46 U.S. jurisdictions do not employ deadbands in their power cost mechanisms. A comparative summary of power cost mechanisms across all 50 U.S. jurisdictions is provided in Attachment A.[7] Furthermore, other states—such as Utah—have affirmatively prohibited such unfair structures in their power cost mechanisms, instead providing that "the commission shall allow an electrical corporation to recover 100% of the electrical corporation's prudently incurred costs as determined and approved by the commission under this section." [8]

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[6] Docket No. UE 307, Order No. 16-482 at 2-3.
[7] Attachment A reflects an analysis conducted in October 2023. It illustrates that four states employ deadbands, and nine states employ sharing bands.
[8] Utah Code § 54-7-13.5 (Energy Balancing Accounts).

Accordingly, PacifiCorp respectfully requests that this proceeding provide a focus on how to restructure the existing deadbands and sharing bands to achieve a performance-based construct that operates within a utility's reasonable control. With such a focus, PacifiCorp can further elaborate on the inherent difficulties associated with forecasting power costs, the limited degree of control utilities have over the major drivers of power costs, the implications of EDAM for managing power-cost risk, and how these bands can be reasonably structured to provide fair and effective performance-based incentives.

II. Conclusion

PacifiCorp appreciates the opportunity to submit these comments and looks forward to continued participation and collaboration in the workshop process.

If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

Robert Meredith
Director, Regulation

Attachment A

Review of PCAM Implementation in Other States

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Alabama			Alabama Power, Spire Alabama and Spire Gulf are regulated under Rate Stabilization and Equalization frameworks that adjust base rates periodically (see the Alternative regulation section). The tariffs of the major energy utilities include adjustment provisions to allow for recovery of changes in income taxes and certain general and local taxes. An Energy Cost Recovery, or ECR, mechanism is also in place for Alabama Power. The ECR mechanism is established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and reflects accumulated over- or underrecovered amounts.
Alaska			Electric fuel and gas commodity costs are recovered through mechanisms that are separate from base distribution rates. Alaska Electric Light and Power Co. utilizes a power cost adjustment that is updated quarterly. ENSTAR Natural Gas Co.'s gas cost adjustment is updated annually; both are subject to true-up.
Arizona		Yes. **APS'** PSA is subject to a $0.004/kWh annual cap on rate increases or decreases, unless the base cost of fuel and purchased power is reset.	Arizona Public Service Co., or APS, utilizes a Power Supply Adjustor, or PSA, a mechanism that permits the deferral and recovery of fuel and purchased power costs, certain production-related variable costs, and certain energy storage costs outside of a rate case. The PSA is subject to a $0.004/kWh annual cap on rate increases or decreases, unless the base cost of fuel and purchased power is reset. The PSA incorporates a forward-looking estimate of fuel and purchased power costs to set a rate that is subsequently reconciled with actual costs. The PSA consists of three components: the "forward component" that recovers or refunds differences between expected fuel and purchased power costs and those reflected in base rates; the "historical component," which tracks the differences between actual costs and those recovered through the combination of base rates and the forward component; and the "transition component," which provides for the recovery or refund of deferred balances stemming from the operation of the old PSA. The PSA also reflects margins from the sale of emissions allowances. Tucson Electric Power Co., or TEP, utilizes a purchased power and fuel adjustment clause, or PPFAC. The PPFAC includes a forward-looking component. A PPFAC is also in place for UNS Electric Inc., or UNS-E.
Arkansas			State statutes permit the electric utilities to request PSC approval of mechanisms that allow the recovery of costs related to fuel and purchased power, energy efficiency, purchased gas and certain other items. Energy cost recovery, or ECR, riders — Electric utilities recover fuel and purchased power costs through an ECR rider. The ECR rider is calculated annually, reflecting the actual cost in the previous calendar year, with an adjustment for projected changes. ECR rate changes are implemented automatically; however, a utility's ECR rider calculation is subject to a 15-day review period. The staff is permitted to audit any utility's ECR rider and can recommend adjustments to the ECR rate filed by the company.
California			The state’s major electric utilities utilize a balancing account, the energy resource recovery account, or ERRA, that is designed to track and allow recovery of the difference between electric procurement costs included in rates and actual costs incurred under each utility’s procurement plan. The PUC must review the revenues and costs associated with each utility’s electricity procurement plan at least annually and adjust retail electricity rates or order refunds as appropriate, typically once a year. In addition, rate changes can be implemented based on the ERRA trigger mechanism, which is effective when aggregate over-collections or undercollections exceed 5% of the utility’s prior-year electric generation revenues, excluding amounts collected for the Department of Water Resources. The PUC would make the final determination of an ERRA trigger mechanism rate change.
Colorado			Public Service Company of Colorado's, or PSCO's, fuel and purchased energy costs are recovered through an incentive based electric commodity adjustment, or ECA, that compares actual fuel and purchased power expenses to a formula based benchmark. The ECA also contains certain earnings-sharing provisions related to energy trading activities (see the Alternative Regulation section). PSCO utilizes a purchased capacity cost adjustment clause that allows for recovery of the costs of purchased power not included in base rates or other recovery mechanisms. Black Hills Colorado Electric Utility Company, or BHCE, is subject to an energy cost adjustment mechanism under which all fuel and purchased energy cost differences from the company's base energy cost rate are fully recovered from, or credited to, customers. The impacts of certain incentive mechanisms also flow through the mechanism.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Florida			The fuel cost recovery clause, or FCRC, and the capacity cost recovery clause, or CCRC, provide for recovery of prudently incurred fuel and purchased power costs, respectively. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek or the PSC may require a midterm modification to the factors if updated projected costs for the year vary from updated projected revenues by plus or minus 10%. Interest is accrued on both over- and under-recovered balances. Included in the FCRC is a generating performance incentive factor that provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis point ROE spread. The PSC generally requires market-based pricing of coal purchased from an affiliate. The FCRC also reflects gains from non-firm energy sales. A three-year moving average based on eligible sales is determined, and 100% of the sales up to this benchmark are credited to ratepayers. For sales above the benchmark, 80% of the gains accrue to ratepayers, with 20% retained by Duke Energy Florida LLC, Tampa Electric Co. Company, or TEC, and Gulf Power Co
Georgia			A non-automatic fuel adjustment mechanism, known as the fuel cost recovery clause, is in place for Georgia Power, or GP. Hearings are required before increases or decreases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered/over-recovered fuel costs is considered in setting new rates. The energy portion of purchased power transactions is reflected in the mechanism; the capacity component is recovered through base rates. The cost of GP's natural gas and oil procurement hedging program, including any net gains or losses, are also recovered through the fuel cost recovery clause.
Hawaii		Yes. **Hawaiian Electric Companies** recover 98% of fuel cost fluctuations from customers and incur 2% (with utility exposure capped at $2.5 million)	Fuel adjustment clauses are in place for electric utilities. The clauses are adjusted monthly for changes in fuel costs and the fuel-cost component of purchased energy, and for variations from the forecasted generation mix. Hawaiian Electric Company's, or HECO's, purchased power adjustment clause, or PPAC, is designed to recover purchased power capacity costs and the O&M expense component of purchased power energy costs. Similar mechanisms are in place for Hawaii Electric Light Company, or HELCO, and Maui Electric Company, or MECO. Rates under the PPAC mechanisms are adjusted monthly,
Idaho		Yes. **Avista's** PCA enables the company to defer 90% of net power cost deviations, similar to **PacifiCorp. Idaho Power**'s PCA includes a 95% sharing mechanism	Electric power cost adjustment (PCA) mechanisms are utilized by Avista Corporation, Idaho Power (IP), and PacifiCorp. Semi-automatic purchased gas adjustments are utilized by Avista and Intermountain Gas. Electric and gas utilities may seek PUC approval to issue energy cost recovery (securitization) bonds to moderate the impact of power cost increases on customers (see the Securitization section). Avista's PCA enables the company to defer, in a balancing account, 90% of the difference between actual net power costs and the amount included in retail rates. IP has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, wholesale energy prices, and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.
Indiana			FAC proceedings Electric utilities may adjust rates for changes in fuel and purchased power — energy component only — costs generally every three months, following hearings, through the FAC. The FAC is based on estimated costs of fuel and purchased power for a future three-month period, with an additional factor to account for over- or under recoveries caused by variances between estimated and actual costs in the previous three-month period. No carrying charges accrue on over- or under-recoveries. The adjustment factor may be modified more frequently than every three months under emergency circumstances. By law, the URC may not approve an FAC rate adjustment if it will result in the utility earning a net operating income, or NOI, in excess of that authorized.
Iowa			Energy adjustment clauses, or EACs, are modified monthly based on forecast energy costs and fuel and purchased power for two months. The capacity/demand portions of purchased power are recovered through base rates. Under- and over-recoveries are deferred and respectively charged and credited to customers in the succeeding months. Interstate Power and Light Co., or IP&L, uses an EAC that provides for recovery of fuel and purchased power costs as well as revenues and costs associated with sales or purchases of emission allowances. MidAmerican Energy Co. uses an EAC that excludes chemical-related costs.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Missouri		Yes. **Empire District Electric Co, Kansas City Power and Light,** and **Union Electric** can all recover 95% of fuel and purchased power costs, net emissions allowance costs and OSS revenues that vary from levels included in base rates.	Empire District Electric Co. utilizes an FAC that provides for the company to recover from/flow to ratepayers, on a semi-annual basis over six-month recovery periods, 95% of incremental variations in "prudently incurred" fuel and purchased power costs, net emissions allowance costs and OSS revenues from the levels included in base rates. In a 2015 rate case decision, the PSC required that a portion of the transmission costs Empire incurs related to its participation in the Southwest Power Pool, or SPP, market be excluded from its FAC [...] Union Electric Co., or UE, utilizes an FAC that provides for the company to recover from/flow to ratepayers 95% of incremental variations in prudently incurred fuel and purchased power costs, net emissions allowances and OSS revenues from the levels included in base rates. UE's FAC incorporates three adjustments per year and eight-month-long recovery periods [...] In a 2015 rate case decision, the PSC authorized Kansas City Power and Light Co., or KCP&L, to implement an FAC that provides for the company to recover from/flow to ratepayers 95% of incremental variations in prudently incurred fuel and purchased power costs, net emissions allowances and OSS revenues from the levels included in base rates. KCP&L's FAC incorporates two adjustments per year and 12-month recovery periods.
Montana		Yes. **NorthWestern Energy** and **MDU Resources Group** both have power cost adjustment mechanisms that include a 90% rate payers/10% shareholders cost share	On July 14, 2017, NorthWestern filed its Power Costs and Credits Adjustment Mechanism, or PCCAM, proposal with the commission. The proposed PCCAM provides for annual adjustments based on 12 months of actual data, and provides of a 90%/10% allocation between rate payers and shareholders of the related costs. The PCCAM would temporarily apply to Demand Side Management program costs and certain administrative and general costs until future treatment is determined as part of NorthWestern's next general electric rate case. The commission is expected to hold a hearing on the matter on May 31, 2018. MDU Resources Group utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions, including a 90%/10% sharing of the costs reflected in the mechanism.
Nevada			Electric utilities are subject to a deferred energy cost recognition procedure, under which Commission approval is required prior to implementation of changes in the recovery of fuel and purchased power costs. In accordance with this procedure, Nevada Power Company, or NPC, and Sierra Pacific Power Company, or SPP, file quarterly deferred energy adjustment applications, or DEAAs, proposing to recover or refund the deferred balances, representing the difference between actual fuel and purchased power costs incurred and the amounts currently reflected in rates. Electric utilities must reset, on a quarterly basis, the rate for ongoing fuel and purchased power costs, referred to as the base tariff energy rate, or BTER. The quarterly reset is designed to reflect power costs on a more current basis, thereby eliminating large deferred energy balances. These quarterly BTER adjustments are reviewed annually by the PUC as part of the companies' DEAA filings. Costs eligible for recovery include all prudent expenses incurred to purchase fuel, capacity, and energy, as well as the carrying charges on deferred balances. The burden of proof regarding prudence rests with the utility.
New Mexico			Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause, or FPPCAC, for an electric utility is calculated monthly, but a variance from monthly reporting may be sought. The FPPAC includes a balancing account in which there is approximately a two-month collection lag. A utility is required to reapply for continuation of an FPPCAC every four years, at which time a comprehensive review of the clause is undertaken. In 2008, the PRC authorized Public Service Co. of New Mexico, or PSNM, to establish an emergency FPPCAC. The clause contained several conditions, including that the recoverable costs were subject to a prudence review. PSNM's FPPCAC had been eliminated in 1994, following a stipulation. In 2009, the PRC adopted a rate case settlement that included the reinstatement of the company's FPPCAC on a permanent basis. The fuel factor is adjusted annually. Additionally, the approved settlement contained an SO2 rider through which customers are credited with their share of revenues from allowance sales. El Paso Electric Co., or EPE, may seek approval to adjust its FPPCAC if the company experiences an over- or under-recovery balance of at least $2 million of fuel and purchase power expenses as of Dec. 31 and June 30 of each year. Southwestern Public Service Co., or SWPS, uses an FPPCAC under which it may petition for a change in the fuel factor if the over/under-recovery balance reaches $5 million.
North Carolina			Prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause, or FAC. Each utility has an annual hearing to review fuel costs, with a test period determined by the NCUC for each company. The proceedings provide for a true up of any over or undercollections from the previous year, with interest included only for overcollections. The costs of certain reagents used in reducing or treating emissions, as well as certain nonfuel purchased power costs for economic purchases, may be recovered through the FAC. The law limits the annual increase in recoverable costs related to certain purchased power contracts to 2% of a utility's total retail revenues.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
North Dakota			Mechanisms that provide for automatic recognition of changes in fuel and the energy portion of purchased power costs are in place for Northern States Power, or NSP, MDU Resources Group and Otter Tail Power, or OTP. Fuel and purchased power cost adjustments are implemented monthly and are based on a rolling four-month history. There is generally a two-month lag for recovery. MDU also recovers capacity costs associated with purchased power through its fuel and purchased power adjustment clause.
Oklahoma			Fully automatic electric FACs are prohibited in Oklahoma. However, semi-automatic FACs are in place. Utilities may propose a change in the current FAC billing factor according to each company's Commission-approved FAC tariff. Once the utility files for a change in its FAC rate, the staff has five days within which to respond. If the staff files objections to the change, a formal investigation is initiated; if the staff files no objections, the proposed rates become effective. The historic costs and revenues included in the FAC are reviewed by the OCC after each calendar year for accuracy and prudence. Oklahoma Gas & Electric Co.'s, or OG&E's, FAC is typically adjusted semi-annually but can be adjusted quarterly if costs have changed and are expected to remain at their current levels for the foreseeable future or if the monthly over or undercollected FAC amounts for a given period are greater than 5% of the company's projected annual Oklahoma-jurisdictional fuel costs. Purchased power and certain cogeneration and capacity payment differentials are reflected in the FAC. OG&E also recovers a portion of the transportation costs associated with gas deliveries to its generating facilities through the FAC. Public Service Co. of Oklahoma's, or PSO's, FAC is adjusted annually, subject to a cap on under and overrecoveries. However, an immediate adjustment may be implemented if the under or overrecovered balance exceeds $50 million. Otherwise, amounts that differ from the levels reflected in base rates are deferred in a balancing account, and the deferrals are recovered over the subsequent 12 months. The FAC also allows for current recovery of line losses above or below the amount recognized in PSO's base rates. Such under or overrecoveries are recovered from, or refunded to, customers during subsequent months. Ratepayers' 90% share of off system sales margins flow through PSO's FAC.
Oregon	Yes, **PGE** and **PacifiCorp** have a -$15 to $30 million deadband, while **Idaho Power's** costs/savings are reduced by a deadband of 250/125 ROE basis points	Yes. PCAMs for **PGE, PacifiCorp,** and **Idaho Power** all recover 90% of cost deviations outside of a deadband	Portland General Electric, or PGE, PacifiCorp, and Idaho Power, or IP are permitted to annually adjust rates to reflect forecasted power costs. PGE's and IP's mechanisms include a component under which a portion of the difference between actual and forecasted power costs is deferred for future recovery or refund. PGE's current power cost recovery framework includes both an annual update, under which rates change each January 1 to reflect updated net variable power costs, or NVPC, and a power cost adjustment mechanism, or PCAM, that is designed to capture a portion of the difference between the NVPC forecast established through the annual update, i.e., baseline NVPC, and the actual NVPC incurred by PGE for that year. The PCAM is subject to a deadband of $15 million below to $30 million above the ultimately established NVPC, a sharing ratio, and an earnings test. PGE absorbs 100% of the costs/benefits within a PUC-determined deadband, and amounts above or below the deadband are allocated 90% to customers and 10% to PGE shareholders. A surcharge or a refund would occur only if PGE's actual ROE is more than 100 basis points below or above PGE's last authorized ROE. PacifiCorp and IP have similar mechanisms.
South Carolina			Nonautomatic electric fuel and purchased gas adjustment clauses are in place for the state's utilities. Each electric utility is required to furnish the PSC an estimate of its fuel costs, including the cost of purchased power, for a prospective 12-month period. The PSC then determines the fuel-related costs to be included in base rates for that period, including adjustments for over or under recovery from the preceding 12-month period. Electric companies are required to account on a monthly basis for the difference between fuel costs recovered through base rates and actual fuel costs by booking the difference to unbilled revenue with a corresponding deferred debit or credit. Emissions allowance costs and the cost of certain materials used in reducing or treating emissions are reflected in the fuel clause.
South Dakota			Automatic fuel, purchased power, and gas cost adjustment clauses are permitted. Through these clauses, the utilities recover actual fuel, purchased power — energy portion only — and purchased gas expenses incurred; carrying costs accrue on unrecovered balances. The fuel clauses of Northern States Power-Minnesota, or NSP-MN, and Black Hills Power, or BHP, and NorthWestern Corp. contain certain incentive provisions.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
Tennessee			Automatic purchased power and gas commodity recovery clauses are permitted. The state's gas utilities are allowed to reflect a portion of uncollectible expenses in these clauses. Kingsport Power, or KP, has a fuel and purchased power adjustment rider that reflects any changes in the wholesale costs of the company's power supplier, affiliate Appalachian Power, or APCO, as well as transmission expenses. KP has no generating capacity of its own, and purchases 100% of its power requirements from APCO. Chattanooga Gas, or CG, has a purchased gas adjustment rider in place.
Utah			The PSC may allow electric and gas utilities to implement balancing accounts to recover purchased power and fuel costs. In 2011, PacifiCorp implemented a pilot energy balancing account, or EBA, that was to remain in place through 2016 and contained incentive provisions. However, legislation was enacted on March 29, 2016, that removed the incentive provision of the mechanism and extended the EBA through 2019. Also, PacifiCorp operates under a renewable energy credit mechanism that contains certain incentive provisions.
Vermont	Yes. **Green Mountain Power** can recover or credit costs outside a $0.3 million band	Yes. Through its power supply cost adjustment mechanism, **Green Mountain Power** can annually pass through to ratepayers 90% of the energy costs (or benefits) varying by more than $0.3 million from the energy costs included in rates	Green Mountain Power Corp., or GMP, has a PCA in place that allows the company to recover from, or credit to, customers on an annual basis 90% of the energy costs that are more than $0.3 million higher or lower than the energy costs included in rates through a power supply cost adjustment mechanism. Vermont Gas Systems, or VGS, has a PGA mechanism in place that allows for the recovery of all gas-cost variations on a quarterly basis. The Vermont Supreme Court has prohibited the use of PCA and PGA mechanisms, finding them to be inconsistent with the customer notice requirements under state law. However, these mechanisms are permitted when adopted as part of an alternative regulation plan.
Virginia			Electric fuel adjustment clauses, or FACs provisions are permitted. The SCC's FAC procedure provides for electric rates to be reset annually based on projected usage and costs. The utilities maintain accounts for any over or underaccruals, and these balancing accounts are reconciled through the following year's fuel factor. Purchased power and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor, but capacity charges are recovered through base rates. Appalachian Power Co., or APCO, Virginia Electric and Power Co., or VEPCO, and Kentucky Utilities Co., all use an FAC.
Washington	Yes. **Avista, PSE**, and **PacifiCorp** employ deadbands of respectively ± $4 million, ±$17 million, and ±$4 million respectively	Yes. Under **Avista's** ERM, if costs are $4 million - $10 million lower than those included in base rates, 75% of the energy cost savings flow to customers. Costs between $4 million to $10 million higher are shared equally, while differences above $10 million are allocated 90% to customers and 10% to shareholders. **PSE** and **PacifiCorp** similarly pass costs to customers outside of a deadband based on a	Avista Corporation's Energy Recovery Mechanism, or ERM, allows the company to adjust rates to reflect changes in power supply-related costs, with 75% of any energy cost savings to flow to customers and 25% to the company when actual annual power costs are between $4 million and $10 million lower than those included in base rates. Equal sharing is to occur when actual power costs are between $4 million and $10 million greater than the amount included in base rates. Any differences in excess of $10 million are to be allocated 90% to customers and 10% to shareholders. The ERM contains an adjustment trigger under which a surcharge or rebate occurs when the deferred ERM balance reaches ±$30 million. Puget Sound Energy's, or PSE's, Power Cost Adjustment Mechanism, or PCAM, allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers. Beginning in 2017, to the extent power costs are above/below the PCAM baseline amount, PSE is to absorb/retain the first $17 million above/below the baseline, and 10% of any amount that exceeds $40 million. For costs between $17 million and $40 million above the baseline, PSE is to absorb 50%. For costs between $17 million and $40 million below the baseline, PSE is to retain 35% of the benefits. A PCAM rate surcharge/credit is to be implemented when the deferred power cost balance reaches ±$20 million. Fixed production costs are no longer included in the PCAM. [...] In May 2015, the WUTC adopted a PCAM for PacifiCorp, following a settlement. The PCAM is a first for the company in Washington. The PCAM includes a $4 million dead band for net power cost variances, relative to a benchmark. For net power cost variances between $4 million and $10 million, the PCAM reflects asymmetrical sharing bands in which positive variances are to be allocated 50% to customers and 50% to PacifiCorp, and negative variances are to be allocated 75% to customers and 25% to PacifiCorp. Positive or negative net power cost variances in excess of $10 million are to be allocated 90% to customers and 10% to PacifiCorp.

State	Deadband	Risk Sharing	SNL Description of Adjustment Clause
West Virginia			Electric fuel and/or purchased power costs may be recovered through an ENEC proceeding. In addition to fuel costs, the ENEC reflects the energy portion of purchased power costs, the net benefit associated with affiliated and other wholesale sales, the demand portion of purchased power transactions, transmission costs and credits and any regional transmission organizationrelated costs. ENEC factors are set annually based on projected data for the prospective 12 months. Over- or under-recoveries based on actual data for the prior 12 month period are deferred for reconciliation as part of the next ENEC proceeding, with no carrying charges on the deferred balance. ENEC proceedings are typically completed within four months of filing.
Wisconsin	Yes, recovery for the five largest IOUs is subject to a ±2% deadband		Under the PSC's electric fuel rules, which apply to the state's five largest investor-owned utilities — Northern States Power Co. – WI, Wisconsin Power and Light Co., Madison Gas and Electric Co., Wisconsin Electric Power Co., and Wisconsin Public Service Corp. — each utility forecasts the monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts and if the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is permitted to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return.
Wyoming		Yes. **Cheyenne Light, Fuel & Power** can allocate steam production costs 85% to ratepayers and 15% to shareholders, and other eligible costs 95% to customers and 5% to shareholders. **PacifiCorp** similarly has cost-sharing in place, but allocates 80% to ratepayers and 20% to shareholders	Cheyenne Light, Fuel & Power, or CLF&P, operates under a power cost adjustment mechanism through which the company's power costs are classified into two categories. Category 1 costs include steam production costs, while category 2 costs include purchased power and capacity costs, transmission expenses, and certain other costs, and reflect any margins realized from off-system sales. Deviations in Category 1 costs from a base level are allocated 85% to ratepayers and 15% to shareholders. Deviations in Category 2 costs are allocated 95% to customers and 5% to shareholders. PacifiCorp operates under an energy cost adjustment mechanism, or ECAM, that is in place through 2017. Under the ECAM, incremental variations in net power costs that differ from the base level are allocated 80% to ratepayers and 20% to shareholders. In December 2015, the PSC approved the continuation of the current ECAM with certain modifications that allow for the inclusion of reagent chemical costs and start-up fuel costs. In addition, MDU Resources Group collects from/credits to ratepayers variations in fuel and purchased power costs that deviate from an established base level through a power supply cost adjustment mechanism.

Sources and Notes:

Descriptions of fuel adjustment clauses from SNL Energy Regulatory Research Associates (RRA) summaries. Deadband and Risk Sharing columns represent The Brattle Group interpretations of mechanisms according to these descriptions and research into utility filings.

Attachment B

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

February 20, 2026

VIA ELECTRONIC FILING

Oregon Public Utility Commission
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: AR 676—PacifiCorp's Comments on Multi-year Ratemaking and Performance-Based Ratemaking

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) respectfully submits the following comments in Docket No. AR 676.

PacifiCorp appreciates the opportunity to comment on Staff's questions and provides the following comments, with the hope that we can continue to have more in-depth conversations with all parties on all of the rules in the rulemaking.

Question 1: Please identify goals that best align with your vision for Oregon's regulated utility energy system. For each goal, please identify 1-3 outcomes that you think are most important to prioritize in an updated ratemaking framework. Staff notes that this is a prioritization exercise and not an indication that any particular goal or outcome will be excluded.

PacifiCorp believes that the overall goals of the regulated energy system should be consistent with historical regulatory objectives—namely, to provide safe, reliable, and affordable electric service while also supporting Oregon's energy goals and maintaining a financially healthy utility. Different regulatory mechanisms should not change these long-standing goals. Rather, the central question in this proceeding is how to properly incentivize and support utilities to achieve these goals, rather than adopting approaches that are arbitrary or punitive. In general, the Oregon Public Utility Commission (Commission) should seek to incentivize adaptability and creativity from utilities, as opposed to rigid/prescriptive methods and outcome thresholds for achieving these objectives. A "one-size-fits-all" approach should be avoided, and performance-based ratemaking (PBR) should instead be tailored to the unique goals and circumstances of each utility.

Furthermore, in the context of a multi-year rate plan, it is important to recognize that forecasts for future rate years will be inaccurate. We are operating in a dynamic and rapidly changing regulatory environment. This reality is illustrated by the significant differences between PacifiCorp's 2023 Integrated Resource Plan (IRP) and its subsequent update, which were largely driven by the stay of the Ozone Transport Rule. Similarly, the modeling assumptions for PacifiCorp's 2025 IRP were finalized prior to policy changes under the Trump Administration. Changes in economics and regulations have material effects on the planning environment, and it

should be expected that such uncertainty will continue. Utilities must therefore retain the ability to adapt to the most current and reliable information. While certain parties may desire absolute predictability in ratemaking, such a desire needs to be balanced against the real-world dynamics of utility operations and the uncertainty in the planning environment that cannot be controlled or anticipated.

Given this backdrop, below are PacifiCorp's initial three goals for designing a PBR framework:

Goal 1: ***Adaptability, Review, and Safeguards*** – As stated above, PacifiCorp hopes there is one principle on which all parties can agree: *all forecasts are inherently inaccurate*. This is true for power cost forecasts used in the Transition Adjustment Mechanism (TAM), as well as for forecasts of proxy resources relied upon in an IRP. Each of these forecasts attempts to predict future conditions based on a defined set of assumptions. However, those underlying assumptions will always be different from actual conditions, resulting in outcomes that deviate from the initial forecast. The same will be true for forecasts underlying any multi-year rate plan, and for any forecasts associated with outcome thresholds in a performance incentive mechanism (PIM). This is particularly so for forecasts that result from settlement or Commission adjustment, which necessarily reflect compromise rather than the utility's best estimate of the costs it expects to incur.

Given this dynamic, in the context of PBR, the Commission must carefully balance outcome-based incentives with appropriate safeguards to ensure that utilities are not encouraged to pursue results in a manner inconsistent with sound utility practice, customer interests, or long-term system reliability. This topic is discussed further in the response to Question 2 below. For these same reasons, the Commission should continue to adopt mechanisms that align utility incentives by reducing regulatory lag during a rate plan—such as renewable adjustment clauses and automatic adjustment clauses—as discussed further in the response to Question 4 below.

More generally, utilities must retain the flexibility and creativity to adapt to the inherent inaccuracies associated with forecasts. To accomplish this objective, PacifiCorp recommends that the Commission adopt a "*portfolio approach*" that was adopted by the Washington Utilities and Transportation Commission (WUTC), when reviewing provisional pro forma capital, as discussed in more detail in response to Question 4. Additionally, utilities must retain the ability to deviate from PIM thresholds without penalty when doing so is in the best interest of customers. Appropriate safeguards and periodic assessments are necessary to ensure that utilities are not incentivized to blindly pursue forecasted outcomes or established thresholds when such actions would not serve the interests of customers or the State of Oregon.

Goal 2: ***Utility Control and Achievability****:* Fundamentally, if the purpose is to incentivize a utility to achieve specific outcomes, it is paramount that the utility have control over the factors necessary to achieve those outcomes. For example, a utility does not control the market price of natural gas; therefore, any outcome that depends on certain commodity prices is not within the utility's control.

Likewise, if a goal is premised on a forecasted condition or event that does not ultimately occur, achieving that goal may no longer be feasible or practical. A poorly designed PBR framework would compel a utility to meet a goal solely for the sake of compliance, regardless of whether the goal remains achievable or viable in light of subsequent conditions. Such a rigid approach risks becoming arbitrary and punitive and may result in unintended consequences—rather than serving as a meaningful incentive to advance desired outcomes.

Goal 3: ***Integration with the Broader Regulatory Framework*****:** PBR should be thoughtfully integrated within the existing regulatory framework. For example, performance metrics can be proposed and thereafter can be reported through compliance filings during the pendency of a multi-year rate plan. Similarly, the review of provisional or forecasted capital can also occur within established compliance filing process. PIMs can be proposed following the filing of a multi-year rate plan. These are just a few examples of how PBR can be incorporated into existing regulatory constructs. This approach reflects the discussion of the WUTC in its most recent policy statement.[1]

This concept is important because alternative approaches risk imposing undue burdens on the Commission, Staff, stakeholders, and utilities. A more integrated approach is also consistent with Executive Order 25-29. During the most recent workshop addressing Executive Order 25-29 (in Docket No. UM 2417), Staff highlighted the significant volume of work required of the Commission and discussed strategies for improving efficiency and prioritizing regulatory activities. PacifiCorp recommends that a similar efficiency-focused approach be adopted in this proceeding.

Question 2: What trade-offs and/or risks should be considered in developing a Multi-Year Rate Plan and/or PBR framework for Oregon?

In general, a poorly designed PBR framework elevates outcomes over the means used to achieve those outcomes. In other words, a poorly designed PBR reflects the philosophical view that *the ends justify the means*. For example, a poorly designed PIM may establish an arbitrary outcome that must be achieved by any means, with penalties imposed if the utility fails to meet the prescribed threshold. This outcome would be regardless of potential negative impacts that could occur when achieving the desired outcome. A similar dynamic can arise under a rigid multi-year rate plan, where a utility may be incentivized to blindly adhere to the forecast embedded in the plan even when doing so is no longer the most efficient or economic course of action. Unforeseen circumstances or costs will almost certainly occur during a three-year rate plan—and there must be flexibility for utilities to adapt and to reduce regulatory lag—rather than a rigid ratemaking framework that elevates outcomes over the means used to achieve those outcomes.

PBR *has the potential* to represent a significant departure from traditional ratemaking, under which the Commission focuses primarily on the prudency and reasonableness of a utility's

[1] *See Policy Statement Clarifying Reported Performance Metrics and Addressing Performance Incentives Mechanism Principles*, WUTC Docket No. U-210590 at 20 (January 26, 2026).

actions, rather than solely on the outcomes those actions produce. However, in the context of PBR, it is important to carefully balance outcomes and incentives with appropriate safeguards to ensure that utilities are not encouraged to pursue results in a manner that is inconsistent with sound utility practice, customer interests, or long-term system reliability. In other words, utilities should *not* be rewarded or incentivized to blindly following a multi-year rate plan when prudent utility practice dictates otherwise.

This underscores the importance of this rulemaking. While various parties may seek particular assorted outcomes, Staff must ask: *at what cost will those outcomes be achieved?* PacifiCorp maintains that achieving desired outcomes should not come at the expense of prudent utility practice. Prudent utility practice necessitates considering the most-up-to-date information in the decision making process, including information that arises after a desired outcome and/or threshold is set. Even assuming these outcomes are within a utility's control, utilities must retain the flexibility to adapt where desired outcomes would impose unreasonable costs or result in outcomes that are untenable. If the Commission establishes rigid outcomes that must be met, it should be expected that the utility will comply, and that the costs associated with achieving those outcomes will ultimately be borne by customers.

Accordingly, the central tradeoff in this proceeding is between setting fixed outcomes versus allowing utilities the flexibility to deviate from those outcomes when necessitated by prudent utility practices. It should be acknowledged that all forecasts associated with a multi-year rate plans and PIM *will be inaccurate*. PacifiCorp has specific proposals and believes a reasonable balance can be achieved when utilities have the adaptability are effectively encouraged to pursue desired outcomes and/or thresholds.

Question 3: Which Multi-Year Rate Plan and other PBR mechanisms do you think could be valuable tools for helping achieve the outcomes that are important to you?

PacifiCorp believes that the Commission's adoption of automatic adjustment clauses (AACs), renewable adjustment clauses (RACs), and annually adjusted balancing accounts (such as Schedule 191—System Benefits Charge) represent existing and well-designed PBR mechanisms. These mechanisms appropriately align incentives by reducing regulatory lag in critical areas of utility operations, including wildfire mitigation, renewable energy investments, and demand-side management programs. Such mechanisms may play an increasingly important role under a multi-year rate plan framework by mitigating regulatory lag during the pendency of the plan. PacifiCorp looks forward to more discussion on this topic during this rulemaking.

Furthermore, it is critical that the Commission adopt a *portfolio-based approach* if it elects to conduct provisional review of pro forma capital, similar to the approach used by the WUTC. Given the duration of a multi-year rate plan, unavoidable deviations from planned capital expenditures are almost inevitable. As a result, ratemaking under a multi-year rate plan must allow sufficient flexibility to enable utilities to make ongoing, prudent business decisions. Prudence requires adaptability and consideration of the most up-to-date information—rather than blind adherence to a forecasted capital plan. Rigidly requiring a utility to adhere to a fixed capital

forecast established at a single point in time could unintentionally lead to suboptimal business outcomes that are not in the best interest of customers. In particular, the risk of penalties for adapting to changed circumstances could create inappropriate incentives—either to proceed with capital expenditures as originally planned despite changed conditions, or to prematurely terminate capital projects out of concern over cost overruns driven by factors outside the utility's control.-year rate plan, unavoidable deviations from planned capital expenditures are almost inevitable. As a result, ratemaking under a multi-year rate plan must allow sufficient flexibility to enable utilities to make ongoing, prudent business decisions.

Accordingly, it is critically important that the Commission consider adopting a balanced review and true-up process for provisional capital investments reflected in rates—one that recognizes the flexibility necessary to prudently manage a utility business in a dynamic operating environment and supports the achievement of the best overall outcomes. An approach similar to a portfolio review of provisional pro forma capital can accomplish this purpose. PacifiCorp looks forward to further discussion in the rulemaking.

Question 4: Based on what you've learned about MRP/PBR and your desired outcomes from the ratemaking process and energy system, what specific aspects of Oregon's ratemaking frameworks are working well? Further, what specific areas do you see as high impact opportunities to improve? Please feel free to be as specific about process and ratemaking practices as you want.

Please see above for areas that work very well in Oregon—such as AACs, RACs, and annual balancing account adjustment. All of these mechanisms properly align incentives by reducing regulatory lag in important areas of utility operations. With the implementation of a multi-year rate plan, regulatory lag can become more of a pronounced concern. Accordingly, PacifiCorp supports exploring how these mechanisms can play a more pivotal role in Oregon.

For areas that need improvement, PacifiCorp has attached its most recent comments submitted in Docket No. UM 2417. These comments focused on identifying priorities in implementation of Executive Order 25-25 and 25-29. PacifiCorp has attached these comments as Attachment A. PacifiCorp also recommends that Staff review its Joint Comments filed with Portland General Electric and Idaho Power Company submitted in AR 669—focusing on the inefficiency in resource planning and procurement in Oregon.

However, one aspect of PBR that not functioning well in Oregon are the deadbands associated with the Power Cost Adjustment Mechanism (PCAM). These deadbands historically operate as an effective disallowance of prudently incurred power costs, despite the reality that utilities have only limited control over such costs, and they do not properly align incentives with desired outcomes. For example, if commodity prices for wholesale power or natural gas materially exceed the forecast established in the TAM, PacifiCorp has been—and over the long term will be—effectively disallowed recovery of $30 million of the resulting variance solely due to the application of the deadband. This outcome occurs regardless of whether the underlying costs

were prudently incurred—and the fact that these are *actual costs* (fuel, market purchases, etc.) spent by a utility to serve Oregon.

The deadband is unnecessary because prudence is already reviewed in the annual PCAM filing, where any imprudently incurred costs may be fully examined and contested. That review process provides the appropriate incentive structure, consistent with PacifiCorp's experience in other jurisdictions. These deadbands also create a perverse incentive within the TAM process, encouraging parties to advocate for lower forecasts rather than more accurate forecasts, with the knowledge that PacifiCorp will bear up to a mandatory $30 million disallowance of any variance without any consideration of prudence.

Today, PacifiCorp has limited control over power costs. As PacifiCorp transitions to participation in the Extended Day Ahead Market, PacifiCorp will have even less control over power costs, further underscoring that the deadbands function as a punitive mechanism for uncontrollable or unforecastable variances rather than as a tool to incentivize improved performance-based outcomes. PacifiCorp hopes this workshop will provide a focus on whether the continued use of deadbands in the PCAM is an appropriate PBR mechanism.

Question 5: What additional considerations do you think are important as Oregon works to develop its MRP framework?

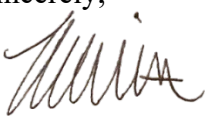
PacifiCorp does not have any further considerations to highlight at this time. However, PacifiCorp would like to take this opportunity to convey its appreciation for Commission Staff. PacifiCorp recognizes that these policy dockets require substantial resources, including Staff's efforts to organize the dockets, review and consider numerous stakeholder comments, and develop Staff proposals. PacifiCorp also appreciates Staff's decision to engage outside consultants to provide additional perspectives on PBR.

Conclusion

PacifiCorp looks forward to, and remains committed to, working collaboratively with Staff and other stakeholders, including by sharing its experience and perspectives gained from implementing PBR frameworks in other jurisdictions.

If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,



Robert Meredith
Director, Regulation

Attachment A

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

January 12, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UM 2417 – In the Matter of Public Utility Commission of Oregon Identifying Priorities in Implementation of Executive Order 25-25 and 25-29

PacifiCorp d/b/a Pacific Power is committed to providing safe, reliable and affordable service while meeting the policy and clean energy goals that have been outlined by the State of Oregon and articulated in detail through the Governor's Executive Orders 25-25 and 25-29, among others.

Balancing all three of these essential goals remains a significant challenge, especially when accounting for the rapidly changing energy landscape, increasing pressures on load growth, wildfire risks and a rising cost environment. It is essential for there to be broad support among stakeholders to prioritize creating a positive, efficient and proactive regulatory environment that supports long-term certainty, creates stability for utilities, and is nimble enough to meet customer needs while promoting economic development. Oregon has made great strides and it is our hope that these executive orders help Oregon take control of its own energy future. The time is now, and we applaud the Commission for taking this first important step.

Under the current policy and cost environment, Oregon's planned clean energy transition creates a disconnect between goals and an achievable reality for utilities and their customers. Deploying capital to build generation, storage and transmission is currently risky and unattractive in Oregon. Additionally, the process for utilities to obtain approval to procure resources, even for assets owned by third parties, is burdensome and prolonged. Finally, circumstances have changed such that a rapid move to renewable generation, and the infrastructure needed to support these investments, creates real challenges with customer affordability and economic development. Certainty and stability is needed for both customers and utilities to make continual progress.

Investing in clean energy in Oregon currently creates additional financial risk for utilities

Financially healthy utilities are essential to finance and build transmission, renewable generation, and storage, but recent decisions and the current liability environment have made maintaining that financial health more difficult. PacifiCorp first recommends adopting a formal preapproval pathway for major projects, which would explicitly include advance approval of interjurisdictional allocation treatment, so that prudent, used and useful assets can earn the authorized return when placed in service. This would reduce financing risk, lower customer costs

over time and provide a more viable path toward the clean energy build out Oregon requires while supporting economic development.

At the same time, wildfire liability in Oregon remains a very significant risk. Litigation exposure, insurance premiums and uncertainty around cost recovery elevate financing costs and constrain balance sheet capacity. To sustain the scale of investment customers need, Oregon should adopt policies that establish reasonable limitations of liability and a constructive framework for insurance and recovery, which would keep utilities financially healthy and viable while maintaining accountability for prudent operations.

Finally, significant investments in transmission and infrastructure need to be given a consistent and clear framework for recovery. In the company's last general rate case, the commission limited PacifiCorp's return on the Gateway South transmission project to the modified blended treasury rate until benefits are later demonstrated, rather than allowing the full authorized return.[1] Gateway South is precisely the kind of long lead transmission needed to integrate large volumes of renewables, which the data has demonstrated. Signaling that such investments may not earn a full return at the time they enter service makes Oregon an uncertain environment in which to commit capital, especially when other jurisdictions offer clearer, more predictable recovery.

Resource procurement approval needs to be more efficient

A faster, more flexible framework would improve competitiveness for Oregon customers and better support timely procurement. Such actions can also support multi-jurisdictional planning and procurement, as other applicable western states do not have comparable regulatory hurdles. The commission currently has the opportunity to modernize both its procurement and planning rules in Docket No. AR 669. The actions in that docket should be informed by goals of Executive Orders 25-25 and 25-29. PacifiCorp has submitted joint comments with other electric utilities on staff's current proposal that provide detailed recommendations to make this process more efficient.[2]

Oregon's procurement approval is already among the slowest in the region and proposed rule changes being considered[3] would lengthen it further. Before a request for proposals (RFP) can be filed, the process typically requires an independent evaluator (IE) solicitation and docket, bidder workshops, pre-approval of scoring, and extensive staff/IE consultations; after filing, additional mandatory steps (including acknowledgement of shortlists and IE reports) add months. In practice, RFPs often take well over a year from filing to final shortlist, increasing transaction costs and price-hold risk. Other jurisdictions move faster, and large corporate buyers, who face none of these regulatory delays, can secure renewable power purchase agreements quicker. Developers have opportunities to submit bids into RFPs in other jurisdictions or sell directly to large load customers.

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[1] *In the Matter of the Application for PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 433, Order No. 24-447 at 39-44 (Dec. 19, 2024).
[2] *See Comments of PacifiCorp, Portland General Electric, and Idaho Power*, Docket No. AR 669 (Nov. 14, 2025).
[3] *Id.* at 2 ("[T]he proposed rules largely impose additional, cumbersome regulatory requirements that go beyond what is already in place in Oregon").

PacifiCorp's recent Washington situs RFP moved from filing to market in roughly half the time than its recent Oregon situs RFP. Washington limits IE involvement to cases with benchmark resources, does not require regulatory acknowledgement of shortlists, and imposes minimal post-issuance barriers before contracting, which allows bidders to keep pricing firm and projects to advance. This contrasts with the recent example of Idaho Power's most recent Phase I of its RFP in Oregon that took 17 months from initial filing to acknowledgement of the final shortlist. Oregon should streamline and align with neighboring states, make the 80-day RFP approval timeline real (not aspirational), avoid duplicative shortlist requirements, right-size IE scope to the specifics of each solicitation and reduce post-issuance process steps. Other jurisdictions do not impose similarly prescriptive substantive and process requirements; instead, they allow utilities the flexibility to design processes that meet their specific needs.[4] All of these suggested efficiency considerations are to the benefit of customers.

Rapid clean energy deployment is raising concerns about severe impacts to customer affordability

Rapid clean energy deployment at the current pace would produce severe affordability impacts for Oregon customers. PacifiCorp's 2025 Clean Energy Plan (2025 CEP) indicates that, given today's technology and costs, meeting House Bill (HB) 2021 targets at the required scale would result in large rate increases. The 2025 CEP results show materially higher customer bills under HB 2021-compliant portfolios compared to the counterfactual. See table 1 below for these results:

Table 1. Estimated HB 2021 Average Annual Compliance Costs 2025-2045 ($millions) and Percentage of 2025 Revenue Requirement (shown in parenthesis)

	Annual Cost with System Transmission	Annual Cost with Situs Transmission	Annual Cost with System Transmission (No PTC/ITCs)	Annual Cost with Situs Transmission (No PTCs/ITCs)
CEP Preferred Portfolio (Annual Clean)	$135 (10%)	$161 (11%)	$214 (12%)	$241 (14%)
Hourly Clean Portfolio	$1,609 (91%)	$1,800 (101%)	$2,287 (129%)	$2,479 (140%)

Table 1 shows that the average annual incremental rate impact for HB 2021 compliance ranges from 10 percent to 140 percent, depending on the scenario. Such rate increases would disproportionately impact energy-burdened households as a larger share of their income must go to essential needs.

[4] PacifiCorp provides more detail on this topic within its joint comments with other electric utilities within AR 669. However, one recent example is Idaho newly adopted rules Public Utilities Commission's RFP requirements are far less rigid and permit flexibility in RFP design. *See* Idaho PUC Case No. GNR-E-25-01. Likewise, other states tend to have more streamlined procedures—for instance, none require a process for acknowledgment of a final shortlist prior to contract execution or independent evaluator monitoring of contract negotiations.

Under ORS 469A.445, once the actual or anticipated rate impact from HB 2021 compliance exceeds six percent of revenue requirement, the commission must grant an exemption from further compliance. PacifiCorp's position, set out in docket UM 2273 Phase 2 reply comments, is that the cap operates as a hard ceiling on additional compliance costs and will likely be reached given the volume of resources required.[5] To ensure an appropriate level of procurement and to prevent unnecessary price-hold and bid-refresh risks, the commission should provide clear, front-end guidance on the cost cap and allow for a fast-track Section 10 process aligned to the RFP's final shortlist process, before contracts are executed. Specifically for multi-jurisdictional utilities, the commission should make an interjurisdictional allocation determination for each resource as part of its Section 10 decision.

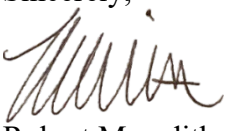
Oregon's planned clean energy deployment is financially untenable for households and increasingly risky for utilities. This means that we have an obligation today to evaluate and adjust course, if necessary, to ensure that the goal of a 100% carbon-free future for Oregon is realized. PacifiCorp recommends calibrating the pace of procurement to what customers can reasonably afford, while establishing clear, predictable guardrails so the transition is durable for customers and viable for the company.

Conclusion

Ultimately, Oregon's clean energy transition will succeed only if it is affordable for households and achievable by utilities. PacifiCorp urges alignment of pace with affordability, streamlined procurement approval, and preapproval of major projects and their associated interjurisdictional cost allocation treatment. Further, establishing clear limitations of liability and a constructive recovery framework will preserve the utilities' financial viability and capacity to fund transmission, renewable generation and storage, and support economic development in the state. PacifiCorp appreciates the opportunity to provide these comments that will identify principles and priorities for staff to develop its workplan in response to Executive Orders 25-25 and 25-29.

If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,



Robert Meredith
Director, Regulation

[5] *In the Matter of Public Utility Commission of Oregon, Investigation Into House Bill 2021 Implementation Issues*, Docket No. UM 2273, PacifiCorp's Phase 2 Reply Comments (Sept. 29, 2025).