PACIFIC POWER.
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

March 29, 2023

VIA ELECTRONIC FILING

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

Re: Advice No. 23-007/UE 419—Schedule 202—PacifiCorp's 2024 Renewable Adjustment Clause

In compliance with ORS 757.205, OAR 860-022-0025, OAR 860-022-0030, and ORS 757.210, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing with the Public Utility Commission of Oregon (Commission) the enclosed Schedule 202 Renewable Adjustment Clause Supply Service Adjustment (Schedule 202), of the Company's Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules and regulations applicable to electric service in the State of Oregon. The Company respectfully requests an effective date of January 1, 2024, for this tariff sheet.

Sheet Number	Schedule/Rule	Title
Tenth Revision of Sheet No. 202-1	Schedule 202	Renewable Adjustment Clause

The purpose of this filing is to implement Schedule 202 rates to recover costs associated with the acquisition and repowering of the Foote Creek II, Foote Creek III, and Foote Creek IV wind resources as described further below and in the enclosed supporting testimony.

A. Description of Filing

In Order No. 07-572, the Commission approved a Renewable Adjustment Clause (RAC) for PacifiCorp, under Senate Bill 838, enacted on June 6, 2007. The Commission directed PacifiCorp to file Schedule 202, to be effective January 1, 2008. In Advice No. 07-027, PacifiCorp filed Schedule 202 in compliance with Order No. 07-572. Schedule 202 provides that the Company file any proposed charges under Schedule 202 by April 1 of each year, as necessary. These filings include new eligible renewable resources and associated transmission and are also used to update charges already included in the schedule.

As described in more detail in the supporting testimony, the Foote Creek Rim wind energy projects, consisting of Foote Creek I, II, III and IV, were the first utility-scale, commercial wind energy projects in the state of Wyoming. Construction of the Foote Creek Rim projects was completed between 1999 and 2000.

PacifiCorp acquired full ownership of the Foote Creek I project in 2019 and completed repowering of the project in March 2021. In June 2022, PacifiCorp acquired full ownership of Foote Creek II, III, and IV and is now in the process of repowering these projects. Construction is expected to be complete in November 2023.

This tariff filing is supported by testimony and exhibits from the following Company witnesses:

- Matthew McVee, Vice President, Regulatory Policy and Operations
- Timothy J. Hemstreet, Vice President, Renewable Energy Development
- Thomas R. Burns, Vice President, Resource Planning and Acquisitions
- Shelley E. McCoy, Director, Revenue Requirement
- Judith M. Ridenour, Specialist, Pricing and Cost of Service

Confidential information has been provided under Order No. 23-104.

This supporting testimony sets forth the benefits of repowering (including qualification for production tax credits), provides support for a finding that the investments were prudent and in the public interest, sets forth the details of the Company's RAC and the Company's proposal for ratemaking treatment of the repowering projects, provides the construction timeline for the repowering projects, addresses how repowering was included in the Company's 2021 Integrated Resource Plan, and provides the revenue requirement associated with the repowering projects.

B. Proposed Procedural Schedule

PacifiCorp proposes the procedural schedule described as follows, subject to the availability of the Commission and interested parties:

RAC Filed	March 29, 2023
Prehearing Conference	April 14, 2023
Settlement Conference	May 12, 2023
Settlement Conference	June 2, 2023
Staff and Intervenor Testimony	June 16, 2023
Settlement Conference	June 30, 2023
PacifiCorp Reply Testimony	July 28, 2022
Hearing	September 12, 2023
Target Commission Decision	October 24, 2023
RAC Update Filing (if needed)	November 15, 2024
Revised Tariff Sheet Filing for Rate Change	December 1, 2023
Effective Date for New Rates	January 1, 2024

C. Tariff Sheets

To support this filing and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, PacifiCorp submits proposed Schedule 202 as Exhibit PAC/502 and has included in the exhibits accompanying the direct testimony of Ms. Ridenour the following:

Exhibit PAC/501—Renewable Adjustment Clause, Rate Spread and Rate Calculations
Exhibit PAC/503—Estimated Effect of Proposed Price Changes
Exhibit PAC/504—Monthly Billing Comparisons

As shown on Exhibit PAC/503, the filing results in an overall increase of $3.1 million or 0.2 percent, on a net basis, effective January 1, 2024. A residential customer using 900 kilowatt-hours per month would see a monthly bill increase of $0.18 beginning January 1, 2024.

D. Correspondence

It is respectfully requested that all communications on this filing be addressed to:

Oregon Dockets	Ajay Kumar
PacifiCorp	Assistant General Counsel
825 NE Multnomah Street, Ste. 2000	825 NE Multnomah Street, Ste. 2000
Portland, OR 97232	Portland, OR 97232
oregondockets@pacificorp.com	Ajay.kumar@pacificorp.com

Additionally, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail:
Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Cathie Allen, Manager, Regulatory Affairs, at (503) 813-5934.

A copy of this filing has been served on all parties in dockets UE 399.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

Cc: UE 399 Service List

Docket No. UE 419
Exhibit PAC/100
Witness: Matthew McVee

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Matthew McVee

March 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is Matthew McVee, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulatory Policy and Operations.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Biology from Lewis and Clark College and a Juris Doctorate Degree from Lewis and Clark Law School. I have provided legal counsel to various clients in regulatory matters at both state regulatory commissions and the Federal Energy Regulatory Commission, and acted as administrative attorney to a commissioner at the Nevada Public Utilities Commission. I joined PacifiCorp in 2005 as senior legal counsel for transmission. I became General Counsel for the Western Electricity Coordinating Counsel in 2008 and joined the law firm Troutman Sanders P.C. as a partner in 2010. I rejoined the PacifiCorp legal department in 2013. Before taking my current position in November 2021, I was Chief Regulatory Counsel for PacifiCorp. My current responsibilities include: managing regulatory relations with the California, Oregon, and Washington state regulatory commissions, staffs, and stakeholders; developing regulatory policy strategies for PacifiCorp; and managing PacifiCorp's regulatory discovery and filings group.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified in Oregon, California, and Washington.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony explains the benefits to customers from acquiring and repowering the Company's Foote Creek II (1.8 megawatts (MW)), Foote Creek III (24.75 MW) and Foote Creek IV (16.8 MW) facilities (collectively, the Projects) and outlines why wind repowering is an opportunity for customers that is both prudent and in the public interest. I also discuss PacifiCorp's Renewable Adjustment Clause (RAC) mechanism and describe the Company's proposal for the ratemaking treatment of the repowering project.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. Following the successful repowering of PacifiCorp's wind fleet in March 2021, PacifiCorp decided to pursue additional benefits by acquiring and repowering additional wind facilities that were adjacent to the Company's Foote Creek I facility in Carbon County, Wyoming. These projects were identified as beneficial in the 2021 Integrated Resource Plan (IRP), as described in further detail in the testimony of Company witness Mr. Thomas Burns. After acquiring these resources, the Company has proceeded to upgrade or "repower" 43.35 MW at the Projects with longer blades and new technology to generate more energy in a wider range of wind conditions. The upgrades will increase output of the wind facilities, and allow the facilities to requalify for federal production tax credits (PTCs) for an additional 10 years.

Q. Please identify the other PacifiCorp witnesses supporting this RAC.

A. PacifiCorp's filing is supported by testimony from the following Company witnesses:

Mr. Timothy J. Hemstreet, Vice President of Renewable Energy Development, provides a detailed scope of the Projects, including technical details, qualification for PTC benefits, energy benefits, and continued system reliability. Mr. Hemstreet also addresses the process and timing of wind-turbine generator equipment purchases, construction requirements, and construction timelines.

Mr. Thomas R. Burns, Vice President of Resource Planning and Acquisitions, testifies on the economic analysis that supports the prudence of PacifiCorp's wind repowering project and quantifies customer benefits resulting from repowering. Mr. Burns also explains the wind repowering planning and analysis included in the Company's 2021 IRP.

Ms. Shelley E. McCoy, Director of Revenue Requirement, provides the revenue requirement associated with the wind repowering project and explains the proposal for the ratemaking treatment of the costs and benefits of the wind repowering project in rates, and the inter-jurisdictional allocation of costs.

Ms. Judith M. Ridenour, Specialist**,** Pricing and Cost of Service, presents the company's proposed RAC prices and provides the impact of the proposed rate changes on customers' bills.

IV. RENEWABLE ADJUSTMENT CLAUSE

Q. Please describe PacifiCorp's RAC.

A. The RAC is the automatic adjustment clause created in accordance with Section 13 of Senate Bill 838 to allow for the timely recovery of costs associated with renewable portfolio standard compliance.[1] The RAC was adopted in 2007 through a stipulation

[1] *See In the Matter of the Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 1 (Dec. 19, 2007).

agreed to by PacifiCorp, Portland General Electric Company, Public Utility Commission of Oregon Staff, the Alliance of Western Energy Consumers (AWEC) (known at that time as the Industrial Customers of Northwest Utilities or ICNU), and the Oregon Citizens' Utility Board (CUB).[2] PacifiCorp's RAC is set forth in Schedule 202.[3]

Q. Has PacifiCorp previously used the RAC to incorporate renewable resources into rates?

A. Yes. The Commission authorized recovery through the RAC for PacifiCorp's investments in the Leaning Juniper, Marengo, and Blundell resources in 2008,[4] and Seven Mile Hill II and Glenrock III resources in 2009.[5] The Commission authorized recovery for the repowering of Glenrock I, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, Marengo I, Marengo II, and Goodnoe Hills in 2019.[6] The Commission also authorized recovery for repowering the Glenrock III and Dunlap wind resources in 2020.[7]

Q. What is PacifiCorp's proposal for cost recovery through the RAC in this proceeding?

A. The Company seeks to recover the revenue requirement associated with the investments related to the acquisition and repowering of the Projects as described in

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[2] Order No. 07-572 at 2.
[3] Order No. 07-572, App. A at 20-21.
[4] *In the matter of PacifiCorp, dba Pacific Power, Application for an Accounting Order Approving Deferral of Costs Relating to Renewable Resources Pursuant to Senate Bill 838*, Docket No. UM 1338, Order No. 08-508 (Oct. 22, 2008).
[5] See *In the matter of PacifiCorp, dba Pacific Power, Application for Deferred Accounting*, Docket No. UM 1412, Order No. 09-072 (March 2, 2009).
[6] See *In the Matter of PacifiCorp, dba Pacific Power, 2019 Renewable Adjustment Clause,* Docket No. UE 352, Order No. 19-304 (Sept. 16, 2019).
[7] See *In the Matter of PacifiCorp, dba Pacific Power, 2020 Renewable Adjustment Clause,* Docket No. UE 369, Order No. 20-067 (March 9, 2020).

this filing, supported by the testimony and exhibits from the identified company witnesses. PacifiCorp proposes to implement a rate change on January 1, 2024, following completion of the Projects.

Q. When costs for these RAC resources are rolled into base rates as part of a general rate case, will direct access customers pay those costs?

A. Yes. The cost of the RAC resources are generation costs that are recovered through Schedule 200, Base Supply Service. Direct access customers pay the rates in Schedule 200.

Q. Has the proposed tariff been included in this filing?

A. Yes. The proposed tariff is provided in Exhibit PAC/502 accompanying the direct testimony of Ms. Ridenour.

Q. Why is PacifiCorp filing the RAC now?

A. The RAC specifies that it will be filed by April 1, concurrent with the filing of a Transition Adjustment Mechanism (TAM).

Q. In the RAC stipulation approved by the Commission in Order No. 07-072, did parties agree that recovery of variable costs and benefits in PacifiCorp's TAM and power cost adjustment mechanism would be conditioned on matching fixed cost recovery in the RAC?

A. Yes. The stipulating parties in that case, which included Staff, CUB and AWEC's predecessor, ICNU, agreed that "if the fixed costs of an eligible resource are not included in RAC charges, or otherwise included in rates, then the variable costs and cost offsets of the eligible resource likewise should not be included in the annual power cost update filings or power cost adjustment mechanisms."[8] The 2024 TAM filed on April 3, 2023[9] will include the benefits of the repowered Projects. If the facilities are placed in service prior to January 1, 2024, PacifiCorp will use deferred accounting to recover the prudently incurred costs net of dispatch benefits for the period between when the resource is placed in service and when the resource enters rates on January 1, 2024, through the RAC schedule.[10]

V. OVERVIEW OF FOOTE CREEK ACQUIRE AND REPOWER

Q. Which wind resources have been acquired?

A. PacifiCorp has acquired and will be repowering Foote Creek II (1.8 MW), Foote Creek III (24.75 MW), and Foote Creek IV (16.8 MW).

Q. Please describe the repowering of PacifiCorp's wind facilities.

A. Wind repowering takes advantage of technological advancements that enable increased generation from existing wind resources. PacifiCorp's wind repowering efforts for which it seeks recovery in this proceeding involve installation of new rotors with longer blades and new nacelles with higher-capacity generators. These plant upgrades increase energy output without changing the footprint, towers, and energy collector systems of the wind facilities. Longer blades allow wind turbines to produce more energy over a wider range of wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles include sophisticated control

[8] *In the Matter of Public Utility Commission of Oregon, Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572, at 5 (Dec. 19, 2007).
[9] The April 1 deadline for filing the TAM falls on Saturday. Consistent with [list rule] the 2024 TAM will be filed on the next business day.
[10] *In the Matter of Public Utility Commission of Oregon, Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572, Appendix A at 5-6 (Dec. 19, 2007).

systems, higher capacity generators, and more robust components necessary to handle the greater loads that come with longer blades.

Q. What is the total acquire and repowering cost PacifiCorp is seeking recovery for at this time?

A. As described in Ms. McCoy's testimony, the requested RAC recovery amounts are $3.1 million, through rates effective January 1, 2024.

VI. CUSTOMER BENEFITS

Q. What are the customer benefits resulting from acquiring and repowering these wind facilities?

A. The customer benefits resulting from acquiring and repowering these wind facilities derive in part from the fact that repowering allows for the acquisition of additional renewable generation and for these wind resources to requalify for federal PTCs—the benefits of which will be passed back to Oregon customers through decreased net power costs contemporaneous with the cost recovery for these facilities. As noted above, the total revenue requirement related to the cost of acquiring and repowering the Projects is $3.1 million. As described in the testimony of Mr. Burns, the customer benefits, however, exceed the cost, meaning the acquisition and repowering will save customers money.

Wind repowering creates these benefits by:

- Reducing customer costs by requalifying the wind facilities for PTCs for an additional 10 years; and
- Improving the ability of the wind facilities to deliver cost-effective, renewable energy into the transmission system through enhanced voltage support and power quality.

The repowered facilities will deliver cost-effective energy to Oregon customers, while saving customers money over the life of the investment.

Q. Did PacifiCorp analyze acquiring and repowering the Projects in the 2021 IRP?

A. Yes. PacifiCorp's 2021 IRP, which was acknowledged by Commission Order No. 22-178 issued on May 23, 2022, includes acquiring and repowering the Projects as an integral component of the preferred portfolio, meaning that it was selected as a least-cost, least-risk resource option.[11]

Q. Does PacifiCorp's economic analysis demonstrate that the wind repowering project will provide net benefits to customers?

A. Yes. PacifiCorp's economic analysis of acquiring and repowering the Projects demonstrates that it will provide substantial customer benefits. As described in more detail in Mr. Burns's testimony, PacifiCorp analyzed various scenarios, each with varying natural gas and carbon dioxide (CO_2) price assumptions, and all scenarios show customer benefits ranging from $6.33 million to $104.23 million.

Q. Is acquiring and repowering the Projects prudent and in the public interest?

A. Yes. As described above and in more detail in the testimony of Mr. Burns, acquiring and repowering these facilities provides substantial customer benefits and is in the public interest. Acquiring these resources helps PacifiCorp meet an identified resource need from the 2021 IRP. Repowering these facilities additionally extends the life of these wind resources, thus providing long-term, cost-effective, emission-free generation to serve Oregon customers. Therefore, PacifiCorp is requesting that the

[11] *In the Matter of PacifiCorp dba Pacific Power, 2022 Integrated Resource Plan,* Docket No. LC 77, Order No. 22-178 (May 23, 2022).

Commission find that the acquisition and repowering of the Projects is prudent and in the public interest.

VII. CONCLUSION

Q. What is your recommendation to the Commission?

A. I recommend the Commission find that PacifiCorp's decision to acquire and repower the Projects is prudent and in the public interest, and approve the Company's proposals for cost recovery with rates effective January 1, 2024

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 419
Exhibit PAC/200
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Timothy J. Hemstreet

March 2023

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. My present position is Vice President of Renewable Energy Development for PacifiCorp.

Q. Briefly describe your education and professional experience.

A. I hold a Bachelor of Science degree in Civil Engineering from the University of Notre Dame in Indiana and a Master of Science degree in Civil Engineering from the University of Texas at Austin. I am also a Registered Professional Engineer in the State of Oregon. Prior to joining the Company in 2004, I held positions in engineering consulting and environmental compliance. Since joining the Company, I have held positions in environmental policy, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed a role in renewable energy development, and in June 2019 I assumed a role focusing on PacifiCorp's wind repowering effort, and assumed my current role in September 2022, in which I oversee the development of renewable energy resources that enhance and complement PacifiCorp's existing renewable energy resource portfolio.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously sponsored testimony in California, Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to provide an overview and demonstrate the prudency of the Company's efforts to repower the 1.8 megawatt (MW) Foote Creek II, 24.75 MW Foote Creek III and 16.8 MW Foote Creek IV facilities (collectively, the Projects), to be included in the Oregon renewable adjustment clause (RAC). My testimony provides detail on the Company's commercial and other arrangements related to the Projects and explains their customer benefits. Specifically, my testimony addresses:

- the background of the Projects;
- the scope of the repowering effort and the Projects' relationship to the Company's earlier repowering efforts;
- the contracting arrangements, implementation status, permitting status, and schedule for the Projects;
- the energy benefits of the Projects;
- the financial benefits for customers of repowering resulting from production tax credit (PTC) qualification of the Projects; and
- the evaluation of the Projects in the 2021 Integrated Resource Plan (IRP).

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. In March 2021, PacifiCorp completed a significant effort to repower the entirety of its owned wind resources that were originally constructed before 2011, including the Foote Creek I facility. These repowered facilities are now delivering enhanced value and long-term customer benefits. The Company is pursuing additional benefits for customers by acquiring and repowering additional wind facilities adjacent to the

Company's Foote Creek I facility in Carbon County, Wyoming. The Projects will allow the Company to leverage existing long-term wind energy lease rights, facilities, and infrastructure in the local area (including staff and contractor resources) that will provide customers with benefits from these cost-effective, high-capacity-factor wind energy resources.

Acquiring and repowering the Projects is consistent with the Company's 2021 IRP, that identified the Projects as beneficial to customers and included their repowering in the Company's least-cost, least risk preferred portfolio. Repowering these Projects is also consistent with recent Wyoming Public Service Commission (Wyoming Commission) decisions that approved certificates of public convenience and necessity (CPCNs) for the Projects.[1] PacifiCorp purchased the Projects in June 2022 and construction began in the summer of 2022. The Projects are on track to reach commercial operation in late 2023.

IV. THE PROJECTS BACKGROUND, SCOPE AND RELATION TO PRIOR REPOWERING PROJECT

Q. Please explain the background of the Projects.

A. The Foote Creek Rim wind energy projects, consisting of Foote Creek I, II, III and IV, were the first utility-scale, commercial wind energy projects in the state of Wyoming. The projects are located at Foote Creek Rim due to the extraordinary combination of geography and wind energy resource at the site that causes already robust winds to accelerate as they move over the elevated plateau of the Foote Creek

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[1] *In re Application of RMP for a Certificate of Public Convenience and Necessity to Construct New Wind Turbines and Update Collector Lines at the Existing Foote Creek II-IV Wind Energy Facility,* Docket No. 20000-606-EN-21 (Record No. 16955) (a bench decision was rendered by the Wyoming Commission on April 26, 2022; a written order has not been issued at the time of drafting this testimony).

Rim. Development of wind energy facilities to take advantage of these favorable wind energy characteristics began in the early 1990s, and construction of the Foote Creek Rim projects was completed between 1999 and 2000.

PacifiCorp participated in wind energy development at the Foote Creek Rim site in partnership with the Eugene Water & Electric Board (EWEB) and the Bonneville Power Administration (BPA). PacifiCorp and EWEB were co-owners of the Foote Creek I wind energy facility that reached commercial operation in 1999, and BPA purchased a portion of the project's output. PacifiCorp acquired full ownership of the Foote Creek I project in 2019 and completed repowering of the project in March 2021. The Projects, which were previously owned by Terra-Gen, LLC (Terra-Gen), were independently developed and their generation output was sold to other utilities under power purchase agreements. The Projects were constructed with 64 wind turbines (of which 33 turbines had a nameplate capacity of 0.6 MW each and 31 turbines had a nameplate capacity of 0.75 MW) with a total nameplate capacity of 43.35 MW.

Q. What does it mean to repower a wind energy facility?

A. Repowering a wind energy facility means upgrading the wind turbine generator (WTG) equipment at an existing wind energy project with more efficient equipment to increase the power generation from the facility and extend the life of the facility. Specifically, repowering the Projects involves installing new turbines while reusing other pre-existing facility infrastructure.

Q. Please briefly describe PacifiCorp's effort to repower the Projects facilities.

A. Similar to the Company's effort to repower its neighboring Foote Creek I facility, repowering of the Projects involves installing modern WTGs.

At the Projects, the repowering effort will involve installing 11 new WTGs of the same type recently installed at Foote Creek I to replace the older wind turbines of much smaller capacity that were previously at the site.

The new WTGs at the Projects will be supported on new foundations and connected to the Foote Creek Substation with new energy collector circuits. The turbines will have updated switchgear and controls, and the new WTG locations will be linked by new turbine access roads. The proposed site layout for the Projects repowering effort is shown in Exhibit PAC/201.

Q. Will the Projects benefit from PacifiCorp's prior efforts to repower the adjacent facilities?

A. Yes. As part of the Foote Creek I repowering effort, the Company obtained the master wind energy lease rights for the entire Foote Creek Rim site, encompassing the original Foote Creek I, Foote Creek II, Foote Creek III, and Foote Creek IV wind energy project boundaries. These rights were acquired in August 2019 and their acquisition enhanced the customer benefits of the Foote Creek I repowering project by reducing the ongoing land rights cost of the project. Similarly, repowering the Projects' facilities will allow customers to fully benefit from these wind energy lease rights, which provide the ability to cost-effectively generate power at one of the most favorable wind energy locations in Wyoming. Acquiring the Projects' facilities allows the Company to nearly double the number of modern turbines it operates at the

Foote Creek Rim, increasing operations and maintenance efficiencies associated with current operations at the repowered Foote Creek I facility.

Q. Are there other ways in which the Projects will benefit from PacifiCorp's prior repowering effort at Foote Creek I?

A. Yes. As part of the Projects, an existing 2.0 MW turbine previously constructed as part of the Foote Creek I repowering project will be interconnected to the 1.8 MW Foote Creek II interconnection. This will allow this small Foote Creek II interconnection to be used by an existing, appropriately sized turbine while also allowing more generation from the existing Foote Creek I turbines as a result of less curtailment at higher wind speeds. Additionally, the Foote Creek I repowering project required access road upgrades to the Foote Creek Rim plateau to allow larger, modern wind turbine equipment to be delivered to the site. These improvements will also be used for the Projects facilities, and the enclosed switchgear building constructed adjacent to the Foote Creek Substation as part of the Foote Creek I repowering project will be used for equipment that will support the repowered Projects, reducing costs. Finally, the Projects will be operated from the Company's existing operations and maintenance building for the Foote Creek I project, so no additional facilities are needed for operations.

Q. Will the larger blades from the new turbines increase the potential for avian impacts at the repowered facilities?

A. Monthly monitoring conducted at the Projects over the last several years shows no significant avian impacts. Although the larger blades and greater rotor-swept area will increase the overall risk zone of the repowered wind turbines, this does not necessarily correlate with an increased risk of avian impacts. The significant reduction in the number of turbines that will be deployed at the site also means that less of the overall project site area will be covered by wind turbines. To further mitigate any potential impacts at the Projects, new turbine locations have been sited to avoid areas of higher avian use such as the edges of the plateaus.

The Company also performs monthly monitoring at all Company-owned Wyoming wind facilities and reports to both the Wyoming Game and Fish Department and the U.S. Fish and Wildlife Service. Once repowering concludes, the Company will begin this monthly monitoring at the Projects to determine if the new turbines cause additional impacts to avian species and will engage with the appropriate agency to discuss and, if prudent and practicable, implement additional avoidance, minimization, or mitigation measures. In addition, the Company is coordinating with both the Wyoming Game and Fish Department and the U.S. Fish and Wildlife Service on the Projects, including the development of an Eagle Conservation Plan and Bird and Bat Conservation Strategy for the new turbines.

V. THE PROJECTS' CONTRACTING AND PERMITTING STATUS, SCHEDULE, AND COST

Q. What commercial arrangements has PacifiCorp made to acquire and repower the Projects?

A. In addition to the earlier acquisition of the master wind energy lease rights for the project site, PacifiCorp executed a Purchase and Sale Option Agreement (PSOA) with Terra-Gen to acquire 100 percent of its interests in the facilities. Pursuant to the PSOA, Terra-Gen has removed the original 64 turbines from the site and completed site restoration activities in preparation for repowering of the facility by the Company. The Company closed on the acquisition of the facilities pursuant to the PSOA in June 2022, following the approval of the Company's CPCN application by the Wyoming Commission.

Q. What other commercial arrangements has PacifiCorp made with respect to the Projects?

A. The Company executed a master supply agreement and a turbine supply agreement for the repowering turbines with Vestas-American Wind Energy, Inc. (Vestas) in which Vestas will supply and commission WTGs suitable for the site of the same type used at the Foote Creek I facility. The Company has also executed a contract for balance of plant wind energy construction services following a competitive procurement process in which proposals from qualified wind energy construction companies were solicited. The Company has also executed a turbine service and maintenance agreement with Vestas, which will provide service for the repowered turbines consistent with negotiated pricing and terms.

Q. What is the status of necessary permitting to begin construction of the repowering Projects?

A. The Company has received the necessary Federal Aviation Administration no-hazard determinations to install the larger new turbines at the site. The Company has received a Conditional Use Permit for the repowering efforts from Carbon County, Wyoming. The Company has also received a building permit from Carbon County for the Projects.

Q. What is the anticipated construction schedule for the Projects?

A. The Company began construction for the Projects in the summer of 2022, and turbines and commissioning activities will occur in 2023. The Projects are anticipated to be fully online and serving customers in November 2023. Major milestones for completion of the Projects are shown below:

Milestone	Completion Date
Wyoming CPCN Approval	May 2022
Acquisition of Projects	June 2022
Construction Mobilization	June 2022
Turbine Foundation Completion	November 2022
	Anticipated Date
Access Road Completion	May 2023
Complete Turbine Deliveries	June 2023
Mechanical and Electrical Completion	August 2023
Turbine Commissioning Completion	November 2023
Final Completion/Site Restoration	July 2024

Q. What is the construction status of the Projects?

A. At the Projects, 96 percent of the access road improvements have been completed and all 11 foundations have been completed and backfilled and are ready to support the new turbines. Approximately 95 percent of the collection cable and fiber optic cable has been installed. Construction activities have been halted for the winter, and the contractor is expected to resume site work in April 2023 to prepare to receive and install the new turbines.

Q. What is the forecasted cost of the Projects?

A. The cost of acquiring and repowering the Projects facilities is estimated at $[redacted] on a total-Company basis.

Q. Does the acquisition and repowering of the Projects benefit customers?

A. Yes. Acquisition and repowering of the Projects will result in significant benefits for customers as a result of the energy and PTC benefits of the Projects, as more fully detailed in the testimony of Company witness Mr. Thomas R. Burns.

VI. THE PROJECTS REPOWERING BENEFITS INCLUDING REQUALIFICATION FOR PRODUCTION TAX CREDITS

Q. What benefits will customers realize from the Projects once repowered?

A. Given the extraordinary wind resource in the area, the Projects will provide significant energy benefits to customers: the Projects' facilities are estimated to have a high net capacity factor of [redacted] percent. These high net capacity factors allow the facilities to contribute to system capacity needs.

Q. Will the repowered Projects qualify for PTCs?

A. Yes. Repowering will requalify the Projects for PTCs, which will be passed on to the Company's customers.

Q. What is the value of the PTC for the Projects?

A. For 2023, the value of the federal PTC is 2.75 cents per kilowatt-hour, or $27.50 per megawatt-hour. This PTC value is adjusted annually based upon an inflation index, and the PTC is available for energy produced during the 10-year period after the wind facility begins commercial operation. Pursuant to the Inflation Reduction Act of 2022, the Projects are expected to qualify for 110 percent of the value of the federal PTC given the location is in Carbon County, which is expected to meet the definition of an "energy community" under the law. Location in an "energy community" increases the PTC value from 100 percent to 110 percent under the Inflation Reduction Act.

Q. Are there other requirements that the repowered Projects must satisfy to qualify for the PTC?

A. Yes, the repowered Projects must be in service before the end of 2025, to meet the IRS continuous efforts safe harbor and qualify for the PTC by completing construction within four calendar years. Because repowering at the Projects will not incorporate retained components from the existing wind turbines at the site there are no requirements related to the Internal Revenue Service "80/20" test—a test that was applicable to the repowering of the majority of PacifiCorp's wind fleet in which the foundations and towers were retained.[2]

Q. Will repowering increase the overall generating capacity of the Projects?

A. No. The existing interconnections will be fully used but the generating capacity of the Projects is not expected to be expanded as a result of repowering. The wind turbine equipment that will be used at the Projects has been optimized to make full use of the existing interconnection capacities and the Company does not at this time anticipate increasing the interconnection capacity for the facilities.

Q. What is the anticipated generation that the Projects will produce?

A. The Company retained the engineering consulting firm Black & Veatch, Inc. (Black & Veatch) to evaluate the energy production expected from the Projects. To complete this assessment, Black & Veatch used site wind data, wind turbine location data, operational performance data, and other available site-specific information to model

[2] *Internal Revenue Service Notice 2016-31*, § 6 (May 5, 2016) (available at https://www.irs.gov/pub/irs-drop/n-16-31.pdf).

the expected generation from the Projects. The wind model also evaluated generation losses resulting from the wake losses at each turbine location. Wake losses are the reduction in generation at turbines downwind of other turbines due to reduced wind speed and increased turbulence in the airflow—or wake—behind a turbine. At the Projects, the estimated annual energy production from the 11 new turbines is expected to be [redacted] gigawatt-hours (GWh), resulting in a high net capacity factor of [redacted] percent. An additional [redacted] GWh per year is expected to be produced as a result of interconnecting a previously constructed 2.0 MW turbine at Foote Creek I to the Foote Creek II interconnection. In total, the repowered Projects will produce an amount of energy used by nearly 20,000 homes. The technical analysis documenting the expected generation from the Projects is provided in Confidential Exhibit PAC/202.

VII. REVIEW OF WIND REPOWERING PROJECTS IN THE 2021 IRP

Q. Were the Projects reviewed as part of the Company's 2021 IRP?

A. Yes. The Projects were made available as a potential resource that could meet customer energy and capacity needs in the model used to develop the Company's 2021 IRP.[3] Because the resources were beneficial to customers, they were included in the Company's least-cost, least-risk preferred portfolio.

Q. Was the acquisition and repowering of the Projects included in the 2021 IRP Action Plan?

A. Yes. Action Item 2b of the 2021 IRP notes the Company will pursue necessary regulatory approvals to authorize the acquisition and repowering of the Projects in

[3] *In re PacifiCorp's 2021 Integrated Resource Plan,* at 295 (Sept. 1, 2021).

order to support a late 2023 in-service date.[4] The Company's 2021 IRP Update continued to include acquisition and repowering of the Projects in the preferred portfolio.[5]

X. CONCLUSION

Q. Please summarize your testimony.

A. Repowering the Projects leverages federal PTC benefits to renew not only some of Wyoming's first utility-scale wind plants, but also expands the Company's wind operations in one of the most favorable wind energy locations in the Country, while increasing customer benefits and savings.

Q. What is your recommendation?

A. I recommend the Public Utility Commission of Oregon find that acquiring and repowering the Projects is reasonable and in the public interest and will benefit customers and allow the Company to recover the cost of these investments in retail rates.

Q. Does this conclude your direct testimony?

A. Yes.

[4] *Id.* at 323.
[5] *In re PacifiCorp's 2021 IRP Update,* at 5 (Mar. 31, 2022).

Docket No. UE 419
Exhibit PAC/201
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

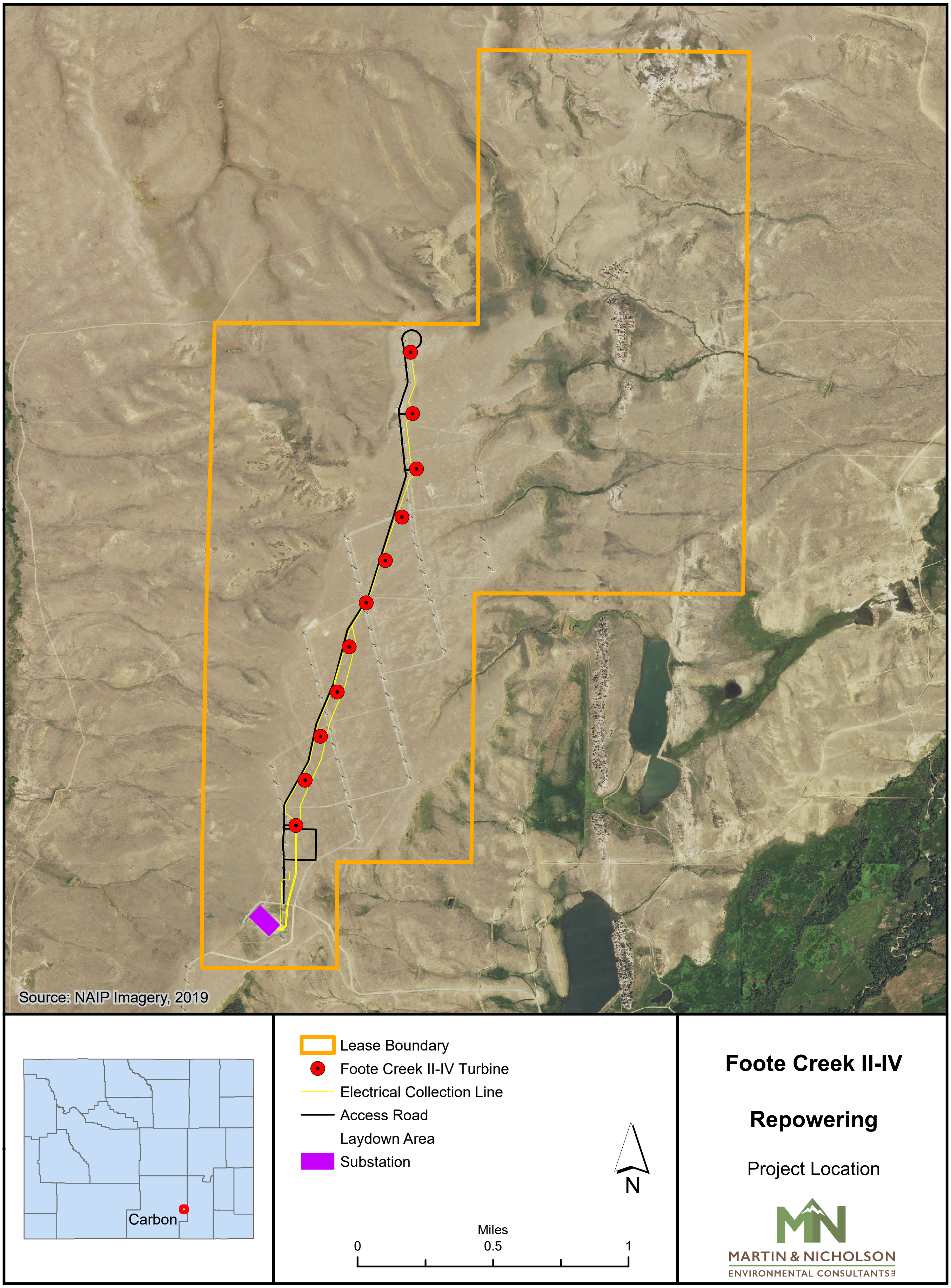
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Foote Creek II-IV Site Layout

March 2023


Source: NAIP Imagery, 2019
Carbon
Lease Boundary
Foote Creek II-IV Turbine
Electrical Collection Line
Access Road
Laydown Area
Substation
N
Miles
0
0.5
1
Foote Creek II-IV
Repowering
Project Location
MARTIN & NICHOLSON
ENVIRONMENTAL CONSULTANTS

REDACTED
Docket No. UE 419
Exhibit PAC/202
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Energy Production Analysis Report

March 2023

THIS EXHIBIT IS CONFIDENTIAL PER PROTECTIVE ORDER 23-104 AND IS PROVIDED SEPARATELY

Docket No. UE 419
Exhibit PAC/300
Witness: Thomas R. Burns

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Thomas R. Burns

March 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company).

A. My name is Thomas R. Burns, my business address is 825 NE Multnomah Street, Suite LCT 600, Portland, Oregon 97232. I am currently employed as Vice President of Resource Planning and Acquisitions for PacifiCorp.

Q. Please describe your education and professional experience.

A. I graduated from Illinois State University with a Bachelor of Science degree in Economics. I joined PacifiCorp in 2007 and assumed the responsibilities of my current position in September 2022. Over this period, I held several operational, analytical and leadership positions within the Company. My previous role with PacifiCorp was Director of Energy Supply Management, Operations, and Reliability. In that role I was instrumental in the design and implementation of the Western Energy Imbalance Market.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for aspects of PacifiCorp's resource planning and procurement functions, which include the integrated resource plan (IRP), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this renewable adjustment clause filing, I oversee the significant planning, analysis, and outreach processes that are used to develop PacifiCorp's IRP, and the economic analysis that helps guide the Company's resource acquisitions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I provide economic analysis that supports PacifiCorp's decisions to acquire and repower the 43 megawatt (MW) Foote Creek II, III, and IV wind facilities in Wyoming ("Wind Projects"). I also summarize PacifiCorp's assessment of the project from the 2021 IRP and IRP Update and discuss customer benefits that result from these projects.

Q. Please provide an overview of your testimony.

A. As discussed below, my economic analyses indicate that acquiring and repowering the Wind Projects is in the public interest and will generate benefits for Oregon customers.

Benefits for the Wind Projects range from $53.07 million when using medium natural gas and medium carbon dioxide (CO_2) assumptions, to $80.8 million for high natural gas and high CO_2 assumptions prior to adjusting for benefits from the Inflation Reduction Act (IRA). These benefits increase to $76.49 million when using medium natural gas and medium CO_2 assumptions, and $104.23 million for high natural gas and high CO_2 assumptions when factoring in the IRA. Conservatively, these benefits do not assign any value to the renewable energy credits (RECs) that will be generated by the Wind Projects.

Q. Does your testimony support the prudency of the Company's investments for the Wind Projects?

A. Yes.

III. REPOWERING WIND PROJECTS

Q. Please describe the acquisition and repowering of the Wind Projects.

A. As described in the testimony of Company witness Mr. Timothy J. Hemstreet, Exhibit PAC/200, PacifiCorp is acquiring and repowering the 43 MW Wind Projects. This involves installing approximately 11 modern Wind Turbine Generators at the Foote Creek facilities, that will increase the power generation from, and extend the service lives of, both facilities. These new turbines will increase the power generation from the previous capability and allow customers to benefit from these favorable wind sites.

My testimony below provides the economic justification for the Company's decision to acquire and repower the Wind Projects, including a discussion of: identified resource need, modeling methodology, and assumptions and results.

A. Resource Need

Q. Please provide an overview of the Company's IRP process.

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk to develop the Company's plans to provide reliable and reasonably priced service to its customers. The primary objective of the IRP is to identify the least-cost, least-risk portfolio of resources to serve customers in the future. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks.

The Company completes an IRP cycle every two years (odd-numbered years), which includes preparation of a full IRP every two years and preparation of an update to the full IRP in the off years (even-numbered years). The Company submits both its IRP and IRP Update to each of the six regulatory commissions in the states where the Company provides retail service. Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process which typically spans at least a full year prior to the release of a full IRP, PacifiCorp holds regular meetings with stakeholders to solicit feedback on the Company's planning assumptions, methodologies and model results.

Q. How does the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflects a cost-conscious plan that includes near-term investments in renewable resources that can capture tax credits before they expire or decrease and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Did the 2021 IRP identify the need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of the 2021 IRP is to forecast the need for resources and then evaluate different ways to meet that need over time. In the 2021 IRP, the assessment of resource need is presented in Volume I, Chapter 6. The load-and-resource balance shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and rising to 6,600 MW by 2040.[1] Consistent with prior IRPs, all resource portfolios produced in the 2021 IRP that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, and market resources to fill this need.

[1] 2021 IRP, Vol. I, Table 6.12.

This need has continued to increase due to increases in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[2] The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[3]

Since the Company moved forward with the Wind Projects, national tariff policies, global supply-chain issues, and inflationary pressures eliminated some bids from the Company's 2020 All-Source Request for Proposals final shortlist. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. Additional resources are needed to reduce PacifiCorp's reliance on the market.

Q. Did PacifiCorp's preferred portfolio of resources developed in the Company's 2021 IRP include the Wind Projects?

A. Yes.[4]

Q. Please describe the key factors for including the Wind Projects in the 2021 IRP preferred portfolio.

A. The Wind Projects are anticipated to be fully online and serving customers by 2024. This timing enables the Wind Projects to deliver needed energy and capacity value for customers prior to the availability of either new proxy resources or final shortlist project generation expected to be enabled by the Energy Gateway South transmission line as identified in the Company's 2020 All-Source Request for Proposals. Without the Wind

[2] *Id.* at Table 4.2.
[3] *Id.* at 2.
[4] *Id.* at Ch. 1 Action Plan, Action Item 2b, at 25.

Projects, the risk of shortfalls is increased as is reliance on energy markets. In their current states, the existing Wind Projects are not operating as turbines and have been removed pending the repowering of the sites. Repowering will allow the facilities to once again provide energy and capacity to serve load and reduce market reliance, while allowing the newly installed turbines to qualify for substantial federal production tax credits (PTCs).

Q. Were the Wind Projects included in the Company's 2021 IRP Update?

A. Yes.[5]

B. Methodology

Q. Please describe the modeling tool used to provide economic analysis of the Wind Projects.

A. PacifiCorp uses the PLEXOS modeling system. The PLEXOS modeling system provides three platforms of the PLEXOS tool (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The PLEXOS tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique

[5] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022) (available here).

regarding the type, timing, location and amount of new resources that could be pursued to serve customers over the next 20 years. Portfolios from the LT model are informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk among several price-policy scenarios that combine various natural gas and carbon prices. A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used the ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR), which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, resource portfolios were developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management (DSM) alternatives within PacifiCorp's system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years to retrieve two critical pieces of data: 1) shortfalls by hour; and 2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of the Wind Projects?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The LT model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource and transmission capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Wind Projects. The ST and MT models provide additional granularity on how the Wind Projects are projected to affect system operations while assessing stochastic risks. Together, the LT, MT, and ST models are best suited to perform a benefit analysis of the Wind Projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

C. Assumptions and Results

Q. Has the Company performed updated analyses of the Wind Projects after filing the 2021 IRP?

A. Yes. The Company performed a 30-year analysis of each project's economics through end-of-life using its PLEXOS modeling system, the same modeling system used for the 2021 IRP.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analyses for the Wind Projects.

A. The economic analysis for each of the projects included three price-policy scenarios—representing low, medium and high natural gas prices, and zero, medium and high CO_2 prices. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario, the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario, and the price-policy scenario that pairs high natural gas prices with a high CO_2 price is referred to as the "HH" scenario. While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the LN and the HH scenarios provide informative analytical bookends scenarios.

These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net power costs (NPC), non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Wind Projects. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO_2 price assumptions are summarized in Table 1.

Table 1. Price-Policy Assumptions

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
HH	$5.64	22.57/ton starting 2025 rising to 102.48/ton in 2040
MM	$4.44	$9.93/ton starting in 2025 rising
LN	$2.94	None
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated March 31, 2021, which was the most recent OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, May 2021 is the prompt month in this case. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used three different CO_2 price scenarios—zero, medium, and high. The medium scenario is derived from a survey of third-party industry experts, including IHS Cambridge Energy Research Associates, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. Both scenarios apply a CO_2 price as a tax beginning 2025.

Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of analyzing the Wind Projects?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client, "off-the-shelf" subscription services.

Q. Please explain how you conducted your analyses.

A. The methodologies are consistent with the approach used to perform the economic analysis of portfolios in the 2021 IRP. The system value of incremental wind energy for each project is calculated from two PLEXOS ST model simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. The system value of incremental wind energy is then converted to a dollar-per-megawatt-hour (MWh) value by dividing the change in annual system cost by the change in incremental wind energy for both price-policy scenarios through 2040. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2038-2040 timeframe. The assumed system value, expressed in dollars per MWh, is applied to the incremental energy output associated with the Wind Projects.

Q. Was your initial economic analyses of the Wind Projects conducted prior to passage of the IRA?

A. Yes.

Q. How does the IRA impact your analyses?

A. Based on existing law, PacifiCorp's initial economic analyses assumed that the Wind Projects qualified for 60 percent of available PTCs. After passage of the IRA, the Company understands that the Wind Projects qualifies for 110 percent of available PTCs. The Company has updated its economic analyses to reflect the new PTC value for both projects, and the results are reflected in Table 2 below.

Q. Please summarize the PVRR(d) and levelized results for the Wind Projects.

A. Table 2 summarizes the PVRR differential (PVRR(d)) between cases, with and without the Wind Projects, for customer benefits prior to, and after passage of, the IRA. This table also presents the same information on a levelized dollar-per-MWh basis.

Table 2. Wind Project (Benefits)/Costs

Price-Policy Scenario	Pre-IRA PVRR(d) ($ million)	Pre-IRA Net Benefit ($/MWh)	Post-IRA PVRR(d) ($ million)	Post-IRA Net Benefit ($/MWh)
HH	($80.80)	($38/MWh)	($104.23)	($49/MWh)
MM	($53.07)	($25/MWh)	($76.49)	($36/MWh)
LN	$17.09	$8/MWh	($6.33)	($3/MWh)

Prior to passage of the IRA, the Wind Projects were expected to deliver $53.07 million in present-value net customer benefits in the MM scenario, and $80.8 million in the HH scenario. This is contrasted with $17.09 million cost in the LN scenario. Under the MM and HH scenarios, nominal levelized net benefits are $25/MWh and $38/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $8/MWh. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering the Wind Projects.

After passage of the IRA, customer benefits increased substantially: the Wind Projects will now deliver $76.49 million in present-value net customer benefits in the MM scenario and $104.23 million in the HH scenario. Importantly, the only scenario where the Wind Projects were expected to generate customer costs prior to passage of the IRA—the LN scenario ($17.09 million)—has transformed to a $6.33 million customer benefit. While the Company decided to move forward with the Wind Projects prior to passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

Q. Are the Company's economic analyses of the expected customer benefits from the Wind Projects conservative?

A. Yes. The PVRR(d) results for the Wind Projects do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Customer benefits for all price-policy scenarios would improve significantly for every dollar assigned to the incremental RECs that will be generated through 2040 by both projects, and these RECs can also be used for compliance with various state requirements, providing additional customer benefits.

IV. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis shows that acquiring and repowering the Wind Projects are necessary and will provide substantial customer benefits compared to anticipated project costs.

Q. What is your recommendation?

A. As supported by PacifiCorp's economic analysis, I recommend that the Public Utility Commission of Oregon determine that the Company's decisions to acquire and repower the Wind Projects are prudent and reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 419
Exhibit PAC/400
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Shelley E. McCoy

March 2023

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is Shelley E. McCoy, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, OR 97232. My present position is Director of Revenue Requirements.

Q. Briefly describe your education and professional experience.

A. I earned my Bachelor of Science degree in Accounting from Portland State University. In addition to my formal education, I have attended several utility accounting, ratemaking, and leadership seminars and courses. I have been employed by PacifiCorp since November of 1996. My past responsibilities have included general and regulatory accounting, budgeting, forecasting, and reporting.

Q. What are your current responsibilities with PacifiCorp?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings and revenue requirement, assuring that the interjurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in regulatory proceedings before the Public Utility Commission of Oregon, as well as the California and Washington commissions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I present and explain the calculation of the Foote Creek II 1.8 megawatts (MW), Foote Creek III 24.75 MW and Foote Creek IV 16.8 MW facilities' (collectively, the Projects) non-transition adjustment mechanism[1] related revenue requirement to be included in the renewable adjustment clause (RAC). Specifically, my testimony:

- Describes the proposed ratemaking for the Projects;
- Calculates the Oregon-allocated incremental operating expenses and capital revenue requirement cost associated with the Projects;
- Specifies the amounts that the Company requests to recover through the RAC attributable to the revenue requirement changes associated with the Company's proposed RAC rate change effective date.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. In this RAC filing, PacifiCorp seeks recovery of the non-transition adjustment mechanism Oregon-allocated revenue requirement associated with the Projects' wind resources. PacifiCorp proposes to implement the RAC with an effective date of January 1, 2024, to recover costs in a manner that will coincide with the forecasted customer benefits from NPC and PTC included in the 2024 TAM. The requested RAC recovery amount is $3.1 million.

[1] PacifiCorp's Transition Adjustment Mechanism (TAM) captures the net power costs (NPC) and production tax credits (PTC) benefits of the Projects.

IV. PROPOSED RATEMAKING

Q. Please explain PacifiCorp's proposed ratemaking for inclusion of the wind project in rates.

A. PacifiCorp seeks recovery of the revenue requirement associated with the costs of the Projects that is scheduled to be completed in November 2023, through this RAC filing. The NPC and PTCs benefits associated with this wind project will be included as part of PacifiCorp's 2024 TAM. PacifiCorp proposes a rate effective date of January 1, 2024, for implementing the proposed rate changes. This proposed date will allow for recovery of the revenue requirement changes for the wind project while minimizing potential regulatory lag and maximizing the matching of costs and benefits.

Q. Given that the wind project is scheduled to be completed before the rate effective date of January 1, 2024, is PacifiCorp proposing to defer the costs and benefits between the completion and rate effective dates for future amortization?

A. Yes. PacifiCorp will file a deferral application at the time of project completion for deferral of project costs and benefits.

V. REVENUE REQUIREMENT

Q. Have you prepared exhibits that show the calculation of the proposed RAC rate adjustments for the rate effective date, January 1, 2024?

A. Yes. Please refer to Confidential Exhibit PAC/401, which shows the annual revenue requirement of the incremental capital and operating costs associated with the Projects for the one-year period of January 1 through December 31, 2024. This project is scheduled to achieve final turbine commissioning in November 2023. As calculated in Confidential Exhibit PAC/401, PacifiCorp is seeking an annual recovery of $3.1 million through the RAC with a proposed effective date of January 1, 2024.

Q. How are the revenue requirement costs allocated to Oregon?

A. All costs excluding property tax are allocated using the 2023 System Generation factor used in PacifiCorp's last general rate case, docket UE 399 (2023 Rate Case). Property tax is allocated using the Gross Plant System factor from PacifiCorp's 2023 Rate Case, consistent with the calculation of the average Oregon property tax rate also from the 2023 Rate Case, addressed later in my testimony.

Q. Is the methodology used in calculating the revenue requirement components consistent with the methodology agreed upon in the Stipulation to the previously approved 2020 RAC?[2]

A. Yes.

Q. Please describe the revenue requirement components included in Confidential Exhibit PAC/401.

A. The plant revenue requirement consists of the incremental pre-tax rate of return on average net rate base, operation and maintenance expense (O&M), depreciation, property taxes, and wind tax. NPC and PTCs are excluded from the RAC and will instead be included in the 2024 TAM filing. Through the combination of the TAM and the RAC, the benefits and costs of the wind project will be incorporated into customer rates.

Net rate base is calculated using a 13-month average of gross plant less accumulated depreciation and accumulated deferred income tax balances. The

[2] *See In the Matter of PacifiCorp dba Pacific Power, 2020 Renewable Adjustment Clause,* Disposition: All Party Stipulation Adopted, Docket No. UE 369, (Jan. 31, 2020).

13--month average balances are derived from the periods December 2023 through December 2024 for the rate effective date of January 1, 2024. Confidential Exhibit PAC/402 provides the monthly detail used to derive the 13-month averages.

Q. Are capital additions that are anticipated to be incurred after the corresponding rate effective date included in the 13-month average net rate base?

A. Yes. The net rate base includes the capital placed in-service on or before and after the rate-effective date.

Q. Please describe the capital structure and pre-tax cost of capital proposed in the RAC.

A. Please refer to Exhibit PAC/403. The capital structure and capital costs are taken from the Company's 2023 Rate Case, reflecting the Company's current authorized capital structure and capital costs. The cost of capital is grossed up to a pre-tax rate of return using the consolidated tax rate consistent with current tax law.

Q. Does the O&M shown in Confidential Exhibit PAC/401 represent the O&M associated with the wind resource?

A. Yes. The associated O&M is explained in the testimony of Company witness Mr. Timothy J. Hemstreet, Exhibit PAC/200.

Q. Please explain the depreciation expense in Confidential Exhibit PAC/401.

A. The depreciation expense shown in Confidential Exhibit PAC/401 is the increased depreciation expense associated with the incremental capital investment placed in service due to this wind project.

Q. Please describe the property tax calculation included in the proposed RAC.

A. Please refer to Exhibit PAC/403, which shows the calculation of the average Oregon property tax rate from PacifiCorp's 2023 Rate Case filing. The average property tax rate is calculated by dividing the Oregon-allocated property taxes by the Oregon-allocated net electric plant in service (EPIS). The property taxes attributable to the wind project are calculated by multiplying this average property tax rate by the net EPIS of the wind project.

Q. Are there any other cost considerations that should be addressed as part of the wind project RAC?

A. Yes. The RAC revenue requirement adjustment includes a gross-up for the incremental rate burden associated with incremental franchise taxes, bad debt expense, resource suppliers tax, and public utility commission fees. These costs have been included in Confidential Exhibit PAC/401.

VI. REQUEST FOR RECOVERY OF WIND PROJECT COSTS

Q. What is the amount of rate adjustment that PacifiCorp is requesting through the RAC?

A. PacifiCorp is requesting an annualized amount of $3.1 million through the RAC rates proposed to be effective January 1, 2024, to recover the Projects' capital and operating revenue requirement concurrent with the rate reductions provided through the TAM for the Projects' NPC and PTC benefits. PacifiCorp will update these costs consistent with the requirements of Order No. 07-572.[3]

Q. Does this conclude your direct testimony?

A. Yes.

[3] *In the Matter of Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 4 (Dec. 19, 2007).

REDACTED
Docket No. UE 419
Exhibit PAC/401
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Annual RAC Wind Project Revenue Requirement

March 2023

REDACTED

PacifiCorp
Oregon
Renewable Adjustment Clause
Revenue Requirement- Foote Creek II-IV

			(a)	(b)	(c)	(d)
			Effective Date: 1/1/2024			
	$-Thousands		**Dec. 2023 - Dec. 2024**			
Line No.		Reference	**Total Company**	**Factor**	**Factor %**	**Oregon Allocated**
	Plant Revenue Requirement					
1	Capital Investment	Footnote 1	[redacted]	SG	26.002%	[redacted]
2	Depreciation Reserve	Footnote 1		SG	26.002%	
3	Accumulated DIT Balance	Footnote 1		SG	26.002%	
4	Net Rate Base	sum of lines 1-3				
5	Pre-Tax Rate of Return	line 20	8.658%			8.658%
6	Pre-Tax Return on Rate Base	line 4 * line 5	[redacted]			[redacted]
7	Operation & Maintenance	Footnote 2		SG	26.002%	[redacted]
8	Depreciation	Footnote 3		SG	26.002%	
9	Property Taxes	Footnote 2		GPS	27.087%	
10	Wind Tax	Footnote 2		SG	26.002%	
11	Deferred Income Tax Expense	Footnote 4	[redacted]	SG	26.002%	[redacted]
12	**Rev. Reqt. Before Revenue Gross-up**	sum of lines 6-11	**11,433**			**2,982**
13	Franchise Taxes	PAC/403, line 17				71
14	Bad Debt Expense	PAC/403, line 18				16
15	Resource Supplier Tax	PAC/403, line 19				4
16	PUC Fee	PAC/403, line 20				13
17	**Total Revenue Requirement**	sum of lines 12-16				**3,085**
18	Federal/State Combined Tax Rate	PAC/403, line 5	24.587%			
19	Net to Gross Bump up Factor = (1/(1-tax rate))	PAC/403, line 6	1.3260			
20	Pretax Return	PAC/403, line 4	8.658%			
21	Property Tax Rate	PAC/403, line 14	1.003%			
22	Oregon SG Factor	PAC/403, line 15	26.0018%			
23	Oregon GPS Factor	PAC/403, line 16	27.0866%			

Footnotes:
1) Capital balances equal the 13-month average of the monthly balances in PAC/402.
2) Equals the annual cost of the first full year subsequent to the rate effective date. See PAC/402.
3) Equals the 12 consecutive months beginning with the rate effective date. See PAC/402.
4) This represents the Deferred Income Tax Flow through.

REDACTED
Docket No. UE 419
Exhibit PAC/402
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Monthly RAC Wind Project Amounts
November 2023 through December 2024

March 2023

REDACTED

PacifiCorp
Oregon
Foote Creek II-IV - Monthly

Line No.	**$-Thousands**	Reference	**2023** November	**2023** December	**2024** January	**2024** February	**2024** March	**2024** April	**2024** May	**2024** June	**2024** July	**2024** August	**2024** September	**2024** October	**2024** November	**2024** December
Total Company																
	Plant Revenue Requirement															
1	Capital Investment		[redacted]													
2	Depreciation Reserve															
3	Accumulated DIT Balance															
4	Net Rate Base	sum of lines 1-3														
5	Operation & Maintenance		[redacted]													
6	Depreciation	Footnote 1														
7	Property Taxes	Full In-service date (line 1 + line 2) x line 9														
8	Wind Tax															
9	Property Tax Rate	PAC/403, line 14	1.003%													

Footnotes:
1) Depreciation rates utilized in OR GRC Docket No. UE 399

Docket No. UE 419
Exhibit PAC/403
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Capital Structure, Property Tax, Revenue Requirement Gross-up

March 2023

PacifiCorp
Oregon
Foote II-IV- Capital Structure, Property Tax, and Rev Reqt Gross-up

Oregon General Rate Case Docket No. UE 399
Updated with new consolidated tax rate consistent with the new tax law
Effective 1/1/2023

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Tax Gross-up	Pre-Tax Cost
1	Debt	49.990%	4.717%	2.358%		2.358%
2	Preferred	0.010%	6.750%	0.001%	1.326	0.001%
3	Common	50.000%	9.500%	4.750%	1.326	6.299%
4			**TOTAL**	**7.109%**		**8.658%**
5	Consolidated Tax Rate		24.587%			
6	Tax Gross-up factor for PTC = (1/(1 - tax rate))		1.3260			

Line no.	**Property Tax Calculation as filed in Oregon General Rate Case Docket No. UE 399**	
7	Total Company	185,977,000
8	Oregon GPS Factor [1]	27.087%
9	Oregon Property Taxes	50,374,880
10	Oregon Gross EPIS	8,800,629,820
11	Oregon Accum. Depr.	(3,558,696,312)
12	Oregon Accum. Amort.	(217,647,490)
13	Oregon Net EPIS	5,024,286,018
14	Estimated Oregon Property Tax Rate	1.003%
15	Oregon General Rate Case Docket No. UE 399 SG Factor [1]	26.002%
16	Oregon General Rate Case Docket No. UE 399 GPS Factor [1]	27.087%

Line no.	**Franchise Tax and Bad Debt Percentage [2]**	**Percentage of Revenue**	**w/ Tax Gross-up**
17	Franchise Tax	2.303%	2.383%
18	Bad Debt Percentage	0.505%	0.522%
19	Resource Suppliers Tax	0.125%	0.130%
20	PUC Fee	0.430%	0.445%

Footnotes:

1 SG Factor & GPS Factor from Oregon General Rate Case Docket No. UE 399
2 Oregon General Rate Case Docket No. UE 399

Docket No. UE 419
Exhibit PAC/500
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

March 2023

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six-state service territory.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I present the Company's proposed Renewable Adjustment Clause (RAC) prices and proposed tariff changes. I also provide a summary of the impact of the proposed rate changes on customers' bills.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. I show that the proposed RAC results in an overall rate increase of $3.1 million or 0.2 percent on January 1, 2024. The rate impact varies by customer class with rate spread based on present generation revenues. The bill for the average residential customer will increase $0.18 per month.

IV. RATES AND TARIFF

Q. Please describe the Company's tariff rate schedule that collects the RAC adjustment from customers.

A. The Company's Schedule 202, Renewable Adjustment Clause describes the RAC and contains the per kilowatt-hour adjustments applied to customer bills. The current tariff rates were set to zero in 2021 when the amounts previously collected through the rate schedule were incorporated into base rates as part of the Company's general rate case, docket UE 374.

Q. What is the total repowering revenue requirement PacifiCorp is seeking recovery for at this time?

A. As described in the testimony of Ms. Shelley E. McCoy, the requested RAC recovery amount is $3.1 million.

Q. What basis is used for the RAC rate spread?

A. The special conditions in Schedule 202 provide that "Costs recovered through the rate schedule will be allocated across customer classes using the applicable forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kilowatt-hour to each applicable rate schedule."[1]

The Company calculated a generation rate spread based on the applicable forecast energy and generation revenue based on a 2024 test year.

[1] PacifiCorp rate schedule 202, Renewable Adjustment Clause, Supply Service Adjustment page 2, special condition 3.

Q. Have you calculated proposed RAC per kilowatt-hour adjustment rates by rate schedule?

A. Yes. Exhibit PAC/501 shows the rate spread and the calculation of the proposed RAC rates.

Q. Please describe Exhibit PAC/502.

A. Exhibit PAC/502 presents the proposed Schedule 202, RAC tariff.

V. COMPARISON OF PRESENT AND PROPOSED RATES

Q. What are the overall rate effects of the changes proposed in this filing?

A. The overall effect of the proposed rates is a rate increase of 0.2 percent, on a net basis, effective January 1, 2024. The rate change varies by customer type. Exhibit PAC/503 shows the effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Fund (Schedule 91), the Low Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

Q. Did you prepare exhibits showing the impact on customer bills as a result of the proposed rate changes?

A. Yes. Exhibit PAC/504 contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each comparison shows the customer bill before and after the proposed change and shows the change as a percentage. These bill comparisons include the effects of all adjustments schedules including the Low Income Bill Payment Assistance Fund (Schedule 91), the Low Income Discount Cost Recovery Adjustment (Schedule 92) the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is $0.18.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 419
Exhibit PAC/501
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Renewable Adjustment Clause, Rate Spread and Rate Calculation

March 2023

PACIFIC POWER
Calculation of Proposed Renewable Adjustment Clause - Schedule 202

FORECAST 12 MONTHS ENDED DECEMBER 31, 2024

Line No.	Description	Sch No.	MWh*	Generation Rate Spread	Proposed Schedule 202 RAC Rate (¢/kWh)	Proposed Schedule 202 RAC Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Residential	4	5,829,081	37.4%	0.020	$1,165.816
2	**Total Residential**		5,829,081			$1,165.816
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,166,351	7.0%	0.019	$221.607
4	Gen. Svc. 31 - 200 kW	28	2,084,027	12.4%	0.018	$375.125
5	Gen. Svc. 201 - 999 kW	30	1,325,081	7.7%	0.018	$238.515
6	Large General Service >= 1,000 kW	48	6,123,426	33.9%	0.017	$1,040.982
7	Partial Req. Svc. >= 1,000 kW	47	32,263		0.017	$5.485
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	0		-	$0.000
9	Agricultural Pumping Service	41	237,644	1.4%	0.018	$42.776
10	**Total Commercial & Industrial**		10,968,792			$1,924.489
	Lighting					
11	Outdoor Area Lighting Service	15	2,054		0.014	$0.288
12	Street Lighting Service Comp. Owned	51	7,381		0.014	$1.033
13	Street Lighting Service Cust. Owned	53	7,519		0.014	$1.053
14	Recreational Field Lighting	54	1,394		0.014	$0.195
15	**Total Lighting**		18,348	0.1%	0.014	$2.569
16	**Subtotal**		16,816,221	100.0%		$3,092.874
17	Emplolyee Discount					($0.674)
18	**Total Sales with Employee Discount**					$3,092.200

* Includes lighting tariff MWh

Docket No. UE 419
Exhibit PAC/502
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule 202, Renewable Adjustment Clause

March 2023

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 202

RENEWABLE ADJUSTMENT CLAUSE
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers, between rate cases, the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

This adjustment is to recover the actual and forecasted revenue requirement associated with the prudently incurred costs of resources, including associated transmission, that are eligible under Senate Bill 838 (2007) and in service as of the date of the proposed rate change. The revenue requirement includes the actual return of and grossed up return on capital costs of the renewable energy source and associated transmission at the currently authorized rate of return, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs not captured in the Transition Adjustment Mechanism (TAM). The revenue requirement for Oregon will be calculated using the forecasted inter-jurisdictional allocation factors based on the same 12-month period used in the TAM.

Applicable

To all Residential consumers and Nonresidential consumers except consumers who began service under the five-year cost of service opt-out program described in Schedule 296 before January 1, 2019.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge	
4	0.020 cents per kWh	(I)
5	0.020 cents per kWh	
15	0.014 cents per kWh	
23, 723	0.019 cents per kWh	
28, 728	0.018 cents per kWh	
30, 730	0.018 cents per kWh	
41, 741	0.018 cents per kWh	
47, 747	0.017 cents per kWh	
48, 748	0.017 cents per kWh	
51, 751	0.014 cents per kWh	
53, 753	0.014 cents per kWh	
54, 754	0.014 cents per kWh	(I)

(continued)

Docket No. UE 419
Exhibit PAC/503
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed Price Changes

March 2023

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2024

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	540,041	5,829,081	$737,548	$8,977	$746,525	$738,714	$8,977	$747,691	$1,166	0.2%	$1,166	0.2%	1
2	**Total Residential**		540,041	5,829,081	$737,548	$8,977	$746,525	$738,714	$8,977	$747,691	$1,166	0.2%	$1,166	0.2%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	85,313	1,166,351	$149,483	$2,496	$151,978	$149,704	$2,496	$152,200	$222	0.2%	$222	0.2%	3
4	Gen. Svc. 31 - 200 kW	28	10,587	2,084,027	$186,116	$20,590	$206,706	$186,492	$20,590	$207,081	$375	0.2%	$375	0.2%	4
5	Gen. Svc. 201 - 999 kW	30	872	1,325,081	$105,890	$12,417	$118,307	$106,128	$12,417	$118,546	$239	0.2%	$239	0.2%	5
6	Large General Service >= 1,000 kW	48	182	6,123,426	$435,177	$16,877	$452,053	$436,218	$16,877	$453,094	$1,041	0.2%	$1,041	0.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	32,263	$4,320	$88	$4,409	$4,326	$88	$4,414	$5	0.2%	$5	0.2%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,219	$111	$1,329	$1,219	$111	$1,329	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	7,913	237,644	$30,384	($2,916)	$27,468	$30,427	($2,916)	$27,511	$43	0.1%	$43	0.2%	9
10	**Total Commercial & Industrial**		104,874	10,968,792	$912,589	$49,663	$962,251	$914,513	$49,663	$964,176	$1,924	0.2%	$1,924	0.2%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,703	8,050	$788	$242	$1,031	$789	$242	$1,031	$0	0.0%	$0	0.0%	11
12	Street Lighting Service Comp. Owned	51	1,121	21,063	$2,715	$933	$3,648	$2,716	$933	$3,649	$1	0.0%	$1	0.0%	12
13	Street Lighting Service Cust. Owned	53	292	7,519	$392	$221	$613	$393	$221	$614	$1	0.3%	$1	0.2%	13
14	Recreational Field Lighting	54	100	1,394	$88	$52	$140	$88	$52	$140	$0	0.2%	$0	0.1%	14
15	**Total Public Street Lighting**		7,215	38,026	$3,983	$1,448	$5,431	$3,985	$1,448	$5,433	$3	0.1%	$3	0.1%	15
16	**Subtotal**		652,131	16,835,899	$1,654,120	$60,087	$1,714,207	$1,657,213	$60,087	$1,717,300	$3,093	0.2%	$3,093	0.2%	16
17	Emplolyee Discount		*975*	*13,481*	($419)	($5)	($424)	($420)	($5)	($425)	($1)		($1)		17
17	Paperless Credit				($2,072)		($2,072)	($2,072)		($2,072)	$0		$0		17
18	AGA Revenue				$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization				$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**		652,131	16,835,899	$1,656,916	$60,082	$1,716,998	$1,660,008	$60,082	$1,720,091	$3,092	0.2%	$3,092	0.2%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), Low Income Discount Cost Recovery Adjustment (Sch. 92), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Docket No. UE 419
Exhibit PAC/504
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Monthly Billing Comparisons

March 2023

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

kWh	Monthly Billing* Present Price	Proposed Price	Difference	Percent Difference
100	$24.02	$24.04	$0.02	0.08%
200	$35.49	$35.53	$0.04	0.11%
300	$46.97	$47.03	$0.06	0.13%
400	$58.45	$58.53	$0.08	0.14%
500	$69.92	$70.02	$0.10	0.14%
600	$81.40	$81.52	$0.12	0.15%
700	$92.88	$93.02	$0.14	0.15%
800	$104.36	$104.52	$0.16	0.15%
900	**$115.83**	**$116.01**	**$0.18**	**0.16%**
1,000	$127.30	$127.51	$0.21	0.16%
1,100	$138.78	$139.01	$0.23	0.17%
1,200	$150.25	$150.50	$0.25	0.17%
1,300	$161.73	$162.00	$0.27	0.17%
1,400	$173.21	$173.49	$0.28	0.16%
1,500	$184.68	$184.98	$0.30	0.16%
1,600	$196.16	$196.48	$0.32	0.16%
2,000	$242.06	$242.47	$0.41	0.17%
3,000	$366.55	$367.16	$0.61	0.17%
4,000	$491.04	$491.86	$0.82	0.17%
5,000	$615.53	$616.55	$1.02	0.17%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Multi-Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.98	$21.00	$0.02	0.10%
200	$32.45	$32.49	$0.04	0.12%
300	$43.93	$43.99	$0.06	0.14%
400	$55.41	$55.49	$0.08	0.14%
500	$66.87	$66.98	$0.11	0.16%
600	$78.35	$78.48	$0.13	0.17%
700	$89.83	$89.97	$0.14	0.16%
800	$101.31	$101.47	$0.16	0.16%
900	$112.78	$112.96	$0.18	0.16%
1,000	$124.26	$124.46	$0.20	0.16%
1,100	$135.74	$135.96	$0.22	0.16%
1,200	$147.21	$147.45	$0.24	0.16%
1,300	$158.69	$158.95	$0.26	0.16%
1,400	$170.17	$170.45	$0.28	0.16%
1,500	$181.63	$181.94	$0.31	0.17%
1,600	$193.11	$193.44	$0.33	0.17%
2,000	$239.02	$239.43	$0.41	0.17%
3,000	$363.51	$364.12	$0.61	0.17%
4,000	$488.00	$488.81	$0.81	0.17%
5,000	$612.49	$613.50	$1.01	0.16%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$78	$87	$79	$87	0.13%	0.10%
	750	$109	$118	$109	$118	0.14%	0.13%
	1,000	$139	$148	$140	$148	0.14%	0.13%
	1,500	$200	$209	$201	$209	0.14%	0.13%
10	1,000	$139	$148	$140	$148	0.14%	0.13%
	2,000	$261	$270	$261	$270	0.15%	0.14%
	3,000	$383	$392	$383	$392	0.15%	0.15%
	4,000	$489	$497	$489	$498	0.16%	0.15%
20	4,000	$524	$533	$525	$534	0.15%	0.15%
	6,000	$736	$745	$737	$746	0.16%	0.16%
	8,000	$948	$957	$949	$958	0.16%	0.16%
	10,000	$1,160	$1,168	$1,161	$1,170	0.17%	0.17%
30	9,000	$1,125	$1,134	$1,127	$1,136	0.15%	0.15%
	12,000	$1,443	$1,451	$1,445	$1,454	0.16%	0.16%
	15,000	$1,760	$1,769	$1,763	$1,772	0.16%	0.16%
	18,000	$2,078	$2,086	$2,081	$2,090	0.17%	0.17%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$77	$86	$77	$86	0.12%	0.10%
	750	$107	$116	$107	$116	0.14%	0.12%
	1,000	$137	$146	$137	$146	0.15%	0.14%
	1,500	$197	$205	$197	$206	0.15%	0.14%
10	1,000	$137	$146	$137	$146	0.15%	0.14%
	2,000	$256	$265	$257	$266	0.15%	0.14%
	3,000	$376	$385	$376	$385	0.15%	0.15%
	4,000	$480	$488	$481	$489	0.16%	0.16%
20	4,000	$515	$524	$516	$525	0.15%	0.15%
	6,000	$723	$732	$724	$733	0.16%	0.16%
	8,000	$931	$939	$932	$941	0.17%	0.16%
	10,000	$1,139	$1,147	$1,141	$1,149	0.17%	0.17%
30	9,000	$1,106	$1,114	$1,107	$1,116	0.16%	0.16%
	12,000	$1,417	$1,426	$1,420	$1,428	0.16%	0.16%
	15,000	$1,729	$1,738	$1,732	$1,741	0.17%	0.17%
	18,000	$2,041	$2,049	$2,044	$2,053	0.17%	0.17%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$366	$366	0.15%
	4,500	$485	$486	0.17%
	7,500	$724	$725	0.19%
31	6,200	$737	$738	0.15%
	9,300	$983	$985	0.17%
	15,500	$1,477	$1,480	0.19%
40	8,000	$945	$947	0.15%
	12,000	$1,264	$1,266	0.17%
	20,000	$1,900	$1,904	0.19%
60	12,000	$1,410	$1,412	0.16%
	18,000	$1,887	$1,891	0.17%
	30,000	$2,842	$2,848	0.19%
80	16,000	$1,868	$1,871	0.16%
	24,000	$2,505	$2,509	0.18%
	40,000	$3,778	$3,786	0.19%
100	20,000	$2,327	$2,330	0.16%
	30,000	$3,122	$3,128	0.18%
	50,000	$4,714	$4,723	0.19%
200	40,000	$4,595	$4,603	0.16%
	60,000	$6,187	$6,198	0.18%
	100,000	$9,370	$9,389	0.19%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$448	$448	0.18%
	6,000	$560	$561	0.20%
	7,500	$671	$673	0.20%
31	9,300	$906	$907	0.19%
	12,400	$1,137	$1,139	0.20%
	15,500	$1,368	$1,371	0.21%
40	12,000	$1,163	$1,165	0.19%
	16,000	$1,462	$1,465	0.20%
	20,000	$1,760	$1,764	0.21%
60	18,000	$1,737	$1,740	0.19%
	24,000	$2,185	$2,189	0.20%
	30,000	$2,632	$2,638	0.21%
80	24,000	$2,305	$2,310	0.19%
	32,000	$2,902	$2,908	0.20%
	40,000	$3,499	$3,506	0.21%
100	30,000	$2,874	$2,879	0.19%
	40,000	$3,620	$3,627	0.20%
	50,000	$4,366	$4,375	0.21%
200	60,000	$5,696	$5,707	0.19%
	80,000	$7,188	$7,203	0.20%
	100,000	$8,680	$8,698	0.21%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$2,795	$2,799	0.13%
	30,000	$3,363	$3,369	0.16%
	50,000	$4,500	$4,509	0.20%
200	40,000	$5,148	$5,155	0.14%
	60,000	$6,284	$6,295	0.17%
	100,000	$8,557	$8,576	0.21%
300	60,000	$7,658	$7,668	0.14%
	90,000	$9,362	$9,379	0.18%
	150,000	$12,772	$12,800	0.21%
400	80,000	$10,054	$10,068	0.15%
	120,000	$12,327	$12,349	0.18%
	200,000	$16,873	$16,910	0.22%
500	100,000	$12,482	$12,501	0.15%
	150,000	$15,324	$15,351	0.18%
	250,000	$21,007	$21,052	0.22%
600	120,000	$14,911	$14,933	0.15%
	180,000	$18,321	$18,354	0.18%
	300,000	$25,140	$25,195	0.22%
800	160,000	$19,768	$19,798	0.15%
	240,000	$24,315	$24,359	0.18%
	400,000	$33,407	$33,480	0.22%
1000	200,000	$24,626	$24,662	0.15%
	300,000	$30,309	$30,363	0.18%
	500,000	$41,647	$41,738	0.22%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,318	$3,323	0.17%
	40,000	$3,882	$3,889	0.19%
	50,000	$4,446	$4,455	0.21%
200	60,000	$6,220	$6,231	0.18%
	80,000	$7,349	$7,363	0.20%
	100,000	$8,477	$8,495	0.22%
300	90,000	$9,265	$9,281	0.18%
	120,000	$10,958	$10,980	0.20%
	150,000	$12,650	$12,678	0.22%
400	120,000	$12,237	$12,258	0.18%
	160,000	$14,493	$14,523	0.20%
	200,000	$16,750	$16,787	0.22%
500	150,000	$15,210	$15,238	0.18%
	200,000	$18,031	$18,068	0.20%
	250,000	$20,852	$20,898	0.22%
600	180,000	$18,184	$18,217	0.18%
	240,000	$21,569	$21,613	0.20%
	300,000	$24,954	$25,009	0.22%
800	240,000	$24,131	$24,175	0.18%
	320,000	$28,645	$28,703	0.20%
	400,000	$33,159	$33,232	0.22%
1000	300,000	$30,078	$30,133	0.18%
	400,000	$35,721	$35,794	0.20%
	500,000	$41,335	$41,427	0.22%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	2,000	$200	$174	$200	$174	0.19%	0.00%
	3,000	$300	$174	$300	$174	0.18%	0.00%
	5,000	$499	$174	$500	$174	0.18%	0.00%
Three Phase							
20	4,000	$400	$347	$400	$347	0.18%	0.00%
	6,000	$599	$347	$600	$347	0.18%	0.00%
	10,000	$999	$347	$1,001	$347	0.18%	0.00%
100	20,000	$1,998	$1,604	$2,001	$1,604	0.18%	0.00%
	30,000	$2,996	$1,604	$3,002	$1,604	0.18%	0.00%
	50,000	$4,994	$1,604	$5,003	$1,604	0.18%	0.00%
300	60,000	$5,993	$3,980	$6,004	$3,980	0.18%	0.00%
	90,000	$8,989	$3,980	$9,006	$3,980	0.18%	0.00%
	150,000	$14,982	$3,980	$15,009	$3,980	0.18%	0.00%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	3,000	$294	$172	$295	$172	0.19%	0.00%
	4,000	$392	$172	$393	$172	0.19%	0.00%
	5,000	$490	$172	$491	$172	0.19%	0.00%
Three Phase							
20	6,000	$589	$343	$590	$343	0.19%	0.00%
	8,000	$785	$343	$786	$343	0.19%	0.00%
	10,000	$981	$343	$983	$343	0.19%	0.00%
100	30,000	$2,943	$1,573	$2,948	$1,573	0.19%	0.00%
	40,000	$3,924	$1,573	$3,931	$1,573	0.19%	0.00%
	50,000	$4,905	$1,573	$4,914	$1,573	0.19%	0.00%
300	90,000	$8,828	$3,909	$8,845	$3,909	0.19%	0.00%
	120,000	$11,771	$3,909	$11,793	$3,909	0.19%	0.00%
	150,000	$14,714	$3,909	$14,741	$3,909	0.19%	0.00%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$29,758	$29,809	0.17%
	500,000	$42,017	$42,103	0.21%
	700,000	$54,020	$54,141	0.22%
2,000	600,000	$58,757	$58,861	0.18%
	1,000,000	$80,935	$81,111	0.22%
	1,400,000	$104,018	$104,265	0.24%
6,000	1,800,000	$160,846	$161,163	0.20%
	3,000,000	$230,095	$230,624	0.23%
	4,200,000	$299,344	$300,084	0.25%
12,000	3,600,000	$319,350	$319,984	0.20%
	6,000,000	$457,848	$458,905	0.23%
	8,400,000	$596,346	$597,826	0.25%

Notes:

On-Peak kWh	38.11%
Off-Peak kWh	61.89%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	300,000	$28,147	$28,199	0.18%
	500,000	$40,172	$40,258	0.21%
	700,000	$51,940	$52,061	0.23%
2,000	600,000	$55,546	$55,650	0.19%
	1,000,000	$77,175	$77,352	0.23%
	1,400,000	$99,779	$100,026	0.25%
6,000	1,800,000	$157,538	$157,855	0.20%
	3,000,000	$225,349	$225,878	0.23%
	4,200,000	$293,160	$293,900	0.25%
12,000	3,600,000	$312,765	$313,400	0.20%
	6,000,000	$448,387	$449,445	0.24%
	8,400,000	$584,009	$585,490	0.25%

Notes:

On-Peak kWh	37.88%
Off-Peak kWh	62.12%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$38,289	$38,375	0.23%
	700,000	$49,620	$49,741	0.24%
2,000	1,000,000	$73,182	$73,358	0.24%
	1,400,000	$94,893	$95,140	0.26%
6,000	3,000,000	$216,614	$217,143	0.24%
	4,200,000	$281,749	$282,489	0.26%
12,000	6,000,000	$430,659	$431,717	0.25%
	8,400,000	$560,928	$562,408	0.26%

Notes:

On-Peak kWh	37.63%
Off-Peak kWh	62.37%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of **PacifiCorp's Schedule 202—PacifiCorp's 2024 Renewable Adjustment Clause** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List UE 399

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Dated this 29th day of March 2023.

Alisha Till

Alisha Till
Paralegal, McDowell Rackner Gibson PC