Cascade Policy Institute
OREGON

June 30, 2023

Oregon Public Utility Commission
201 High Street, SE
Salem, OR 97301

Re: LC 82 – PacifiCorp's 2023 Clean Energy Plan

Dear Commissioners,

Thank you for the opportunity to review PacifiCorp's 2023 CEP. We offer the following comments for your consideration:

Small-scale renewables (SSR): PacifiCorp anticipates the need for 802 MW of incremental SSR between 2023 and 2037. There is a great deal of uncertainty in how this goal will be achieved, but the estimated cost impacts are substantial.

Under Pathway 1 to emissions compliance, the total increased cost from 2030 to 2042 is $1.87 billion. Under Pathway 2, the total is $1.82 billion. The total nominal cost of the additional small-scale renewables over this same period is $671 million, a significant premium to be added to the already high costs of compliance with House Bill 2021.

From the standpoint of ratepayers, this is all cost and no benefit. Customers don't care whether electricity comes from small-scale or utility-scale resources; they just want reliable service at reasonable rates.

The PUC should consider ways of minimizing or deferring costs from this requirement, perhaps under authority granted to the Commission in Section 9 of HB 2021.

Community-Based Renewable Energy (CBRE): PacifiCorp forecasts the need for at least 95 MW of CBRE through 2030. According to studies cited by ODOE and NREL, this is likely to be twice as expensive as utility-scale solar. The company admits that among the many stakeholders, there is "no consensus on how to pay for these above-market costs."

There is also no clear blueprint for how the resources can even be obtained. One sentence from the CEP (p. 45) summarizes the problem: "These projects are imagined to be actualized in a CBRE Project Grant Pilot that the company proposes to develop."

Ratepayers need a lot more than imagination and hope.

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In various sensitivity runs (pp. 68-69), PacifiCorp hypothesizes that 100 MW of CBRE resources could replace 100 MW of small-scale renewables, but this "incurs a steep cost increase." The total increased cost from 2030 to 2042 over the preferred portfolio is $841 million, an even greater cost than that of the SSRs.

As with the SSR program, we suggest that the PUC consider all regulatory tools available to defer or avoid these costs, since they have few benefits for customers relative to utility-scale resources.

Allocation of Transmission Costs: PacifiCorp's 2,365-mile Energy Gateway Transmission Expansion Plan is expected to cost $11 billion through 2027. Much of the impetus for this plan comes from the forced transition to non-dispatchable resources, "while still ensuring reliability for customers" (if that's even possible).

As we understand it, transmission costs have historically been accounted for as 75% demand-driven and 25% energy-driven. This is an issue that deserves discussion by the Commission. It appears that roughly 68% of the 2,365 miles of new transmission are being built primarily to bring wind and solar plants online. If that's the case, a large percentage of the transmission costs should be assigned to the capital cost of procurement for those projects.

PacifiCorp claims that wind and solar are "the most cost-effective resources for our customers," but that is difficult to believe given the cost of transmission to these remote resources, and the simple fact that every increment of intermittent power needs to be backed up by dispatchable sources that are now a scarce commodity.

Admittedly, it may be that there are no cost-effective resources left now that Oregon has banned nuclear, coal and gas, but ratepayers have the right to know what the incremental cost of compliance will be for HB 2021. The question of *who pays* for new transmission is central to that inquiry.

Free riders: As a multi-state utility, PacifiCorp must comply with various and conflicting IRP regulations within its service territory. This creates many possibilities for gaming the system, as is hinted at in the CEP.

The basic problem is that the company "relies on managing dispatch from natural gas fueled resources" (p. 71), but Oregon legislators have imposed a prohibition on fossil resources after 2040.

PacifiCorp anticipates "ongoing multi-state negotiations on the allocation of costs and benefits" from the company's resource portfolio among the six states. The purpose will be to allow aggressive states like Oregon to accept "more of the cost and benefits of new non-emitting resources, but must also prevent leaning on other resources to maintain reliability" (p. 71).

In its discussion of compliance pathways, PacifiCorp discusses various ways of doing this. For instance, the company states:

> Gas conversions can be excluded from serving Oregon categorically, or specific natural gas units may be excluded from serving Oregon. Under all cost allocation structures, it is assumed that no coal is allocated to Oregon starting in 2030 consistent with ORS 457.518, and that no thermal resources or market purchases are allocated to Oregon as a post-model adjustment starting 2040.

These are just accounting tricks. Electricity flows throughout the grid, regardless of state boundaries or political mandates. So for any multi-state utility, complying with ORS 457.518 is a bit like workers in the former Soviet Union who sometimes claimed: "We pretend to work, and they pretend to pay us."

Under these scenarios, Oregon will prohibit any new coal or natural gas plants from being built, while free-riding on other states that allow fossil resources necessary for grid reliability. Aside from interstate equity issues, this is not a sustainable strategy. If every western state adopted Oregon's CEP standards, there would be very little dispatchable electricity left after 2030.

The Commission should endeavor to protect ratepayers by allowing PacifiCorp to do whatever is necessary to maintain reliability, even if certain HB 2021 standards are temporarily violated.

Financial impacts of taking Hunter and Huntington plants offline prematurely: These coal plants will be upgraded just before being taken offline. This is likely to negatively affect ratepayers. They are also being closed in 2031 and 2032, respectively, when those dates could conceivably be moved back by two years. Delaying the closures would be better for the company, while having minimal effect on regulatory deadlines.

Relying on technology that hasn't been invented yet: PacifiCorp notes that when natural gas and coal fired thermal resources are eliminated from the system to achieve emissions reduction targets, "replacement resources that have flexible operating capabilities will be needed to maintain reliable service."

PacifiCorp refers to this category as "non-emitting peaking resources", and actually makes up a number for what the capacity will be: 1240 MW. Even by the loose standards of long-range modeling, this is highly misleading.

For planning purposes, we suggest that no amount of electricity be forecasted from technologies that don't exist.

Sincerely,

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