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September 25, 2026

VIA ELECTRONIC FILING

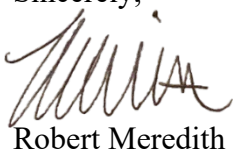
Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: AR 676—PacifiCorp's Pre-Read: Track 1: Electric Transmission and Other Costs

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

Enclosures

DOCKET NO. AR 676
Rulemaking to Establish a Multi-Year Rate Plan Framework (HB 3179 & SB 688)

Track 1 Utility Pre-Read—Electric Transmission & Other Costs: Cost Information
Treatment of Cost Categories—Utility Perspectives and Major Considerations

Overview and Purpose

This pre-read presents PacifiCorp's perspective on the major considerations that should frame the Track 1 workshop discussion of how electric transmission and other costs (costs other than distribution) could be treated within a multi-year rate plan (MYRP). It is organized around the six focus areas Staff identified: (i) going-in rates; (ii) current timelines and relevance to utility planning dockets; (iii) limitations related to indexed adjustments; (iv) use of deferrals and balancing accounts; (v) performance incentive mechanisms (PIMs); and (vi) rebasing. Section 5 addresses several adjacent cost categories under discussion in Track 2.

PacifiCorp's central message is that the indexed treatment will work well for a significant share of costs, but the renewable adjustment clause (RAC) and a new supplemental capital funding mechanism (SCFM) will be necessary to ensure timely recovery of large capital projects along with deferrals and/or use of the z-factor for items that are material, policy-driven, and/or outside of the utility's control.

1. Going-In Rates

- "Going-in rates" are the base rates in effect at the start of the MYRP term. Because the index escalates from that opening base across a five-year term, an inaccurate baseline compounds for the life of the plan. Going-in rates should be established through a traditional, fully litigated proceeding using conventional cost-of-service methods. This will ensure that the first year rate base and expense levels rest on a complete, tested record.

2. Current Timelines and Relevance to Utility Planning Dockets

Transmission and other costs do not enter rates in isolation. Their size and timing are driven by the company's planning and its policy requirements. Below is a list of dockets that have relevance to PacifiCorp's transmission and other costs:

Relevant Docket/ Process	Relevance to transmission and other costs
IRP / CEP (LC 85)	Resource acquisition and HB 2021 compliance drive the size and timing of resources and transmission investment entering going-in rates and later adjustments.
TAM / PCAM	Net power costs are outside of the plan and recovered through these two mechanisms.
RAC (ORS 469A.120 / UE 451)	Recovers renewable resources together with interconnection and associated transmission; amounts recovered here must be netted out of the index.

UE 463 (LEUF / Schedule 401)	Determines how the cost of serving new and certain existing LEUFs will be assigned.
AR 685 (HB 2021 cost cap)	Sets the projected annual revenue requirement and rate impact methodology for compliance costs.
Interjurisdictional allocation	Changes in allocation methodology can materially shift the allocation of system costs to Oregon customers.

3. Limitations Related to Indexed Adjustments

Under the Phase 1 framework, annual revenue is adjusted by the index formula I – X – S + G + Z (inflation, productivity offset, stretch factor, customer growth, and exogenous events). For a significant share of costs, PacifiCorp believes the index framework will allow the company to keep up with cost increases related to inflation and customer growth, provided the index adjustment methodology is reasonable. However, given HB 2021 and SB 1547 clean energy transition requirements, PacifiCorp will need to make significant investments that go above and beyond what is needed to simply maintain the existing system and keep up with customer growth. It is essential for tools to exist that allow utilities to capture changes to their cost landscape (both positive and negative) that transpire during the term of the MYRP. Five years is a long time and a lot can happen in that time. Utilities cannot control nor predict changes to federal and state policy, catastrophic events like earthquakes or pandemics, and supply chain disruptions.

It is essential that the index approach be supplemented by the existing RAC mechanism and a SCFM for large or extraordinary capital outside the index. A robust Z-factor or the ability to file for a deferral is also needed to capture catastrophic events or other material events that cannot be predicted.

The table below is a non-exhaustive list of different cost categories and PacifiCorp's recommended treatment of them under the MYRP framework:

Cost category	Nature of the cost	Recommended treatment
Energy storage	Large, lumpy capital or long-term storage agreements	Supplemental capital funding mechanism for owned storage; power cost mechanisms for 3rd party owned storage.
Renewable resources and associated transmission	Large, lumpy capital or purchase power agreements; acquisition needed to meet HB 2021 and SB 1547 compliance.	RAC for owned renewables; power cost mechanisms for purchase power agreements.
Transmission O&M and non-major capital	Steady but escalating cost to operate and maintain the system and investments needed maintain reliability, serve	Adjusted by the index

	customer load growth, and interconnect new resources	
Major transmission capital	Large, lumpy capital	Supplemental capital funding mechanism
Net power costs (NPC)	Fuel, purchased power, and wheeling, net of wholesale sales; market-driven and, under EDAM, largely optimized and outside the company's control.	Outside of the MYRP and recovered through TAM and PCAM
Non-emitting resources	Large, lumpy capital or purchase power agreements for resources such as non-emitting peakers and nuclear that do not meet the definition of renewable	Supplemental capital funding mechanism; power cost mechanisms for purchase power agreements.
Demand response	Customer program spending that varies with participation	Either exclude from MYRP scope and continue recovery through a separate rider with balancing accounts; or include in MYRP and defer costs above or below plan and amortize in the subsequent MYRP
Large IT investment	Enterprise technology platforms — lumpy, multi-year capital that may be needed to replace legacy systems and may be procured on a timeline that does not align with MYRPs	Supplemental capital funding mechanism

4. Use of Deferrals and Balancing Accounts

Deferrals, balancing accounts, and automatic adjustment clauses should remain as an option for certain categories. Statutory pass-throughs and Commission-directed costs should be recovered dollar-for-dollar through riders or deferrals with balancing accounts outside any cap, since they are unavoidable compliance costs rather than discretionary spending. For example, the residential exchange BPA credit should remain a separate sur-credit and be out of the MYRP. The company also proposes that the direct cost of participant benefits from the LID program (bill discounts and arrearage management) continue to be recovered through a separate surcharge and that demand response either continue to be recovered through a separate surcharge and tracked via a deferral and balancing account or be included in base rates with any over-/under-spend of what is in base rates tracked through a deferral and amortized over the subsequent MYRP term. During the term of the MYRP, utilities should be able to request deferred cost treatment for new costs that arise for items such as a new Commission-mandated program or a material tax change.

5. Performance Incentive Mechanisms (PIMs)

PIMs can complement an MYRP but are difficult to design well. While this topic will be addressed in a different track, the company recommends that the following principles be considered:

- **Do not discourage needed investment.** An asset-utilization target for example could work against building the transmission capacity required for long-range load growth and HB 2021 compliance.
- **Do not penalize outcomes the utility does not control.** Reliability is heavily influenced by weather and wildfire. Any metric should be normalized for major events and exclude causes outside the company's control.
- **Set thresholds on a principled baseline.** A PIM's design should be based upon sufficient data and thresholds should not be set so low that rewards are virtually guaranteed, nor so high that it is effectively unattainable and functions as a penalty rather than an incentive.

6. Rebasing

Rebasing resets the revenue-requirement baseline at the start of each new MYRP term, so rates realign with actual, prudently incurred cost of service rather than the escalated forecast carried through the prior plan. Rebasing should function the same as going-in rates and be similar to the existing general rate case process.

This pre-read is intended to inform the Track 1 workshop discussion and does not represent formal comments in Docket No. AR 676.