CASE: UE 463
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

May 14, 2026

Q. Please state your name, occupation, and business address.

A. My name is Bret Stevens. I am a Senior Economist employed in the Energy Program of the Public Utility Commission of Oregon (OPUC or Commission). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. In this testimony I will cover multiple topics including the risks associated with large load customers, PacifiCorp's Large Energy Use Facility Agreements, a new data center rate class, PacifiCorp's cost of service study, and HB 2021 compliance concerns associated with LEUFs.

Q. Did you prepare any exhibits for this docket?

A. Yes. Exhibit Staff/102 displays relevant non-confidential data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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Issue 1. Large Energy Use Facility Agreements 29
Issue 2. Cost of Service 47
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OVERVIEW

Q. Please provide a brief procedural history of this case.

A. On October 2, 2025, PacifCorp filed Advice No. 25-015, proposing creation of a new schedule, Schedule 401, and modification of Schedules 47, 48, and 90. The new Schedule 401 would require customers who fit the Large Energy Use Facility (LEUF) description to sign contracts with special provisions which are compliant with the POWER Act. The filing also modified Schedules 47 and 48 to specify that only customers that are not required to take service under Schedule 401 are allowed to take service under those schedules.

On October 31, 2025, Amazon Data Services (ADS) filed a motion to suspend the filing and initiate a contested case proceeding. On November 17, 2025, the Alliance of Western Energy Consumers (AWEC) filed a motion to dismiss PacifiCorp's filing. On December 16, 2025, the Commission opened a contested case, UE 463, with Order No. 25-516.

Q. Please provide background on the POWER Act.

A. On June 16, 2025, the POWER Act was signed into law, which provides requirements regarding electric service for customers over 20 MW that are primarily engaged in providing a service under code 518210 of the North American Industry Classification System (NAICS). The POWER Act has two primary requirements. First, Section 5 requires that LEUFs enter into contracts with utilities that covers the provision of the electricity service, including transmission, distribution, energy, capacity or ancillary electricity services. Further, Section 2 requires the Commission to establish a rate class for large

load customers that is separate and distinct from classifications of service for other commercial or industrial retail electricity customers.

Q. How is the 518210 NAICS code defined?

A. The NAICS Association describes code 518210 businesses as:

> primarily engaged in providing infrastructure for hosting or data processing services. These establishments may provide specialized hosting activities, such as Web hosting, streaming services, or application hosting (except software publishing), or they may provide general time-share mainframe facilities to clients. Data processing establishments provide complete processing and specialized reports from data supplied by clients or provide automated data processing and data entry services.[1]

Q. What direction does the POWER Act give in terms of this new rate class?

A. The POWER Act provides:

> The Public Utility Commission shall provide for a classification of service under ORS 757.230 for retail electricity consumers that are large energy use facilities. The classification of service must be separate and distinct from classifications of service for other commercial or industrial retail electricity consumers and have its own tariff schedule.[2]
>
> Further, this schedule must:
>
> - Allocate the costs of serving the class of retail electricity consumers that are large energy use facilities to the class in a manner that is equal or proportional to the costs of serving the class; or [d]irectly assign the costs of serving a retail electricity consumer that is a large energy use facility to the retail electricity consumer;
>
> - Mitigate the risk of [o]ther classes of retail electricity consumers paying unwarranted costs; and [s]hifting the costs, in an unwarranted manner, of serving a retail electricity consumer that is a large energy

[1] United States Census Bureau, 2022 North American Classification System, available at: https://www.census.gov/naics/?input=518210&year=2022&details=518210.

[2] Oregon Laws 2025, Chapter 323 (HB 3546, Adopted, Section 2) (Sections 2 and 5 of the 2025 Act are added to and made a part of ORS Chapter 757).

use facility to other classes of retail electricity consumers, including costs of an electric company to meet load requirements resulting from the provision of electricity service to a retail electricity consumer that is a large energy use facility.[3]

In deciding whether to approve a proposed tariff the Commission shall consider whether the rates:

- Result in, or have the potential to result in, increased costs or unwarranted risk to other retail electricity consumers;
- Provide for equitable contributions to grid efficiency, reliability and resiliency benefits;
- Impede the electric company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy;
- Allow for procurement of our contracts for generation resources that support the electric company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy; and
- Meet any other conditions the commission may require in the public interest.[4]

Lastly, the POWER Act requires that large energy use facility customers execute a contract with the utility providing electricity service.[5] These contracts must:

- Be consistent with the criteria listed in the rest of the POWER Act;
- Specify the duration of the contract and be no shorter than 10 years;
- Specify the date or estimated date that the electric company will begin to provide electricity service to the large energy use facility customer;

[3] *Id.*
[4] *Id.* at Section 3.
[5] *Id.* at Section 5.

- Obligate the large energy use facility customer to pay a Commission-determined minimum amount or percentage based on the retail electricity consumer's projected electricity load; and

- Meet any other conditions the Commission may require in the public interest.[6]

The contracts may also include a charge for excess demand for the electricity services the electric company is contracted to provide that is in addition to the tariff schedule.[7]

Q. Does the POWER Act specify which customers must be served under the tariff?

A. Yes. The POWER Act states that the customer contract provision is applicable to all LEUF customers that enter into a contract for electricity service with an electric company on or after the effective date of this 2025 Act; or enter into a contract for electricity service with an electric company before the effective date of this 2025 Act, if the provision of electricity service requires the electric company to make significant investments or incur costs after the effective date of this 2025 Act that could result in increased costs or risks to other retail electricity consumers of the electric company.

Q. Has the Commission ruled on any other cases with similar issues to UE 463?

A. Yes. The Commission addressed PacifiCorp large load issues in two PacifiCorp filings, Docket Nos. UE 424 and UE 433. Further, the Commission

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6 *Id.*
7 *Id.* at section 5(1)(B).

recently issued an order in a Portland General Electric (PGE) investigation into large load issues - UM 2377.

Q. Please summarize UE 424.

A. In Docket No. UE 424, PacifiCorp testified the Company is increasingly receiving requests from large customers that typically require a dedicated substation, new transmission and distribution lines, or other facility upgrades. The Company proposed changes to its rule regarding line extensions for customers receiving loads above 25,000 kilowatts, Oregon Rule 13. The Commission approved the Company's proposed modifications to Oregon Rule 13 limiting the Line Extension Allowance to the cost of metering equipment necessary to measure the customers' usage.[8]

Q. Please summarize the large load related issues covered in UE 433.

A. UE 433 was PacifiCorp's most recently completed General Rate Case (GRC) and concluded prior to the passage of the POWER Act. PacifiCorp proposed changes regarding how the Company manages large load requests. The Company explained that the size of new large customers' load requests distinguishes them from other customers' requests, making them riskier from a cost-shifting perspective.[9] PacifiCorp proposed changes regarding the adoption of a capacity reservation charge and an excess demand charge.[10]

Q. What was the Commission's response to PacifiCorp's proposal?

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8 *In the matter of PacifiCorp, Revision of Rule 13 Line Extension Policy,* Docket No. UE 424, Order No. 23-472.

9 *In the Matter of PacifiCorp, Request for a General Rate Revision,* Docket No. UE 433, Order No. 24-447 at 92.

10 Docket No. UE 433, PAC/1800, DeMers/5.

A. The Commission agreed that a capacity reservation charge and an excess demand charge are appropriate solutions to address the risks identified by the company. The Commission adopted a capacity reservation charge of $3.68 per kW that applies to any customer whose peak demand falls more than 10 percent below their reserved capacity and an excess demand charge of three times the capacity reservation charge for any exceedance of the reserved capacity.[11]

Q. Did PacifiCorp's GRC UE 433 include any testimony regarding Contributions in Aid of Construction (CIAC)?

A. Yes. AWEC proposed removing the cost of capital associated with distribution and local transmission facilities for customers over 25 MW and for transmission customers. AWEC explained that this was to ensure such customers are not charged in rates for the return on and return of substation and transmission assets they paid for.

Q. What was PacifiCorp's response to AWEC's proposal?

A. PacifiCorp testified that the only large new primary voltage customer with a load over 25 MW had a service agreement in place prior to the Rule 13 change and had received a line extension allowance, thus no adjustment was needed at that time.

Q. Did the Commission issue a ruling regarding AWEC's proposal for CIAC?

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[11] *In the Matter of PacifiCorp, Request for a General Rate Revision,* Docket No. UE 433, Order No. 24-447 at 98.

A. Yes. The Commission ruled that there are no primary voltage customers over 25 MW in the forecast period that were subject to Rule 13, as revised, and declined to require an adjustment at that time.[12]

Q. Have there been any other dockets that have dealt with the implementation of the Power Act?

A. Yes. On March 15, 2025, the Commission opened UM 2377 which investigated PGE's marginal cost treatment and contract terms for large customers. While the POWER Act was passed after the start of UM 2377, this docket was effectively used to implement the POWER Act while also addressing other large load issues.

Q. Please summarize the Commission's findings in UM 2377.

A. In Order No. 26-154, the Commission made decisions on a myriad of issues relevant to this case. The most pertinent of these decisions will be outlined here, but this description should not be seen as exhaustive.

- **Minimum Contract Lengths:** Scale with customer size. Minimum 10 years for customers with an allocated capacity of 20 MW and increase in length by one year for each 10 MW increment in allocated capacity up to 30 years for customers 220 MW and larger.[13]
- **Minimum Demand Charges:** 90 percent minimum transmission demand (MTD) and minimum generation demand (MGD) charges.[14]

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12 *Id.* at 125.
13 *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 35-37.
14 *Id.* at 38-44.

- **Flat Distribution Charge:** Flat distribution charges based on the customer's incremental distribution asset costs paired with a class-wide distribution O&M charge.[15]
- **Early Exit Fee:** If customers exit the system before the end of their contract they will be subject to an Exit Fee. The Exit Fee is calculated as the sum of the net book value of the incremental distribution assets caused by the customer, and the greater of (a) the remaining MTD and MGD charges for the remainder of the contract, or (b) three years' worth of MTD and MGD charges at the highest allocated system capacity during the contract.[16]
- **Direct Assignment of Assets:** Distribution assets should be directly assigned to the customer causing the incremental investments. Transmission assets may be directly assigned if they are built to exclusively serve that customer.[17]
- **Special Contracts:** Approved the use of special contracts for generation resources. Contracts will be considered on a case-by-case basis. Filings should contain a comparison of the resource with cost-of-service procurements in the RFP, an analysis of whether the resource meets HB 2021 emissions targets, advances reliability, and

[15] *Id.*
[16] *Id.* at 48-52.
[17] *Id.* at 30-32.

meets Resource Adequacy (RA) obligations; and a demonstration that the contract meets the requirements of section 5 of the POWER Act.[18]

- **Peak Growth Modifier:** Adopted the Peak Growth Modifier (PGM) to spread the cost of growth-related shared assets. Adopted a framework for identification of growth-related assets and methodology for spreading revenue requirement for these assets in a way that is commensurate with recent class-level load growth.[19]
- **Energy Growth Modifier:** Allowed the use of the Energy Growth Modifier in PGE's 2027 AUT. Noted that further consideration is required for use in future AUT filings as there are concerns that the proposal as presented in UM 2377 would not accurately reflect allocations over multiple years. The Commission also directed PGE to contemplate how incremental data center costs would be spread in the PCAM.[20]
- **Queue for Large Load Customers:** Customers will not be served until a reliable plan of service can be established that matches resources to the load's capacity scale up plan. Customers are able to move up in the queue if an HB 2021 compliant plan of service is developed. Such a plan may include the customer's own non-emitting resources - energy and capacity - in a Commission-approved special

[18] *Id.* at 58-60.
[19] *Id.* at 16-23.
[20] *Id.* at 29-30.

contract. It may also include use of direct access, load flexibility, or customer funded load reductions in PGE's service territory.[21]

Q. How does Staff view the relationship between UM 2377 and UE 463?

A. The Commission's decisions in UM 2377 will strongly inform Staff's analysis and recommendations in this docket. As discussed in the next section, the risks of large loads are similar for both companies, and the POWER Act applies equally to each of them. However, Staff is not proposing that all decisions made in UM 2377 be directly applied in this case. There are utility specific contexts that will lead to different optimal solutions. As such, Staff's recommendations in this case will rely on the Commission's decisions in UM 2377 where applicable, and provide targeted utility-specific solutions where Staff feels that it is more appropriate.

Q. What are some of the rationales for the differential treatment between PGE and PacifiCorp?

A. Staff recognizes that the locations where LEUF growth may be happening between PGE and PacifiCorp's service territories may differ. Much of PGE's service territory is urban, whereas PacifiCorp serves more rural areas. PGE's urban service territory and more condensed siting of LEUFs leads to difficulty in directly assigning certain infrastructure improvements, whereas PacifiCorp's service territory makes the identification of customer induced costs easier to isolate.

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[21] *Id.* at 62-65.

In general, Staff is amenable to the direct assignment of customer caused costs when these costs are easily attributable to a single customer as it reduces intra- and inter-class cross subsidization concerns. However, Staff does not believe that this difference between the service territories makes PacifiCorp's proposal for bespoke customer contracts with a limited framework reasonable - especially in comparison to the robust and transparent framework recently adopted in UM 2377.

Q. Please provide a brief description of PacifiCorp's proposal in this docket.

A. PacifiCorp is proposing to create a new customer class of new LEUFs called Schedule 401. This new schedule would require new LEUFs to enter into a Large Energy Use Facility Agreement (Agreement) with the company that specifies the terms and conditions of service, including the applicable monthly charges prior to receiving service. Each of these Agreements would be bespoke and negotiated between the customer and Company. Once an Agreement is signed, PacifiCorp proposes that the Commission would have 60 days to approve or reject the Agreement.

The only criteria regarding the substance of the Agreements provided in the tariff are given below. Notably, each of these conditions are listed in the POWER Act. As such, PacifiCorp's only proposed criteria for LEUF Agreements are those already required by statute.

(a) The Large Energy Use Facility Agreement shall not result in, or have the potential to result in, increased costs or unwarranted risk to other customers.

(b) The Large Energy Use Facility Agreement shall provide for equitable contributions to grid efficiency, reliability and resiliency benefits.

(c) The Large Energy Use Facility Agreement shall not impede the Company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy.

(d) The Large Energy Use Facility Agreement shall allow for procurement of or contracts for generation resources that support the Company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy.

(e) The Large Energy Use Facility Agreement shall specify a term that is 10 years or more.

(f) The Large Energy Use Facility Agreement shall specify the date or estimated date that the Company will begin to provide service to the Customer.

(g) The Large Energy Use Facility Agreement shall obligate the Customer to pay a minimum amount or percentage based on the Customer's projected usage for the electricity services the Company is contracted to provide for the duration of the contract.

Q. Does Staff support PacifiCorp's proposal in this docket?

A. No. Staff has several concerns with PacifiCorp's proposal. These concerns can largely be broken down into four categories: discrimination risk, administrative burden, transparency, and cost assignment. Staff's discrimination concerns are largely centered on the concept that PacifiCorp will be negotiating all contract terms including: contract length, penalties and fees, minimum payments, the cost allocation of shared resources, on a case-by-case basis with each customer.

Staff finds this concerning as this will lead to a complicated contract, and thus contract review process, particularly when determining if contract terms are both fair to the customer, other customers in the LEUF class, and other customer classes. This sets up a paradigm in which different mechanisms or standards can be used to allocate the same cost categories to different LEUFs. This flexibility may be appealing to the Company, and potentially some customers, but can make the comparison of contracts extremely difficult. This is particularly true over time. To ensure that the utility is not unduly discriminating against future or existing customers, the Commission would have to compare any new contracts to all existing contracts on an indefinite basis. This places an unreasonable burden on the Commission. Lastly, all of these concerns are compounded by PacifiCorp's proposed 60 day review timeline. This proposed review period is less than is given for many standard advice filings, while likely requiring much more dedicated Staff attention.

One way that these discrimination concerns could be assuaged is by transparency in the contracting process. Although, while Staff and the Commission will have access to these contract terms, it is unlikely that all interested parties, including existing and prospective LEUFs, will be able to access the full set of contract terms as many of the parameters will likely be considered sensitive to competitors. This lack of transparency of contract terms to other customers, and the public, is particularly problematic in this space given the amount of capital and resources that may be dedicated to serving LEUFs. In a recent paper, Martin & Peskoe describe the challenges with special contract review as:

> Detecting wealth transfers from ratepayers to utility shareholders and Big Tech companies is particularly challenging because utilities ask PUCs for confidential treatment of their contracts with data centers, which limits scrutiny of utilities' proposed deals and narrows the scope of regulators' options when they consider utilities' prices and terms.[22]

While Commission review will certainly serve as a valuable tool against discrimination and cross subsidization, input from stakeholders is essential in any Commission process. Staff's recommendations in this case serve to create an open forum for the discussion of contract terms so that contract review largely is centered around defining customer-caused costs.

[22] Martin, E & Peskoe, A. (2025), *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power* [White paper]. Harvard Law School Environmental & Energy Law Program. eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf.

Staff is also concerned that no cost-of-service option is offered to LEUFs, a practice which differs from all other customer classes. While the POWER Act requires customer contracts and allows for special contracts to be used, it does not require the use of special contracts nor force the Commission to accept proposals that only include a special contract.[23] As a matter of policy, Staff finds the combination of a cost of service option with the option of special contracts to be a preferrable approach to LEUF load growth. This approach provides transparency around the allocation of shared assets and safeguards for other customers while allowing for customer-specific costs to be directly assigned to LEUFs.

Lastly, Staff is concerned about cost assignment of shared resources under PacifiCorp's proposal. PacifiCorp has not provided any concrete proposal for how these bespoke special contacts would allocate costs associated with shared resources. Staff does not support the adoption of a system that would allocate the costs of shared system resources via ad hoc negotiated mechanisms that can vary from one contract to another. This paradigm does not ensure fair treatment to either the LEUFs or other customer classes and again places unreasonable stress on the contract review process.

Q. Has PacifiCorp presented overarching principles or favored mechanisms that are not listed in the filing?

A. No. Other than the legal requirements from the POWER Act, PacifiCorp has not provided any preferred mechanisms that would guarantee compliance

[23] Oregon Laws 2025, Chapter 323 (HB 3546, Adopted, Section 5).

with the POWER Act or any other policy goals. Staff asked multiple data requests regarding the substance of future contacts, all of which were answered with ambiguity.[24] The imprecision of PacifiCorp's current proposal is concerning especially in the context of UM 2377. In UM 2377, a robust record was developed, and was necessary, for the determination of concrete mechanisms and their parameterization to ensure that the directives given by the POWER Act were met. The ad hoc nature of the PacifiCorp's proposal in this case does not give Staff confidence that the criteria laid out by the POWER Act will be met, at least without significant Commission review and/or intervention.

Q. Is Staff opposed to any use of special contracts for LEUFs?

A. Not entirely. Staff is opposed to the use of a special contract to assign *all* costs, both direct assigned and not, to *every* LEUF customer. Staff is open to presenting LEUFs with the option of a special contract for generation resources – particularly with the upside of faster interconnection. Staff will discuss this further later in this testimony.

Q. Does Staff have an alternative proposal?

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[24] PacifiCorp Response to Staff DR 8
PacifiCorp Response to Staff DR 10
PacifiCorp Response to Staff DR 11
PacifiCorp Response to Staff DR 12
PacifiCorp Response to Staff DR 13
PacifiCorp Response to Staff DR 14
PacifiCorp Response to Staff DR 16
PacifiCorp Response to Staff DR 17
PacifiCorp Response to Staff DR 18
PacifiCorp Response to Staff DR 19
PacifiCorp Response to Staff DR 20
PacifiCorp Response to Staff DR 24

A. Yes.

Q. Please provide a high-level summary of Staff's recommendation.

A. Staff recommends rejecting PacifiCorp's filing and adopting Staff's alternative proposals for the POWER Act's implementation. Staff proposes to standardize many aspects of customer contracts, create a stated rate and standard methodology for the allocation of shared system costs called Schedule 49, and to create a generation queue to ensure that LEUFs do not impede HB 2021 compliance. This approach largely mirrors that adopted in UM 2377. At this time, Staff sees a limited set of cases where the recent Commission decisions in Order 26-154 could not also be applied in this case. The differences Staff has identified are largely centered around the characteristics of each company's service territory, as discussed earlier. However, the risks imposed by LEUFs are similar for both utilities and the tools for mitigating these risks are reasonably applicable to both utilities. Further, the framework developed in UM 2377 alleviates the risk of discrimination, uncertainty, and administrative burden concerns Staff has with PacifiCorp's proposal.

The standardization of customer contracts and the allocation of shared system costs is crucial for minimizing the risk of discrimination, reducing the administrative burden of contract review, and can reduce speculative load requests. Further, Staff's proposed generation queue for LEUFs ensures that LEUFs do not impede HB 2021 compliance, as directed by the POWER Act.[25] A summary of Staff's positions are below.

[25] Oregon Laws 2025, Chapter 323 (HB 3546, Adopted, Section 2).

Table 1. Summary of Staff's Positions

Issue	Staff Proposal
Issue 1. Large Energy Use Facility Agreements	
1.A. Agreement Lengths	• Adopt UM 2377 resolution to have contract lengths scale with customer size. • Minimum contract length of 10 years for renewed Agreements.
1.B Reserved Capacity	• Negotiated in customer contract.
1.C Load Ramps	• Only allow load ramping provisions if caused by utility construction time.
1.D Site Aggregation	• Treat capacity requests as one site if they are within 2,500 feet from each other or connected to the same substation and have similar ownership. • If customers have similar ownership and are located anywhere in PacifiCorp's Oregon service territory, their capacity requests would be aggregated for the purposes of qualifying as a LEUF, minimum generation demand, the exit fee, and the exceedance penalty.
1.E Customer-Caused Distribution Costs	• Direct assignment, customer pays revenue requirement of associated assets.
1.F Direct Assignment of Generation Assets	• Special contracts are optional, but not required. • Special contracts must address certain issues to be considered.
1.G Direct Assignment of Transmission Assets	• Transmission assets that serve a single customer may be direct assigned. • Regional transmission upgrades may be directly assigned if sufficient evidence is presented.
1.H Flexibility	• PacifiCorp should pursue development of a uniform flexibility framework. • Flexibility framework should address Staff principles.
1.I Credit Requirements	• Adopt UM 2377 requirements of senior long-term debt rating of A- (S&P) or A3 (Moody's). If a customer cannot meet these requirements, the applicant would need a letter of credit or guarantee from a credit worthy parent.

	• Credit requirements stated in tariff and uniform.
1.J Minimum Demand Charges	• 90 percent Minimum Demands charges. • Exempt LEUFs from Capacity Reservation Charge.
1.K Exceedance Penalty	• Exceedance penalty equal to 4 times transmission rate and 1.5 times generation rate.
1.L Exit Fee	• Make the Exit Fee for LEUF customers equal to the sum of minimum demand charges for the remainder of the contract length and the net book value of the incremental assets directly assigned to the customer. • Make a partial or full refund available to customers if another customer assumes all or a portion of the exiting customer's capacity and cost responsibilities before their contract would have ended.
1.M Contributions in Aid of Construction	• Customers may contribute up to 100% of direct assigned costs.
Issue 2. Cost of Service	
2.A Scope of Cost of Service Rate	• Recovers revenue requirement for shared system resources. • Provides uniform cost of service rate for all LEUF customers. • Total customer bills would be augmented by contract specific charges related to direct assigned assets. • Does not include distribution costs, as they will all be direct assigned.
2.B Generation Marginal Cost Study	• Shared growth-related assets identified by utility in each GRC and allocated through PGM. • Direct assigned generation assets excluded, costs recovered solely by customers assigned that asset.
2.C Transmission Marginal Cost Study	• Shared growth-related assets identified by utility in each GRC and allocated through PGM. • Direct assigned transmission assets excluded, costs recovered solely by customers assigned that asset.

2.D Net Power Costs	• In TAM, PacifiCorp will calculate counterfactual power costs given net LEUF load and assign incremental costs to LEUF class. • PacifiCorp will develop proposal for PCAM.
2.F Schedule 49 Rate Design	• Similar to Schedule 48, accounting for direct assignment of distribution assets.
Issue 3. HB 2021 Compliance	
3.A Generation Queue	• Establish a generation queue to ensure LEUFs do not impede HB 2021 compliance. • Allow customers to move up in queue with special contracts, flexibility agreements, and CIAC.

RISKS OF LARGE LOAD

Q. What cost sharing risks are typically posed by rapid load growth?

A. When load growth is happening quickly across all classes and matches forecasted load growth relatively closely, there are typically no major issues posed other than constraints on capital access for the utility. In fact, load growth has historically been seen as a net positive as you can spread fixed costs of the system across more kWhs. However, when load growth is occurring primarily through a single customer class, there is potential for unfair and significant cost shifting if the marginal costs to serve the high-growth customer segment do not align with the embedded costs used to set rates. This problem can be exacerbated if the load that materializes meaningfully deviates from the forecasted load growth.

Q. Is the load growth caused by large customers, particularly data centers, different than generic load growth?

A. Yes. Since this large and rapid load growth is coming from one industry, there are multiple risks imposed. Staff has generally categorized these as allocative risks, stranded asset risks, and planning risks.

Q. Please discuss the allocative risks Staff has identified.

A. The allocative risks imposed by LEUF growth are largely addressed by the implementation of the POWER Act. Under PacifiCorp's proposal, allocative risks could be addressed, but given the nebulous nature of the proposal, it is difficult to have any certainty of this or to discuss any merit to alternative, but similar, proposals. As such, the discussion here will focus on the

allocative risks faced by LEUF growth under the normal cost-of-service paradigm.

Imagine over the next 2 years LEUF customer load increases by 500 MW while all other classes' load remains flat. In response, PacifiCorp would have to build both new generation and transmission resources to meet this sizable increase in load. Using PacifiCorp's marginal cost study from UE 433, the cost of these new assets would be largely allocated on each class's contribution to peak demand and total energy for generation assets and each class's contribution to peak demand for transmission assets.

If we assume, in this example, the 500 MW increase in large load customers' consumption was paired with an 80 percent load factor the residential class's allocation of fixed generation costs would decrease roughly, from 41 percent to 34 percent.[26] As such, even with their allocations decreasing, residential customers in this example would still be allocated roughly 34 percent of the costs of projects they did not cause. This results in an outcome that seems to strongly deviate from cost causation principles.

To be clear, this example is purely illustrative. PacifiCorp will be adding new resources in the near future for a multitude of reasons including replacing aging assets and meeting state climate goals. Further, by decreasing residential customers' share of peak demand, it would also decrease their

[26] This example is based on data provided in UE 433 and assumes no load growth from any other class.

allocations of older assets. However, complexity of reality does not detract from the fact that if fast load growth is coming from one rate class, other rate classes will be allocated a very large portion of costs they did not cause under PacifiCrorp's current cost allocation methodology.

Q. Is the triggering of new investments the only concern Staff has with PacifiCorp's current cost allocation methodology?

A. No. Staff is also concerned that PacifiCorp's current allocation methodology does not properly account for the off-peak strain large load customers will put on the system.

Customers of this size are typically expected to have high load factors, that is, they are expected to consume a large amount of energy at all hours. This is in comparison to residential customers, for example, who consume most of their energy in the evening and very little overnight.

In the past, PacifiCorp's resource strategy focused on serving afternoon peak with traditional baseload and peaking resources. However, given the assumed lack of demand flexibility and high load factors of new large load customers, more energy will be needed in hours traditionally treated as off-peak in planning and cost-allocation. Serving an influx of large customers with high load factors carries a new level of cost, reliability, and compliance risk for PacifiCorp and its other customers. This issue was highlighted by a recent

Level 3 NERC Alert issued on May 4, 2026, in relation to reliability concerns due to large load interconnections.[27]

These issues are exacerbated by the transition to a decarbonized system under severe infrastructure and market constraints. For example, dispatchable carbon-free resources, such as nuclear or emerging hydrogen technologies, may be needed to satisfy the large consistent load from these customers. These types of resources can carry much higher costs, regulatory barriers, and feasibility issues compared to commercially available least cost, least risk resources to serve more typical load profiles and load growth trajectories. Under PacifiCorp's current cost of service study, none of these off-peak cost or planning impacts are represented.

Q. Does Staff view these allocative risks as a near-term or long-term issue?

A. Both. The assets being built for these customers have long economic lives—up to 60 years. As such, these investments will have implications for long-term planning and rates for many years. It is vital that the allocation of these new costs be addressed in this docket.

Q. Please discuss the definition of a "stranded asset".

A. A stranded asset is one that has prematurely lost value or has turned into a liability. Stranded assets are often discussed in the context of climate

[27] *Essential Action to Industry: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control*. May 4, 2026.North American Electric Reliability Corporation. www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf.

change regulation as certain carbon intensive generation sources may become stranded as regulation and technology improvements phase them out before the end of their economic life. However, in this context Staff is concerned about assets which are primarily built to serve large customers.

Q. What stranded asset risks are posed by rapid large load growth?

A. When large load customers connect to the system, often significant system upgrades are needed to maintain reliable service. These include upgrades to the local transmission network, dedicated distribution assets, and sometimes new generation assets.

There are two ways these assets can become stranded. The most straightforward is the customer leaving the system before the assets have been fully depreciated or reached the end of their economic lives. The distribution infrastructure is the most at risk of becoming stranded in this case as it often cannot be fully repurposed to serve other customers, this is particularly the case for data centers.

The second way these assets can become stranded is in the case that the customer overestimates its needs or its capacity needs change over time, leading to an overbuild of resources. For example, imagine a customer requesting a reserved capacity of 50 MW in an area that can only reliably handle 30 MW of new capacity. As a result, the utility will need to upgrade the local transmission network in order to interconnect the customer. However, if the customer then only consumes 25 MW, far below its requested allocation, the upgrade to the transmission line will be significantly underutilized and the

utility will not recover the anticipated cost of that upgrade from the customer who caused the upgrade. As a result, the costs from this upgrade would be socialized across all customers until more customers connected in the area to use the excess capacity. PacifiCorp's reserved capacity charge adopted in UE 433 is meant to alleviate this issue.

Q. Please discuss the policy risks imposed by rapid large load growth.

A. A pressing policy risk imposed by large load growth is HB 2021 compliance. HB 2021 is an Oregon bill that was passed in 2021 regarding greenhouse gas emission by Oregon utilities. The bill requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers to 80 percent below baseline emissions levels by 2030, 90 percent below baseline emissions levels by 2035, and 100 percent below baseline emissions levels by 2040.[28] HB 2021 also requires that 10 percent of PacifiCorp's aggregate generating capacity come from resources that are smaller than 20 MW.[29]

It is important to note that these requirements are not on a per MWh basis. As such, PacifiCorp is required to decrease its *total* emission to the levels described above. New large load presents a challenge to PacifiCorp's ability to meet these goals as PacifiCorp will have to not only build out new non-emitting generation to meet this growth but will have to do so very quickly. According to the Company's 2025 IRP Update, a large portion of

[28] ORS 469A.410.
[29] ORS 469A.210.

PAC's near-term 2030 resource adequacy need is driven by large-meter loads.[30]

Traditionally, if the procurement of new generation assets lagged behind load growth, a utility would be able to meet new growth with market purchases. However, market purchases are assigned an emissions factor, meaning if PacifiCorp relies on market purchases to meet significant load growth, they will be at risk of not meeting HB 2021's emissions targets as the targets increase. Further, with the potential rapid load growth imposed by large load customers, PacifiCorp's need for small-scale renewable energy projects would grow commensurately—creating additional risk for PacifiCorp's compliance with HB 2021 mandates.

[30] Docket No. LC 85, PacifiCorp's 2025 Integrated Resource Plan Update – Corrected at75 (April 14, 2026).

ISSUE 1. LARGE ENERGY USE FACILITY AGREEMENTS

Q. What is the role of Large Energy Use Facility Agreements in Staff's proposal?

A. Under Staff's proposal, Large Energy Use Facility Agreements will serve many purposes. In particular, they will identify a customer's reserved capacity, customer caused costs, agreed upon CIAC, and contract length. Further, they will establish terms regarding the cost recovery of customer caused costs, responsibilities if the customer exits the system prior to their contract's termination, minimum demand levels, and requirements for service. Notably, under Staff's proposal, many of these contract terms will be standardized to ensure that customers are being offered similar terms - streamlining contract review and ensuring that policy goals are met.

Agreement Lengths

Q. How is Staff proposing that minimum contract lengths be set?

A. The Commission recently made a decision on this issue in UM 2377, PGE's large load policy docket.[31] In that order, the Commission ordered that all LEUF customer contracts have a minimum contract term of 10 years that increases with the size of the customer's load. Specifically, the Commission ordered that the minimum contract length be 10 years for a 20 MW load, with the term increasing by one year for each 10 MW increment in load - maxing out at 30 years for a load 220 MW or greater. In their reasoning for

[31] *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 35-37.

this, the Commission stated that larger customers create greater risks of stranded assets and thus greater risk of unwarranted cost shifts to other ratepayers and that the assets built for very large customers are harder to repurpose after their departure. The scaling contract length framework adopted by the Commission paired with a robust Exit Fee minimizes stranded asset risk – for both shared and directly assigned assets.

At this time, Staff sees no reason for a different treatment for PacifiCorp LEUF customers. PacifiCorp faces similar risks imposed by large customers – primarily in the risk of stranded assets which are not directly assigned to a specific large load customer.

Q. Is Staff proposing a maximum contract length?

A. No.

Q. Once the initial contract term has expired, what should the contract renewal term be?

A. Staff is proposing a 10-year contract renewal term. This length is in line with the minimum contract length outlined in the POWER Act and the Commission's decision in UM 2377.[32]

Reserved Capacity

Q. How is Staff proposing that capacity reservations are determined?

A. In a customer's application for service, it will specify its desired level of reserved capacity. A customer is allowed to request any level of system capacity and all company studies will be tailored to this requested amount. If

[32] *Id.*

an agreement is executed between the Company and the customer, the minimum demand charge, excess demand charge, contract length, and exit fee will all be pegged to this requested reserved capacity.

Q. After a contract is executed, should a customer be able to change its reserved capacity?

A. Yes, but with caveats. Different considerations must be made depending on whether the customer is requesting to increase or decrease its reserved capacity. If a customer is requesting to increase its reserved capacity, contract terms must be updated to reflect the higher allocation. This includes contract terms around agreement length, minimum demands, the exit fee, and exceedance penalty thresholds. Further, any incremental costs that can be directly assigned to the customer that are incurred by Company to accommodate this increase in reserved capacity should be included in the new agreement. Lastly, any increases in reserved capacity should be subject to the large load generation queue. These provisions work together to ensure that cost causation principles are adhered to and that the ability for the utility to meet its HB 2021 obligations are not impeded by any requests to increase a customer's reserved capacity.

In the case that a customer is requesting to decrease its reserved capacity, the primary concern becomes the potential for stranded assets. In particular, if shared generation and transmission upgrades were undertaken, in part, to accommodate this customer's requested reserved capacity, these assets will become underutilized. As such, Staff is proposing that for a

customer to reduce its reserved capacity, another customer that is sufficiently electrically connected must be willing to increase their reserved capacity by the same amount. This restriction ensures that customers do not inflate their reserved capacity requests, creating stranded asset obligations for other customers. Further, Staff's proposal mirrors the proposal that was adopted by the Commission in UE 430.[33]

One exception Staff would be willing to consider in this case is a provision which states that a customer could reduce their reserved capacity during a planned load ramp if the utility has not begun construction on the requisite capacity additions. For example, suppose that a customer's ultimate reserved capacity is 500 MW, but PacifiCorp is planning to accommodate this request in two phases. In Phase 1 they will increase the customer's reserved capacity to 250 MW and in Phase 2 they will increase its reserved capacity to 500 MW. If during the construction of Phase 1, the customer requests to reduce its reserved capacity request to 250 MW with enough lead time to avoid the construction or procurement of resources to serve the full 500 MW, the Company may be able to accommodate this request with little to no impact on other customers.

[33] *In the Matter of Portland General Electric Company, Investigation into New Load Connection Costs*, Docket No. UE 430, Order No. 25-091, Appendix A at 7-8 (March 6, 2025).

Load Ramps

Q. It is common for data centers to ramp their load over time. Is Staff contemplating a mechanism to account for load ramping?

A. Yes. Staff is willing to allow for contract terms allowing for a load ramp only if utility construction timelines present the capacity bottleneck causing the need for a load ramp. Using the same example as in the previous question, it seems reasonable to adjust the contract terms to accommodate for the fact that the customer is not able to access its fully requested reserved capacity until the end of Phase 2. Any agreements regarding load ramps should be made on a case-by-case basis depending on the needs of the customer and construction timelines set by the utility.

Q. Why is Staff not contemplating load ramps in cases where the customer needs to scale up operations, but the utility has provided the full requested capacity?

A. In these cases, the utility would have invested the equipment needed to serve the customer's full request and thus require compensation for these investments. Allowing for the customer to scale up operations after these investments have been made creates a hole in PacifiCorp's revenue requirement that would need to be filled by revenues from other customers. Regardless of whether this revenue comes from other LEUFs or non-LEUFs, this creates an undue level of subsidization for customers during their load ramp. As such, Staff does not recommend allowing load ramps in cases

where the utility has met its obligations to the customer given their initial reserved capacity request.

Site Aggregation

Q. What is Staff's proposal for site aggregation?

A. Staff proposes that there be two separate criteria for site aggregation for customers that qualify for Large Use Energy Facility Agreements. First, if two sites have common ownership and are within 2,500 feet of each other or are served by the same substation, the sites will be treated as one for the purpose of capacity allocation and the qualification for an Agreement. This recommendation is similar to that adopted by the Commission in UM 2377.

Second, Staff is proposing that data center customers with similar ownership that are located anywhere in PacifiCorp's territory have their reserved capacity summed for the purposes of LEUF qualification and minimum contract lengths. The purpose of this proposal is to dissuade customers from siting multiple smaller data centers in PacifiCorp's service territory in order to avoid policies that scale with customer size. For example, a customer could site two 19 MW facilities in PacifiCorp's Oregon service territory in an attempt to be exempt from all LEUF requirements created by the POWER Act. Under Staff's proposal, these facilities would both qualify as LEUFs and both be subject to 11 year contracts. However, the minimum demands and Exit Fees for both facilities would be based on their 19 MW reserved capacities. Since the minimum demand charges are based on a percentage of the customer's reserved capacity it makes no difference whether

the load of the two facilities is aggregated. Further, the separation allows for the customer to have one facility exit the system early while leaving the other facility able to continue operation.

Q. Are there any additional modifications PacifiCorp needs to make in order to accommodate Staff's site aggregation proposal?

A. Yes. In order to implement Staff's proposal, PacifiCorp would have to adopt a definition of common ownership in its rules. This change is important as it will limit the ability for LEUFs to manipulate rules by siting multiple smaller data centers within PacifiCorp territory either by spreading them around the territory or using different subsidiaries to feign a lack of corporate affiliation. Staff recommends that PacifiCorp develop a definition to put into its rules that would give the Company the authority to deem entities related to one another based on common ownership.

Customer-Caused Distribution Costs

Q. How does Staff propose customer-caused distribution asset costs be recovered?

A. Staff proposes that all customer-caused distribution asset costs be directly assigned to each customer. The customer would be charged a flat distribution charge equal to the revenue requirement of the distribution assets in that billing period. If any of the customer's distribution assets are shared with other customers, the Company would be expected to provide evidence demonstrating that the assigned share of distribution asset costs is fair, just, and reasonable. The O&M costs related to these assets will not be

recovered through this charge, but instead through a class-specific distribution charge that is recovered in Staff's proposed LEUF rate schedule – which will be discussed in the following section.

Direct Assignment of Generation Assets

Q. Is Staff proposing that all customer-caused generation assets be direct assigned?

A. No. Generation assets are used flexibly to serve the system. As such, it seems reasonable to assign more generation costs to fast growing load, but not necessarily directly assign particular assets to these customers. However, if a customer would like to procure a particular type of resource or would like to fast track their connection by signing a special contract, this would essentially act as direct assigning generation plant to a customer. Staff is generally open to this framework. However, a clear framework for how direct assigned generation assets are chosen, contracted, and compensated for needs to be developed before these agreements can be executed. PacifiCorp's proposal to simply negotiate all terms of an agreement and then request Commission approval is unacceptable in its current form.

Q. Does Staff have a proposed framework for these generation special contracts?

A. Staff is still developing its full proposal but will identify the primary issues and Staff's principles here. First, as outlined in the Commission's UM 2377 order, a special contract should contain a comparison of the resource with

cost-of-service procurements in the RFP, an analysis of whether the resource meets HB 2021 emissions targets, advances reliability, and meets RA obligations; and a demonstration that the contract meets the requirements of section 5 of the POWER Act. Further, the general process should be similar to the one currently used in reviewing VRET agreements. Parties should file special contracts with the Commission at least 60 days ahead of a requested decision, though contracts with novel issues or technologies may take more time.[34]

Staff also has concerns regarding how special contracts will interact with the allocation of shared resources. If a customer opts to sign a special contract directly assigning the costs of a particular plant, it will still rely on the shared generation system. There is no way to guarantee that any plant will perfectly match the load of a particular customer- meaning this directly assigned plant may be either under- or over- generating power in any given moment. As such, a compensation scheme, based on hourly or daily generation and load should be developed to ensure that no other customers are paying more than they would be charged in the absence of this agreement. Conversely, other customers should not be unduly benefiting from the contract either.

Further, considerations must be made regarding what happens to the contract in the case that the customer exits before the end of its contract.

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[34] *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 58-60.

Terms regarding whether the customer will pay of the balance of the contract or whether other customers will absorb the future cost of the contract should be detailed. Conversely, if the customer stays on the system long enough for the contract to expire, a glidepath should be outlined for the customer to decide whether it will sign a new special contract or move to the cost of service schedule. If the latter option is chosen, sufficient time must be given for the utility to accommodate the transition.

Q. Excluding cases where customers sign special contracts, how does Staff propose to assign the costs of generation?

A. For customers that choose not to sign special contracts, Staff proposes that they be able to be served under Staff's proposed Schedule 49. Schedule 49 is discussed further in the next section.

Direct Assignment of Transmission Assets

Q. Is Staff proposing that all customer-caused transmission assets be direct assigned?

A. No. In accordance with the Commission's decision in UM 2377, Staff is proposing that transmission assets that only serve a single customer, such as radial lines, can be direct assigned to customers. This would allow the Company to recover the revenue requirement for these assets directly from a single customer.

However, Staff is open to the direct assignment of local transmission upgrades to LEUF customers in PacifiCorp's service territory as well. As discussed earlier, a key difference between PGE and PacifiCorp's service

territory is that PacifiCorp's service territory is largely rural, whereas PGE's service territory is largely urban. The density of PGE's service territory, particularly in terms of LEUF siting, can make it difficult to assign direct attribution of certain transmission projects to particular customers. However, in PacifiCorp's case, it may be more straightforward to point to a single customer as the trigger for a particular project. Staff finds it in the best interest of both LEUFs and other classes to assign the costs of these projects to the customers who cause these costs. This would minimize the risk of both inter- and intra-class cross subsidization. The determination of direct assignment of local transmission upgrades would have to be made on a case-by-case basis based on the facilities studies performed by the Company.

Flexibility

Q. Is Staff proposing flexibility requirements in this case?

A. No, but Staff recommends that the Company work to establish a uniform framework for compensating projects for the value of asset-backed or demonstrable flexibility. While further study and data are needed, Staff believes an appropriate framework would compensate flexible projects for capacity value made available to the system during times of peak need in a non-discriminatory manner.

Q. Why is flexibility valuable to the electric system?

A. Flexible large loads that can adjust their demand offer meaningful value to the electric grid by providing demand side capacity when called upon, improving grid reliability and cost efficiency and often with lower levels of

infrastructure investment. Flexible loads are typically able to reduce consumption during periods of grid stress either through the use of on-site generation or by shifting workloads to off-peak times. A sufficiently advanced and integrated flexible large load may even be able to provide ancillary services. Flexibility offers the opportunity to support the grid while reducing the need for additional costly peaking resources.

Q. What data would Staff like the Company to collect through study?

A. Staff would be interested in characteristic data for the POWER Act regulated large load class such as:

- The amount that load can be reduced
- The duration that load can be reduced
- How frequently load can be reduced
- Anticipated potential and performance of data center flexibility programs, both with and without the utility's ability to dispatch the demand reduction
- The ability of flexible loads to provide ancillary services

These data may aid the Company, Staff, and stakeholders in further understanding the value of flexibility, adequate compensation, and whether creation of a controllable load resource program for large loads, as seen in states such as California or Texas, would be viable.

Q. What principles does Staff share for a flexibility framework?

A. Staff's flexibility framework begins with the foundational planning principles that cost-effective demand-side resources should be pursued before supply-

side investments and should compete equally with supply-side resources. Demand-side flexible resources should be treated no differently than generation assets when considering how to manage load.

Q. Does Staff have a compensation framework in mind for flexible resources?

A. Staff believes that a reasonable initial approach for compensating project flexibility, when called upon, would be to compensate flexible resources according to the avoided cost of capacity, including transmission buildout that may be avoided, that the utility would otherwise acquire if not for the flexible resource. Further, as raised in the UM 2377 Order, a large load project in an interconnection queue may be able to move up the queue by including flexibility in its service plan, providing meaningful non-monetary value for project flexibility in addition to the value of freed capacity and avoided transmission buildout.[35]

Credit Requirements

Q. What is Staff's proposal regarding credit requirements?

A. Staff proposes the same credit requirements adopted by the Commission in Order 26-154. These are given as:

> i. The senior unsecured long term debt of a customer has a rating of A- or higher by Standard & Poor's or Fitch, A (low) or higher by DBRS, or A3 or higher by Moody's Investor Services, Inc.; provided that if a Person is rated by multiple credit rating agencies, the Person will be deemed to satisfy the Creditworthiness Requirements only if at least two of the foregoing standards are met, or

[35] *Id.* at 62-65.

ii. (ii) if there is no such rating of the customer's senior unsecured long-term debt, the customer has an equivalent rating as determined by the utility through its standard internal process review.

The Commission ordered that these credit requirements be specified in the tariff and uniform. PGE would also allow for letters of credit, surety bonds or cash to be used as collateral. At this time, Staff sees no need for differentiation between PGE and PacifiCorp on this issue. Staff is open to alternative proposals if justified but is not open to customer-specific credit requirements given discrimination concerns.

Minimum Demand Charges

Q. Is Staff proposing a minimum demand charge for LEUFs?

A. Yes. Staff proposes that both a 90 percent minimum transmission demand (MTD) charge and minimum generation charge (MGD) be adopted in this case. This recommendation mirrors the policy adopted in Order 26-154. Staff is also proposing that LEUFs be exempt from the Company's Capacity Reservation Charge currently in effect for customers 50 MW or higher.[36] Staff proposes to move away from the capacity reservation charge and towards a minimum demand structure for LEUFs as Staff sees the combination of both the MTD and MGD as a more robust set of protections that are more streamlined than the Capacity Reservation Charge that is intended to provide similar incentives to the capacity reservation charge.

[36] Pacific Power, Oregon Rule 13, Line Extensions, at 9-10 (Effective for service on and after January 1, 2025) (available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rules/13_Line_Extensions.pdf)

The Capacity Reservation Charge was developed and approved in UE 433 to address similar stranded asset concerns as a minimum demand charge. These stranded asset concerns are largely associated with the potential for large customers to overestimate their capacity needs. The Capacity Reservation Charge holds customers accountable to their initial requests by guaranteeing a minimum amount of revenue is recovered regardless of a customer's actual consumption. A minimum demand charge has a similar function. However, the Capacity Reservation Charge is currently set to primarily account for transmission costs with some additional consideration given to the effect that reserved capacity has on the planning reserve margin.[37]

Given the legislative mandate provided by the POWER Act to sequester LEUF costs, Staff finds that using minimum demand charges will more holistically ensure that costs for shared transmission and generation assets that were built to largely accommodate load growth for LEUFs are recovered from those customers. Staff's proposed cost allocation methodology for shared generation and transmission assets proportionally allocates the costs of these resources to the LEUF rate class based on recent customer load growth. Pairing this methodology with minimum demand charges minimizes inter-class cross subsidization concerns.

As a practical matter, Staff also notes that the thresholds where Staff's proposed minimum demand charges are triggered is the same as the current

[37] *In the Matter of PacifiCorp, Request for a General Rate Revision,* Docket No. UE 433, Order No. 24-447 at 92-94.

Capacity Reservation Charge. Staff believes that it is more straightforward and administratively efficient to subject a single properly calibrated minimum demand charge that waives the Capacity Reservation Charge than to have two charges meant to address the similar concerns that are triggered at the same time. Further, Staff also recommends that the Capacity Reservation Charge be converted to a Minimum Demand Charge in UE 470 - PacifiCorp's current rate case.

Excess Demand Charge

Q. Is Staff proposing an excess demand charge for LEUFs?

A. Yes. Again, Staff is proposing that LEUFs be subject to an excess demand charge that is based on the transmission and generation demand charges set in Schedule 49. Staff is proposing that these excess demand charges be set at four times the transmission rate plus 1.5 times the generation rate per hour for exceedances of their reserved capacity. This proposal is aligned with the position adopted by the Commission in Order 26-154.[38] The excess demand charge would not be listed in each customer's Agreement, but instead in PacifiCorp's rules in order to preserve flexibility to adjust the penalty as needed.

Staff proposes to adopt a new excess demand charge for LEUFs as the current excess demand charge is based on the capacity reservation charge. Since Staff is proposing to exempt LEUFs from the Capacity Reservation

[38] *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 45-47.

Charge and move to a minimum demand framework that is based on Schedule 49 rates, the excess demand charge for LEUFs needs to be updated to conform to Staff's proposal. If Staff's proposal to move away from the Capacity Reservation Charge for LEUFs is not adopted, Staff's excess demand charge proposal is not needed.

Exit Fee

Q. Is Staff proposing an Exit Fee for LEUFs?

A. Yes. Staff proposes a standardized Exit Fee for all LEUFs. This Exit Fee would be assessed if the customer exits the system prior to the end of their contract, or in some cases, at the end of their contract. The Exit Fee would be calculated as the sum of (1) the net book value of all directly assigned assets and (2) the greater of (a) the remaining MTD and MGD charges for the remainder of the contract, or (b) three years' worth of MTD and MGD charges at the highest allocated system capacity during the contract. If the customer exits at the end of their contract, the Exit Fee would only consist of the net book value of the directly assigned assets. This proposed structure is similar to the Exit Fee described in Order 26-154.[39] The intent of the Exit Fee is to hold the utility and other customers harmless in the case that an exiting customer creates stranded assets when leaving the system.

Staff is also proposing a refund mechanism where if another customer assumes all or a portion of the exiting customer's capacity and cost responsibilities within three years of the customer exiting, the exiting customer

[39] *Id.* at 48-52.

would receive a full or partial refund of the exit fee less the minimum demand and distribution charges that cover the time between when the customer exited and the new customer connected to the system. Again, this is similar to the framework adopted in UM 2377.[40]

Contributions in Aid of Construction

Q. What is Staff's proposal regarding Contributions in Aid of Construction (CIAC)?

A. Staff proposes that customers be allowed to contribute up to 100% of the construction costs of all direct assigned assets in order to reduce their Exit Fee and monthly payments. However, Staff is not proposing that customers be obligated to provide any CIAC. This is similar to the resolution adopted by the Commission in Order 26-154.[41]

[40] *Id.* at 51.
[41] *Id.* at 60-62.

ISSUE 2. COST OF SERVICE

Q. Please describe Staff's proposal for a LEUF cost of service schedule at a high level.

A. Staff proposes that PacifiCorp create a new cost of service schedule applicable only to LEUFs called Schedule 49. Schedule 49 would allocate the costs of shared generation, transmission, and administrative costs via a uniform set of rates. Under PacifiCorp's proposal, it is unclear how the costs of shared system assets would be allocated to customers – leaving it up to individually negotiated contracts to determine this allocation. This may lead to a patchwork approach where the allocation methodology of these costs differs from customer to customer. This again raises concerns around discrimination between LEUF customers and protections for non-LEUF customers. Staff's proposal would provide a predictable, transparent, and fair allocation of these shared system costs.

Staff is not proposing that any direct assigned asset costs be included in the LEUF cost of service schedule. These costs, and their associated billed charges, would be outlined in the LEUF Agreement between the company and the customer. Staff is also not proposing that any distribution costs be recovered through this schedule as all LEUF distribution assets should be direct assigned.

The creation of Schedule 49 will require changes to PacifiCorp's current marginal cost study. Staff outlines its proposals for these changes here.

Further, Staff outlines the proposed rate design for Schedule 49 and how net power costs will be allocated.

Generation Marginal Cost Study

Q. Please generally describe PAC's marginal cost study as implemented in UE 433.

A. PAC breaks its marginal cost study into subsets. The primary subsets of the study are generation costs, transmission costs, distribution costs, and customer service costs. Each of these sub-studies produces unique marginal costs for each cost category. Book costs are then allocated based on the marginal cost and an allocation factor.

Q. Please describe PacifiCorp's generation marginal cost study.

A. The generation marginal cost study is used to allocate both fixed generation costs and net variable power costs. PAC uses proxy resource costs to estimate the long-run marginal cost of both capacity and energy. In UE 433, PAC used a four hour battery as its capacity proxy resource. For energy, PAC relies on a market price forecast, after deducting a capacity credit, to meet the Company's peak load requirements.[42] From this, PAC derived a marginal energy and capacity cost for the system. Finally, each class was allocated generation costs based on a combination of their class-level marginal cost and usage characteristics. In particular, energy costs were allocated based on the marginal energy cost in each month and each class's

[42] UE 433, PAC/1908, Meredith/1-2.

forecasted monthly consumption. Capacity costs were allocated to each class's contribution to the 4 month coincident peak.

Q. Will PacifiCorp's current generation marginal cost study properly allocate shared generation and transmission costs to LEUFs?

A. No. Staff is concerned that PacifiCorp's generation marginal cost study does not accurately reflect the new costs large customers may impose on the system, nor will it reflect the changing costs imposed by this customer type as the system transitions.

As discussed above, there has not been a period in the recent past where rapid load growth has primarily come from one customer class. The way PacifiCorp's currently allocates energy costs is based on the marginal cost of energy. Effectively, PacifiCorp estimates the marginal cost of energy and capacity, multiplies that amount by each schedule's total energy and capacity needs to create each class's cost to the system evaluated at the marginal generation cost. This number is then the basis for the generation rate spread. In general, this methodology is in line with economic pricing principles. However, there is an obvious issue with fairness that this method overlooks.

Imagine a scenario with flat load growth for all customer classes except large load customers. In response, the utility must construct new generation facilities leading to a rate case. Given PacifiCorp's current methodology, these new costs would be spread to all customers based on their consumption characteristics. While this rate spread methodology sets prices in a way that reflects the cost of energy and incentivizes efficient use by all customers, it

ignores the fact that this rate increase would not be necessary but for load growth from a single class. As such, costs incurred by one class are recovered proportionally by all classes. Using PacifiCorp's current methodology, it is possible for the vast majority of these new generation costs to be recovered by other classes – which is now prohibited by the POWER Act.

Q. Does Staff have any other concerns regarding PacifiCorp's generation marginal cost study?

A. Yes. First, Staff is concerned about whether PacifiCorp's generation marginal cost study reflects which customers cause new generation costs. PacifiCorp's marginal cost study divides generation costs into energy and capacity costs. This method has been practiced for many years and was representative of PacifiCorp's cost drivers in the past, particularly when the system was largely served by thermal resources. In this period, resource planning focused on optimizing low $/MWh baseload generation resources and expensive, but efficient peaking generation to meet peak demand and total energy needs in a least cost manner.

However, with the evolution of the grid and the move towards variable and energy limited non-emitting resources, the drivers for resource acquisition have changed. Resource acquisition is now largely focused on reliability and reducing the loss of load expectation (LOLE) in critical hours. LOLE is driven by two factors: the demand in any given hour and the amount of expected generation or available transmission in the same hour. Often, the generation profiles of renewable resources do not align perfectly with load curves. This

can lead to high LOLE in hours where demand is not at peak. As such, generation resource acquisition decisions are not only based on peak load, but also net load. Being a large, but steady load has a greater impact under a thermal generation constrained resource strategy. This reality is not reflected in PacifiCorp's current generation marginal cost study.

Q. What additional costs could this type of demand impose on the system?

A. Staff is concerned about a few potential negative outcomes of this type of load growth. First, this can lead to an increased need for market purchases in off-peak hours, an increased need for transmission capacity, and the acquisition of costly resources that would otherwise not be needed. Given that transmission is currently allocated on peak demand only, this could lead to a misallocation of costs. This will be discussed in more detail later in this section.

Second, it could lead to the need for more geographically diverse renewable resources. By requiring geographically diverse resources, these customers would increase the utilities transmission costs associated with this new generation. Lastly, this consumption profile could lead PacifiCorp to purchase more expensive non-emitting dispatchable resources like nuclear, hydrogen peakers, and enhanced geothermal that would not otherwise be needed but for the new LEUF load. This impact would not be represented in PacifiCorp's current marginal cost study.

Q. Does Staff have a preferred recommendation to solve these issues in the generation marginal cost study?

A. Yes, Staff is proposing that PacifiCorp adopt the Peak-Growth Modifier (PGM), as adopted by the Commission in Order 26-154, for the purpose of allocating shared generation resources.[43] This mechanism would require PacifiCorp to identify generation resources that are built for the purpose of meeting load growth. Then, after these resources are identified, they would be allocated via the PGM. The PGM is calculated by identifying each customer class's share of weather normalized load growth over the past three years and the Test Year and spreading the growth-related generation-assets revenue requirement over these shares. All other non-growth-related assets are spread via the standard marginal cost study methodology. Allocations via the PGM would be indefinite, meaning a growth-related asset will remain in the PGM until it is demonstrated that system usage no longer supports the allocation. This approach will require PacifiCorp to track consecutive vintages of assets with different allocation percentages

Q. How would growth-related generation assets be identified?

A. Staff proposes that the classification adopted by the Commission in Order 26-154 be adopted here as well.[44] This definition states that growth-related

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[43] *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 16-21.

[44] *Id.* at 22-23.

investments are triggered by the need for incremental capacity or energy to reliably serve increased demand, including:

- New Capacity Additions – Investments for new renewable generation (wind, solar, etc.) when added to meet load growth and not policy compliance, battery storage and flexible demand-side (non-wires alternatives) to satisfy resource adequacy for growing peak demand.
- Upgrades or Efficiency Improvements – Projects to support load growth that are related to turbine upgrades that increase MW capacity and heat-rate improvements that expand available output.
- Portfolio Additions for Resource Adequacy (RA) – Projects to improve peak capacity deficits and planning reserve margin shortfalls.

Q. If a framework is developed that allows for generation assets to be directly assigned, how would this impact Staff's proposals in this section?

A. The costs related to direct assigned generation assets would not be allocated through the marginal cost study, but instead through agreements. As such, any proposed framework for direct assigned generation assets should credit LEUFs with direct assigned generation assets such that their contributions to the shared system are proportional to their reliance on the system. This reliance will largely depend on the net hourly differential between the customer's load and the direct assigned assets hourly generation.

In general, either firm resources or shaped intermittent resources will allow for the most load matching. That said, Staff anticipates that direct assigned generation assets will still be dispatched based on the EDAM, as opposed to directly match a customer's load in any given hour. As such, even if the customer is directly paying for additional capacity, it may still rely largely on the existing system and thus should provide proportional contributions to the cost to operate this system. PacifiCorp's lack of specificity around this issue reinforces Staff's concerns with the Company's proposal.

Transmission Marginal Cost Study

Q. Please describe PacifiCorp's transmission marginal cost study.

A. PacifiCorp calculates marginal transmission costs based on a five-year analysis of forecasted expenditures to meet load growth on its transmission system. Except for the Company's investments in bulk power lines, all the growth-related transmission investments are classified to demand. Transmission investments for each year of the analysis are valued to the same base year and summed. Total transmission investment is divided by the capacity gained from the investment to arrive at the marginal investment per kilowatt. Loading factors for A&G expense and transmission O&M are added to the per kW investment as annual charges to arrive at long-run transmission marginal cost.[45]

[45] UE 433, PAC/1908, Meredith/2.

Q. What concerns does Staff have with PacifiCorp's transmission marginal cost study?

A. PacifiCorp is currently allocating all transmission costs based on each class's peak demand. Similar to the generation marginal cost study, this may have been true in the past but is losing relevance as the grid evolves.

First, a distinction must be made between transmission projects that carry energy from outside or across the eastern to western side of PacifiCorp's service territory to PacifiCorp's service territory and lines that carry high voltage energy within a more local portion of PacifiCorp's service territory. For the sake of this testimony, I will refer to lines used to carry high voltage power within PacifiCorp's service territory as "local" transmission, and the longer lines used as "regional" transmission.

PacifiCorp's current transmission marginal cost study does not make a distinction between local and regional transmission. This is concerning as a single large load customer may trigger a significant amount of local transmission investment if they are of a sufficient size. These upgrades are necessary simply to deliver the power being requested by the customer if the customer is located in an area that does not have sufficient transmission capacity to remain reliable after their interconnection. Given the potential size of data centers, particularly hyperscalers, this investment can be significant.

LEUFs may also trigger regional transmission upgrades, but these investments, unless being used to tie in a directly assigned generation resource, will be difficult to solely assign to a single customer. Typically,

regional transmission lines are used to serve all customers. Expansion of the transmission system may be caused by a single customer or class of customer's load growth, but financially tying a single customer to a piece of infrastructure that is used to serve the entire service territory is problematic – especially as the use of that asset changes over time.

PacifiCorp's current transmission cost allocation methodology would assign these unilaterally imposed costs to all customers based on peak demand. In PacifiCorp's most recent rate case, UE 433, this would have likely led to non-LEUF customers paying over 75 percent of the cost of this project when these customers had no part in causing the investment.[46] This outcome is an obvious deviation from cost causation principles.

Q. Does Staff have a preferred recommendation to solve these issues in the transmission marginal cost study?

A. Yes. Staff recommends that shared transmission assets also be subject to the PGM. This ensures that even if assets are not able to be assigned to a particular customer, if the class of LEUFs at large are causing significant transmission investment, they will be allocated the bulk of these costs.

Q. How would growth-related transmission assets be identified?

A. Staff proposes that the classification adopted by the Commission in Order 26-154 be adopted here as well.[47] This definition states that transmission assets

[46] This figure was calculated by the summing non-Schedule 48 contribution to peak demand in UE 433.

[47] *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 22-23.

are considered growth-related when they are triggered by new or increasing load, including, but not limited to:

- Load-Driven System Upgrades – Projects needed because projected load will exceed system capacity and will introduce exceedance to thermal, voltage, or stability limits. Examples include:
  - Reconductoring lines to higher capacity
  - New transmission line to serve load pockets or large customer additions
  - Transformer capacity expansions
  - Transmission projects which are triggered by new or additional loads causing the company to be subject to more stringent planning or reliability standards
- Grid Enhancing Technologies (GETs) - investments in advanced technologies such as:
  - Dynamic line ratings
  - Other solutions that increase the capacity of existing transmission infrastructure to accommodate load growth without traditional infrastructure expansion

Net Power Costs

Q. Please describe how PacifiCorp's net power costs are currently spread.

A. PacifiCorp currently spreads net power costs based on the generation rate spread derived in its most recent rate case.[48]

Q. Does Staff see any potential issues with PacifiCorp's net power cost methodology in the face of rapid LEUF growth?

A. Yes. The high load factor and total volume of potential LEUF growth could increase net power costs disproportionately to meet LEUF load growth. Load growth can have a non-linear impact on power costs if the marginal cost curve for the power market is increasing at an increasing rate. As such, LEUF load growth could significantly move PacifiCorp up this marginal cost curve, increasing overall costs for all customers. PacifiCorp's current methodology, even if paired with Staff's PGM proposal would not capture this effect.

Q. Is Staff proposing a solution for this issue?

A. Yes. Staff proposes that in PacifiCorp's forward-looking power costs filings the Company allocate the marginal increase in power costs caused by LEUFs to the class of LEUFs. To do this, PacifiCorp would calculate a counterfactual level of power costs absent LEUF growth since 2025. Then, calculate the revenues, at that year's rates, this load growth generates. These figures would be summed and then differenced by the actual

[48] UE 469, PAC/300, Ridenour/2.

forecasted power costs in that case. The difference between these figures represents the incremental increase in power costs caused by LEUFs and would be directly assigned to the class. This approach is similar to what PGE proposed in UM 2377 and UE 465.

Q. Would 2025 be used as the base year in perpetuity?

A. Not necessarily. This calculation is meant to address costs from increased market purchases. Staff expects that over time, generation assets would be built to accommodate LEUF load and the reliance on market purchases may decrease. While Staff believes using a 2025 base year is most appropriate currently, Staff is open to proposals in future Transition Adjustment Mechanism (TAM) filings to adjust the base year.

Q. Would changes need to be made to the Power Cost Adjustment Mechanism (PCAM) as well?

A. Yes. LEUF load growth has the potential to greatly increase power costs during high cost energy events. This issue is particularly concerning given no LEUF currently has a flexibility agreement with PacifiCorp.[49] Further, there is no guarantee that under PacifiCorp's proposal, that LEUFs with direct assigned generation assets will not lean on the system during high cost energy events.

Staff does not have a proposal for PacifiCorp's PCAM at this time. Staff will continue to develop a proposal over the course of this case and

[49] PacifiCorp Response to Staff DR 22.

strongly encourages the Company to develop its own and present it either in this case or its next GRC.

Schedule 49 Rate Design

Q. Please describe Staff's proposal for Schedule 49's rate design.

A. Staff proposes that Schedule 49 be structured similar to Schedule 48 but account for directly assigned distribution assets. Since Staff is proposing that all distribution assets used to serve LEUFs be directly assigned, there will be no shared distribution asset costs to spread to Schedule 49. Staff's proposed rate design would include the following charges:

- Transmission & Ancillary Services Charge
- System Usage Charge

In Schedule 48, the Basic Charge, Facilities Charge, and On-Peak Demand Charge, are used to recover the allocated distribution revenue requirement. Staff proposes that Schedule 49 include none of these charges. Instead, Schedule 49 would include only a singular transmission charge which would be set to recover the class's entire allocated transmission revenue requirement. The Transmission Minimum Demand Charge would apply to this charge. The System Usage Charge would be set to recover Schedule 49's allocated portion of Franchise Fees.

Schedule 49 would also be subject to Schedule 200 and Schedule 201. Schedule 49's Schedule 200 rate would be set to recover the entirety of its allocated fixed generation costs. This charge would be subject to the Minimum

Generation Demand charge. Schedule 49's Schedule 201 rate would be set to recover the entirety of its allocated NVPCs.

ISSUE 3. HB 2021 COMPLIANCE

Q. What does the POWER Act provide regarding HB 2021 compliance?

A. The POWER Act states at section (3)(c) that the Commission shall consider whether the utility's rates in question "[i]mpede the electric company's ability to meet the clean energy targets set forth in ORS 469A.410 or reduce the emissions of greenhouse gases consistent with state policy".[50]

Q. Did the Commission consider a framework to protect HB 2021 compliance in UM 2377?

A. Yes, the Commission established an interconnection queue in Order 26-154 in order to protect HB 2021 compliance targets. The interconnection queue would prevent large loads from connecting until a reliable plan of service that matches resources to the load's capacity scale up plan can be established for the load that does not impede the Company's HB 2021 obligations.

The Commission also contemplated a framework for customers moving within the queue. The Commission stated that to the degree that a load in a higher position does not have a reliable, HB 2021 compliant plan of service in place, a lower queued load may move forward if they are ready with a reliable, HB 2021 compliant plan of service that matches their planned scale up schedule. The Commission also clarified that the plan of service may include the customer's own non-emitting resources - energy and capacity - in a Commission-approved special contract. It may also include use of direct

[50] HB 3546(3)(c).

access, load flexibility or customer funded load reductions in PGE's service territory.[51]

Q. Does Staff support use of an interconnection queue in this docket?

A. Yes. Staff maintains support for the use of an interconnection queue to prioritize connection of projects with reliable HB 2021 compliant plans of service that match their planned scale up schedule.

Q. Does Staff recommend establishing a fast-track queue for flexible loads?

A. Not at this time. While flexibility may be an important consideration in a project's service plan, the record remains insufficient to support creation of such a fast-track interconnection queue until adequate evidence exists to establish reasonable criteria to identify qualifying flexible loads. As the Commission provided in Order 26-154, a project's plan of service may include "use of direct access, load flexibility or customer funded load reductions".[52] This still provides the ability for a project to move up in the interconnection queue using load flexibility, as one of several options, by more quickly establishing a reliable HB 2021 compliant plan of service.

Q. What criteria might be useful for establishing a potential fast track interconnection queue?

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[51] *In the Matter of Public Utility Commission of Oregon, Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* Docket No. UM 2377, Order No. 26-154 at 62-65.

[52] *Id.* at 63.

A. Staff envisions that useful criteria for establishment of a fast track interconnection queue would include a project's demonstrated ability to flex its load, asset-backed ability to reduce load, and support for real time dispatch of load flexibility by the utility. Real time dispatchability of a project's load flexibility may allow a project to provide ancillary grid services, along with supporting renewables integration.

Q. Does Staff have concerns with flexible projects moving up the interconnection queue?

A. Staff encourages prioritization of interconnecting projects that have sufficiently demonstrated flexibility, for the reasons stated above. Flexibility may help mitigate resource adequacy risks with the interconnection of large loads, and should allow projects in the queue to reduce their need to bring owned energy resources.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 463
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

May 14, 2026

WITNESS QUALIFICATIONS STATEMENT

NAME: Bret Stevens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Rates, Safety, and Utility Performance

ADDRESS: 201 High Street SE. Suite 100
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EDUCATION: Ph.D., Agricultural & Resource Economics (2023)
University of California, Davis

M.S., Agricultural & Resource Economics (2017)
University of California, Davis

B.A., Economics/Environmental Studies (2016)
Western Washington University

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since September of 2022. My primary responsibilities revolve around providing research and analysis on rate spread and rate design. I have been a staff witness in UE 407, UE 410, UE 412, UE 414, UE 416, UE 421, UE 426, UE 433, UE 435, UG 461, UG 490, UG 519, UG 520, and UM 2377. Prior to working for the Commission, I was employed by the University of California, Davis as a graduate student researcher, associate instructor, and teaching assistant. I taught courses on econometrics, finance, and microeconomics.

CASE: UE 463
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Non-Confidential
Data Responses

May 14, 2026

Staff Data Request 8

Has PacifiCorp created a template for the Large Energy Use Facility Agreement (Agreement)? If so, please provide this template.

(a) If not, please describe the Company's understanding of what the Agreement would cover. In this description, please describe what exact mechanisms the Company will use to accomplish the criteria outlined in the proposed Schedule 401 Special Conditions 3(a)-3(g).

Response to OPUC Data Request 8

No.

(a) PacifiCorp does not anticipate having a standardized template for Large Energy Use Facility Agreements. Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service and would meet the requirements of the POWER Act, which are also listed on proposed Schedule 401.

Staff Data Request 10

How does the Company plan to attribute the costs of transmission upgrades through the Large Energy Use Facility Agreement?

(a) Does the Company plan to attribute the costs of regional transmission upgrades to a single customer? If so, what analysis would the Company use for this cost assignment?
(b) If in the future, if these transmission lines are proven to provide reliability benefits to the system at large, would the Company propose cost reassignment?
(c) If the costs of regional transmission lines are attributed to a single customer, how would these costs be allocated in PacifiCorp's current MSP proposal in UM 2401?

Response to OPUC Data Request 10

The assignment of transmission upgrades to a Large Energy Use Facility through a Large Energy Use Facility Agreement will depend upon the unique facts and circumstances of the transmission upgrades and the requirements for the Large Energy Use Facility.

(a) Assignment of the costs of regional transmission upgrades to a Large Energy Use Facility would depend upon the unique facts and circumstances of the transmission upgrades and the requirements for the Large Energy Use Facility.

(b) Please refer to the company's response to subpart (a) of this request.
(c) If all, or a portion, of the costs were solely assigned to a single customer, the company would propose situs treatment to the state for the amount solely assigned to the single customer.

Staff Data Request 11

How does the Company intend to allocate fixed generation costs through the Large Energy Use Facility Agreements?

(a) Will fixed generation costs related to new resources directly assigned to specific customers?
(b) How does the Company intend to spread fixed generation costs of existing assets?

Response to OPUC Data Request 11

How PacifiCorp intends to allocate fixed generation to Large Energy Use Facilities will depend on the facts and circumstances of each Large Energy Use Facility and the generation that will be required to serve the customer. The calculation of rates for a Large Energy Use Facility may include incremental costs, contributions to existing costs, or a combination of both.

Staff Data Request 12

How does the Company intend to allocate net power costs through the Large Energy Use Facility Agreement?

Response to OPUC Data Request 12

How PacifiCorp intends to allocate net power costs (NPC) to Large Energy Use Facilities will depend on the facts and circumstances of each Large Energy Use Facility and the generation that will be required to serve the customer. Rates that recover NPC for a Large Energy Use Facility may be based on incremental costs, existing cost, reference to a specific index such as the locational marginal price at a node in the Extended Day-Ahead Market (EDAM), or a combination of these elements, as appropriate.

Staff Data Request 13

If assets that are directly assigned to a customer are placed into service before the customer connects to the system, will the Company attempt to collect the revenue requirement for these assets from other customers?

Response to OPUC Data Request 13

PacifiCorp intends to structure any Large Energy Use Facility Agreement in a way that directly assigned costs will not be recovered from other customers.

Staff Data Request 14

What is the standard contract length the Company is planning to use for the Large Energy Use Facility Agreements?

(a) When the contract expires, what is the Company's proposal for renewals?

Response to OPUC Data Request 14

Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service and would meet the requirements of the POWER Act, which are also listed on proposed Schedule 401. The POWER Act specifies a minimum contract duration of "10 years or longer" in 757-5(1)(b)(A)(ii).

(a) Upon expiration of an initial agreement, future service would be subject to a new Large Energy Use Facility Agreement.

Staff Data Request 15

How are interconnection studies currently funded for very large customers?

(a) Does the Company contemplate changing these practices with the creation of the Large Energy Use Facility Agreements?

Response to OPUC Data Request 15

Interconnection system impact studies (SIS) for very large load customers are funded by the customer through a cash advance. Unspent amounts can be put toward project costs or refunded to the customer. Estimated upfront payment varies per project based on complexity of the study and area of service.

(a) The company does not contemplate changing this practice with the creation of the Large Energy Use Facility Agreements.

Staff Data Request 16

Is the Company planning on imposing exit fees in the Large Energy Use Facility Agreements? If so, please provide details on how these exit fees would be constructed.

Response to OPUC Data Request 16

Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service and would meet the

requirements of the POWER Act, which are also listed on proposed Schedule 401.

Staff Data Request 17

Is the Company planning on imposing credit requirements on Large Energy Use Facilities? If so, please describe how these requirements will be set.

Response to OPUC Data Request 17

Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service, including credit requirements, and would meet the requirements of the POWER Act, which are also listed on proposed Schedule 401.

Staff Data Request 18

Is the Company planning on imposing take or pay provisions in its Large Energy Use Facility Agreements? If so, please describe how these mechanisms would work in detail.

Response to OPUC Data Request 18

Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service, including take or pay provisions, and would meet the requirements of the POWER Act, which are also listed on proposed Schedule 401.

Staff Data Request 19

Is the Company planning to request any payments ahead of construction of facilities? If so, please give detail on how and when these fees would be assessed.

Response to OPUC Data Request 19

Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service, including payments ahead of construction of facilities, and would meet the requirements of the POWER Act, which are also listed on proposed Schedule 401.

Staff Data Request 20

Is the Company generally opposed to a stated rate for Large Energy Use Facilities which would calculate rates for these customers' share of non-

customer specific costs, paired with an Large Energy Use Facility Agreement which directly assigns customer specific costs?

(a) If yes, please discuss the Company's questions or concerns.
(b) If the Company's position depends on specific details of this proposal, please describe the Company's preferences for these specific details.

Response to OPUC Data Request 20

Given the unique cost characteristics for individual customers that qualify as Large Energy Use Facilities, PacifiCorp believes that pricing should reflect the specific costs and risks that a Large Energy Use Facility cause. Therefore, the company envisions rates for these customers would likely include a combination of incremental customer specific costs and contributions to existing costs.

Staff Data Request 22

Of the customers identified in DR 1, how many have flexibility provisions, such as demand response or preferential curtailment, in their customer agreements?

(a) If there are any, please provide a narrative on how these flexibility provisions operate.

Response to OPUC Data Request 22

The company assumes that the reference to "DR 1" is intended to be a reference to the company's response to OPUC Data Request 1. Based on the foregoing assumption, the company responds as follows: None.

Staff Data Request 24

How does PacifiCorp's Large Energy Use Facility Agreement framework reflect the value of flexible load?

Response to OPUC Data Request 24

Please refer to the proposed Schedule 401 included with PacifiCorp's Advice No. 25-015 filing dated October 2, 2025. A Large Energy Use Facility Agreement will specify the pricing and terms of service, inclusive of any flexible load characteristics of the specific customer.