

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

PacifiCorp's 2025 Integrated Resource Plan	<u>DOCKET NO. 25-035-22</u>
	<u>ORDER</u>

ISSUED: June 25, 2026

SHORT TITLE
PacifiCorp's 2025 Integrated Resource Plan

SYNOPSIS

The Public Service Commission acknowledges PacifiCorp's 2025 Integrated Resource Plan ("IRP") based on substantial compliance, as described in more detail below, and provides guidance in the development of the next IRP.

TABLE OF CONTENTS

I. INTRODUCTION AND PROCEDURAL HISTORY 1

 A. *Summary of the 2025 Integrated Resource Plan* 2

 B. *The IRP Process and Standard of Evaluation* 5

II. SUMMARY OF ISSUES ADDRESSED IN COMMENTS 7

III. PARTIES' POSITIONS ON ACKNOWLEDGMENT OF THE 2025 IRP 8

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS 11

 A. *Draft IRP, Utah IRP, and Final 2025 IRP* 11

 1. Draft IRP 11

 2. Utah IRP 11

 B. *Jurisdictional Portfolio Modeling Methodology* 14

 C. *Deliverability Challenges* 17

 D. *End Effects Analysis in Preferred Portfolio Selection* 19

 E. *Expedited RFP To Leverage Tax Opportunities* 22

 F. *Assumptions* 25

 1. Load Forecast and Exclusion of Certain Loads and Resources 25

 2. Front Office Transactions 29

 3. DSM, 2025 Conservation Potential Assessment (CPA), and Distributed Generation 31

 G. *Transmission* 33

 1. Boardman to Hemingway 33

 2. Transparency & Advanced Transmission Technologies (ATT) 35

 H. *Sodium and 100-Hour Batteries* 37

 I. *Preferred Portfolio* 39

V. SUMMARY AND CONCLUSIONS 42

VI. ORDER 42

I. INTRODUCTION AND PROCEDURAL HISTORY

On March 31, 2025,¹ PacifiCorp filed with the Public Service Commission (PSC) its seventeenth Integrated Resource Plan (“2025 IRP”). The PSC reviews PacifiCorp’s IRP filings for compliance with the IRP Standards and Guidelines (“Guidelines”) the PSC established in 1992.² PacifiCorp requests the PSC (1) acknowledge the 2025 IRP; and (2) support the 2025 IRP’s conclusions, including the proposed action plan (“Action Plan”).

The Division of Public Utilities (DPU) and the Office of Consumer Services (OCS) participated in the docket, and the following parties intervened: the Utah Association of Energy Users (UAE), Utah Clean Energy (UCE), Western Resource Advocates (WRA), the Interwest Energy Alliance (IEA), and Sierra Club.

By September 26, 2025, the following parties filed comments: DPU, OCS, UAE, WRA, IEA, Vote Solar, Sierra Club, and UCE.³ On November 25, 2025, PacifiCorp, DPU, WRA, Sierra Club, and UCE filed reply comments.

¹ PacifiCorp filed confidential and highly confidential workpapers supporting its 2025 IRP on April 15, 2025.

² See *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Docket No. 90-2035-01, Report and Order on Standards and Guidelines issued June 18, 1992. Hereafter, any reference to a “Guideline” followed by a number refers to a numbered guideline in this prior order.

³ UCE submitted both individual and joint comments with Southwest Energy Efficiency Project (SWEEP).

A. *Summary of the 2025 Integrated Resource Plan*

The 2025 IRP presents PacifiCorp's plan to supply energy and capacity to provide for and manage the growing electricity demand in its six-state service territory over the next 20 years. The report identifies PacifiCorp's preferred least-cost, least-risk plan ("Preferred Portfolio") reflecting investments in or continued operation of power plants, transmission facilities, firm power purchases, and demand side management (DSM) resources. The 2025 IRP identifies the type, timing, and magnitude of resource additions and provides a short-term Action Plan.

The Preferred Portfolio in the 2025 IRP responds to the rapidly expanding arena of new state and federal regulatory requirements. The 2025 IRP assesses the cost-effectiveness of individual resources considering the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional portfolios were presented: (i) Washington; (ii) Oregon; and (iii) PacifiCorp's remaining service territories including Utah, Idaho, Wyoming, and California (collectively, "UIWC"). According to PacifiCorp, for each jurisdiction, it determines the optimal combination of resources through analysis that measures cost and risk. PacifiCorp explains the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

According to PacifiCorp, the 2025 IRP includes many key advancements in modeling and evaluation strategy, many driven by stakeholder input. For the 2025 IRP, portfolios must achieve regional and system Western Resource Adequacy Program (WRAP) compliance and existing thermal units can operate indefinitely with ongoing maintenance. In addition, Inflation Reduction Act (IRA) tax credits are extended through the model horizon, and jurisdictional portfolios are used to integrate final portfolios. PacifiCorp represents it has improved granularity and reliability evaluation. Also, transmission representation now includes a distinct bubble for the Wasatch Front, and no federal CO2 policy adder is assumed in the expected case. A new price-policy variation case was added, no market purchases were allowed in peak hours on the five days with the highest peak load in each month, but they were allowed up to transmission limits in all other hours. Stochastic analysis incorporated wide-ranging historical volatility in renewable shapes, thermal outages, load, market prices, and hydro availability.

PacifiCorp selected its Preferred Portfolio,⁴ which it asserts is the least-cost plan, adjusting for risk and uncertainty.⁵ To serve system-wide peak hour demand over the next 20 years, the Preferred Portfolio identifies cumulative supply additions

⁴ See 2025 IRP, Volume I at 227-241. The Preferred Portfolio is the Integrated Base MN (medium gas price/no CO2) price policy scenario portfolio.

⁵ PacifiCorp explains that, as in previous IRPs, “model results can indicate the need to examine costs and risks beyond the model horizon” and “[e]nd effects were applied to all portfolios run under the MN price-policy [scenario] for a [five]-year period after the study horizon.” *Id.* at 260.

(both long- and short-term resources) of 3,782 MW of new wind resources, 7,524 MW of storage resources (including 4-hour and 100-hour durations), 5,912 MW of new solar resources (including utility-scale and small-scale), 500 MW of advanced nuclear (the Natrium reactor demonstration project), 5,255 MW of capacity saved through energy efficiency programs, and 769 MW of capacity saved through direct load control programs. PacifiCorp also identifies various upgrades to increase transfer capability from southern Utah to the major load center in the Wasatch Front, updates to its transfer capability between Oregon and Idaho, new transmission facilities in Oregon, and additional local transmission upgrades to connect clean resources to the transmission system in Utah, Oregon, and Washington.

The 2025 IRP also (1) converts 562 MW of coal units to natural gas units, (2) exits PacifiCorp's share in 386 MW of minority-owned coal, and (3) assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The remaining coal units continue to operate through the end of the study horizon. The balance of the coal units, including Hunter and Huntington, continue to operate through the end of the study horizon.

The 2025 IRP Action Plan identifies specific actions PacifiCorp will take over the next two to four years to deliver its Preferred Portfolio. Action items are based on the size, type, and timing of resources in the Preferred Portfolio, findings from analysis

completed over the course of portfolio modeling, and feedback received from stakeholders in the 2025 IRP public input process. PacifiCorp's 2025 IRP Action Plan includes action items for existing resources, new resources, transmission, DSM resources, short-term firm market purchases, and the purchase and sale of renewable energy credits.

B. The IRP Process and Standard of Evaluation

Utah Code § 54-1-10 requires the PSC to “engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources.” To fulfill this planning requirement, the PSC relies, in part, on PacifiCorp's IRP process.

The Guidelines governing the IRP process were originally developed and approved by the PSC in 1992.⁶ The PSC's acknowledgment of an IRP suggests substantial compliance with these Guidelines; however, such acknowledgment does not constitute PSC approval of any specific resource acquisition decision or PacifiCorp's strategy for meeting its obligation to serve. Decisions regarding resource approval and cost recovery are addressed in dockets separate from the IRP.

PacifiCorp provided an itemized table detailing its efforts to comply with each state's specific standards and guidelines in Appendix B. While two states, Oregon and Washington, require a draft IRP, Idaho, Wyoming, and Utah do not. PacifiCorp satisfies

⁶ See *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Docket No. 90-2035-01, Report and Order on Standards and Guidelines issued June 18, 1992.

the public input requirements through virtual public input meetings and the submission of stakeholder comments to both PacifiCorp and regulatory bodies.

In the 2023 IRP cycle, comments from numerous stakeholders shared concerns about their having an insufficient opportunity to participate in PacifiCorp's IRP development process, which prompted an order from the PSC soliciting recommendations for changes to the IRP schedule.⁷ Based on this feedback, for the 2025 IRP, PacifiCorp committed to incorporating all model inputs by September 1, 2024. To comply with Oregon and Washington requirements, PacifiCorp planned to file a draft IRP with the PSC by January 1, 2025 ("Draft IRP").⁸ The PSC subsequently ordered PacifiCorp to disclose the modeling results, including the ranking of portfolios, at a public input meeting (PIM) to be held on or before October 15, 2024.⁹

The result of these revisions is the inclusion of a section in the 2025 IRP, which PacifiCorp defines as the "Utah IRP." The subsequent IRP process became more complex, and the parties largely elected to disregard the Utah IRP, choosing instead to focus their comments on the final model outcome.

The PSC recognizes that the data input to the IRP modeling is foundational for an endogenously¹⁰ selected portfolio and the subsequent analysis required to

⁷ See *PacifiCorp's 2023 Integrated Resource Plan*, Docket No. 23-035-10, Order issued April 17, 2024, at 42.

⁸ *Id.*, Order issued July 11, 2024, at 9.

⁹ *Id.*

¹⁰ An endogenous variable is an outcome or dependent variable explained *by* the model itself, not an external input.

determine the preferred portfolio. Parties' concerns about the Preferred Portfolio may stem not from inadequate time to review the outcome but from insufficient review of the input data. That is, if the parties concur with the data used in the input, the endogenously selected portfolio is likely to be less controversial.

In its 2023 order, the PSC acknowledged that the 2025 IRP was already underway and that full implementation of the ordered deadlines was not anticipated until the 2027 IRP cycle. Our review of the record reveals that our guidance and direction for the 2025 IRP cycle improved the IRP process. However, it was not the PSC's intent for PacifiCorp to create two IRPs. The data lockdown date in October 2024 apparently resulted in the creation of a Utah IRP that proved largely meaningless for stakeholders. Having learned from the outcome of our guidance and its impact on the 2025 IRP, we modify the process once again for the 2027 IRP cycle and beyond and discuss the modifications below.

II. SUMMARY OF ISSUES ADDRESSED IN COMMENTS

As discussed in more detail below, several parties urge us to decline to acknowledge the 2025 IRP. Many express serious concerns regarding the allegedly inadequate public input process due to late submission of key data, the proposed jurisdictional first modeling approach that, they say, departs from least-cost, least-risk portfolio planning, as well as inadequate load forecasting due to the exclusion of large industrial and data center loads and Utah Community Clean Energy Program (UCCEP) resources and loads. Certain parties also noted limited opportunity for

sufficient review and feedback on modeling results and the dual 2025/Utah IRPs.

Some parties contend that the Preferred Portfolio was not shared until after PacifiCorp filed the Draft IRP on December 31, 2024. In addition, certain parties argue that PacifiCorp failed to share with stakeholders either the Preferred Portfolio as updated in Chapter 9 or the modeling results of its end effects analysis prior to filing the final IRP. Overall, the parties take issue with several aspects of the 2025 IRP, including, without limitation:

- a. the disclosure of the Preferred Portfolio being too late for adequate stakeholder review;
- b. inconsistent or incomplete end effects analysis for stakeholder review;
- c. the separation of the proposed final 2025 IRP and the Utah IRP (commenting either that the Utah IRP served no purpose or ignoring it altogether and recommending the PSC direct PacifiCorp to file only a final IRP in the 2027 IRP cycle); and
- d. the separation of Oregon, Washington, and UIWC into different jurisdictions, which they contend undermines least-cost principles and was not punctually provided for stakeholder review.

III. PARTIES' POSITIONS ON ACKNOWLEDGMENT OF THE 2025 IRP

DPU recommends acknowledgment of the IRP with several exceptions. DPU opposes acknowledgment of Chapters 11-13 of the Utah IRP and the portions of the Preferred Portfolio containing the Natrium plant and 100-hour iron air storage. DPU

comments that the creation of two IRPs — the 2025 IRP and Utah IRP — placed Utah stakeholders in the difficult position of not being able to clearly and effectively analyze the submitted materials and further complicated DPU's ability to assess whether PacifiCorp complied with past PSC orders. DPU comments that if the 2025 IRP is considered the official IRP, then Guidelines were violated by PacifiCorp's introduction of final modeling results for the first time on March 31, 2025.

OCS does not oppose acknowledgment of the 2025 IRP but declines to expressly endorse it until it can understand the implications of the new jurisdictional first modeling approach, including its impacts on system resource adequacy and Utah ratepayer costs. OCS states it is not able to determine whether the 2025 IRP meets the Guidelines given the significant modeling changes in the IRP and their impact, including the jurisdictional first portfolio approach and the removal of new large loads from the IRP's load forecast.

OCS appreciates the progress PacifiCorp has made in the 2025 IRP in some areas found to be deficient in prior IRPs, specifically providing preliminary modeling results to stakeholders and not deliberately handicapping natural gas resources relative to company-favored resources.

Sierra Club, WRA, UAE, UCE, IEA, and Vote Solar recommend the PSC decline to acknowledge the 2025 IRP, generally arguing that the public input process continued to be deficient in the 2025 IRP cycle and violated Guideline 3. They argue that PacifiCorp's jurisdictional portfolio modeling approach results in sub-optimal

portfolios and departs from least-cost, least-risk planning. They also highlight that the Preferred Portfolio was chosen based on end effects, an analysis that was not discussed, or only discussed briefly at the end of the planning process, before the 2025 IRP filing. They also criticized the load forecast, tax credits, the Boardman to Hemingway (“B2H”) transmission line, and DSM assumptions used in the modeling.

PacifiCorp defends its public input process as unprecedented in scope and fully compliant with Guideline 3, noting its nine PIMs, 69 stakeholder feedback forms documented in Appendix M, and the first-ever publication of a complete draft IRP — including a draft preferred portfolio and numerous variant portfolios — three months before the 2025 IRP filing. PacifiCorp rejects WRA’s and UAE’s suggestion that it should have disregarded the PSC’s 2023 IRP Order, quoting its plain text directing PacifiCorp to adhere to the schedule. It contends the 2025 IRP fully complies with the Guidelines and requests the PSC acknowledge it based on robust and extensive portfolio modeling across a wide range of price-policy scenarios and prudent planning assumptions developed with stakeholder input, resulting in the selection of a least-cost, least-risk preferred portfolio. Second, PacifiCorp argues the IRP includes a sound Action Plan that is consistent with the long-term public interest that will be updated on a regular basis consistent with both business and regulatory practice. Third, PacifiCorp urges meaningful stakeholder engagement and participation existed throughout the planning process that fostered constructive dialogue and informed long-term resource planning.

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS

A. Draft IRP, Utah IRP, and Final 2025 IRP

1. Draft IRP

PacifiCorp produced the Draft IRP on December 31, 2024, consistent with other states' requirements. While the Draft IRP was not filed in Utah, it is part of the public input process and most intervening parties in this docket provided comments related to it. WRA noted that the Draft IRP was incomplete and contained significant errors. Most of the other parties in the docket commented that modeling methodologies, modeling results, and the preferred portfolios changed after the Draft IRP's publication.

2. Utah IRP

DPU and Sierra Club disapproved of PacifiCorp's filing of both the 2025 IRP and the Utah IRP. They largely contain the same information, except for Chapters 11 (Utah's modeling results), 12 (Utah's preferred portfolio), and 13 (Utah's Action Plan). The data that informed the Utah IRP was locked down in September 2024, earlier than the data that informed the 2025 IRP (i.e., modeling results, preferred portfolio, and Action Plan). DPU and Sierra Club commented generally that the Utah IRP served no clear purpose. DPU explained that PacifiCorp's strategy of filing two versions resulted from its overly technical reading of the PSC's 2023 order. OCS focused its review on the 2025 IRP, stating that the 2025 IRP reflects PacifiCorp's actual roadmap for future

resources. Like DPU, UAE and WRA commented that the Utah IRP was created to satisfy the PSC's 2023 order, and they also focused their reviews on the 2025 IRP.

PacifiCorp confirmed that it filed the Utah IRP to meet the PSC's directives in the 2023 order,¹¹ explaining that it locked down modeling inputs and assumption changes as of the publication of the Draft IRP on December 31, 2024.¹² Because other jurisdictions did not have the same restriction, PacifiCorp continued to modify inputs and assumptions to incorporate the best available information at the time, resulting in different modeling results and preferred portfolios in the final 2025 IRP. Thus, the Utah IRP included stale information that was disregarded by the parties and did not reflect PacifiCorp's actual roadmap for future resources.

The PSC did not direct PacifiCorp to create a Utah-specific IRP in our 2023 order. We ordered a lockdown date, after which inputs and assumptions could not be modified, to provide ample opportunity for stakeholders to review modeling results and participate in portfolio selections consistent with our Guidelines.¹³ The PSC appreciates PacifiCorp's efforts to comply with our directives, but we find the Utah IRP to be inconsequential to our analysis because it does not reflect the modeling or plan PacifiCorp intends to rely upon or use. Accordingly, PacifiCorp need not develop or publish a Utah-specific IRP in the 2027 IRP cycle.

¹¹ See PacifiCorp's Reply Comments at 27.

¹² See 2025 IRP at 319.

¹³ See Guideline 3 ("PacifiCorp will provide ample opportunity for public involvement and the exchange of information during the development of its Plan").

Recognizing that assumptions and inputs may continue to evolve due to many factors after the publication of a draft IRP, we eliminate our requirement to lockdown inputs and assumptions on a specific date before the draft IRP is published. However, if PacifiCorp continues to publish a draft IRP,¹⁴ we continue to direct it to provide stakeholders with an opportunity to review initial modeling results and provide meaningful feedback in a PIM before PacifiCorp produces a draft IRP.

While improvements were made in the 2025 IRP process, PacifiCorp still struggled to remediate some of the ongoing issues plaguing former cycles. For example, many parties commented that updated assumptions, changes to the modeling methodology, and updated modeling results were either not provided before or were provided very close to the 2025 IRP's filing. The PSC appreciates that PacifiCorp held two PIMs after the Draft IRP was published; however, two PIMs did not provide sufficient time to review changes to PacifiCorp's modeling methodology, updated modeling results, and portfolio selections with stakeholders before the 2025 IRP filing. Therefore, if after the second PIM to be held in 2027, there is new information that PacifiCorp believes must be incorporated into the IRP before its filing, and the information materially impacts the modeling methodology,

¹⁴ We do not see the value of publishing a draft IRP. While we acknowledge that Oregon and Washington require PacifiCorp to file a draft IRP, we find that this requirement hinders PacifiCorp's ability to allow ample opportunity for stakeholder input on assumptions and modeling results and participation in portfolio selections that are reflected in the final IRP, which is the version that actually drives PacifiCorp's resource procurement decisions.

assumptions, inputs, or modeling results, we direct PacifiCorp to hold an additional PIM to review such information with and allow meaningful feedback from stakeholders. The PIM must be held with sufficient time to incorporate reasonable feedback in the final 2027 IRP, before its filing. Recognizing the delay our directive may cause in filing the final 2027 IRP by March 31, 2027, PacifiCorp may request an extension and the PSC will grant it to the extent warranted.

B. Jurisdictional Portfolio Modeling Methodology

DPU finds the jurisdictional portfolio modeling methodology approach (“Regional Approach”) difficult to accurately classify and states that changes from the Draft IRP to the 2025 IRP made it difficult or impossible to provide feedback on this issue.

OCS explains PacifiCorp adopted the Regional Approach to comply with laws in Oregon and Washington concerning reduction of emissions and transitioning to non-emitting resources. OCS expresses concerns regarding whether the Regional Approach strictly complies with the PSC’s Guidelines. Acknowledging that region-specific resources will be situs-assigned, OCS nevertheless fears additional undue costs — estimated at over \$5 billion — may still fall on Utah ratepayers. OCS warns that this potential shift moves the IRP away from its historical role as a six-state, least-cost/least-risk single-system planning tool.

WRA supports PacifiCorp’s goal to develop a plan that meets all state-specific requirements. While WRA does not necessarily oppose the system-based,

jurisdictional planning method presented in the Draft IRP, stakeholders were unable to properly evaluate this approach as it was ultimately abandoned for “a bifurcated plan” that is very different from the plan that was presented in the Draft IRP.¹⁵ WRA explains that the concept of jurisdictional portfolios was introduced and discussed for the first time in the January 22-23, 2025, PIMs. It urges the PSC to require PacifiCorp to compare the two approaches for the 2027 IRP.

UCE argues that the Regional Approach departs from least-cost, least-risk system planning. UAE emphasizes that the Regional Approach assigns solar and storage resources exclusively to the west side of the system, leaving Utah stakeholders out of procurement decisions for system-wide resources. Sierra Club claims that the approach fragments PacifiCorp’s multi-state system into three separate “mini-systems” optimized in Excel rather than using PLEXOS, undermining system-wide efficiency.¹⁶ Sierra Club explains that resources located in the east are determined solely by the UIWC portfolio, while West resources use the maximum of Oregon and Washington elections, eliminating synergies from PacifiCorp’s geographically diverse footprint.

PacifiCorp defends its Regional Approach by arguing that divergent state policies make a single system-optimized portfolio impossible.¹⁷ While parties claim

¹⁵ WRA’s Comments at 5-25; *see also* WRA’s Reply Comments at 4.

¹⁶ Sierra Club’s Comments at 5-6.

¹⁷ For example, Washington law requires a social cost of greenhouse gas emissions (SCGHG) as a cost adder in resource selection, while Utah has no such requirement.

the approach yields a suboptimal, non-least-cost portfolio, PacifiCorp counters that jurisdictional requirements by their very nature depart from pure system optimization, and its method still optimizes all state requirements individually while preventing regional conflicts and overbuilding. It also notes that the repeal of the Ozone Transport Rule (OTR) has shifted compliance costs so that state-specific clean energy mandates are no longer system-allocated. Even so, PacifiCorp commits to working with stakeholders on potentially revising its methodology in future planning cycles, including the 2027 IRP process currently underway.

We find that the repeal of the OTR and state-specific clean energy mandates across PacifiCorp's service territory — including Washington's requirement to apply a social cost of GHG as a cost adder, which Utah does not impose — render the Regional Approach reasonable at present. We find that optimizing each jurisdiction's requirements first and subsequently integrating optimized portfolios is an alternative way to meet our Guidelines. Specifically, the approach facilitates planning to meet Utah's needs without ignoring the rules governing the planning process in place in other jurisdictions.

We also find that the Regional Approach transparently identifies regional cost-causation and assigns jurisdiction-specific resources (and their costs) that are driven by state policies on a situs basis. We reaffirm that least-cost, least-risk planning is the fundamental objective of the IRP process. Recognizing our collective concerns regarding transparency and ratepayer impacts, the PSC directs PacifiCorp to review

the Regional Approach with stakeholders in the 2027 IRP cycle for their input. We also find value in WRA's recommendation for PacifiCorp to discuss alternative approaches and their comparative advantages and disadvantages with stakeholders during the 2027 IRP cycle. The PSC shares the OCS's concern that, in comparing the Present Value Revenue Requirements (PVRR) among the Base MN Preferred Portfolio (\$27.233 billion), Oregon jurisdictional portfolio (\$26.298 billion) and UIWC jurisdictional portfolio (\$21.842 billion), Oregon policies appear to impose approximately \$4.5 billion in additional system costs, and Oregon and Washington policies combined impose an additional \$5.4 billion to system costs. While our concern is mitigated by PacifiCorp's representations that resources acquired specifically for Oregon and Washington environmental compliance will be allocated to those respective states, we direct PacifiCorp to specify and explain in the 2027 IRP cycle what drives the differences in costs between the Preferred Portfolio and the UIWC jurisdictional portfolio.

C. Deliverability Challenges

Relatedly, WRA challenges PacifiCorp's decision to bifurcate planning for the east and west sides because it was never vetted through the public input process, indicating that stakeholders only learned of it after PacifiCorp's brief mention in the final minutes of the last PIM before it published the Draft IRP. WRA argues that separate planning is inherently suboptimal and more costly. In restricting west-side proxy resources to Oregon and Washington compliance and east-side resources to

the UIWC jurisdiction, WRA argues, PacifiCorp replaces cost-effective, model-optimized east-side renewables with necessarily more expensive west-side alternatives, requiring ad hoc decision making and approximately 330 miles of new west-side transmission projects that would not have been needed under integrated planning. It notes that the delayed online date for Gateway West further entrenches system separation and growing costs over time at the expense of customers. WRA asserts that PacifiCorp violated Guidelines 1, 3, and 4 by presenting a bifurcated IRP at the final PIM.

For the 2027 IRP, WRA recommends PacifiCorp include two system-level optimizations for every study variation. The first optimization would focus solely on reliability requirements. The second would integrate state-specific compliance. The cost difference between the two would isolate the cost of meeting state requirements. This isolated cost would serve as a baseline for evaluating jurisdictional cost consequences, aligning with principles of cost causation and unified planning/operation.

PacifiCorp responds that the deliverability challenges reflect current transmission limitations – specifically, that east-side resources allocated to the west side already exceed the 1,600 MW of available firm transmission by 2030. PacifiCorp argues that planning non-firm or short-term transmission is not reasonable least-cost, least-risk long-term planning. Further, building a plan around transmission that is not guaranteed introduces unacceptable reliability risk. PacifiCorp describes the

January 2024 extreme weather event, during which the Pacific Northwest imported up to 6,000 MW of energy, with wholesale prices exceeding \$1,000/MWh – while east-side prices were half of that.

We find PacifiCorp’s explanation regarding its planning approach around the deliverability challenge to be reasonable. Accounting for deliverability challenges aligns with least-cost, least-risk planning and with the objective of meeting state specific requirements. The approach is also consistent with Guidelines 1 and 4 because it reflects an evaluation of PacifiCorp’s integrated system to meet current and future electricity demand, considering transmission constraints.

While we find that the public input requirement in Guideline 3 would have been better served if more time had been spent explaining the deliverability challenges during a PIM, we do not find this deficiency to constitute a clear violation of Guideline 3. Nevertheless, we direct PacifiCorp to address the deliverability challenges early in the 2027 IRP cycle and run a sensitivity analysis to show how removing this challenge would impact the portfolio.

D. End Effects Analysis in Preferred Portfolio Selection

PacifiCorp used end effects modeling (“End Effects”) to evaluate portfolio performance beyond the 21-year planning horizon – specifically, by repeating the final year of the planning period for five additional years under medium gas/zero CO₂ assumptions. Its rationale was to capture tax credit expiration risks that could make a portfolio more expensive after the planning period ends.

DPU and WRA state that PacifiCorp failed to explain End Effects analysis in detail early in the IRP process. DPU cautions its use to the extent that its values are based on the 20th year, which is itself just one of many in the wide range of scenarios that could occur in that year.

OCS states that PacifiCorp added the End Effects analysis as its final analytical step in selecting the preferred portfolio, resulting in the Base MN case being chosen over the Base HH and Hunter Retire cases, even though those two cases had lower PVRRs before End Effects were applied. Nevertheless, the OCS agrees with the End Effects analysis — particularly given that the One Big Beautiful Bill Act (OBBBA) has already significantly altered PTC and ITC assumptions since PacifiCorp filed the 2025 IRP. OCS also reiterates PacifiCorp's representations that PacifiCorp does not need new resources in the near term to serve Utah and resource needs are more urgent for Oregon and Washington to meet state policy requirements.¹⁸ OCS's sole objection is that PacifiCorp added the End Effects evaluation at the last minute and failed to discuss the approach with stakeholders in any PIM.

UAE argues that End Effects modeling was given undue weight in selecting the Integrated Base MN Preferred Portfolio. UAE comments that the Base MN portfolio

¹⁸ OCS also reiterates PacifiCorp's representations that both Base HH and Hunter Retire show significantly higher costs beginning in 2040 — coinciding with the expiration of PTCs for resources coming online in 2030 — and extending the last modeled year by five additional years was a reasonable method of capturing those out-of-horizon costs and risks.

ranked 4th, 5th, and 8th across the three price-policy scenarios during the actual 21-year planning horizon, while the Integrated Base HH portfolio outperformed it by at least \$100 million in every scenario — yet PacifiCorp selected MN because it edged out Base HH by \$51 million in the End Effects model run. UAE believes the End Effects analysis is also internally inconsistent because PacifiCorp already levelizes capital costs over a resource's life (which inherently addresses end effects concerns) yet models PTCs in nominal terms, overstating the value of high-PTC portfolios.

Repeating the final year's revenue requirement for five additional years, according to UAE and WRA, fails to capture actual post-horizon costs or benefits and is statistically unreliable because it amplifies the conditions of the final year of the 21-year horizon by repeating it for five additional years beyond the required planning period.

PacifiCorp represents that the variant portfolios (including Base HH and Hunter Retire) show higher PVRR than the Preferred Portfolio when PTCs are recalculated on a levelized basis. While admitting that post-horizon impacts may be diminished by the levelization of PTCs across each resource's operational life, PacifiCorp contends that the use of End Effects is considered "best practice" in long-term planning and has been used in past IRPs; thus, its inclusion in the 2025 IRP is consistent with established methodology. PacifiCorp explains that the use of End Effects was partially driven by stakeholder participation during the public input process and that parties' criticism now is somewhat ironic. Finally, it notes that the use of End Effects is required by other jurisdictions, including Oregon.

The PSC finds the End Effects analysis to be a reasonable tool, and its purpose appears to be legitimate and consistent with long-term planning best practices. We find, however, that PacifiCorp's narrow application to a single scenario could limit its effectiveness. Unfortunately, PacifiCorp introduced End Effects late in the process with limited or no stakeholder input. We observe that the analysis produced results that overrode portfolios that dominated on every horizon metric, by apparently a statistically narrow margin with the Base MN selection resting on a \$51 million PVRR. Because the Action Plans across all three cases (the Base MN, Base HH, and Hunter Retire) are not significantly different, we find that any potential harm of the portfolio selection is minor in the short-term. In the future, if PacifiCorp uses End Effects, it must be discussed early in the process in a PIM, and we direct PacifiCorp to allow stakeholder input regarding how the end effects values are chosen. We authorize PacifiCorp to continue to use the methodology and, if used, we direct it to expand its application to include additional price-policy scenarios to enable more meaningful comparison across the top performing portfolios.

E. Expedited RFP To Leverage Tax Opportunities¹⁹

Sierra Club and IEA recommend that PacifiCorp issue an expedited RFP to capture remaining federal tax credits for solar and wind resources. IEA notes that the

¹⁹ The PSC is mindful of the motion UCE filed on April 29, 2026, concerning PacifiCorp's compliance with the PSC's prior order, in a separate docket, that directed PacifiCorp to discuss the actions it undertook to evaluate and pursue opportunities to

UIWC jurisdictional slice of the 2025 IRP requires 668 MW of solar and 744 MW of wind in 2030 and argues, along with Sierra Club, that PacifiCorp should not wait until 2030 to procure these large amounts of resources. Noting the OBBBA and subsequent U.S. Treasury guidance (broadly, the reduction or termination of 12 clean energy tax credits), they argue PacifiCorp should further accelerate procurement. IEA emphasizes that PacifiCorp's exclusion of large industrial and data center loads from its load forecast compounds the urgency. Sierra Club highlights that Hunter's 1,100 MW capacity must be replaced, if its retirement is confirmed in the 2027 IRP. Accordingly, both IEA and Sierra Club recommend the PSC require immediate clean resource procurements for Utah to capture available federal tax incentives before the window closes.

PacifiCorp cites the PSC's 2025 Order, denying UCE's request to order a clean energy resource RFP, and indicating that resource solicitation and procurement decisions belong to PacifiCorp.²⁰ Instead, the 2025 Order requested the 2025 IRP

procure resources that qualify for expiring tax credits in its 2025 IRP Update. *See Utah Clean Energy's Request for Expedited Investigatory Docket and Agency Action*, Docket No. 25-035-52, Order issued October 17, 2025 [hereafter, "2025 Order"]. As UCE's reply in support of that motion was filed relatively recently, on June 8, 2026, and it concerns the 2025 IRP Update, as opposed to the 2025 IRP, the PSC will address the motion in a separate, forthcoming order.

²⁰ *See id.*

Update include a detailed explanation about the analysis and resulting actions taken related to expiring federal tax credits for new renewable resources.²¹

The law has not changed insofar as resource solicitation and procurement decisions belong to PacifiCorp's management, which is accountable for those decisions. The PSC declines to order the issuance of an expedited RFP for new clean energy resources. The PSC recognizes that the 2025 IRP assumptions were locked down before the recent significant changes to federal law and policy with the 2025 IRP filed more than three months before the OBBBA became law. This made it impossible for tax credit changes to be included in the 2025 IRP, underscoring the reality that an IRP is a dynamic planning tool that represents a snapshot in time. The PSC directs PacifiCorp to continue to pursue time-limited opportunities to procure new economic resources to benefit Utah ratepayers.

²¹ In response, PacifiCorp's 2025 IRP Update states that the OBBBA altered federal taxes, credits, and deductions. It accelerated the phaseout of PTC, technology neutral tax credits, and added foreign entity concern rules for credit qualification. Generally, the 2025 IRP Update states that OBBBA will make coal a more cost-effective resource and the construction of wind and solar projects would likely need to start within the next year to qualify for a tax benefit. PacifiCorp notes it also impacts DSM resources, accelerating the end dates of energy credits and deductions for homes and businesses. PacifiCorp commits to studying these in the 2027 IRP cycle as part of the Conservation Assessment and the Distributed Generation Study.

F. Assumptions

1. Load Forecast and Exclusion of Certain Loads and Resources

IEA contends that excluding large prospective industrial and data center loads from the 2025 IRP base forecast, on the basis that these loads are “expected to provide or pay for” their own resources, violates Guidelines 4.a.i. and ii., which require consideration of all economic and demographic factors and all on-system load obligations, with the only legitimate exception being customers with executed direct access agreements at the time the forecast is developed. IEA argues the exclusion of the loads suppresses native load growth that PacifiCorp cited as justification for removing the B2H transmission line, understates true resource needs, undermines the IRP’s value as a comprehensive least-cost plan, risks shortfalls in reliability and WRAP compliance, and amplifies the urgency for an expedited RFP to capture remaining federal tax credits before the window closes.

OCS states PacifiCorp’s decision to no longer include the demand of new large load customers in the primary load forecast is appropriate. OCS explains that this approach is meant to protect existing customers from the significant costs associated with the generation and transmission investments required to serve these large loads. OCS references PacifiCorp’s commitment that it will work with new large load customers to ensure they bring their own resources. UAE, WRA, UCE, and Vote Solar disagree with OCS and argue that exclusion of large loads from the 2025 IRP load forecast is inappropriate and unjustified.

Relatedly, Sierra Club criticizes the exclusion of resources from the UCCEP,²² and disagrees with the assumed zero UCCEP participation across all portfolios, ignoring resources that Sierra Club contends will be added to the system. It argues the omission distorts the resource forecast by overstating how much new generation must be procured and could artificially inflate the need to retain resources like Hunter — since the 500 MW of committed UCCEP renewables would directly reduce the capacity gap Hunter is meant to fill.

PacifiCorp argues the exclusion of large loads from the 2025 IRP load forecast appropriately protects other retail customers from costs to be incurred to serve new large loads. It states that isolating large load impacts from optimized resource selections directly protects its other retail customers and the RFP procurement process from the significant influence of these large projects. PacifiCorp provides market signaling as an example, stating it would be inappropriate to signal in an IRP that PacifiCorp has a large volume of speculative large load customers. It also cites the PSC's direction in its most recent general case, in Docket No. 24-035-04, for PacifiCorp to reduce the load forecast to account for the instability of data center load projection.²³ PacifiCorp notes its exclusion of large loads was in direct response to the

²² The UCCEP enables participating communities to procure renewable resources toward net-100% renewable electricity by 2030, with the program's RFP anticipating approximately 500 MW of aggregate capacity.

²³ See *Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service*

criticism from many parties for including large loads in the load forecast in the 2023 IRP cycle. Regarding the exclusion of resources to be procured for the UCCEP, PacifiCorp argues that such resources are too speculative at this time to include in the IRP's modeling.

The PSC finds that excluding large prospective industrial and data center loads and UCCEP resources from the 2025 IRP base load forecast is appropriate and consistent with sound resource planning principles. The prospective load from these large customers is distinct. Utah's Large-Scale Electric Service Requirements statute²⁴ (the "Large Load Act") requires that all large load incremental costs be allocated to and paid for by the large load customer. These costs are not to be shared with PacifiCorp's retail customers. Thus, neither the resources for, nor this load, needs to be included or accounted for in IRP planning as resources that PacifiCorp can use to serve (or meet the demand of) its traditional retail customers. In addition, the PSC recently approved a settlement agreement approving a large load contract in which PacifiCorp agreed to remove the costs and revenues of the large load customer from its revenue requirement in Utah to ensure Utah customers are not burdened with any associated costs. No party opposed the settlement stipulation. We find that

Schedules and Electric Service Regulations, Docket No. 24-035-04, Order issued April 25, 2025, at 58.

²⁴ Utah Code § 54-26-101, *et seq.*

PacifiCorp's assumption of zero participation in the UCCEP is also appropriate because the load at the time was (and may still be) too speculative.

Contrary to parties' arguments that PacifiCorp violated Guidelines 4.a.i. and ii., we find that PacifiCorp's approach is consistent with Guideline 4.a.i. which requires utilities to "include ... all on-system loads and those off-system loads which [the utility has] a contractual obligation to fulfill" and that "[n]on-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet." The PSC interprets "on-system" loads to mean those loads that PacifiCorp is obligated to serve with system resources, *i.e.*, resources that are shared and paid for by all retail customers. Loads that are legally excluded from this category need not be incorporated into the IRP process. Finally, we find PacifiCorp's explanation that it excluded these loads as a direct and reasonable response to criticism from multiple parties in the 2023 IRP cycle for including large loads in the forecast during the 2023 IRP cycle to be credible.

In the future, the PSC directs PacifiCorp to work with new large load customers to ensure they bring their own resources to insulate retail customers from undue risk exposure. For the 2027 IRP and beyond, the PSC directs PacifiCorp to continue to exclude Large Load Act customers' resources and loads and to include UCCEP resources and load to the extent the resources have been procured and PacifiCorp has reasonable UCCEP participation estimates. In addition, consistent with Guideline 4.a.ii., the PSC directs PacifiCorp to add a new section to the IRP, analyzing how large

customer loads under the different contractual arrangements set forth in the Large Load Act could impact risks associated with different system acquisition strategies, as well as any risks associated with the transmission system.

2. Front Office Transactions

OCS raises concerns that reliance on market purchases over investment in new or contracted generation in prior IRPs has been very costly for ratepayers.²⁵ This notwithstanding, the OCS highlights several improvements that PacifiCorp made in the 2025 IRP, including: (1) market purchases are treated as purely economic and no longer count toward capacity; (2) purchases are restricted on the top five peak load days during peak hours; and (3) short-term market products are excluded from WRAP compliance. The OCS states the changes are a meaningful acknowledgment of market risk and also support PacifiCorp's intention to pursue economic purchases through the EIM and EDAM markets when advantageous for customers.

Sierra Club and WRA criticize the 2025 IRP's inclusion of natural gas resources and market purchases, stating that Utah customers are exposed to price risks associated with the UIWC portfolio's inclusion of 562 MW of coal-to-gas conversions and market purchases. Sierra Club highlights that PacifiCorp has consistently under-

²⁵ For example, OCS states that in both 2023 and 2024, actual purchased power costs dramatically exceeded base assumptions — by \$815 million and \$820 million, respectively — with actual 2024 market purchases of \$1.421 billion against a base assumption of only \$601 million, and actual purchase volumes of 20,600 GWh versus a base of 13,800 GWh at a 59% higher average price.

forecasted natural gas and wholesale power prices across multiple IRP cycles. WRA highlights that none of the jurisdictional portfolios applied a planning reserve margin to system load (only to jurisdictional load), leaving the system underbuilt and WRAP non-compliant. The result, in WRA's view, is a system that will continue to rely on volatile spot market purchases to meet load, shifting cost and risk onto customers.

PacifiCorp reiterates OCS's endorsement of the changes to the modeling of market purchases in the 2025 IRP. PacifiCorp states that it will continue to review and evaluate the ways in which the system and markets interact and access and use market products as they remain an important component of the IRP for the foreseeable future.

The PSC finds that treating market purchases as purely economic and no longer counting them toward capacity, restricting purchases on the top five peak load days during peak hours, and excluding short-term market products from WRAP compliance are meaningful improvements in the 2025 IRP. The PSC shares parties' concern that continued reliance on market purchases over investment in new or contracted generation has proven costly for ratepayers. This lack of generation investment risks ongoing and increasing dependence on market purchases, subjecting customers to fuel and purchase power price volatility. While PacifiCorp asserts that participation in the EDAM market will likely mitigate costs related to market purchases, the PSC directs PacifiCorp to purchase market products that minimize ratepayer costs and risk exposure to the greatest extent possible. As an example, we

note that PacifiCorp has begun to use the recently available index price contracts that minimize the economic loss on sales of the unused energy under those contracts.

3. DSM, 2025 Conservation Potential Assessment (CPA), and Distributed Generation

Vote Solar criticizes the CPA's modeling of distributed generation (DG) adoption by state, not by location, and explains that location-specific forecasting provides locational benefits by reducing loading on nearby distribution equipment, avoiding line losses, and potentially delaying distribution upgrades. Vote Solar and UCE/SWEEP recommend incorporating DG into the supply-side resource table so that PacifiCorp's models can select the optimal mix of DG vs. utility-scale resources and explicitly allowing DG and aggregated virtual power plants to bid into technology-neutral All Source RFPs. UCE/SWEEP also urge the PSC to require PacifiCorp to (a) stabilize DSM selections; (b) align IRP assumptions with delivered results; (c) conduct DSM sensitivity analyses; (d) treat demand response as dispatchable capacity; (e) correct "modeling bias"; and (f) adopt procedural remedies.

PacifiCorp responds that DG is privately planned and owned by customers and is not available for resource selection. Rather, the IRP accounts for DG impacts by adjusting the load forecast. PacifiCorp pushes back on a perceived bias against DSM, stating that the CPA (created by trusted third-party experts) models its potential and costs with the latest utility-specific inputs. It explains that DSM is modeled as a resource to be selected and optimized just as other supply-side resources are.

PacifiCorp also contends UCE/SWEEP are factually mistaken, including their assertion that full deployment of DSM potential by 2030 could offset “more than 1,000 MW” of new generation. PacifiCorp explains that the CPA only estimated about 440 MW of demand response potential by that year, of which the IRP chose 88 percent as being cost effective. PacifiCorp confirms that it has begun a new vintage of its DG study, which it anticipates will reflect the latest market conditions and DG adoption across all of PacifiCorp’s six-state territory. PacifiCorp plans to share the study in the 2027 IRP cycle and is also exploring whether to pursue a more granular “locational” forecast of DG, which will be discussed in future PIMs. Finally, PacifiCorp indicates that existing reports, plans, and DSM committee meetings already provide robust documentation for stakeholders.

The PSC finds that PacifiCorp’s consultant appears to be modeling DSM and DG appropriately in the CPA, using the latest utility-specific inputs. The PSC also finds it reasonable for PacifiCorp to explore whether using a more granular “locational” DG forecast would be optimal. Finally, the PSC directs PacifiCorp to share and discuss the updated DG study with stakeholders in PIMs in preparation of the 2027 IRP and consider innovative ideas for attaining a system-optimal amount of DG and DSM in both PIMs and DSM committee meetings. The PSC also directs PacifiCorp to explore ways to optimize incentives for customers’ use of DG and DSM resources such as Subscriber Solar and Blue Sky to mitigate customer rate increases. As an example, PacifiCorp could consider offering or increasing monetary incentives to all customer

classes to manage their usage on peak grid demand days including within the Cool Keeper, Wattsmart® Homes, and Wattsmart® commercial programs, among other programs.

G. Transmission

1. Boardman to Hemingway

OCS supports PacifiCorp's decision to exclude the B2H transmission line from the Preferred Portfolio, stating the decision is reasonable given the lack of transmission rights from Bonneville Power Administration ("BPA") that are necessary to deliver power to Oregon load centers through B2H. OCS reiterates that the use of transmission capacity made available by B2H is unknown until BPA performs a new transmission cluster study.

Sierra Club and UCE argue the removal of B2H from the Preferred Portfolio was a mistake. Sierra Club states that B2H is needed to deliver cost-effective east-side renewables westward. It notes that, without B2H, resources to satisfy PACW reliability shortfalls can only be built in the West — forcing 1,252 MW of western wind when only 296 MW of eastern wind would achieve the same capacity benefit, a 76 percent reduction in required capacity and corresponding cost savings. It adds that because WRAP reliability obligations are shared system costs historically allocated across all states, B2H's removal directly harms PACE and Utah customers who will share in the cost of inefficiently sited western resources.

PacifiCorp argues its modeling of B2H in the 2025 IRP is reasonable based on its lack of needed transmission rights to serve existing PACW load. It explains that assuming B2H will serve the load under such circumstances is high-risk and inconsistent with least-cost, least-risk planning. If accessible B2H transmission capacity changes, PacifiCorp states it will update subsequent IRP filings to capture that change. PacifiCorp disputes arguments that B2H was fully removed from the Preferred Portfolio. It indicates the 600 MW of eastbound transfer capability that B2H unlocked is still included in the Preferred Portfolio. PacifiCorp explains that the 2025 IRP excludes the westbound transfer capability – the ability for B2H to deliver power to Oregon and Washington customer loads because it lacks the transmission rights to move westbound transfers across B2H to those customers. PacifiCorp also explains that, as of the filing of the 2025 IRP, its redirect requests to BPA remain in study status with no known timeline for resolution.

We find that PacifiCorp's modeling of the B2H transmission line is responsible, reasonable, and consistent with least-cost, least-risk planning. The lack of transmission rights that are necessary for PacifiCorp to deliver power to its Oregon load centers means that PacifiCorp cannot plan for the B2H to be available to deliver that load into PACW at this time. Therefore, we decline to order PacifiCorp to model it differently. We note, though, that the decision increases costs and we direct PacifiCorp to ensure those costs are situs assigned to PACW.

2. Transparency & Advanced Transmission Technologies (ATT)

UCE proposes PacifiCorp improve transparency in transmission planning in the IRP. The core problem, according to UCE, is that PacifiCorp presents two levels of information, neither of which is adequate nor helpful, and the information is either too high level or too technical. For example, in PIMs, PacifiCorp provides a list of transmission projects and cluster study names, on-line dates, resource types, and major project names, but no meaningful context about the technologies it considered, their costs and benefits, whether tradeoffs were evaluated, or why alternatives were rejected. According to UCE, PacifiCorp provides nothing for stakeholders to evaluate the transmission decisions PacifiCorp makes, and when stakeholders seek additional details, PacifiCorp directs them to the highly technical cluster studies on the OASIS website.

DPU, UCE, and IEA request the PSC provide guidance on how to implement Utah Code § 54-17-1101 (“ATT Statute”), which concerns advanced transmission technologies (ATT). The ATT Statute requires an electric utility to analyze the cost effectiveness and timetable for deployment of ATT as alternatives to building new transmission infrastructure. DPU recommends the PSC either provide details regarding how cost effectiveness should be determined or consider requesting further input on this topic from interested parties. UCE recommends the PSC direct PacifiCorp to provide, in a PIM, information for each transmission project option that includes: (1) technologies considered; (2) their costs and benefits; (3) the tradeoffs

that PacifiCorp evaluated; and (4) an explanation of why the alternatives were not selected.

The statute provides, in pertinent part:

(2) In an [IRP], a general rate case, or other proceeding in which [PacifiCorp] proposes additions or expansions to the transmission system, [PacifiCorp] shall: (a) analyze: (i) the cost effectiveness and timetable for deployment of advanced transmission technologies as an alternative strategy to meet electric system needs; and (ii) whether the technologies would: (A) increase transmission capacity; (B) increase transmission efficiency; (C) reduce transmission system congestion; (D) reduce curtailment of energy generation resources; (E) increase reliability; (F) reduce the risk of igniting wildfire; (G) increase resiliency; and (H) increase capacity to connect new energy resources; and (b) include the analysis described in Subsection 2(a) in the filing to the [PSC].²⁶

The PSC appreciates the parties' recommendations and finds them to be useful but premature. To address our mandate properly, we must assess how much of, and how effectively, the existing transmission network is being used. The PSC directs PacifiCorp to include a transmission study in the 2027 IRP showing how effectively the existing grid is being used, using a heavy-summer peak case when demand is near its highest, and the grid is under stress. The PSC is interested in knowing how much power each transmission line (above 100 kV) and large power transformer is carrying and how well the lines and transformers stand up to stress-testing (by taking one line or transformer out of service at a time, for example). PacifiCorp can use a transmission study that is already completed so long as it is updated with the

²⁶ Utah Code § 54-17-1101(2).

information we request here. The results must show which parts of the grid repeatedly operate close to their limits, and at what voltage levels. At a PIM prior to filing the final 2027 IRP, PacifiCorp must present the outcome of the study. The PSC finds that this transmission utilization study will (1) support more informed decisions about where transmission upgrades are needed and (2) be useful in determining the types of ATT that can be deployed as alternatives or supplemental strategies, in a timely and cost-effective way.

H. Sodium and 100-Hour Batteries

DPU and UAE generally argue that the selection of Sodium and 100-Hour Batteries in the Preferred Portfolio (Integrated Base MN) is not appropriate and results in a Preferred Portfolio that is neither least-cost nor least-risk. They explain that Sodium was modeled at zero cost due to the lack of an executed agreement with TerraPower. DPU also criticizes inclusion of 100-hour iron air storage batteries, stating that they are not yet operating at utility scale anywhere in the country.

Despite DPU's and UAE's opposition based on the lack of actual cost or performance data, PacifiCorp maintains its support for acknowledging both the Sodium project and 100-hour batteries within the 2025 IRP. PacifiCorp argues that the absence of commercial operating data is not a sufficient reason to exclude them from consideration, as it disagrees with the notion that only resources that are currently available and deployed at scale should be available for selection in the

preferred portfolio. PacifiCorp argues that the IRP selects proxy resources, not specific projects, with the goal of sending general market signals. PacifiCorp also clarifies that no costs associated with Natrium were included in the 2025 IRP modeling because they were not known at the time it developed the IRP. It explains that it would have been inappropriate to apply generic costs to Natrium because PacifiCorp expected to negotiate a mutually beneficial agreement with TerraPower. Finally, PacifiCorp asserts that the inclusion of Natrium signals market interest in advanced nuclear technology but does not lock it into procuring that specific technology.

The PSC finds reasonable the inclusion of both the Natrium project and 100-hour batteries in the Preferred Portfolio. In a recent docket, DPU, OCS, WRA, and PacifiCorp filed a settlement stipulation (the "Stipulation") recommending the PSC approve PacifiCorp's decision to enter into a power purchase agreement with the owner of the Natrium project ("PPA"), indicating the PPA is in the public interest.²⁷ There was no opposition to the Stipulation.

The PSC recognizes that signatories to the Stipulation entered and filed it after the filing of the 2025 IRP and after the comment and reply comment deadline set in this IRP docket. This highlights a dynamic IRP planning process that produces an IRP

²⁷ See *Application of Rocky Mountain Power for Approval of a Waiver of the Requirement for Solicitation Process and of a Significant Energy Resource Decision and Report of Sale*, Docket No. 25-035-55.

reflecting a snapshot in time that will evolve over time. Given the Stipulation and the lack of opposition from non-signatories, the PSC acknowledges that the Natrium project was appropriately selected in the Preferred Portfolio. In addition, the PSC finds that the 20-year planning horizon of the IRP facilitates the selection of resources that are not yet available nor deployed at scale in the Preferred Portfolio. We further find that the absence of commercial operating data is not a good enough reason to exclude them from consideration. We find PacifiCorp's argument that the IRP selects proxy resources, not specific projects, with the goal of sending general market signals to be reasonable.

I. Preferred Portfolio

DPU, UAE, WRA, and Sierra Club all argue that the selected Preferred Portfolio (Integrated Base NM) is neither least cost nor least risk. The parties criticize the End Effects modeling which was never explained in a PIM. UAE, WRA, and Sierra Club note that the Integrated Base HH portfolio beat Base MN in every price-policy scenario over the full 21-year planning horizon (by \$106M in MN, \$236M in LN, and \$3B in HH), yet PacifiCorp selected it anyway based solely on the End Effects model run conducted only under the MN scenario.

While the OCS did not endorse a particular portfolio, it did not substantively criticize the End Effects analysis that informed the preferred portfolio selection. The OCS highlights that the near-term implications of the Preferred Portfolio for Utah customers are minimal, reiterating PacifiCorp's representations that new resources

are not needed to serve Utah customers. Further, resource needs are significantly more urgent for Oregon and Washington customers to meet their states' policies. Therefore, according to OCS, the near-term actions are primarily oriented towards supporting Oregon and Washington and costs of the resources acquired for their states' environmental compliance will be allocated to them.

In addition to defending its selection of the Base MN portfolio as the Preferred Portfolio based on End Effects analysis, discussed above, PacifiCorp argues that any actual procurement would account for costs and benefits over the entirety of a resource's operating life. PacifiCorp further argues that when the levelized PTC value is applied — better reflecting the cost structure of third-party owned resources likely to be procured in the near term — the Base MN portfolio is independently confirmed as the least-cost portfolio, making its selection reasonable under any methodology.

The PSC acknowledges that since End Effects was only applied to the Base MN price-policy scenarios, its effectiveness was likely limited. However, it appears that the Base MN, Base HH, and Hunter Retire are not materially different in the near-term, and new resources are not needed to serve Utah customers. Rather, the near-term actions in the Action Plan appear to support Oregon and Washington, and costs of the resources acquired for their environmental attributes will be allocated to those states. For these reasons, the PSC also acknowledges the Preferred Portfolio and the near-term Action Plan (2026–2029). Given this and recognizing that the OBBBA altered the PTC/ITC assumptions underlying the 2025 IRP, we also accept the Base MN

Preferred Portfolio as the basis for avoided cost determinations for Schedule Nos. 37 and 38.

Finally, in this 2025 IRP cycle, both DPU and the OCS noted an improved process as compared to historical practice. The OCS specifically acknowledges PacifiCorp's improved public input process to allow stakeholders to review initial modeling results. DPU implies that modeling results were reviewed prior to the filing of the Draft IRP. UAE, Sierra Club, IEA, WRA, UCE, UCE/SWEEP, and Vote Solar recommended that we decline to acknowledge the 2025 IRP for various reasons. While the PSC appreciates their comments and recommendations, we cannot ignore the vast amount of work and planning involved in producing the 2025 IRP and the difficulty of planning in an environment of evolving federal and state laws and differing state policies, while also incorporating input from many stakeholders across numerous jurisdictions and directives from the numerous state commissions.

Given these challenges, as well as the requirement for PacifiCorp to file the Draft IRP in some jurisdictions and PacifiCorp's attempt to meet our directive by also filing a Utah-specific IRP, which added time and complexity to the process, the PSC finds that PacifiCorp substantially complied with the Guidelines and therefore acknowledges the 2025 IRP. In the future, the PSC directs PacifiCorp to continue to improve the public input process and stakeholder engagement, as directed in this order.

V. SUMMARY AND CONCLUSIONS

We recognize the substantial body of quality work completed by PacifiCorp in preparing the 2025 IRP. PacifiCorp filed extensive documentation and workpapers with the 2025 IRP. The level of detail is useful, and the information provided is well organized. We encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.

We also appreciate the diligent efforts and thoughtful comments provided by all parties. After fully considering the 2025 IRP and the parties' comments and reply comments, we acknowledge the 2025 IRP, the Preferred Portfolio, and the Action Plan, based on substantial compliance.

VI. ORDER

The PSC acknowledges the 2025 IRP, the Preferred Portfolio, and the Action Plan. In addition, going forward, the PSC orders as follows:

1. If PacifiCorp continues to publish a draft IRP, we direct PacifiCorp to provide stakeholders with an opportunity to review initial modeling results and provide meaningful feedback in a PIM before PacifiCorp produces a draft IRP.
2. If after the second PIM to be held in 2027, there is new information that PacifiCorp believes must be incorporated into the IRP before its filing, and the information materially impacts the modeling methodology, assumptions, inputs, or modeling results, we direct PacifiCorp to hold an additional PIM to review such information with and allow meaningful feedback from stakeholders. The PIM must be

held with sufficient time to incorporate reasonable feedback in the final 2027 IRP, before its filing. In the future, the PSC directs PacifiCorp to continue to improve the public input process and stakeholder engagement, as directed in this order.

3. We direct PacifiCorp to review the Regional Approach with stakeholders and discuss alternative approaches and their comparative advantages and disadvantages with stakeholders in the 2027 IRP cycle for their input.

4. We direct PacifiCorp to specify and explain in the 2027 IRP cycle what drives the differences in costs between the Preferred Portfolio and the UIWC jurisdictional portfolio.

5. We direct PacifiCorp to address the deliverability challenges reflecting current transmission limitations related to east-side resources allocated to the west side, in the 2027 IRP cycle and run a sensitivity analysis to show how removing this challenge would impact the portfolio(s).

6. We direct PacifiCorp to discuss End Effects and allow stakeholder input regarding how the End Effects values are chosen as early in the 2027 IRP process as possible. We further direct PacifiCorp to expand its application to include additional price-policy scenarios to enable more meaningful comparison across the top performing portfolios.

7. We direct PacifiCorp to continue to pursue time-limited opportunities to procure new resources to benefit Utah customers.

8. We direct PacifiCorp to continue to exclude Large Load Act customers' resources and loads from IRP planning and include UCCEP resources and loads to the extent the resources have been procured and PacifiCorp has reasonable UCCEP participation estimates. We also direct PacifiCorp to work with new Large Load Act customers (such as data centers) to ensure they bring their own resources to insulate retail customers from undue risk exposure.

9. We direct PacifiCorp to purchase market products that minimize costs and risk exposure to the greatest extent possible.

10. We direct PacifiCorp to share and discuss the updated DG study with stakeholders in PIMs in preparation of the 2027 IRP and consider innovative ideas for attaining a system-optimal amount of DG and DSM in both PIMs and DSM committee meetings. In addition, we direct PacifiCorp to explore how to optimize incentives for customers' use of DG and DSM resources such as Subscriber Solar and Blue Sky to mitigate customer rate increases.

11. We direct PacifiCorp to include a transmission study in the 2027 IRP showing how effectively the existing grid is being used, using a heavy-summer peak case when demand is near its highest, and the grid is under stress, as further detailed in this Order. We decline to order PacifiCorp to model the B2H transmission line differently, but to the extent that costs increase, we direct PacifiCorp to ensure those costs are situs assigned to PACW.

DATED at Salt Lake City, Utah, June 25, 2026.

/s/ Jerry D. Fenn, Chair

/s/ David R. Clark, Commissioner

/s/ John S. Harvey, Ph.D. Commissioner

Attest:

/s/ Gary L. Widerburg

PSC Secretary

DW#345930

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 30 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on June 25, 2026, a true and correct copy of the foregoing was served upon the following as indicated below:

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