BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket No. LC 85

In the Matter of PACIFICORP, dba PACIFIC POWER, 2025 Integrated Resource Plan.	Opening Comments of NW Energy Coalition

The NW Energy Coalition (NWEC), together with Mobilizing Climate Action Together (MCAT), appreciates the opportunity to provide initial comments on the PacifiCorp (Company) 2025 Integrated Resource Program (IRP) and Clean Energy Plan (CEP).

As we continue to review the voluminous information in the IRP, CEP and related materials, here we present a high level view of key issues for the Oregon Public Utility Commission (Commission or OPUC) review and decision with respect to acknowledgement.

Summary

To summarize, we make the following recommendations:

1. The Commission should direct PacifiCorp to reincorporate the missing demand forecast, resource development and transmission elements in the IRP and CEP modeling, as described below. Unless the modeling reflects these essential inputs, we believe it is not appropriate for the Commission to reach a final determination, including potential acknowledgment, on these filings.
2. We recommend that the Commission also consider whether Staff should conduct its own separate modeling exercise, in conjunction with outside technical experts as appropriate, to provide an integrity check on IRP and CEP inputs, assumptions and methods.
3. While continuing the review under Docket No. LC 85, we recommend the Commission give consideration as to the near term actions that may be appropriate for PacifiCorp to pursue in other processes, for example:
    - The Western Resource Adequacy Program and the Commission's directives in Order No. 22-468 in Docket No. UM 2011 and related matters.
    - The ongoing efforts to renovate or replace the Multi-State Protocol under Docket No. UM 1050.

- And urgently, an effort by PacifiCorp to advance a rapid acquisition process focused on capturing the expiring federal tax credits, especially for wind and solar, where such resources can be acquired on a "no regrets" basis and avoid the loss of millions of dollars of benefits for PacifiCorp customers.

Introduction

The IRP guidelines in OPUC Order No. 07-002 as subsequently amended are quite clear. Aside from specified exceptions, all relevant information on current and potential future electric demand, resources and transmission must be included within a utility's IRP in order for the Commission to have a full record for review.

Guideline 1(a) states:

> All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power . . . and demand-side options which focus on conservation and demand response.
>
> Order No. 07-002.

Furthermore, Guideline 10 provides:

> Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, **on an integrated-system basis** that achieves a best cost/risk portfolio **for all their retail customers**.
>
> Ibid., emphasis added.

Therefore, a foundational issue for the Commission review is whether all relevant aspects of demand, resources and transmission are fully and appropriately included in the PacifiCorp 2025 IRP and CEP. As we will describe below, this does not appear to be the case, and the result is substantial distortions in the analysis, the preferred portfolio and the Action Plan.

1. Is the treatment of new industrial load consistent with Commission policy?

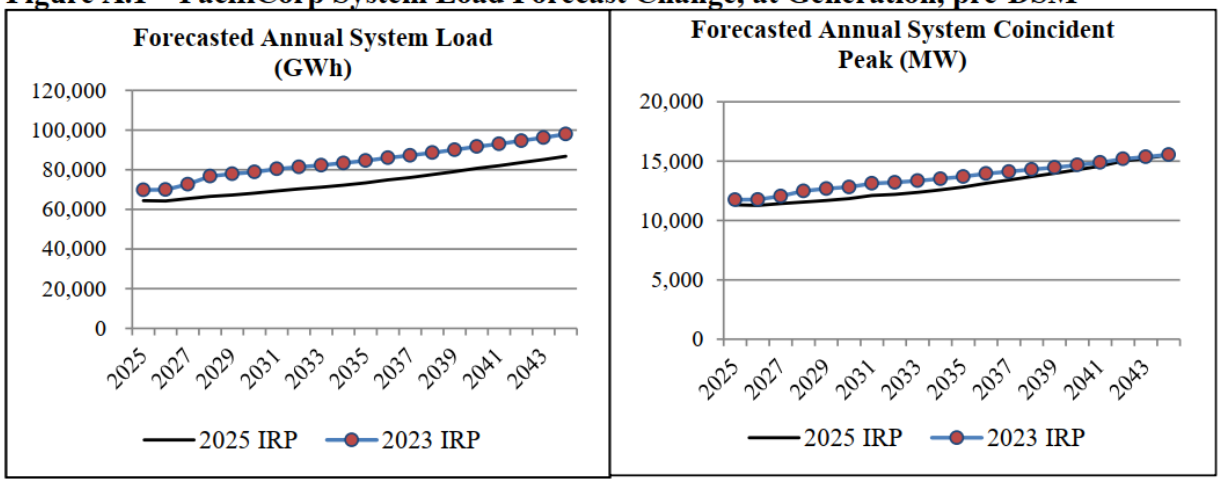
In Appendix A, p. 1 of the IRP, the Company states:

> PacifiCorp updated its load forecast in May 2024. The primary driver to changes in PacifiCorp's 2025 IRP load forecast are due to the exclusion of specific new large

customers who are expected to provide or pay for the resources and transmission necessary to support their load. These customers are expected to acquire their own resources; therefore, their loads have been excluded so that the PLEXOS capacity expansion optimization model does not plan Company resources to serve them.

Figure A1 illustrates this clearly:

Figure A.1 – PacifiCorp System Load Forecast Change, at Generation, pre-DSM



The IRP further states, "The compound annual load growth rate for the 10-year period (2025 through 2034) is 1.28 percent. Relative to the load forecast prepared for the 2023 IRP, PacifiCorp's 2034 forecast load requirement decreased in all states other than Washington **resulting in PacifiCorp system load requirement to decline 13.35 percent in 2034.**" Ibid., emphasis added.

Likewise, reflecting updates to the IRP demand forecast and continuing the arbitrary exclusion of potential new large loads, the CEP states: "PacifiCorp's current CEP load forecast reflects a modest growth rate in Oregon retail sales over the next 10-year period (a compounded annual growth rate of 0.07 percent). **This is a material difference from the 2023 CEP, which forecasted a 4.39 percent 10-year compounded annual growth rate."** CEP at 102, emphasis added.

Yet the CEP continues: "These forecasts can differ dramatically each CEP cycle based on the timing and siting of data center load. For example, the 2025 IRP includes a high data center load forecast scenario, which indicates an approximate 7.5 GW of additional system resources that could be needed to meet increased demand by 2045. High data center load growth presents material compliance issues for HB 2021 purposes."

We agree that volatility in the near term for major data center and other industrial load growth is one of the primary focuses of the planning process for the Company, the Commission and stakeholders alike. But PacifiCorp is not given leeway to shield this pivotal part of the planning environment from full scrutiny. Removal of prospective major new load undermines the IRP's role as the main direction-setting mechanism for investment in new resources for the benefit of PacifiCorp customers.

The clear intention of Commission policy is not to allow utilities to pick and choose which future load additions to include in the IRP. The one clear exception is for direct access. Under IRP Guideline 9, "an electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier." However, this exception is clearly limited to additional loads with a resource plan that has been approved by the Commission under its standard review processes.

In all previous IRPs, PacifiCorp made no distinction between different kinds of new loads forecasted to be added to service requirements. The modeling change in the 2025 IRP is predicated on PacifiCorp's separation of an undefined set of prospective new retail loads which do not by definition have executed agreements consistent with the Commission's direct access policy.

As the IRP discussion shows, this change in modeling input assumptions by the Company dramatically shifts the starting point for the demand forecast and consequently all other aspects of the modeling, including the characteristics of the resource scenarios evaluated and the final proposed preferred resource portfolio.

Within the IRP modeling this also affects resource adequacy, adherence to mandatory reliability standards, and achievement of state policies and regulations in all PacifiCorp states as well as Oregon, among many other effects. It also poses the prospect of unregulated and inefficient competition between the Company, acquiring new resources on behalf of customers, and certain of its existing or prospective new customers acquiring resources on their own behalf, but outside the tailored confines of the Commission's direct access policy.

Furthermore, arbitrary exclusion of substantial prospective new loads raises concerns in numerous other contexts, including compliance in the Western Resource Adequacy Program binding phase, FERC review of cost allocation for new transmission, and any agreement to update or replace the Multi-State Protocol.

The Company cannot have it both ways. Commission policy and previous practice strongly suggests there is only one permissible approach: all new demand, other than that included

in Commission-approved direct access agreements, must be included in the IRP and CEP. The Company cannot substitute its self-defined "expected to provide or pay" standard as the baseline for the IRP and CEP.

2. Is the treatment of new resource deliverability consistent with Commission policy?

The following is included in a listing of otherwise unexceptional modeling changes since the 2023 IRP:

> • Jurisdictional portfolios are used to integrate final portfolios.
> o **States are only able to impact the disposition of resources in which they have an active share.**
> **o Resource additions are considered situs and must be able to serve requirements in their associated jurisdiction.**

IRP at 182, emphasis added.

Situs requirements have long played a part in electric IRPs in Oregon. But as noted above, IRP Guideline 10 requires multi-state utilities to plan on an integrated-system basis that achieves the least cost/least risk portfolio for **all** retail customers.

Furthermore, summarizing its decision following a robust debate over situs issues, the Commission prefaced the adoption of Guideline 10 by stating:

> Conservation costs may be charged on a situs basis, but the level of activity in other states affects what other resource costs are incurred in a multi-state system and allocated to Oregon. Other states may have preferences about what resources are acquired to meet their needs, but as long as those choices affect the costs and risks borne by Oregon customers, we will make our own judgment about what resource mix is best.

Order 07-002 at 20.

Situs consideration plays a legitimate but specific and constrained role within IRP preparation and review. For example, as noted in Guideline 10, conservation acquisition levels (energy efficiency or "Class 2 DSM" as referred to by PacifiCorp) are generally set within each state in accord with respective state policy and regulatory review under least cost/least risk IRP principles.

In addition, state policies such as situs requirements for renewable portfolio standards are routinely reflected in the IRP process.

However, there is no general situs obligation for new resources, including for purported reasons of transmission limitation. In fact, each IRP rightly has included any existing or anticipated transmission constraints directly in the planning. PacifiCorp has many tools to handle transmission congestion and constraints, including careful placement of new resources, its robust program of transmission facility upgrades and transmission expansion (including two expansion projects discussed in the next section), and bilateral and organized market transfers. Notably, the Company will be the first entrant in the forthcoming Extended Day-Ahead Market (EDAM) which will significantly expand and optimize the availability of resources needed within operating time to address in-system constraints.

To the extent that fast growing large industrial load places additional burdens and constraints on delivery for any set of customers, including Oregon customers in particular, the whole effort of the IRP and CEP is aimed at fully addressing those prospective issues in a least cost/least risk systemwide manner, just as IRP Guideline 10 commands.

The consequences of a blanket situs constraint on IRP scenarios, the proposed preferred portfolio and Action Plain are plainly evident, restricting the availability, competitive range and optimization of new resources that provide systemwide benefits, thus decreasing value and increasing costs to all retail customers.

We have already seen the value-reducing consequences of this arbitrary constraint in PacifiCorp's proposed conditions for the "Oregon situs" RFP currently under consideration in Docket No. UM 2383. Restricting access only to those with deemed deliverability to PacifiCorp's Oregon system would greatly reduce the competitive range and operational diversity of potential new resources, and would raise costs for all PacifiCorp customers, especially in Oregon.

Electrons do not "see" state borders. PacifiCorp rightly operates its six-state system as an integrated whole, and the IRP construct is, by consensus of those states, a systemwide planning process.

Deliverability is subject to the laws of physics and as noted above, such constraints are dealt with routinely in longstanding IRP planning methods, new resource and transmission investments, market transactions and operational adjustments.

PacifiCorp's unilateral and arbitrary placement of a general situs constraint on new resources in the IRP and CEP modeling is unfounded in good practices for IRP analysis and contrary to Commission policy.

3. Is the exclusion of new transmission consistent with Commission policy?

The Commission's guidelines contain numerous references to inclusion of transmission in electric IRP planning, especially the overarching reference in Guideline 10: "Multi-state utilities should plan their generation **and transmission systems** . . . on an integrated-system basis that achieves a best cost/risk portfolio for **all** their retail customers." Order 07-002, emphasis added.

To its credit, PacifiCorp has long been a leader in including substantial transmission information and Action Plan recommendations in its previous IRPs. Yet the exclusion of two major transmission expansion projects in the 2025 IRP and CEP provides ample reason for close scrutiny of the explanation and motivations for this abrupt turnabout.

One project, Boardman to Hemingway (B2H), has long been central to the Company's plans for new transmission, but has been excluded from the 2025 IRP with only the very briefest of discussion and no analysis or reasoning for that decision.

The other, now denoted as Blueprint, a major proposed new project within Oregon boundaries, is not mentioned whatsoever in the IRP and CEP.

Boardman to Hemingway. B2H, co-owned by Idaho Power as developer and PacifiCorp, is the largest new transmission project in the Northwest for many decades. It will be constructed along a 290-mile corridor from the Hemingway substation west of Boise to the new Bonneville Power Administration (BPA) Longhorn substation near Boardman close to the Columbia River. The line will carry about 1000 MW of bidirectional flow. Idaho Power owns about 45% of the capacity, about half of which is pledged to BPA, and PacifiCorp owns about 55%, including the large majority of east-to-west rights (820 MW) as well as 300 MW west-to-east.[1]

[1] While a figure of 600 MW for PacifiCorp east-west rights is often cited, a recent presentation by Idaho Power to the Idaho Public Utility Commission clarifies that the PacifiCorp transmission rights shares are 820 MW east-to-west and 300 MW west-to-east. See https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/IRPAC_TransmissionUpdate_Mar13.pdf It is possible that the increment of firm transmission capacity available to PacifiCorp may be limited to 600 MW for various reasons including seasonal rights and path ratings. But in addition, if Idaho Power joins the Extended Day-Ahead Market along with PacifiCorp, the EDAM security constrained economic dispatch will co-optimize use of B2H capacity in operational time for both utilities.

B2H has long been a key feature of PacifiCorp's Energy Gateway transmission program and has been featured in numerous previous IRPs. In 2010, PacifiCorp entered into an initial Memorandum of Understanding (MOU) with Idaho Power, the project developer. IRP at 88. PacifiCorp has been fully involved as a full participant in project development since that time, including large expenditures for internal studies as well as co-payments for external project costs.

Furthermore, PacifiCorp testified extensively in favor of the Commission's approval of the Certificate of Public Convenience and Necessity (CPCN) in Docket No. PCN 5. The Company's reasoning is worth considering at full length:

> The B2H transmission line is necessary to meet PacifiCorp's need to reliably and cost effectively serve its customers. The Company's 2021 IRP and 2021 IRP Update examined the portfolio impacts and system impacts of not participating in B2H as compared to the preferred portfolio that included it. The results of its analysis in the 2021 IRP showed that the least-cost, least-risk outcome included the B2H transmission line and was projected to result in $453 million in risk adjusted net benefits over the 20-year planning period. In the Company's 2021 IRP Update, the risked adjusted net benefits were $439 million for the same period. PacifiCorp's analysis did not end with the 2021 IRP. To account for a number of key changes that occurred since the 2021 IRP, the Company refreshed its analysis. The key changes included in this updated analysis were incorporating the most recent load forecast, which significantly increased, the impacts of the Environmental Protection Agency's Ozone Transport Rule, the extended and expanded tax incentives under the federal Inflation Reduction Act, and evolving transmission service requirements. The updated analysis shows that the B2H risk-adjusted net benefits are projected to be $1.713 billion for the period 2023 through 2042, assuming medium natural gas and carbon prices.
>
> Further, there are other benefits resulting from B2H for PacifiCorp and its customers. First, PacifiCorp is forecasting increased load-serving capacity and B2H will allow the Company to avoid a shortfall in 2026. Second, because of B2H, the Company will be able to export additional energy generation capacity from its East balancing authority area to its West balancing authority area while also receiving incremental firm transmission rights from BPA. Third, through the B2H transmission line, the Company will be able to integrate its growing portfolio of clean, renewable energy and storage resources between its two balancing areas, which is important due to the emissions levels in HB 2021 that the Company must meet. Finally,

> PacifiCorp currently has one 500-kV transmission line that connects its two balancing authority areas, which if lost would reduce transfer capability by 1,050 megawatts. The addition of B2H will improve grid reliability and provide better operational control of the backbone transmission system through an additional connection of the two areas. Thus, B2H will add a much-needed connection between the Company's East and West balancing authority areas to the benefit of the Company and its Oregon customers.
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> PacifiCorp's Opening Brief, PCN 5, May 15, 2023 at 5.

In its order approving the B2H CPCN, the Commission not only summarized PacifiCorp's jsubmissions but took specific note of the numerous prospective benefits of the project, including in particular:

> The B2H project will also **enable PacifiCorp to export 600 MW of additional energy generation capacity between its East and West balancing authority areas and is needed to help PacifiCorp move clean energy resources to meet Oregon's greenhouse gas emissions reduction requirements.**
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> Order No. 23-225 at 15.

Surely the conditions addressed in the 2023 IRP and PCN 5 proceedings with respect to reliability, resource adequacy and deliverability are even more applicable today.

PacifiCorp has devoted almost two decades of work and considerable expense in both its own preparation and engineering as well as shared B2H development costs with Idaho Power and Bonneville.

In summary, B2H is a long-established core resource in PacifiCorp's long term strategy to provide reliable, clean and affordable service to all its retail customers, especially but not exclusively those in Oregon.

The 2025 IRP provides a generic B2H description and summary of the January 2022 non-binding memorandum of understanding among Idaho Power, PacifiCorp and BPA. And yet PacifiCorp has removed B2H from inclusion in the modeling, scenario analysis, preferred portfolio and Action Plan in the 2025 IRP and CEP.

Concerning this momentous choice, the Company provides only the most cursory statements and no supporting documentation or analysis whatsoever:

> Currently, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis

> underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.
>
> IRP at 5.
>
> PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.
>
> Footnote to IRP Figure 8.3, Transmission System Model Topology with Major Options.
>
> At this time, PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.
>
> IRP at 84.

Yet despite removal from the IRP and CEP and withdrawing projected net benefits of greater than $1.5 billion from retail customers, especially in Oregon, B2H remains in PacifiCorp's Energy Gateway transmission expansion plan. IRP Table 4.1.

Blueprint. For many years, PacifiCorp has been evolving plans for new transmission expansion across its service area in Oregon. Recently, PacifiCorp has revealed initial plans for a major new multi-part transmission project running approximately north-south from the Columbia River area to southern Oregon.

The first phase is being called Blueprint South and would consist of a 180-mile 500 kV segment from a new substation called Full Circle near Redmond to Chiloquin east of Upper Klamath Lake, continuing to the Snow Goose substation just south of Klamath Falls.

PacifiCorp has been conducting extensive community outreach and the project has received considerable media coverage. In addition to documentation on the PacifiCorp website, the project has a separate branded website at https://blueprintsouth.com. PacifiCorp anticipates commencing the federal National Environmental Policy Act (NEPA) review process in late 2025 or early 2026 followed by other reviews including Oregon Energy Facility Siting Council (EFSC) and Commission CPCN submissions.

There is little information available on what will perhaps be called Blueprint North. However, both segments have been submitted for inclusion in the NorthernGrid 2024-2025

Regional Transmission Plan which is currently in draft undergoing review for completion at the end of 2025.[2]

The NorthernGrid draft plan states that the data submission by PacifiCorp for the northern Blueprint segment is to construct 150 miles of new 500 kV transmission between the new Full Circle substation near Redmond northward to the Apex substation near Boardman.

All told, NWEC anticipates the prospective south and north Blueprint segments will each require upward of $1 billion in expenditures and be completed in the early to mid 2030s.

However, as indicated above, there is no reference whatsoever to Blueprint in the 2025 IRP, and thus no discussion of project purpose and need, how it would integrate with the existing PacifiCorp transmission network as well as adjacent systems, and to what extent it would add value for customers.

As a final note, in the PacifiCorp integrated system, no element of the transmission system operates in isolation from the others. For example, in its review of planned transmission system improvements, the Company notes that a project to replace the entire 500 kV reactive station in Burns, Oregon, including series capacitors, bypass breakers and other equipment, is intended to prevent equipment failure that could limit operation of Jim Bridger coal and Wyoming wind generation more than 500 miles away. IRP at 96.

Thus, inclusion of all relevant transmission developments is fundamental to the IRP modeling, analysis, preferred portfolio and Action Plan. The IRP framework is explicitly required to address transmission resources, and by excluding two major transmission expansion projects, PacifiCorp has deprived the Commission and stakeholders of the opportunity to review those matters as required by the IRP Guidelines.

In summary, the exclusion of B2H and Blueprint from the 2025 IRP and CEP dramatically alters the context of the IRP for the entire PacifCorp system, not only for Oregon. Additional detailed comments by Renewable Northwest and Sierra Club will comprehensively identify the major distortions this causes to the assessment of resource selection, deliverability, resource adequacy and reliability.

[2] https://www.northerngrid.net/private-media/documents/2024-2025_Draft_RTP.pdf

Conclusion

NW Energy Coalition takes the view that the PacifiCorp 2025 IRP and CEP, as submitted, are materially insufficient on all three major components of the review: load growth, new resources and new transmission.

Until those deficiencies are addressed, the IRP and CEP cannot meet the requirements for acknowledgment under the Commission's guidelines. These deficiencies pose substantial potential for ongoing planning and execution uncertainty, lost opportunities, capital misallocation, and direct risks to system reliability, customer affordability and achievement of all the policies of each state across PacifiCorp's service area, not just Oregon's HB 2021.

We offer these points going forward:

1. The Commission has options in remediating the current deficiencies of the PacifiCorp 2025 IRP and CEP.

At a minimum, revised IRP modeling must restore a full view of all forecast load growth, remove the arbitrary barriers on resource situs location and deliverability, and include the Boardman to Hemingway and Blueprint transmission projects. With a complete and fully described set of loads, supply resources and transmission, a clear and robust baseline can be re-established for the IRP and CEP. If PAC feels that further adjustments are required to those starting conditions, they may then present alternative scenarios and analysis supporting those variations.

Under IRP Guideline 3(d), "The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order."

The Commission may hold such public meeting at any time and direct PacifiCorp to revise the IRP and CEP filings with requirements to provide complete load, resource and transmission inputs, and cure modeling deficiencies identified by Staff and stakeholders.

Second, the Commission could direct Staff to conduct its own set of studies, including seeking outside technical services as needed. This may be an appropriate step alongside revisions by the Company to provide an integrity check on IRP and CEP inputs, assumptions and methods.

2. The CEP and IRP are proceeding in a broad context of multiple challenges across resource planning, acquisition and implementation, system operations and cost management and recovery.

While the IRP and CEP run together in a single docket, LC 85, it is important to be mindful during this time of profound change that many other PacifiCorp processes are advancing, including but not limited to the "Oregon situs" RFP, small scale renewable RFPs, preparation for joining the Extended Day-Ahead Market and the binding phase of the Western Resource Adequacy Program, and the revision or replacement of the Multi-State Protocol.

Consideration of the CEP and IRP must proceed in due course but cannot be separated from a holistic approach to assure that all plans and actions the Company takes are conducted in a way that results in maximum benefit to all retail customers in all parts of the PacifiCorp system.

3. The IRP and CEP are all-of-system planning processes, not determination of cost causation, allocation or recovery.

The IRP and CEP are planning processes that are separate from and *ex ante* to processes to determine cost causation, cost allocation and cost recovery. While consideration of those aspects may play a role in the IRP and CEP processes, Guidelines 1(a) and 10 clearly state the foundational purpose of the IRP is to provide a single-system integrated planning approach respecting all reliability and policy constraints, and not based on prejudgment of cost allocation outcomes, in order to define a least cost/least risk resource management and acquisition strategy going forward.

4. PacifiCorp should pursue a systemwide no-regrets near term resource acquisition to capture the full value of federal credits: time is of the essence.

Separately, dramatic changes in the federal policy landscape are posing a severe risk to resource acquisition in the near term. Given forthcoming statutory deadlines under the 2025 Reconciliation Law (H.R. 1), NWEC strongly recommends that the schedule for the ongoing IRP and CEP processes not become a factor in delaying new resource acquisition.

PacifiCorp must not further extend the error of cancelling the 2022 All Source RFP, which has already resulted in major loss of value for customers, and must seize every opportunity to develop no-regrets resources that capture as much of the federal credits as possible. That could amount to many millions of dollars of net benefit for all PacifiCorp retail customers across its six-state service area.

Our view is that the "Oregon situs" RFP is not a sufficient step to address the immediate risk and opportunity. The Commission should consider joining with the regulatory bodies in all of PacifiCorp's service area to support a systemwide all-source RFP as quickly as possible.

Submitted July 29, 2025

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