PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

August 21, 2026

VIA ELECTRONIC FILING

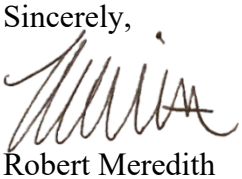
Oregon Public Utility Commission
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: AR 676–PacifiCorp's Pre-Read: Track 1: Electric O&M - Utility Cost Information

PacifiCorp d/b/a Pacific Power (PacifiCorp) respectfully submits the following document in response to Staff's request for a pre-read related to Track 1 of Docket No. AR 676, Rulemaking to Establish Multi-Year Plan Framework.

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

DOCKET NO. AR 676

Rulemaking to Establish a Multi-Year Rate Plan Framework (HB 3179)

Track 1, Workshop 1 Utility Pre-Read – (Operation and Maintenance Costs)

Treatment of Cost Categories—Utility Perspectives and Major Considerations

Introduction: PacifiCorp provides this pre-read in advance of Track 1, Workshop 1, scheduled for August 26. PacifiCorp believes the primary question for this workshop is which costs should be included in a multi-year rate plan (MYRP) and which costs should be excluded from the MYRP cost-containment framework and instead recovered through separate tariff schedules, adjustment mechanisms, or deferral mechanisms. Consistent with that objective, PacifiCorp intends to keep its comments focused and concise and will address the following cost categories:

Customer Programs*:* In the workplan, Staff identifies the treatment of customer programs as a topic for discussion. It is important to recognize that the fundamental purpose of including costs within a five-year multi-year rate plan (MYRP) is cost containment. A MYRP is a form of performance-based ratemaking that seeks to constrain the costs included in rates over the term of the plan.

For purposes of this workshop, it is important *not* to discuss "costs" as an abstract concept—as simply a number that appears on a customer bill. Instead, costs are specific items incurred to achieve specific customer and public policy benefits, such as distribution system investments, demand response programs, community solar programs, and low-income bill discount programs. Thus, including these costs within a MYRP necessarily reflects a policy judgment that the associated spending should be contained within a predetermined budget, even in circumstances where prudent utility practice or evolving customer needs might otherwise support additional investment. PacifiCorp notes that its other jurisdictions that have multi-year rate plans (Washington and California) have not included customer programs within their MYRP—presumably for this reason.

Accordingly, when evaluating whether customer programs should be included in a MYRP, the threshold question is whether public policy favors cost containment for those programs. Stated differently, it must determine whether expenditures for customer programs are appropriately subject to a fixed budget and the performance incentives inherent in a MYRP structure.

PacifiCorp's position is that, if customer programs are included within a MYRP without an associated deferral or cost-recovery mechanism, the amount included in rates effectively becomes both a budget and a spending cap. Under that framework, the utility should not be expected to incur costs beyond the level authorized in rates. As a practical matter, customer programs would therefore be administered only to the extent funding remains available, potentially resulting in first-come, first-served participation when program demand exceeds the authorized budget.

To illustrate why this issue is important, consider the demand response example discussed during the most recent workshop. Assume that, during a MYRP, a utility implements a new demand response program that requires $1 million in spending above the amount authorized in rates. Further assume that the program produces $1.5 million in power cost savings. Under this

scenario, customers would receive the benefit of the $1.5 million reduction through mechanisms such as the Transition Adjustment Mechanism (TAM) or the Power Cost Adjustment Mechanism (PCAM), while the utility would have no means of recovering the $1 million of incremental demand response expenditures. As a result, the costs of the program are not matched with the benefits it produces.

In practical terms, every dollar spent on demand response above the MYRP-authorized budget would become an unrecoverable expense, even where the expenditure creates greater customer savings than its cost. This dynamic can also disincentivize pilot programs on new technologies. Operating customer programs in this manner is not a sustainable model for any business, including a regulated utility. Indeed, it creates a disincentive to pursue additional cost-effective customer programs once the authorized budget has been exhausted.

Another example of how constraining customer program budgets within an MYRP could hurt those programs are low-income bill discount programs. When additional customers sign up to receive a bill discount, the amount of discount the utility distributes increases. If recovery of those costs are set and not updated during an MYRP stay out period, the utility would not recover the increased costs of administering the program. This would create a disincentive to add additional customers to the program. The utility has no other ability to control this cost—which raises the question how a utility should be expected to "contain" these costs in a MYRP structure? It is important to allow approved recovery amounts to track changing costs for programs such as this avoids undermining the program and ensures assistance is available to every eligible customer.

This issue can be readily avoided by continuing the current practice of funding customer programs through separate tariff schedules or adjustment mechanisms outside the MYRP cost-containment framework. This is the approach generally taken in jurisdictions such as Washington and California, where customer program costs are treated separately from the costs subject to MYRP spending constraints. Alternatively, customer programs could be included within a MYRP if accompanied by an appropriate true-up or deferral mechanism that allows prudent expenditures to be reconciled and recovered in a subsequent MYRP under which spending over or under what is in the plan would be recovered or returned to customers.

Furthermore, PacifiCorp does not understand the policy rationale for excluding Energy Trust of Oregon expenditures from the MYRP cost-containment framework while simultaneously including utility-administered customer programs within that construct. Both categories of spending support customer-facing public policy objectives. If Energy Trust expenditures are excluded because the Commission concludes that those programs should not be constrained by a fixed MYRP budget, the same rationale would appear to apply equally to utility-administered programs such as demand response, community solar, and low-income bill discounts. The distinction warrants further explanation before different cost-recovery treatment is adopted.

Unforecastable Costs or Benefits Are More Appropriate for Deferred Recovery: PacifiCorp submits that there is one principle on which all parties should agree: *all forecasts are inherently inaccurate*. This is true for power cost forecasts used in the TAM and the forecasts of proxy resources relied upon in Integrated Resource Plans (IRP). The same is true for the forecasts

underlying any multiyear rate plan. Each forecast rests on a defined set of assumptions about future conditions, and actual outcomes will inevitably diverge from those assumptions. Additionally, unforeseen changes could occur that benefit customers, such as was experienced with the passage of the Tax Cuts and Jobs Act in December 2017. Regulatory mechanisms such as deferrals help mitigate the adverse impacts associated with the inherent inaccuracy of rate plan forecasts and, appropriately align regulatory incentives by linking potential future recovery to the prudent incurrence of costs.

As previously discussed, setting fixed rates on energy efficiency or demand response for five years may not make sense. The same is true for other costs like Independent Evaluator (IE) Costs that are mandated by the Commission in a Request for Proposal. At the time of setting rates in a MYRP, it may be unclear to what extent utilities will need to engage the services of an IE as an request for proposal (RFP) if often triggered by an Integrated Resource Plan (IRP) filing demonstrating a resource need. These circumstances underscore why deferred accounting and similar regulatory mechanisms are particularly important for costs which may fluctuate greatly over the course of a multi-year rate plan.

The alternative—speculating about uncertain compliance costs within a five year multi-year rate plan forecast (like IE costs that may/may not be required in a potential future RFP or a pilot program that might be approved after a rate plan is approved)—is a sub-optimal solution. Such an approach can result in including costs well above what a utility actually incurred—or below. Deferred accounting, by contrast, is a reasonable regulatory tool that can track actual and unavoidable compliance costs incurred and therefore provides a more accurate and equitable ratemaking outcome.

Legal and Policy Implications*:* In this workshop, Staff should consider the legal and policy implications of limiting cost recovery solely to costs included within a MYRP and not allowing separate recovery mechanisms. Certain categories of costs have already been recognized by statute, rule, or Commission policy as pass-through costs, separately collected charges, or costs eligible for deferred accounting. While the examples below are not intended to be exhaustive, they illustrate the broader issue.

One example is Oregon's Public Purpose Charge ("PPC"). ORS 757.612 provides that: "Until January 1, 2036, an electric company ... shall collect a nonbypassable public purpose charge equal to 1.5 percent of the revenues." In other words, the statute requires utilities to collect and remit these funds for specified public purposes. As such, PPC expenditures function as pass-through costs rather than discretionary utility spending subject to cost-containment incentives.

Another example of a pass-through surcharge is the low-income electric bill payment and crisis assistance mandated collection from ORS 757.698. The rate or collection amount for these charges is set by legislation and may be changed by the legislature at any time in the middle of a utility's MYRP stay out period with little to no warning. The utility must change its rates to comply with changes to the law and cannot be constrained by the stay out period of an MYRP. Moreover, as the utility collects these costs from customers, the revenues are passed directly on to the statutorily mandated agencies. The amounts passed-on are not based on a pre-determined budget, but on the actual collection from customers in each billing period based on the approved

rates in effect. It would not be reasonable to include some forecast of these revenues within a MYRP when a different amount would be actually collected from customers and passed on to the agencies, nor would it be appropriate to leave these rates unchanged if the statutes are modified.

The Regional Power Exchange program with the Bonneville Power Administration is another pass-through that should be outside of MYRPs. These benefits are federally negotiated, subject to change on timelines outside of MYRP timelines, subject to potential substantial changes based on periodic revised negotiations and passed through directly to customers. It would not be reasonable to tie these benefits to any MYRP or MYRP timelines.

While not exhaustive, other items that should be considered for exclusion from MYRPs include the following:

- IE costs
- Intervener funding
- Demand response
- Property sales
- REC sales
- Multnomah County Business Income Tax
- Community Solar
- Any new legislative or regulatory mandate that has a material impact on the utility's costs (could be either a positive impact or a negative impact)

PacifiCorp requests that this workshop provide an opportunity to examine the legal and policy implications of including these types of statutory and regulatory compliance costs within a MYRP cost-containment framework. At a minimum, the workshop should identify those costs that, by their nature, are pass-through obligations, mandated and unavoidable compliance expenditures, or otherwise appropriate for separate recovery mechanisms rather than treatment as costs that utilities are expected to absorb within a fixed MYRP budget.