July 9, 2026

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Public Utility Commission of Oregon
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Re: In the Matter of PACIFICORP, dba PACIFIC POWER,
Advice No. 25-015, Schedule 401- Service to New Large Energy Use Facilities
OPUC Docket No. UE 463

Attention Filing Center:

The Data Center Coalition ("DCC") hereby submits the following Rebuttal Testimony for filing in the above-referenced docket. Should you have any questions, or need anything further, please do not hesitate to contact me.

Thank you for your assistance with this matter.

Sincerely,

Sidney Villanueva

Sidney Villanueva
Blue Skies Law, LLC

BEFORE THE OREGON PUBLIC SERVICE COMMISSION

IN THE MATTER OF PACIFICORP, DBA PACIFIC POWER, ADVICE NO. 25-015, SCHEDULE 401 - SERVICE TO NEW LARGE ENERGY USE FACILITIES	))))	**Docket No. UE 463**

REBUTTAL TESTIMONY OF

JUSTIN BIEBER

ON BEHALF OF

THE DATA CENTER COALITION

July 9, 2026

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Justin Bieber. My business address is 111 E Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. ARE YOU THE SAME JUSTIN BIEBER WHO PRE-FILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF THE DATA CENTER COALITION ("DCC")?

A. Yes, I am.

II. OVERVIEW AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony responds to the opening testimony of the Commission's Public Utility Division ("Staff") witness Bret Stevens, Climate Solutions, Community Energy Project, Sierra Club, and Oregon Environmental Council, collectively the Environmental Intervenors, witnesses Jeremy Fisher, Joshua Basofin and Ben Brint, Oregon Citizens' Utility Board ("CUB") witness Ryan Tran, Amazon Data Services ("ADS") witnesses Carolyn A. Berry and Collin Cain and the reply testimony of PacifiCorp witness Robert M. Meredith.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I provide the following recommendations and conclusions:

A. Fundamental Policy Considerations. As a general matter, while it is important to address concerns expressed by intervenors related to the risks of potential stranded assets and cost shifting, it is equally important to give meaningful consideration to the significant potential benefits that new Large Energy Use Facility ("LEUF") loads can provide. While I agree that appropriate protections against cost shifting and stranded assets are necessary, the Commission should adopt a Schedule 401 framework that protects existing customers without unnecessarily limiting those benefits.

New LEUF load can spread PacifiCorp's fixed system costs over a larger billing base and put downward pressure on rates when revenues from new load exceed the incremental costs required to serve it. LEUF customers also make substantial contributions toward public policy program riders, the costs of which generally do not increase in proportion to load growth, reducing the amount that must be recovered from other customer classes. In addition, sustained LEUF load growth can support investment in new generation and transmission infrastructure, facilitate the development of renewable energy resources needed to meet Oregon's clean energy objectives, and contribute to the modernization of Oregon's electric system. A balanced assessment of LEUF load growth therefore requires the Commission to weigh these potential benefits alongside the risks identified.

B. Cost Allocation. For the reasons explained in my opening testimony, I continue to recommend that the Commission adopt a "higher of" pricing policy as the appropriate framework for allocating the costs of shared network

transmission and system generation investments associated with new LEUF load. While it is appropriate to directly assign the costs of sole-use transmission and distribution facilities to the customers that cause those investments, shared network transmission and system generation assets provide integrated system-wide benefits and should not be directly assigned by default. The "higher of" pricing policy protects existing customers from cost shifting when incremental investments would otherwise increase rates, while preserving the opportunity for cost-effective LEUF load growth to spread fixed system costs over a larger billing base and place downward pressure on rates.

I also disagree with PacifiCorp's assertion that a "higher of" pricing policy is not workable for a multi-state utility. As I will explain in further detail below, the higher of pricing framework can be implemented by situs assigning the transmission or generation investments to be recovered through an incremental rate and excluding the corresponding LEUF load from the applicable jurisdictional allocation factors. This approach ensures that PacifiCorp fully recovers the costs of the incremental investments from the LEUF customers that caused them, protects existing Oregon customers from cost shifting, prevents those investments from affecting interstate cost allocation, and ensures that customers in PacifiCorp's other jurisdictions do not bear any portion of those costs.

I further recommend that the Commission reject Staff's proposed Peak Growth Modifier ("PGM") methodology. Compared to the "higher of" pricing policy, the PGM is a significantly more complex ratemaking framework that

relies on subjective classifications of growth-related assets and requires the Company to maintain multiple vintages of generation and transmission investments with different allocation percentages over successive rate cases. In addition, as proposed by Staff, the PGM creates the potential for duplicative cost allocation by using the same increment of LEUF load both to assign growth-related investments and to allocate embedded system costs.

Finally, if the Commission elects to adopt either the PGM or PacifiCorp's proposed direct assignment framework, I recommend modifying those approaches to avoid duplicative cost allocation. Specifically, the portion of LEUF load used to assign incremental generation and transmission investments should not also be used to allocate embedded system costs.

C. Contract term and Minimum Demand. I recommend that the Commission reject Staff's and Environmental Intervenors' recommendation to adopt a minimum contract term that reaches a maximum of 30 years for customers with 220 MW or more of contract capacity, along with a 90% minimum demand charge. These provisions impose an unreasonable and disproportionate financial commitment on LEUF customers. As discussed later in my testimony, under Staff and the Environmental Intervenors' proposed terms, 500 MW of LEUF load would generate a minimum revenue guarantee of approximately $2.3 billion over the minimum contract term at PacifiCorp's filed Schedule 48 rates. That minimum revenue guarantee would increase further if Schedule 401 rates exceed Schedule 48 rates or as rates increase over time, and it goes well

beyond what is necessary to protect other customers from stranded asset risk and cost shifting.

In contrast, ADS witnesses Ms. Berry and Mr. Cain propose a 10-year minimum contract term, an optional five-year ramping period, and an 80% minimum demand charge. This approach is more reasonable and more consistent with provisions adopted in other jurisdictions.

The Commission should approve a more reasonable combination of terms establishing guaranteed minimum revenues from LEUF customers.

D. Surcharge to Fund Non-Cost-Effective Energy Efficiency. I recommend that the Commission reject the Environmental Intervenors' proposed $0.01/kWh surcharge applicable to LEUF customers. As proposed, the surcharge is not based on any identified revenue requirement, program budget, or estimate of the costs necessary to achieve the Environmental Intervenors' stated policy objectives. Instead, it establishes an arbitrary volumetric charge that could collect revenues substantially in excess of the amount actually required to fund any particular program. For illustrative purposes, a hypothetical 500 MW LEUF customer operating at a 90% load factor would contribute approximately $39.4 million annually, or approximately $1.2 billion over the Environmental Intervenors' proposed minimum contract term. When combined with the proposed minimum billing demand and contract term requirements, that customer would face a minimum financial commitment of approximately $3.5 billion.

I also do not support using utility rates to fund energy efficiency measures that are known to be non-cost-effective. Cost-effectiveness should remain a fundamental consideration in determining which energy efficiency programs are funded through utility rates. To the extent certain measures provide benefits that are not adequately reflected in existing cost-effectiveness tests, the Commission should evaluate whether those tests should be modified rather than intentionally funding measures that fail the applicable cost-effectiveness criteria.

Finally, LEUF customers will already make substantial contributions toward existing public purpose and low-income assistance programs through PacifiCorp's existing rider schedules. If the Commission determines that additional funding for low-income assistance, energy efficiency, renewable energy, energy storage, or other public policy initiatives is warranted, it should first determine the appropriate scope of those programs and the associated revenue requirement. The Commission can then establish a transparent, cost-based rider designed to recover that defined amount. In my opinion, that approach is more consistent with sound ratemaking principles than adopting an arbitrary surcharge before defining either the programs to be funded or the level of funding required.

E. Oregon House Bill 2021 ("HB 2021") Compliance. Staff and the Environmental Intervenors express concerns that rapid LEUF load growth could complicate PacifiCorp's ability to comply with HB 2021, particularly given the need to procure significant amounts of new non-emitting generation resources. PacifiCorp is responsible for complying with HB 2021 and other

applicable laws and should appropriately consider those requirements when developing plans of service for new LEUF customers. In particular, I agree that it would not be prudent to rely exclusively on fossil-fueled generation to serve incremental LEUF load growth or to energize new LEUF loads without procuring or developing sufficient clean energy resources.

At the same time, concerns about PacifiCorp's ability to comply with applicable laws should not unnecessarily limit opportunities for beneficial LEUF development. LEUF customers should be permitted to facilitate the development of new non-emitting resources through customer-provided generation, sleeving arrangements, or other Commission-approved special contract provisions when appropriate. These types of arrangements can help accelerate clean resource development while supporting PacifiCorp's compliance with HB 2021.

Finally, to the extent new LEUF load necessitates incremental generation investments, the associated costs should be allocated in accordance with cost-causation principles, consistent with my recommended "higher of" pricing policy or such other cost allocation methodology as the Commission determines appropriate. This approach helps ensure that the costs of complying with HB 2021 to serve incremental LEUF load are borne by the customers that cause those investments while preserving appropriate protections for existing customers.

III. FUNDAMENTAL POLICY CONSIDERATIONS

Q. INTERVENING PARTIES HAVE EXPRESSED CONCERNS REGARDING THE RISKS ASSOCIATED WITH NEW LEUF LOAD GROWTH. WHAT ARE SOME OF THE PRIMARY ISSUES THAT HAVE BEEN IDENTIFIED?

A. In general, the intervening parties, including Staff, the Environmental Intervenors, and CUB emphasize the importance of ensuring that new LEUF load does not shift unwarranted costs or risks to existing customers. Among other things, they express concerns regarding the potential for stranded investments if projected LEUF load growth does not materialize or if customers reduce or terminate service after PacifiCorp has made significant infrastructure investments. They also raise concerns regarding the uncertainty associated with planning for substantial new load growth, including the challenges of procuring sufficient generation resources, maintaining compliance with Oregon's clean energy policies, and achieving the emissions reductions required under HB 2021.

Q. **HOW DO YOU RESPOND TO THESE CONCERNS REGARDING LEUF LOAD GROWTH?**

A. I agree that appropriate protections are necessary and support the implementation of robust safeguards to protect existing customers from unwarranted cost shifting and stranded asset risk. However, it is equally important to recognize the significant potential benefits that responsible LEUF load growth can provide to Oregon ratepayers. A balanced assessment requires the Commission to consider both the risks and the benefits when determining the appropriate Schedule 401 framework

and associated customer protections. Otherwise, an overly one-sided focus on potential risks could result in an unnecessarily restrictive framework that limits beneficial investment in Oregon's energy infrastructure and reduces the opportunities for LEUF load growth to create value for existing customers.

Q. PLEASE DESCRIBE SOME OF THE POTENTIAL BENEFITS THAT LEUF LOAD GROWTH CAN PROVIDE TO OREGON RATEPAYERS?

A. LEUF load growth has the potential to provide several benefits to Oregon ratepayers. In particular, LEUFs increase the amount of load over which PacifiCorp's fixed system costs, including generation, transmission, and distribution infrastructure, can be recovered. Provided appropriate safeguards are in place to prevent unwarranted cost shifting, spreading these fixed costs across a larger customer base places downward pressure on rates for other customers.

LEUF customers also make substantial contributions toward riders and surcharges that fund public policy programs. Because the costs of many of these programs do not increase proportionately (or at all) with LEUF load growth, the additional revenues contributed by LEUF customers can reduce the rider rates paid by other customer classes.

Q: PLEASE PROVIDE A REAL-WORLD EXAMPLE OF THESE BENEFITS.

A: PacifiCorp has recognized this potential benefit in a recent Utah docket seeking approval of a large load special contract. Specifically, the Company explained that a new large load customer would not materially increase the costs of the programs funded through applicable surcharges, while at the same time generating significant additional revenues through those surcharges over the term of the special contract.

Because those surcharges would not be collected absent the new load, the Company concluded that the resulting revenues and associated program benefits represent a benefit of serving the new load.[1]

Q: PLEASE ELABORATE ON OTHER BENEFITS LEUFS CAN PROVIDE TO PACIFICORP AND ITS CUSTOMERS.

A: LEUF load growth can support investment in new generation, transmission, and other grid infrastructure. Increased demand creates opportunities to finance and develop additional renewable resources, expand transmission capacity, and modernize Oregon's electric system. These investments can improve system reliability, support compliance with Oregon's clean energy policies under HB 2021, and provide long-term benefits to all customers.

Q. ARE THERE OTHER PARTIES IN THIS PROCEEDING THAT HAVE ACKNOWLEDGED THE BENEFITS OF DATA CENTER LOAD GROWTH FOR EXISTING CUSTOMERS?

A. Yes. ADS witnesses Ms. Berry and Mr. Cain similarly identify several ways in which data center customers can benefit existing customers. They explain that data centers will contribute substantially to numerous rider schedules and that, because the costs of many of the associated programs do not increase proportionately with LEUF load growth, those additional contributions can reduce rider rates paid by other customers or increase funding available for the programs.[2] They also state

[1] *In the Matter of the Application of Rocky Mountain Power for Approval of Large-Load Service Contract Between PacifiCorp and a Large-Load Customer, UPSC Docket No. 26-035-05*, Direct Testimony of Craig M. Eller at 11-12 (Feb. 10, 2026).
[2] ADS /100, Berry–Cain /9.

that investments made to serve data center customers can displace investments that otherwise would have been required to replace aging infrastructure or improve reliability and resilience, thereby reducing upward pressure on rates.[3]

In addition, Ms. Berry and Mr. Cain describe data centers as drivers of generation and grid innovation, citing investments in technologies such as battery optimization, grid-enhancing technologies, and small modular nuclear reactors that they contend can lower costs for future electricity customers.[4] They further address concerns regarding stranded costs by explaining that allowing LEUF customers to reduce reserved capacity enables unused capacity to be redeployed to other customers and that spreading fixed system costs over a larger volume of energy sales can reduce rates for all customers. They also cite Indiana Michigan Power's February 2026 announcement of a base rate reduction, which the company attributed in part to load growth and increased revenues from large customers, including data centers.[5]

Q. HOW DO YOU RESPOND TO MS. BERRY AND MR. CAIN REGARDING THESE POTENTIAL BENEFITS FROM LEUF LOADS?

A. I generally agree with the analysis presented by Ms. Berry and Mr. Cain. Their testimony is consistent with my conclusion that LEUF load growth has the potential to provide meaningful benefits to existing customers by spreading fixed costs over a larger load base, providing additional contributions toward rider-funded

[3] *Id.* at 10.
[4] *Id.*
[5] *Id.* at 27.

programs, and by supporting investment in generation, transmission, and modernization of the electric grid.

At the same time, I recognize that these benefits will only be realized if Schedule 401 includes balanced customer protections that mitigate the risks of cost shifting and stranded costs without imposing unnecessarily restrictive requirements on LEUF customers. Accordingly, when determining the appropriate structure for Schedule 401, the Commission should give meaningful consideration to both the potential benefits and the risks associated with LEUF load growth.

IV. COST ALLOCATION

Multi-State Jurisdictional Cost Allocation Considerations

Q. HOW DOES PACIFICORP PROPOSE TO ALLOCATE COSTS TO SCHEDULE 401 LEUF CUSTOMERS?

A. In its filing, PacifiCorp proposed to serve new LEUFs under individually negotiated Large Energy Use Facility Agreements, under which all costs would be directly assigned to each customer.[6] PacifiCorp argued that direct assignment complies with Oregon House Bill 3546's ("HB 3546") requirement to mitigate unwarranted cost shifting to other retail customers[7] and that as a multi-jurisdictional utility, directly assigning costs to the customer that causes them is particularly important because

[6] PacifiCorp Application, Advice No. 25-015, Schedule 401, Service to New Large Energy Use Facilities, at 3.
[7] *Id.* at 4.

any spillage of costs due to imperfect cost assignment could implicate cost shifting across state lines.[8]

Q. WHAT POSITION DOES PACIFICORP TAKE IN ITS REBUTTAL TESTIMONY REGARDING COST ALLOCATION?

A. In his rebuttal testimony, PacifiCorp's witness Mr. Meredith continues to defend the direct assignment approach on the same grounds that direct assignment is the most appropriate way to comply with HB 3546's cost shifting requirements and that PacifiCorp's multi-state structure makes direct assignment particularly necessary to prevent Oregon LEUF costs from spilling over to customers in other states.[9]

Q. DO YOU CONTINUE TO SUPPORT YOUR RECOMMENDED "HIGHER OF" PRICING POLICY FOR ALLOCATING SHARED GENERATION AND TRANSMISSION ASSETS?

A. Yes. As discussed in my opening testimony, while direct assignment is appropriate for sole-use transmission and distribution facilities, shared network transmission and system generation assets provide integrated system-wide benefits and do not exclusively serve any single customer. Accordingly, I continue to recommend that the Commission reject direct assignment of those shared assets and instead adopt my proposed "higher of" pricing policy.

Q. ARE THERE SIMILARITIES BETWEEN THE COMPANY'S PROPOSED DIRECT ASSIGNMENT APPROACH AND YOUR RECOMMENDED "HIGHER OF" PRICING POLICY?

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[8] *Id.*
[9] PAC/100, Meredith/18-19.

A. Yes. Under PacifiCorp's proposal, an LEUF customer may be directly assigned the costs associated with certain network transmission or system generation investments required to provide service. Similarly, under my recommended "higher of" pricing policy, if new LEUF load triggers transmission or generation investments that would otherwise place upward pressure on rates for existing customers, the affected LEUF customer would be responsible for 100% of the revenue requirement associated with those investments through an incremental cost-based rate. In both approaches, the underlying objective is to ensure that the costs of incremental investments needed to serve new LEUF load are borne by the customers that cause those investments, rather than being shifted to existing customers.

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN THESE TWO FRAMEWORKS?

A. The primary difference is that my recommended "higher of" pricing policy uses an incremental cost-based rate only when necessary to prevent upward pressure on rates for existing customers. If new LEUF load can be served cost-effectively such that the incremental revenues exceed the incremental costs of serving that load, costs would instead continue to be allocated under the Commission's existing class cost allocation framework. As a result, existing customers would retain the potential benefits associated with load growth, including spreading fixed system costs over a larger billing base and placing downward pressure on rates.

Additionally, as I explain in my opening testimony, my recommended "higher of" pricing policy also avoids the potential for duplicative cost recovery

that can arise under a direct assignment framework if the associated system costs are not appropriately removed from the embedded cost allocation process.[10]

Q. HOW DOES PACIFICORP RESPOND TO DCC'S RECOMMENDED "HIGHER OF" PRICING POLICY?

A. Company witness Robert Meredith explains that PacifiCorp does not believe a "higher of" pricing policy is the appropriate mechanism for implementing HB 3546 in its service territory. According to Mr. Meredith, DCC's proposal was developed for a single-state utility in which shared system costs are allocated entirely within one jurisdiction. He contends that PacifiCorp's multi-state system presents a different challenge because any methodology for allocating shared costs must also account for interstate cost allocation. In Mr. Meredith's view, a class-level "higher of" pricing approach does not address that issue.[11]

Q. HOW DO YOU RESPOND TO MR. MEREDITH'S CONCERNS REGARDING THE APPLICATION OF THE "HIGHER OF" PRICING POLICY WITHIN A MULTI-STATE JURISDICTIONAL SYSTEM?

A. I disagree with Mr. Meredith. While PacifiCorp's multi-state jurisdictional utility framework is an important consideration, the "higher of" pricing policy can effectively and fairly be adopted in the context of PacifiCorp's multi-state operations while at the same time preserving the opportunity for new LEUF loads that can be served relatively cost effectively to put downward pressure on system costs and rates for all customers.

[10] DCC/100, Bieber/35-44.
[11] PAC/100, Meredith/46.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW YOUR RECOMMENDED "HIGHER OF" COST ALLOCATION METHODOLOGY COULD EFFECTIVELY OPERATE WITHIN PACIFICORP'S MULTI-STATE SYSTEM.

A. Under the "higher of" cost allocation methodology, if new transmission or generation investments required to serve an LEUF customer, or a cluster of LEUF customers, are sufficiently costly to trigger an incremental rate, that rate would be designed to recover 100% of the revenue requirement associated with those specific investments from the LEUF customers that caused them.

In PacifiCorp's multi-state system, those investments could be situs assigned to the Oregon jurisdiction, while the corresponding LEUF load is excluded from the applicable jurisdictional and class allocation factors used to allocate shared system costs among PacifiCorp's retail jurisdictions and among customer classes within Oregon.

Q: WHAT OBJECTIVES WOULD THIS APPROACH ACHIEVE?

A: This approach would achieve four important objectives.

1. **PacifiCorp would fully recover its costs.** Because the incremental rate would recover 100% of the revenue requirement associated with the new transmission or generation investments, PacifiCorp would recover its full costs directly from the LEUF customers responsible for those investments.
2. **Existing Oregon customers would be protected from cost shifting.** Because the LEUF customers would pay the full revenue requirement associated with the incremental transmission and generation investments

through the incremental rate, no portion of those costs would be allocated to other Oregon customer classes. At the same time, Schedule 401 load not subject to the incremental rate would continue to be allocated its appropriate share of existing system costs under the Commission's standard cost allocation methodologies. As a result, LEUF customers would remain responsible for their share of embedded system costs while fully bearing the costs of the incremental investments they cause.

3. **The incremental investments would not distort the jurisdictional cost allocation of shared system costs.** Excluding the portion of LEUF load that is assigned to pay an incremental rate from the applicable jurisdictional allocation factors would prevent the addition of that load from increasing Oregon's share of other shared system costs or altering the allocation of those costs among Oregon customer classes.

4. **Customers in other states would not bear any portion of the incremental investment costs.** Situs assigning the investments to Oregon would ensure that those costs are not allocated to customers in PacifiCorp's other retail jurisdictions.

This example illustrates that there is nothing inherently incompatible between a "higher of" pricing framework and PacifiCorp's multi-state jurisdictional cost allocation process. The two mechanisms address different questions. The "higher of" framework determines who should ultimately bear the costs of specific incremental investments, while the jurisdictional allocation process determines how the remaining shared system costs are allocated among PacifiCorp's retail

jurisdictions. With appropriate adjustments described above, these objectives can be implemented in a coordinated and consistent manner.

Q. DOES PACIFICORP ACKNOWLEDGE THAT SITUS ASSIGNMENT CAN BE AN EFFECTIVE MECHANISM TO ADDRESS MULTI-STATE COST ALLOCATION?

A. Yes. In rebuttal testimony, Mr. Meredith explains that costs directly assigned to a Schedule 401 customer would be situs assigned to Oregon, describing that approach as the cleanest way to ensure those costs are not allocated to customers in PacifiCorp's other jurisdictions.[12] Accordingly, PacifiCorp recognizes situs assignment as an appropriate mechanism for addressing multi-state jurisdictional cost allocation concerns.

Although Mr. Meredith discusses situs assignment in the context of the Company's proposed direct assignment framework, the same principle can be applied under my recommended "higher of" pricing policy. When an incremental rate is designed to recover 100% of the revenue requirement associated with specific transmission or generation investments from the LEUF customers that caused those investments, situs assigning those investments to Oregon would likewise ensure that customers in PacifiCorp's other jurisdictions are not responsible for any portion of those costs.

[12] *Id.* at 34.

Peak Growth Modifier ("PGM") Allocation Methodology

Q. WHAT DOES STAFF WITNESS BRET STEVENS PROPOSE REGARDING THE ALLOCATION OF SHARED GENERATION AND TRANSMISSION COSTS TO LEUF CUSTOMERS?

A. Mr. Stevens proposes that PacifiCorp adopt the Peak Growth Modifier ("PGM") cost allocation methodology to allocate shared growth-related generation and transmission costs to LEUF customers, similar to the method that the Commission adopted in PGE's recent large load proceeding, Docket No. UM 2377.[13]

Q. PLEASE DESCRIBE HOW STAFF'S PROPOSED PGM MECHANISM WOULD WORK.

A. Under the proposed PGM, PacifiCorp would first identify generation and transmission resources developed to serve incremental load growth. The revenue requirement associated with those growth-related assets would then be allocated among customer classes based on each class's share of weather-normalized load growth over the prior three years and the Test Year. Existing embedded assets that are not growth-related would continue to be allocated through the standard marginal cost study methodology.[14]

Mr. Stevens also proposes that PGM allocations be indefinite, meaning a growth-related asset would remain in the PGM until it is demonstrated that system usage no longer supports the allocation. This approach would require PacifiCorp to

[13] Staff/100, Stevens/52.
[14] *Id.*

track consecutive vintages of growth-related assets with different allocation percentages over time.[15]

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED PGM COST ALLOCATION METHODOLOGY?

A. I recommend that the Commission reject the proposal to implement PGM methodology to allocate network transmission and system generation costs.

As discussed in my opening testimony, I continue to recommend that the Commission adopt my proposed "higher of" pricing policy to allocate shared generation and transmission costs. That approach is more straightforward, transparent, and administratively workable than the PGM. It also better aligns with cost-causation principles by ensuring that new LEUF customers bear the costs of incremental investments when necessary to protect existing customers, while preserving the potential benefits of cost-effective load growth.

By comparison, the PGM is a highly complex ratemaking methodology that relies on subjective determinations regarding which investments qualify as "growth-related" assets. It would require PacifiCorp to establish and maintain multiple vintages of growth-related generation and transmission investments, each with potentially different allocation percentages that would need to be tracked and updated through successive rate cases. That complexity is particularly problematic for PacifiCorp's integrated multi-state system, where many generation and

[15] *Id.*

transmission resources are shared across multiple jurisdictions and are already subject to complex interstate allocation methodologies.

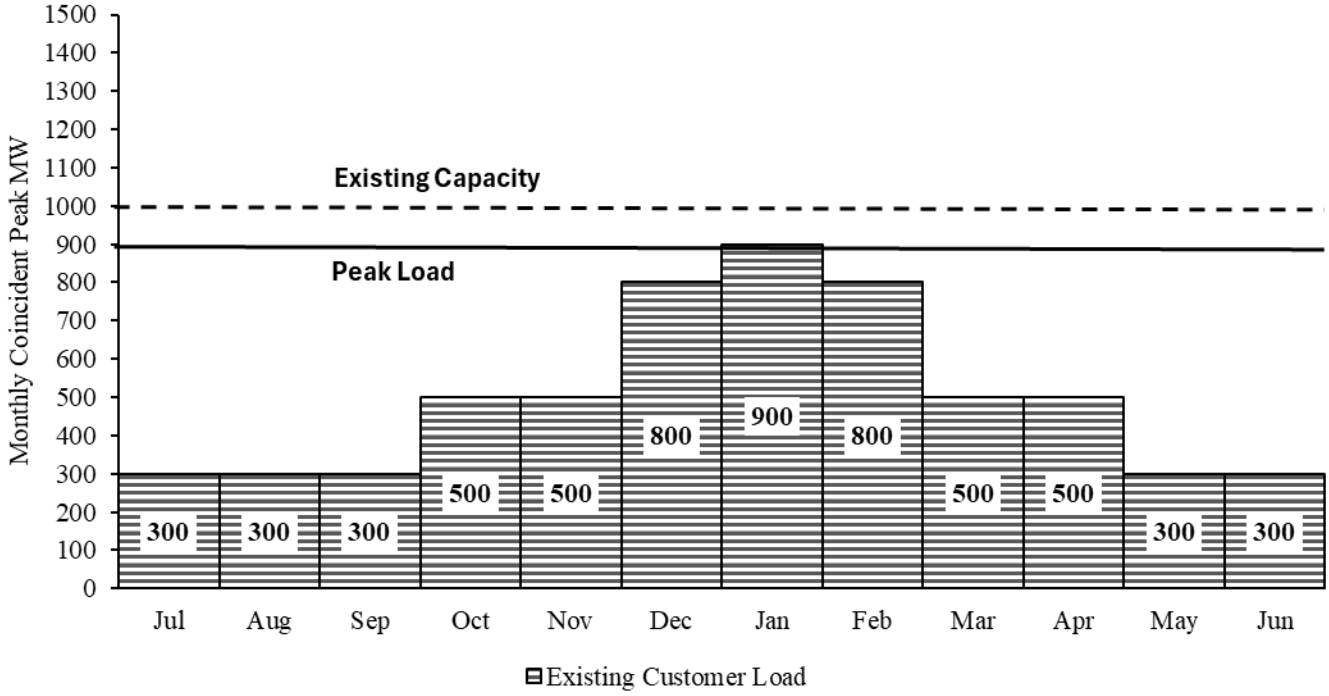
Further, as proposed by Staff, applying the PGM to allocate growth-related investments while simultaneously applying the existing embedded cost allocation methodologies to the remainder of the system costs creates the potential for duplicative cost allocation. It would not be reasonable to allocate growth-related assets based on incremental load growth investments and to allocate existing embedded costs based on that *same* incremental load.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE HOW DUPLICATIVE COST ALLOCATION CAN OCCUR UNDER STAFF'S PROPOSED METHODOLOGY WHEN THE SAME INCREMENTAL LOAD IS USED AS THE BASIS TO ALLOCATE GROWTH-RELATED ASSETS AND EXISTING SYSTEM COSTS?

A. In my opening testimony, I explained how the direct assignment of system facilities can lead to duplicative cost allocation. We can use a similar example to illustrate how the PGM methodology would have a similar result.

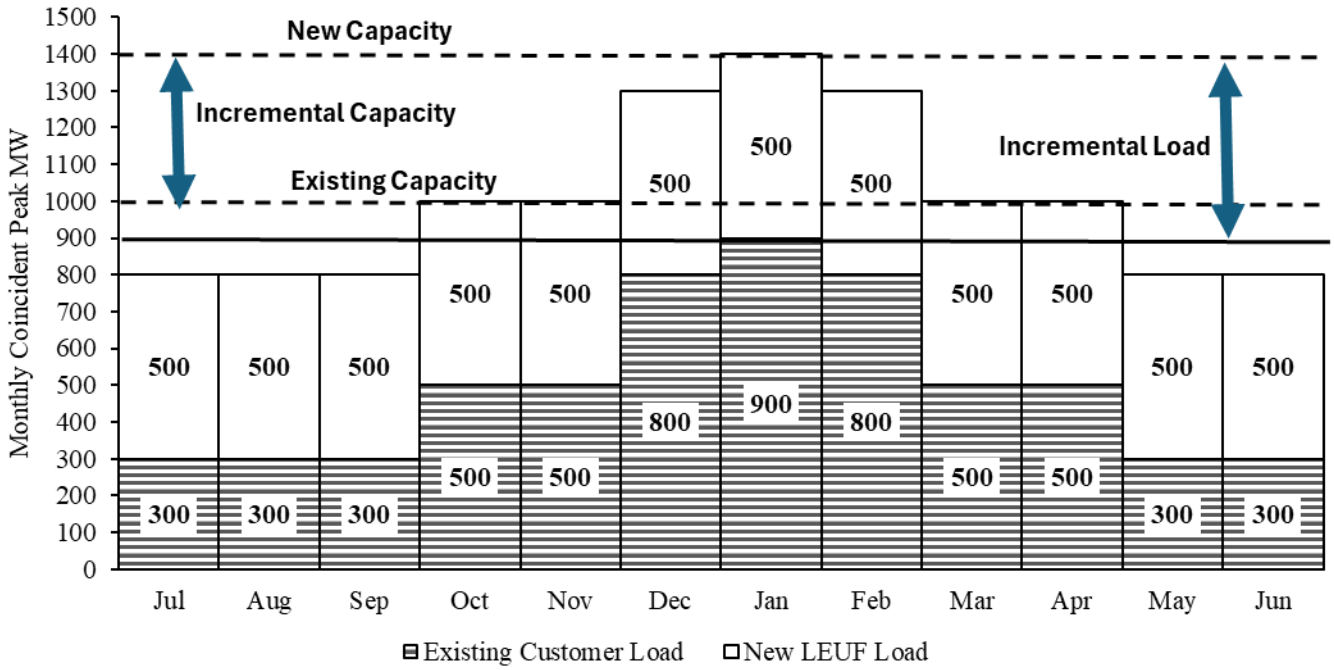
Consider a utility system with a 900 MW peak load that occurs in January, and monthly peak loads throughout the rest of the year that vary between 300 MW to 800 MW. And further, assume that the utility's portfolio of transmission and generation resources is capable of serving 1,000 MW of peak load, resulting in 100 MW of excess capacity, or headroom. This hypothetical system is illustrated in Figure JB-1 below.

Figure JB-1
Hypothetical Utility System Loads and Capacity
Existing System



Now assume that a new 500 MW LEUF customer requests electric service. In order to serve this new customer, the utility must invest in additional transmission and generation resources sufficient to increase total system capacity by 400 MW. The required incremental investment is 400 MW rather than 500 MW because the existing system already had 100 MW of unused capacity available to accommodate part of the new load. This revised system configuration is illustrated in Figure JB-2 below.

Figure JB-2
Hypothetical Utility System Loads and Capacity
Existing System Plus Incremental Load



Prior to the addition of the new large load, existing customers are responsible for the cost of 100% of the utility's 1,000 MW of load serving capacity. Under the PGM, the generation and transmission investments required to provide 400 MW of incremental capacity would be considered growth related and would be allocated to the new load based on its relative load growth. Additionally, under the proposed allocation framework, the embedded costs for existing 1,000 MW of system capacity would be allocated on a proportional basis based on *total* load.

Because the incremental new load was used to allocate the costs of *both* incremental growth-related assets and the existing system, that will result in a duplicative cost allocation to the new large load. Under this example, the new load would be allocated 100% of the incremental 400 MW of capacity plus 5/14ths of

the existing 1,000 MW system capacity,[16] or 357 MW.[17] In total, the customer would effectively be assigned cost responsibility for approximately 757 MW of capacity-related investment[18] despite having only 500 MW of actual incremental load.

Q. IF THE COMMISSION NONETHELESS DECIDES TO ADOPT THE PGM, ARE THERE ANY MODIFICATIONS THAT CAN HELP MITIGATE THIS POTENTIAL FOR DUPLICATIVE COST ALLOCATION?

A. Yes. If the Commission adopts the PGM, the portion of LEUF load growth used to assign growth-related assets under the PGM should not also be used to allocate embedded system costs through the standard marginal cost study. Only the portion of LEUF load that is not used to assign growth-related assets should be used to allocate existing embedded system costs. Otherwise, the same LEUF load would be used both to assign growth-related assets and to allocate embedded system costs, resulting in duplicative cost allocation.

Q. PLEASE ILLUSTRATE THIS RISK OF DUPLICATIVE COST ALLOCATION IN THE CONTEXT OF YOUR PREVIOUS EXAMPLE.

A. Returning to the example above, the utility initially had 100 MW of unused system capacity available before the LEUF customer requested service. Consequently, the utility only needs to construct an incremental 400 MW of capacity because 100

[16] Assuming a single coincident peak allocation methodology, the new 500 MW LEUF customer would be allocated 5/14ths of the existing system capacity costs, equal to their January peak load of 500 MW divided by 1,400 MW, the sum of the existing customers' 900 MW peak load and the new customer's 500 MW peak load during that month.
[17] 5/14ths x 1,000 MW = 357 MW.
[18] 400 MW + 357 MW = 757 MW.

MW of the customer's 500 MW load can be accommodated by existing system capacity. The remaining 400 MW of load necessitates new generation and transmission investments and is already fully reflected in the PGM allocation of the growth-related assets.

Under this modified approach, the LEUF customer would continue to be responsible for 100% of the 400 MW of growth-related investments through the PGM. However, only the 100 MW of load that could have been accommodated by existing system capacity would participate in the allocation of the embedded system costs. The resulting cost allocation is illustrated below.

Table JB-1
Modified PGM Illustrative Example Allocations

System Capacity	Existing Customers Load (MW)	LEUF Load (MW)	Total Load (MW)
Existing System Capacity (1,000 MW)	900 --> 90%	100 --> 10%	1,000 --> 100%
Growth Related Capacity (400 MW)	0 --> 0%	400 --> 100%	400 --> 100%
Total Capacity Allocated (1400 MW)	900 --> 64%	500 --> 36%	1,400 --> 100%

This approach better aligns cost responsibility with cost causation. The LEUF customer remains fully responsible for the 400 MW of new generation and transmission investments required to serve its incremental load while also paying its appropriate share of the existing system capacity.

Importantly, existing customers also benefit from this approach. Prior to the addition of the LEUF customer, the costs of the existing 1,000 MW system were recovered from only 900 MW of existing load. After the LEUF customer begins taking service, the first 100 MW of its load utilizes existing headroom that was already available on the system. Allowing that 100 MW of additional load to

participate in the allocation of embedded system costs spreads the fixed costs of the existing system over a larger billing base, placing downward pressure on rates for existing customers.

Accordingly, if the Commission elects to adopt the PGM, I recommend modifying the methodology so that only the portion of LEUF load not already used to assign growth-related investments is included in the allocation of embedded system costs. This modification preserves the objective of assigning the costs of growth-related investments to the customers that cause them while avoiding duplicative cost allocation and preserving the benefits associated with cost-effective load growth.

Q. YOU EXPLAIN ABOVE THAT THE PGM AND DIRECT ASSIGNMENT APPROACH BOTH HAVE THE POTENTIAL TO RESULT IN DUPLICATIVE COST ALLOCATION. IF THE COMMISSION ADOPTS THE COMPANY'S PROPOSED DIRECT ASSIGNMENT APPROACH, WOULD A SIMILAR MODIFICATION HELP MITIGATE THIS POTENTIAL FOR DUPLICATIVE COST ALLOCATION?

A. Yes. If the Commission adopts a direct assignment approach, the portion of LEUF load growth that is responsible for the direct assignment of new investment should not also be used to allocate embedded system costs through the standard marginal cost study. Only the portion of LEUF load that could not be served with existing system capacity should be used to allocate existing embedded system costs. Otherwise, the same LEUF load would be used to allocate both incremental

generation and transmission investments and to allocate embedded system costs, resulting in duplicative cost allocation.

Any cost allocation framework adopted in this docket must be carefully designed to ensure that the same costs are not recovered from LEUF customers twice through different allocation pathways.

V. CONTRACT TERM AND MINIMUM DEMAND

Q. WHAT DOES STAFF WITNESS BRET STEVENS RECOMMEND REGARDING CONTRACT TERM AND MINIMUM DEMAND CHARGES FOR LEUF CUSTOMERS?

A. Staff witness Mr. Stevens explains that the Commission recently approved a minimum contract term in PGE's large load proceeding under which the minimum contract term begins at 10 years for a 20 MW load and increases by one year for each additional 10 MW of allocated capacity, up to a maximum of 30 years for customers with 220 MW or more of allocated capacity. Mr. Stevens recommends that the Commission adopt a similar minimum contract term with a 10-year contract renewal term.[19] Mr. Stevens also recommends a 90% minimum demand for both generation and transmission, consistent with the framework adopted in that same order.[20]

[19] Staff/100, Stevens/29-30.
[20] *Id.* p. 42.

Q. WHAT DOES ENVIRONMENTAL INTERVENOR WITNESS JEREMY FISHER RECOMMEND REGARDING CONTRACT TERM AND MINIMUM DEMAND CHARGES?

A. Mr. Fisher also recommends a minimum contract term beginning at 10 years for a 20 MW load and increasing by one year for each additional 10 MW of allocated capacity, up to 30 years for loads of 220 MW or greater.[21] Mr. Fisher also recommends a 90% minimum demand charge applicable to both generation and transmission, consistent with the Commission's approval of a 90% minimum demand for generation and transmission in UM 2377.[22]

Q. WHAT DOES ADS PROPOSE REGARDING CONTRACT TERM AND MINIMUM DEMAND CHARGES?

A. ADS witnesses, Ms. Berry and Mr. Cain propose a minimum contract term of 10 years plus an optional five-year ramping period,[23] and an 80% minimum demand charge for transmission and distribution.[24]

Q. PLEASE EXPLAIN HOW THE MINIMUM CONTRACT TERM AND MINIMUM BILLING DEMAND PROVISIONS WORK IN CONJUNCTION WITH EACH OTHER.

A. The proposed minimum contract term and minimum billing demand provisions work together to establish minimum payment obligations that support recovery of peak demand and monthly demand-related charges over a defined period. In

[21] Environmental Intervenors/100, Fisher/24.
[22] *Id.* at 21-22.
[23] ADS/100, Berry–Cain/21
[24] *Id.* at 23-24. ADS does not propose a minimum demand charge for generation.

combination, they create a predictable baseline level of revenue tied to both the duration of service and the capacity reserved for each customer.

As illustrated in Table JB-2 below, under Staff and Environmental Intervenors' proposed minimum Initial Contract Term and Minimum Billing Demand, and at PacifiCorp's proposed Schedule 48 transmission voltage rates in its ongoing 2026 general rate case, Docket No. UE 470, 500 MW of new LEUF load would generate approximately $78.0 million in minimum billing demand revenues annually, or $2.3 billion over the proposed minimum contract term.

Table JB-2
Minimum Billing Demand Example
At Schedule 48 Rates Proposed in UE 470

Generation On-Pk Billing Demand($/kW-Mo)	7.73
Transmission On-Pk Billing Demand ($/kW-Mo)	5.38
Total G&T Demand Rate ($/kW-Mo)	**13.11**
Distribution Max Demand ($/kW-Mo)	1.20
Contract Capacity (MW)	500
Minimum Billing Demand (G&T)%	90%
Minimum Billing Distribution Demand %	100%
Annual Minimum G&T Demand Revenue ($)	70,794,000
Annual Minimum Distribution Demand Revenue ($)	7,200,000
Total Annual Minimum Demand Revenue ($)	**77,994,000**
Minimum Contract Term (Years)	30
Minimum Demand Revenues Over Contract	**2,339,820,000**

It is also important to note that the actual revenues received by the Company would be higher for customers whose loads regularly exceed the minimum billing demand, take service for a longer term, generate additional revenues during a load ramp period, or to the extent that the Company's actual Schedule 401 rates exceed

the rates that have been proposed for Schedule 48 in the Company's ongoing rate case.

Q. WHAT IS YOUR ASSESSMENT OF THESE MINIMUM CONTRACT TERM AND MINIMUM DEMAND PROPOSALS?

A. The combination of the minimum contract term and minimum billing demand proposed by Staff and the Environmental Intervenors is excessive and goes well beyond what is reasonably necessary to protect either existing customers or the Company from stranded asset and cost-shifting risks. Although there is currently significant uncertainty regarding the specific transmission and generation investments that will ultimately be required to serve future LEUF load, the proposed framework would require a 500 MW customer to make a minimum revenue commitment of approximately **$2.3 billion** over a 30-year contract term. In my opinion, a financial commitment of that magnitude is disproportionate to the risks it is intended to address.

A 30-year contractual commitment is also unusually long and exceeds the duration of most power purchase agreements and other long-term commercial energy contracts. Moreover, over the next 30 years PacifiCorp's resource portfolio will inevitably change. Even absent significant load growth, the Company is expected to retire significant coal-fired and other generating capacity over the next 10 to 20 years. Given the magnitude of those planned resource transitions, it is neither reasonable nor necessary to require LEUF customers to guarantee revenues over a 30-year period to protect against stranded investment risk.

In contrast, I find ADS's recommendation of an 80% minimum billing demand combined with a 10-year minimum contract term to be a more balanced approach. It provides meaningful protection against stranded asset risk while avoiding unnecessarily burdensome contractual obligations that could discourage economically beneficial LEUF development. It is also more consistent with the range of minimum demand requirements and contract terms adopted for large-load customers in other jurisdictions. Accordingly, I recommend that the Commission adopt a more balanced combination of minimum contract term and minimum billing demand provisions than those proposed by Staff and the Environmental Intervenors.

Q. ARE YOU AWARE OF OTHER JURISDICTIONS THAT HAVE ADOPTED CONTRACT TERM AND MINIMUM BILLING DEMAND PROVISIONS THAT ARE AS EXCESSIVE OR BURDENSOME AS THOSE RECOMMENDED BY STAFF AND THE ENVIRONMENTAL INTERVENORS?

A. No. Other than the Commission's recent decision in PGE's large load proceeding, I am not aware of any jurisdiction that has adopted minimum contract term and minimum billing demand provisions as restrictive as those recommended by Staff and the Environmental Intervenors. Table JB-3 compares the large load contract provisions recently adopted in several jurisdictions where the Data Center Coalition has participated. As shown below, the provisions adopted in those jurisdictions generally reflect significantly less stringent minimum contract terms and minimum billing demand requirements than those proposed by Staff and the Environmental

Intervenors, suggesting that meaningful protection against stranded asset risk can be achieved through less restrictive contractual requirements.

Table JB-3
Large Load Minimum Billing Demand and Contract Term Provisions In Other Jurisdictions

Utility	Docket No	Minimum Contract Term	Minimum G&T Billing Demand
Indiana Michigan Power Company, Indiana	IN-46097	12 years	80% of Contract Capacity
Consumers Energy Company, Michigan	U-21859	15 years	80% of Contract Capacity
Evergy, Kansas	25-EKME-315-TAR	12 years	80% of Contract Capacity
Evergy, Missouri	EO-2025-0154	12 years	80% of Contract Capacity
Xcel Energy, Minnesota	E-002/M-25-289	15 years	75% of Contract Capacity
Portland General Electric Company, Oregon	UM 2377	10 yrs at 20 MW; + 1 yr per 10 MW; Max 30 yrs at ≥220 MW.	90% of Contract Capacity

VI. SURCHARGE TO FUND NON-COST-EFFECTIVE ENERGY EFFICIENCY

Q. PLEASE EXPLAIN THE ENVIRONMENTAL INTERVENORS RECOMMENDED SURCHARGE ON LEUF CUSTOMERS?

A. Environmental Intervenors' witnesses Mr. Basofin and Mr. Brint recommend that the Commission require PacifiCorp to include a surcharge of $0.01/kWh applicable to all LEUF customers to fund non-cost-effective energy efficiency programs for low-income customers in PacifiCorp's service territory, as well as programs to

deliver renewable energy and storage to low-income customers and communities.[25] The Environmental Intervenors argue that HB 3546 provides the Commission with broad authority to include such a surcharge as a condition of the LEUF tariff in the public interest,[26] and they point to the Commission's recent approval of a similar surcharge for PGE customers with over 100 MW of allocated system capacity as precedent for this recommendation.[27]

Q. HOW MUCH REVENUE WOULD THE PROPOSED SURCHARGE RECOVER?

A. The amount of revenue to be recovered through the proposed surcharge would be dependent on the level of LEUF energy usage, which is currently unknown. However, for a 500 MW LEUF customer with a 90% load factor, the proposed $0.01/kWh surcharge would recover approximately $39.4 million annually, or approximately $1.2 billion over the Environmental Intervenors' proposed minimum contract term. These estimated revenues for a hypothetical 500 MW LEUF customer are illustrated in Table JB-4 below.

[25] Environmental Intervenors/201, Basofin-Brint/5-6.
[26] *Id.* p. 6
[27] *Id.* p. 7-8.

Table JB-4
Environmental Intervenors' Proposed Surcharge Revenues
For a 500 MW LEUF Customer with 90% Load Factor

Contract Capacity (MW)	500
Load Factor (%)	90%
Annual Energy Usage (kWh)	3,942,000,000
Surcharge Rate ($/kWh)	0.01
Annual Surcharge Revenue ($)	**39,420,000**
Minimum Contract Term (Years)	30
Surcharge Revenue over Contract Term ($)	**1,182,600,000**

When combined with the minimum demand revenue guarantee of approximately $2.3 billion resulting from the Environmental Intervenors' recommended contract term and minimum billing demand, the combination of Environmental Intervenor recommendations would impose a minimum financial commitment of approximately $3.5 billion on a 500 MW LEUF customer.

Q. HOW DO YOU RESPOND TO THE ENVIRONMENTAL INTERVENORS' RECOMMENDATION TO FUND NON-COST-EFFECTIVE ENERGY EFFICIENCY PROGRAMS?

A. Cost-effectiveness should remain a fundamental consideration in determining which energy-efficiency programs are funded through utility rates. Simply labeling a program as energy efficiency does not make it a prudent utility investment. To the extent certain measures provide benefits that are not fully captured by existing cost-effectiveness tests, then the Commission should re-evaluate those metrics rather than requiring LEUF customers to pay a substantial and arbitrary charge to fund an unknown level of revenue for programs that are known to be non-cost effective.

Q. WILL LEUF CUSTOMERS CONTRIBUTE TO PUBLIC PURPOSE PROGRAMS ABSENT THE ENVIRONMENTAL INTERVENORS' PROPOSED $0.01/KWH SURCHARGE?

A. Yes. I expect LEUF customers would contribute to the Company's existing rider schedules, including Schedule 90 that recover the costs of public policy programs, Schedule 91 for low-income discount cost recovery, Schedule 94 for vegetation management, Schedule 190 for wildfire mitigation, Schedule 204 for the Oregon Solar Incentive Program, Schedule 207 for Community Solar start-up cost recovery, Schedule 290 for the Public Purpose Charge, and Schedule 291 for the System Benefits Charge.

Q. WHAT IS YOUR ASSESSMENT OF THE ENVIRONMENTAL INTERVENORS' PROPOSED SURCHARGE?

A. I recommend that the Commission reject the proposed $0.01/kWh surcharge. As proposed, the surcharge is not based on any identified revenue requirement, program budget, or estimate of the costs necessary to achieve the Environmental Intervenors' stated policy objectives. Instead, it establishes an arbitrary volumetric charge that could collect revenues substantially in excess of the amount actually needed to fund any particular program.

In addition, the Environmental Intervenors propose using a portion of those revenues to fund non-cost effective energy efficiency measures. While I am not opposed to efforts to assist low-income customers and advance other important public policy objectives, I do not believe utility rates should be used to fund

programs that are known to be non-cost-effective absent a clear policy determination or supporting cost justification.

If the Commission determines that additional funding for low-income assistance, energy efficiency, renewable energy, energy storage, or other public policy initiatives is warranted, it should first determine the appropriate scope of those programs and the corresponding revenue requirement. The Commission can then establish a transparent, cost-based rider designed to recover that defined amount. In my opinion, that approach is more consistent with sound ratemaking principles than adopting an arbitrary surcharge before defining either the programs to be funded or the level of funding required.

VII. HB 2021 COMPLIANCE

Q. WHAT CONCERNS DOES STAFF WITNESS BRET STEVENS RAISE REGARDING HB 2021 COMPLIANCE IN THE CONTEXT OF LEUF LOAD GROWTH?

A. Mr. Stevens raises concerns that rapid LEUF load growth could impede PacifiCorp's ability to comply with HB 2021, particularly given the need to procure significant amounts of new non-emitting generation resources in a short period of time.[28]

Q. WHAT CONCERNS DOES ENVIRONMENTAL INTERVENOR WITNESS JEREMY FISHER RAISE REGARDING HB 2021 COMPLIANCE?

[28] Staff/100, Stevens/28.

A. Mr. Fisher raises two principal concerns. First, he argues that dramatic increases in data center load complicate PacifiCorp's ability to comply with HB 2021. Mr. Fisher asserts that PacifiCorp is not on track to meet its HB 2021 obligations and that even a handful of new data center customers could significantly worsen the Company's emissions profile.[29] Second, he raises concerns that allowing data centers to contract for emitting generation through special contracts would drive up PacifiCorp's emissions and result in indirect cost shifting to other customers as PacifiCorp compensates for those emissions elsewhere on its system.[30]

Q. WHAT IS YOUR RESPONSE TO THE CONCERNS RAISED BY STAFF AND THE ENVIRONMENTAL INTERVENORS REGARDING HB 2021 COMPLIANCE?

A. PacifiCorp is obligated to comply with HB 2021 and other applicable laws and should consider the relevant requirements when developing its plan of service for new loads. While I am not offering a legal opinion, based on my understanding of HB 2021 requirements, I would agree that it would not be prudent for the Company to procure only fossil-fueled generation to serve LEUF load growth or energize new LEUF loads without developing or procuring sufficient clean resources.

To address the concerns raised by Staff and the Environmental Intervenors, I recommend that LEUF customers be allowed to facilitate new resource development through onsite generation or negotiating deals for new resources that can be delivered through PAC (i.e. sleeving arrangements) consistent with Oregon

[29] Environmental Intervenors/100, Fisher/46.
[30] *Id.* p. 41.

law. These types of unique resource procurement arrangements can be handled through special contracts between the customer and PacifiCorp when appropriate, subject to Commission review and approval. This approach provides LEUF customers with flexibility to develop clean resources while supporting PacifiCorp's compliance with HB 2021.

Q. HOW SHOULD THE COSTS OF INCREMENTAL GENERATION RESOURCES TRIGGERED BY LEUF LOAD GROWTH BE ALLOCATED?

A. To the extent that new LEUF loads trigger the need for incremental generation resources, those costs can reasonably be allocated to Schedule 401 and other customer classes consistent with my recommended "higher of" pricing policy, or other cost allocation method determined by the Commission. This can ensure that the costs of clean resources procured to serve LEUF load growth are attributed to the customers that caused them, in a manner consistent with both HB 3546 cost causation requirements and HB 2021 clean energy requirements.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.