BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

In the Matter of	**)**	
PacifiCorp, dba Pacific Power,	**)**	**Docket No. UE 390**
2022 Transition Adjustment	**)**	
Mechanism	**)**	

Opening Testimony and Exhibits of Kevin C. Higgins

on behalf of

Calpine Energy Solutions, LLC

June 9, 2021

OPENING TESTIMONY OF KEVIN C. HIGGINS

<u>Introduction</u>

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this phase of the proceeding?

A. My testimony is being sponsored by Calpine Energy Solutions, LLC ("Calpine Solutions"). Calpine Solutions is a retail energy supplier that serves commercial and industrial end-use customers in 18 states, the District of Columbia, and Baja California, Mexico. Calpine Solutions serves more than 15,000 retail customer sites nationwide, with an aggregate load in excess of 4,500 MW. Calpine Solutions' retail customers are located in the service territories of more than 55 utilities. In Oregon, Calpine Solutions is an Electricity Service Supplier ("ESS") serving customers in the service territories of PacifiCorp and Portland General Electric ("PGE").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before this Commission?

A. Yes. I have testified in 31 prior proceedings in Oregon, including eleven previous PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 375 (2021 TAM), UE 339 (2019 TAM), UE 323 (2018 TAM), UE 307 (2017 TAM), UE 296 (2016 TAM), UE 264 (2014 TAM), UE 245 (2013 TAM), UE 227 (2012 TAM), UE 216 (2011 TAM), UE 207 (2010 TAM), and UE 199 (2009 TAM). I have also participated in seven PacifiCorp general rate cases, UE 374 (2020); UE 263 (2013), UE 246 (2012), UE 210 (2009), UE 179 (2006), UE 170 (2005), and UE 147 (2003), as well as the PacifiCorp Five-Year Opt-Out case, UE 267 (2013).

In addition, I have testified in six previous PGE general rate cases, UE 335 (2018), UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197 (2008), and UE

180 (2006). In addition, I testified in the PGE New Load Direct Access Case, UE 358 (2019); the PGE Opt-Out case, UE 236 (2012); and the PGE restructuring proceeding, UE 115 (2001).

I also testified in the Investigation into PacifiCorp's Non-Standard Avoided Cost Pricing, UM 1802 (2017); the 2017 Inter-Jurisdictional Allocation proceeding, UM 1050 (2016); and Phase II of the Investigation into Qualifying Facility Contracting and Pricing, UM 1610 (2015).

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 230 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also prepared affidavits that have been filed with the Federal Energy Regulatory Commission.

Overview and Conclusions

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

A. My testimony focuses on issues pertaining to direct access service, in particular, the calculation of the Consumer Opt-Out Charge[1] used in PacifiCorp's five-year

[1] The Consumer Opt-Out Charge is occasionally called the Customer Opt-Out Charge. I am using the term employed in PacifiCorp's tariff.

opt-out program and the treatment of Renewable Energy Certificates ("RECs") for direct access service.

Q. What are the primary conclusions and recommendations in your testimony?

A. For the first time since its inception, the calculation of the Consumer Opt-Out Charge produces a *negative* value. That is, the Consumer Opt-Out Charge, at least according to PacifiCorp's sample calculation for the 2022 TAM provided in conjunction with its filing, should be a credit to the customer, not a charge. However, in its presentation of the calculation, PacifiCorp has constrained the calculation such that the Consumer Opt-Out Charge can never be a customer credit, i.e., it is not permitted to fall below zero. Such a constraint is improper. The Commission should order PacifiCorp to remove any constraint on the calculation of the Consumer Opt-Out Charge that prevents it from resulting in a negative value. If the calculation of the Consumer Opt-Out Charge results in a negative value, then the Consumer Opt-Out Charge should properly be applied as a credit in the transition adjustment calculation. Such a symmetrical treatment is fundamental to the calculation of any stranded cost or transition adjustment mechanism.

Currently, PacifiCorp transfers RECs to a direct access customer's ESS to be retired on behalf of the direct access customer during the years for which that customer is paying transition adjustment charges to PacifiCorp. This arrangement was negotiated by Oregon stakeholders and approved by the Commission as an efficient means to resolve a longstanding dispute concerning the double payment by direct access customers for compliance with Oregon's renewable portfolio standard ("RPS"). The going-forward success of this arrangement may be in jeopardy, however, depending on the Commission's ultimate decision in AR 617. I recommend that if the Commission denies the clarification sought by Calpine Solutions in AR 617, and thereby causes the current REC transfer arrangement to no longer retain the full RPS compliance value, then the Commission should require that the market value of the freed-up bundled RECs be credited to direct access customers within the transition adjustment rates through an "RPS Adjustment." I further recommend that the RPS Adjustment be based on the RPS Adder developed by the California Public Utilities Commission ("CPUC") for a similar purpose. The RPS Adjustment should be incorporated into the PacifiCorp transition adjustment by adjusting upward the weighted average market price of energy freed-up by direct access by the amount of the RPS Adjustment that applies to the proportion of resources that must be RPS-eligible.

<u>Direct Access and the Transition Adjustment</u>

Q. What is the purpose of retail direct access under Oregon's direct access law?

A. Under a retail direct access program, the direct access customer continues to use the utility's distribution system but does not use the utility as its power supplier, but instead obtains energy from another supplier. Oregon's direct access law was initially enacted in 1999. In its findings supporting the legislation, the legislative assembly declared that "retail electricity consumers that want and have the technical capability should be allowed, either on their own or through aggregation, to take advantage of competitive electricity markets as soon as is practicable."[2] The direct access law requires that all nonresidential retail customers be allowed direct access to competitive markets by purchasing generation services from Commission-certified ESSs.[3] The law requires the Commission to implement rates that charge *or credit* the direct access customer an amount related to the utility's stranded generation assets that prevents "unwarranted shifting of costs."[4] This charge or credit is the transition adjustment, the derivation of which is a core objective of the TAM proceeding.

Q. What direct access products are available to PacifiCorp customers?

A. Currently, PacifiCorp offers one-year, three-year, and five-year direct access programs to existing customers. Qualifying new customers may also participate in the Company's New Load Direct Access ("NLDA") program.

Prior to the 2016 shopping year, customers in the PacifiCorp territory could only choose between the one-year and three-year programs, pursuant to which the direct access customer pays its ESS for generation supply and continues to pay PacifiCorp for Schedule 200 generation costs, subject to a transition adjustment discussed later in my testimony. At the conclusion of the one-year or three-year term the customer is required to return to cost-of-service or elect a new one-year or three-year term. Under this regime, the customer never stops paying for PacifiCorp's generation resources.

PacifiCorp's five-year opt-out program was initiated for service commencing on January 1, 2016, after the Company was ordered to adopt such a

[2] Or. Laws 1999, Ch. 865.
[3] *See* ORS 757.600(6), (16), -601(1), -649(1)(a).
[4] ORS 757.607(1), (2).

program in Order No. 12-500. In that order, the Commission required PacifiCorp to file a tariff for a five-year opt-out program that would allow a qualified customer to go to direct access and pay transition charges for the next five years, and then to be no longer subject to transition adjustments. After the conclusion of payments of five years of transition adjustments under the program, the customer would only pay PacifiCorp for distribution delivery service.

In contrast to the one-year and three-year programs, the five-year opt-out program allows customers to migrate to 100% market prices for generation services (purchased from an ESS) without any remaining obligations to compensate PacifiCorp for generation resources it has acquired for bundled customers.

Q. What is your understanding of the purpose of the transition adjustment?

A. The purpose of the transition adjustment is to provide the appropriate credit or charge for customers who choose direct access service. The transition adjustment is applied either through Schedule 294, Schedule 295, or Schedule 296. Schedule 294 is applied to customers who choose a one-year direct access option, Schedule 295 is applied to customers who choose a three-year direct access option, and Schedule 296 is applied to customers who select the five-year opt-out that was authorized in UE-267.

PacifiCorp's transition adjustment calculation is a form of Ongoing Valuation as prescribed in OAR 860-038-0140. According to OAR 860-038-0005(41):

Ongoing Valuation means the process of determining transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

The logical premise behind Ongoing Valuation is to credit or charge direct access customers the difference between market prices and cost-of-service rates. The design logic in this approach places customers in an economically "break even" position with respect to the choice of direct access service; that is, if market prices are below cost-of-service rates at the time the transition adjustment is calculated, the direct access customer is charged the difference via the transition adjustment. Conversely, if market prices are *above* cost-of-service rates, the direct access customer is *credited* the difference via the transition adjustment.

The corollary to this design logic is that it holds non-participating customers harmless, as the utility, which buys and sells billions of kilowatt-hours over the course of a year, should be able to dispose of the energy freed up by direct access through market transactions. In the case of PacifiCorp, the transition adjustment analysis consists of evaluating the impact of 25 MW of direct access load on a 10,000 MW system in the calculation of Schedules 294 and 295, and 50 MW of direct access load in the calculation of Schedule 296.

Q. Please explain how direct access can be viable if the design logic of Ongoing Valuation places direct access customers in an economically break even position.

A. For customers who attempt to select direct access service on a year-to-year basis, the Ongoing Valuation approach indeed makes direct access a tenuous value proposition. A one-year direct access selection may be economically viable in certain circumstances, such as, for example, if some market movement occurs during the shopping window, after the transition adjustment has been set. Additionally, other customers may wish to purchase more renewable energy than is available through PacifiCorp's cost-of-service portfolio. Alternatively, some customers may have a strong corporate preference for participating in the market, despite the barrier of contending with a "break even" transition adjustment design. But in general, the year-to-year "break even" model is not particularly attractive for customers. Indeed, more than twenty years after the initiation of direct access service in Oregon, there is only around 10 average megawatts (aMW) of load enrolled in PacifiCorp's one-year program and none in its three-year program at the current time.[5] The only direct access program that has shown signs of sustained success in Oregon outside of the NLDA program is PGE's five-year opt-out program, in which customers pay PGE's Ongoing Valuation transition adjustment for five years, and then migrate fully to market prices (with no further transition adjustments).

As I noted above, pursuant to the Commission's order in UE-267, PacifiCorp implemented a five-year opt-out program effective January 1, 2016. However, as I will discuss later in my testimony, the design of the transition adjustment for the PacifiCorp five-year opt-out has resulted in a negative value proposition for customers due to the inclusion of the Consumer Opt-Out Charge,

[5] *See* PacifiCorp's Response to Calpine Data Request 1.2.c, which is included in Calpine Solutions/102. According to the data response, the 10 aMW amount is "rounded to the nearest 15 average megawatts."

not a "break-even" scenario as discussed above. Consequently, the participation rate is low, with only around 30 aMW of load enrolled in the program.[6]

<u>Calculation of the One-Year and Three-Year Transition Adjustments (Schedules 294 and 295)</u>

Q. What is the basic structure of PacifiCorp's current charges for generation services?

A. PacifiCorp assesses rates for generation services to cost-of-service customers on two different rate schedules. First, the Company charges customers for its net power costs in Schedule 201, which includes long-term power purchase contracts, short-term market purchases, and fuel for power generation. Second, PacifiCorp charges customers for all other generation costs, including the costs of its rate-based generation investments, in Schedule 200.

Q. How is PacifiCorp's transition adjustment mechanism for Schedules 294 and 295 calculated?

A. PacifiCorp's transition adjustment charges (or credits) direct access customers the difference between PacifiCorp's net power cost (as reflected in Schedule 201) and the estimated market value of the electricity that is freed up when a customer chooses direct access service.[7] This is calculated by subtracting the former from

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[6] *See* PacifiCorp's Response to Calpine Data Request 1.2.c, which is included in Calpine Solutions/101. According to the data response, the 30 aMW amount is "rounded to the nearest 5 aMW."

[7] Direct access customers in PacifiCorp's service territory already pay for the Company's fixed generation costs through Schedule 200. Thus, the transition adjustment is calculated by subtracting *net power costs* from the value of freed-up energy rather than subtracting *total generation costs* from the value of freed-up energy. Calculating the transition adjustment in this manner is logically equivalent to subtracting total generation costs from the value of freed-up energy while *not* charging direct access customers for Schedule 200.

the latter, after adjusting the latter for line losses to reflect its value at the point of retail delivery. If the result is a positive number, the difference is applied as a credit to the direct access customer. If the result is a negative number, the difference is applied as a charge to the direct access customer.

Q. If Schedule 294 or 295 is a credit, does that mean that PacifiCorp's generation costs are less expensive than the market and that direct access customers are being paid to leave cost-of-service rates?

A. No. PacifiCorp direct access customers must continue to pay for the Company's fixed generation costs through Schedule 200. A Schedule 294 credit simply means that the Company's *net power costs* are less than market prices. Only if the Schedule 294 credit were greater than the Schedule 200 charge could it be accurate to state that direct access customers were being "paid" to leave cost-of-service rates. That is far from the case today. For example, PacifiCorp's sample 2022 Schedule 294 rate for a Schedule 48-Primary customer is an average credit of $14.27/MWh during Heavy Load Hours and an average credit of $11.07/MWh during Light Load Hours, while the average Schedule 200 charge for these customers in 2022 is projected to be $25.50/MWh.[8] Thus, the Schedule 200 charge is significantly greater than the transition adjustment credit, meaning that the direct access customer makes a net payment to PacifiCorp for generation resources that the customer does not use.

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[8] Sources: The average Schedule 294 credits are derived from PacifiCorp's Non-Confidential 15-Day workpaper, ORTAM22_TransAdjSummary. The average Schedule 200 rate for 2022 is provided by PacifiCorp in the Sample Schedule 296 calculation provided in the Company's Confidential 30-Day workpapers, ORTAM22 10 Yr Customer Opt-Out CONF, which is also provided in Exhibit Calpine Solutions/101. PacifiCorp consented to my use of the projected Schedule 200 charge as non-confidential in this testimony.

Q. Please continue with your explanation of how PacifiCorp's Schedule 294 and 295 transition adjustment mechanism is calculated.

A. The transition adjustment is calculated using PacifiCorp's GRID model. According to PacifiCorp's tariff, the estimated market value of the electricity that is freed up when a customer chooses direct access service is determined by running two system simulations – one simulation with PacifiCorp serving the direct access load and one simulation with the Company not serving the direct access load. At the present time, for the Schedule 294 one-year and Schedule 295 three-year programs, these simulations are run assuming direct access occurs in 25 MW decrements, which are shaped using the load shape of the rate schedule being analyzed for purposes of determining its Schedule 294 or 295 credit (or charge). The difference between the two scenarios is used to calculate the impact on PacifiCorp's total system, which is then used to determine the "weighted market value of the energy" freed up due to direct access.[9] The weighted market value of the energy is then compared to the customer's price under Schedule 201 to determine the Schedule 294 or 295 charge or credit.

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[9] *See* PacifiCorp Tariff, Schedule 294, p. 1. Note that pursuant to a Stipulation in UE 199 approved by the Commission in Order No. 08-543, monthly thermal generation that is backed down for assumed direct access load is priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID.

<u>Calculation of the Five-Year Transition Adjustment (Schedule 296) and Consumer Opt-Out Charge</u>

Q. How is PacifiCorp's transition adjustment mechanism for Schedule 296 calculated?

A. PacifiCorp's sample calculation of Schedule 296 is provided as part of its 30-Day Confidential workpapers.[10] I have provided non-confidential excerpts from this work paper that summarizes PacifiCorp's sample calculation for Schedules 30-S, 30-P, 47/48-S,47/48-P, and 47/48-T in Exhibit Calpine Solutions/101.[11]

Schedule 296 consists of two major parts: (1) a five-year transition adjustment component that structurally is nearly identical to the calculation of the Schedule 294 and 295 transition adjustments, and (2) a Consumer Opt-Out component, which brings forward into Years 1 through 5 the projected Schedule 200 costs for Years 6 through 10, net of projected net power costs savings attributed to the departed opt-out load.

In addition to the Schedule 296 charge, the customer must also pay PacifiCorp the base Schedule 200 charge for five years, which may be updated in each rate case during that period.

From the effective date of the opt-out election forward, the customer also pays charges for the generation and delivery that the customer will use to serve its load, which includes payments to an ESS for the generation and to PacifiCorp for delivery service under an applicable delivery service tariff.

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[10] Specifically, ORTAM22_10 Yr Customer Opt-Out CONF.

[11] PacifiCorp's sample calculations are presented on pages 1, 3, 5, 7, and 9 in Exhibit Calpine Solutions/101. PacifiCorp consented to my use of these excerpts as non-confidential in this testimony.

Q. Does Schedule 296 result in a negative value proposition for customers during the five-year opt-out period?

A. Generally, yes. The primary source of the negative value proposition since the inception of the program has been the Consumer Opt-Out charge, which brings forward projected costs from Years 6 through 10 and recovers them in Years 1 through 5. It is self-evident that even if the transition adjustment itself were a break-even proposition (as intended per the Ongoing Valuation approach) the addition of costs from future years to an otherwise break-even transition adjustment creates a negative value proposition in the amount of the additional charge, i.e., in the amount of the Consumer Opt-Out charge itself.

So, for example, under the current Schedule 296, which resulted from last year's TAM proceeding, a Schedule 748-Primary customer would receive a transition adjustment credit of $14.14/MWh in Year 1 (2021) of the five-year opt-out,[12] while paying an average of around $25.50/MWh for Schedule 200,[13] for a net charge of $11.36/MWh, prior to considering the Consumer Opt-Out charge. Conceptually, under ongoing valuation, this $11.36/MWh net charge is *intended* to produce a "break-even" value proposition for the direct access customer relative to cost-of-service rates, after taking into account the customer's purchase of power from the competitive market. But, in <u>addition</u>, the five-year opt-out customer would pay a Consumer Opt-Out charge of $3.76/MWh.[14] Thus, the Consumer Opt-Out charge has all but ensured that the program would present a

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[12] PacifiCorp tariff, Schedule 296.
[13] I am using PacifiCorp's projection of average Schedule 200 rates for 2022 in this example.
[14] *Id.*

negative value proposition for the participant during the five-year transition period.

Q. You indicated that, structurally, the five-year transition adjustment component of Schedule 296 is nearly identical to the calculation of the Schedule 294 and 295 transition adjustments. In what ways does it differ from the Schedule 294 and 295 calculation?

A. Aside from the obvious fact that it is calculated for five years (instead of one or three), the transition adjustment component of Schedule 296 is calculated assuming 50 MW of direct access load rather than 25 MW, as is assumed for Schedules 294 and 295. The five-year opt-out customers will also pay Schedule 200 rates for each of the first five years of the opt-out period. In this manner, Schedule 296 is comparable to Schedule 294. Schedule 295 is slightly different, in that three-year opt-out customers pay for *projected* Schedule 200 costs, rather than contemporaneous Schedule 200 costs. Otherwise, the Schedule 296 transition adjustment component is calculated in a manner that is identical to the Schedule 294 and 295 transition adjustments.

Q. In prior TAM dockets in recent years, there have been disagreements between PacifiCorp and Calpine Solutions regarding the cost escalation rate for Schedule 200 that is used in the calculation of the Consumer Opt-Out Charge. These disagreements were ultimately resolved through stipulations approved by the Commission. Is the 2022 TAM filed by the Company consistent with the approved stipulations?

A. Yes. In calculating the Consumer Opt-Out Charge, PacifiCorp applies a cost escalator to Schedule 200 costs for the five years of the transition period. For years 6 through 10 of the calculation, which are used to calculate the Consumer Opt-Out Charge, no cost escalation is applied to Schedule 200 costs, consistent with the approved stipulations.

Q. Are there aspects of the Company's sample calculation for the Schedule 296 Consumer Opt-Out Charge that are a concern in this case?

A. Yes. For the first time since its inception, the calculation of the Consumer Opt-Out Charge produces a *negative* value. That is, the Consumer Opt-Out Charge, at least according to the sample calculation, should be a credit, not a charge. However, in its presentation of the calculation, PacifiCorp has constrained the calculation such that the Consumer Opt-Out Charge can never be below zero. Such a constraint is improper. If the calculation of the Consumer Opt-Out Charge results in a negative value, then the Consumer Opt-Out Charge should properly be applied as a credit.

Q. How can the Consumer Opt-Out Charge logically be a credit?

A. Mathematically, the Consumer Opt-Out Charge can result in a credit if the weighted market value of the energy freed-up due to direct access is significantly greater than net power costs in customer rates projected for years 6 through 10 in the transition cost analysis. Recall that the Consumer Opt-Out Charge incorporates the projected Schedule 200 costs for Years 6 through 10, <u>net</u> of projected net power costs savings attributed to the departed opt-out load. If projected net power costs savings attributed to the departed opt-out load are great enough, the Consumer Opt-Out calculation can be negative. That is what is occurring in PacifiCorp's Schedule 296 sample calculation.

Q. Has PacifiCorp explained why it constrained the calculation of the Consumer Opt-Out Charge such that it could never be below zero?

A. Yes. In its response to Calpine Data Request 1.4, PacifiCorp states:

> The customer opt-out charge was designed as a charge to recover PacifiCorp's fixed generation costs, offset by the value of freed-up power made available by departing customers. If the value of freed-up power is greater than the fixed generation costs, then the customer opt-out is unnecessary and it should be eliminated (i.e. zeroed out), not converted into a credit. Such a credit would be inconsistent with a mechanism that protects non-direct access customers from cost-shifting.[15]

Q. What is your response to this argument?

A. The Company's rationale should be rejected by the Commission. PacifiCorp cannot have it both ways. The recovery of Schedule 200 costs extending five years *past* the five-year transition period was PacifiCorp's idea in the first place and it was adopted by the Commission over the objections of nearly every other party to UE 267.[16] Since its inception, the Consumer Opt-Out Charge has created a negative value proposition that has impeded the development of direct access service for existing customers in PacifiCorp's territory. Now that the Consumer Opt-Out Charge *may* be turning negative, it should not be prevented from falling below zero. There is nothing in the Commission's order in UE 267 approving the Consumer Opt-Out Charge that restricts it from becoming negative. Moreover, it

[15] PacifiCorp's Response to Calpine Data Request 1.4 is provided in Exhibit Calpine Solutions 1.4.
[16] In UE 267, ten parties, including the OPUC Staff, entered into a stipulation opposing adoption of PacifiCorp's Consumer Opt-Out Charge proposal. PGE was also a party in that case and took no position on the stipulation.

is well understood that transition adjustment calculations in Oregon are to reflect stranded benefits (i.e., credits) as well as stranded costs (charges).[17] In advocating for inclusion of the Consumer Opt-Out Charge in the five-year program , PacifiCorp's witness, Gregory Duvall, successfully argued: "OAR 860-038-0160(1) expressly provides that direct access customers must pay or receive 100 percent of transition costs *or benefits*."[18] The referenced administrative rule states, in relevant part, that:

> [E]ach Oregon retail electricity consumer . . . *will receive a transition credit or pay a transition charge* equal to 100 percent of the net value of the Oregon share of all economic utility investments and all uneconomic utility investments of the electric company as determined . . . pursuant to . . . an ongoing valuation.[19]

PacifiCorp's position in this case violates this important principle.

Q. Will allowing the Consumer Opt-Out Charge to become a credit cause cost-shifting to non-direct access customers, as PacifiCorp contends?

A. No. As I explained, the only reason that the Consumer Opt-Out Charge can become a credit is if there are substantial net power costs <u>savings</u> attributed to the departed opt-out load in years 6 through 10. That is, the net power cost savings from the departed load at the margin are projected to be much higher than the average net power costs charged to customers in rates. Consequently, costs are <u>not</u> shifted to non-direct access customers if the Consumer Opt-Out Charge is negative because the calculation recognizes the net power cost savings that will be

[17] *See* ORS 757.607(2) (providing for "transition charges" or "transition credits"); ORS 757.600(10) (defining "transition credits" that return the benefits of "economic utility investments").
[18] UE 267 PAC/400, Duvall/3 (emphasis added).
[19] OAR 860-038-0160(1) (emphasis added).

realized by the non-direct access customers as a result of the departure of the opt-out load.

Q. If the constraint is removed from the sample Schedule 296 calculation such that the Consumer Opt-Out Charge were allowed to be negative, how much would the credit be?

A. I present these results in Exhibit Calpine Solutions/101.[20] Using PacifiCorp's inputs and assumptions, but removing the artificial floor on the Consumer Opt-Out Charge, results in a credit ranging from $1.62/MWh to $4.99/MWh, depending on the rate schedule.

Q. If paid, would these credits represent net payments to five-year opt-out customers in the context of the overall transition adjustment mechanism?

A. With limited exceptions, no. As I discussed above, during the five-year transition period, opt-out customers would still be subject to Schedule 200 charges. As shown in Exhibit Calpine Solutions/101 (even pages), the absolute value of the sum of the NPC-related transition adjustment credit and the Consumer Opt-Out credit in columns (c) and (e) is always less than the Schedule 200 charge in column (d) for each eligible rate schedule in the sample calculation, with the limited of exceptions of Schedules 47/48-P and 47/48-T in 2026. Therefore, at the Consumer Opt-Out credit levels I calculated for the sample calculation, five-year opt-out customers would nearly always be making net transition payments to PacifiCorp in order to participate in the program.

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[20] I present these calculations on pages 2, 4, 6, 8, and 10 in Exhibit Calpine Solutions/101. The exhibit is structured such that for each applicable rate schedule, PacifiCorp's sample calculation is presented first, followed on the next page by my calculation showing the Consumer Opt-Out credit amount.

Q. If a Consumer Opt-Out credit results in a net payment to opt-out customers, does that change your recommendation?

A. No. If the transition adjustment calculation results in a net overall credit, then both fairness and consistency with the statute dictate that a net credit should be paid to the opt-out load. Here I am simply pointing out that a Consumer Opt-Out credit by itself does not necessarily result in a net credit overall to opt-out customers. Indeed, as I just explained, for the sample Schedule 296 calculations presented in this case, the recognition of a Consumer Opt-Out credit typically does not result in a net overall credit to opt-out customers.

Q. What is your recommendation to the Commission?

A. The Commission should order PacifiCorp to remove any constraint on the calculation of the Consumer Opt-Out Charge that prevents it from resulting in a negative value. If the ordinary calculation of the charge produces a negative value, then it should be treated as a credit in the transition adjustment calculation. Such a symmetrical treatment is fundamental to the calculation of any stranded cost or transition adjustment mechanism.

<u>**Renewable Energy Certificates ("RECs")**</u>

Q. Please summarize the background related to the treatment of RECs in the context of direct access service.

A. RECs generated by PacifiCorp's renewable resources are freed up by a direct access election because the utility's RPS obligation is reduced proportionately to a direct access customer's load when that customer migrates to direct access.[21] Additionally, during the years in which the direct access customer continues to pay transition charges, the direct access customer continues to pay for the utility's RPS-compliant resources through the transition adjustment charges, Schedule 200 in particular. For each MWh of electric energy produced by the RPS-compliant resources in the utility's portfolio, the resource also produces a REC. However, despite including the value of the freed-up *energy* in the transition adjustment calculation, the transition adjustment mechanism in Oregon was developed without inclusion of any credit for the value of the freed-up RECs. Further, the RPS requires the ESS to meet the RPS obligation for the customers' load it serves, and the direct access customers must pay their ESS for the RECs necessary to meet that RPS obligation tied to those customers' load. In past TAM proceedings, Calpine Solutions pointed out that this situation effectively resulted in double payment by direct access customers for RPS compliance as a condition of participating in direct access.[22]

Q. Please explain the background that led to the adoption of the transfer of freed-up bundled RECs.

A. After Calpine Solutions raised this issue in multiple past TAMs, the Commission adopted a temporary REC credit in PacifiCorp's transition adjustment calculation in Docket No. UE 323, but it directed the parties to work to develop a method of transferring the freed-up RECs to be retired on behalf of the direct access

[21] ORS 469A.052(1)(c), 469A.065.
[22] UE 323 Calpine Solutions/100, Higgins/17-18.

customer.[23] The Commission directed: "In the 2019 TAM, the company is to present its best proposal for REC transfers, so that parties may weigh in and build a full record on this issue that will enable us to decide whether REC transfers are practical and feasible."[24]

In response, the parties worked in good faith to develop an agreement for the transfer of the freed-up RECs to the ESS, which the Commission approved in the next TAM proceeding.[25] Under the agreement, PacifiCorp transfers RECs to the ESS to be retired on behalf of the direct access customer served by that ESS during the years for which that the customer is paying transition adjustment charges to PacifiCorp.[26] PacifiCorp transfers RECs on an annual basis to a WREGIS account identified by the direct access customer's ESS.[27]

The Commission-approved agreement including the following key provisions:

- Transfers will begin following the first year of direct access, to meet the ESS's RPS compliance obligation.
- At least 80 percent of the transferred RECs will be RECs that, before the transfer, were considered bundled.

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[23] *In Re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444, at 19 (Nov. 1, 2017).
[24] *Id.*
[25] *In Re PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, at 9 & App. A, p. 8, ¶ 28 (Oct. 26, 2018). The terms of the agreement were set forth in PacifiCorp's testimony. UE 339 PAC/100, Wilding/46-47.
[26] UE 339 PAC/100, Wilding/46-47.
[27] UE 339 PAC/100, Wilding/46.

- PacifiCorp is not responsible for the retirement of RECs or claims made about the RECs on behalf of the direct access consumer or ESS, or any RPS compliance of the direct access consumer or ESS.[28]

The overall intent of the agreement was that the RECs would be sufficient to meet the RPS compliance requirement – including at least 80 percent bundled and up to 20 percent unbundled proportions – as if that customer were still served by PacifiCorp.

Q. Has the agreement been implemented successfully?

A. Yes. The agreement and its implementation resolved years of disagreement over what had been, up to that point, a seemingly intractable problem. However, the agreement did not address whether the transferred bundled RECs would remain "bundled" RECs for purposes of RPS compliance. That issue was left to be clarified by the Commission.

Q. Why was it important for the Commission to clarify that the transferred bundled RECs would retain their bundled nature for RPS compliance purposes if retired by the ESS on behalf of customers still paying transition charges?

A. This was not a significant issue prior to RPS compliance year 2021 because prior to compliance year 2021 the RPS allowed ESSs to meet their RPS obligation solely with unbundled RECs. However, beginning in compliance year 2021, the categorical exemption from the RPS's limitations on the use of unbundled RECs is eliminated for ESSs, and ESSs must meet at least 80 percent of their RPS

[28] UE 339 PAC/100, Wilding/46-47.

compliance with the use of bundled RECs, subject only to more limited exceptions.[29]

If the Commission concludes that the transferred bundled RECs cannot retain their bundled nature for RPS compliance purposes, the intent of the Commission-approved mechanism to return the benefit of such RECs to direct access customers will be frustrated. The transferred bundled RECs at issue are transferred to an ESS solely for the purpose of returning the stranded benefit of the RECs to the direct access customers who are continuing to pay for the underlying PacifiCorp RPS resources through transition charges. The ESS is merely acting as the agent for the customer in this Commission-approved mechanism to return stranded benefits to the customer. Beginning in RPS compliance year 2021, the customers would be financially harmed if such transferred RECs lose their bundled nature for RPS compliance purposes because the ESS would need to secure additional bundled RECs that would satisfy the limitations on the use of unbundled RECs for RPS compliance – bundled RECs that the direct access customer has already paid for through their transition adjustment charges.

From Calpine Solutions' perspective, this is a customer equity issue, and the direct access customers should not be deprived of the value of this stranded benefit that could be used to offset some of the costs of participating in retail choice.

[29] ORS 469A.145. The exceptions to the bundled REC requirement are allowances for unlimited use of unbundled RECs from net metering facilities and from qualifying facilities located in Oregon. ORS 469A.145(2)-(3).

Q. Has the Commission clarified that the freed-up bundled RECs will retain their bundled nature when retired by an ESS on behalf of direct access customers paying transition charges?

A. Not at this time. Calpine Solutions attempted to obtain such clarification in advance of the 2021 compliance year by asking for such clarification during the Commission's review of Calpine Solutions' 2020 RPS Compliance Filing. However, Staff proposed that the issue should instead be addressed in a rulemaking docket addressing RPS compliance issues, Docket No. AR 617, and Calpine Solutions agreed to seek clarification in that proceeding.

Q. Is the issue being addressed in Docket No. AR 617?

A. My understanding is that the issue has been raised and addressed by Calpine Solutions and Staff. Calpine Solutions requested that the new administrative rules clarify that that the Commission will approve the use of transferred freed-up bundled RECs as bundled RECs for RPS compliance purposes when retired by the recipient ESS, and provided a draft rule that it believed would achieve this result. However, Staff opposed Calpine Solutions' proposal and has taken the position that the transferred freed-up RECs would not retain their bundled nature even if retired by the ESS on behalf of the direct access load still paying transition charges. Staff maintains that existing statutes would not allow for transferred RECs to remain bundled.[30] Given Staff's recommendation, Calpine Solutions is concerned that it will not receive the clarification it hoped would be provided

[30] *Staff Report*, Docket No. AR 617, at 6-7 (March 1, 2021).

after the parties engaged in good faith negotiations to develop the REC transfer mechanism.

Q. What action do you recommend the Commission should take in this case?

A. I recommend that if the Commission denies the clarification sought by Calpine Solutions in AR 617, the Commission should require that the full market value of the freed-up bundled RECs be credited to the direct access customers within the transition adjustment rates. This should occur by adjusting upward the weighted average market price of energy freed-up by direct access by an RPS Adjustment that applies to the proportion of resources that must be RPS-eligible (i.e., 20% at the current time).

Q. How should the value of the RPS Adjustment be determined?

A. This subject was addressed in past TAM proceedings, but parties to previous TAM cases were not able to agree on a valuation method to accomplish this. In large part, the lack of agreement on a valuation method provided the impetus for the REC transfer arrangement that is currently in place.

However, if the Commission denies the clarification sought by Calpine Solutions in AR 617, then it will be necessary to revisit the question of REC valuation. Fortunately, the CPUC has developed an approach for valuing bundled RECs, called the “RPS Adder,” for a similar purpose, i.e., calculating a transition adjustment for direct access load. If it is necessary to value bundled RECs in the calculation of the transition adjustment, then I recommend using the RPS Adder calculated by the CPUC Energy Division for this purpose.

Q. Please explain further.

A. Direct access customers in California are subject to a transition adjustment called the Power Charge Indifference Adjustment "PCIA." The PCIA is calculated annually and exists to address stranded costs associated with direct access customer participation. Similar to the Ongoing Valuation calculation in Oregon, the PCIA is calculated by taking the difference between a utility's actual portfolio cost (i.e., costs related to utility-owned generation and purchased power) and the market value of the portfolio, called the Market Price Benchmark ("MPB"). In calculating the PCIA, the MPB is adjusted upward by the RPS Adder. The RPS Adder is calculated by the CPUC Energy Division using the reported prices of purchases and sales of renewable energy by the state's investor-owned utilities, community choice aggregators, and California's equivalent of ESSs.[31] Thus, significantly, the RPS Adder is based on a wide range of actual market transactions. It is also separated from the underlying value of the energy, making it a reasonable and administratively efficient proxy for setting an RPS Adjustment in Oregon. In 2020, the RPS Adder was calculated to be $15.10/MWh and in 2021 it is projected to be $14.49/MWh.[32]

In summary, if the Commission denies the clarification sought by Calpine Solutions in AR 617, then I recommend that that the full market value of the freed-up bundled RECs be credited to the direct access customers within the transition adjustment rates. This should occur by adjusting upward the weighted

[31] California Public Utilities Commission, Rulemaking 17-06-026, Decision Modifying the Power Charge Indifference Adjustment Methodology (October 11, 2018) at 73 and 120.
[32] *See* CPUC Application 20-07-002 (U 39 E), Pacific Gas and Electric Company, 2021 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast revenue Return and Reconciliation, Update to Prepared Testimony, pp. 11-12.

average market price of energy freed-up by direct access by an RPS Adjustment that applies to the proportion of resources that must be RPS-eligible. For administrative efficiency, I recommend that the RPS Adder calculated by the CPUC Energy Division be used to set my recommended RPS Adjustment.

To be clear, my primary recommendation is that the Commission continue to facilitate the current practice of transferring bundled RECs as negotiated by stakeholders. However, if the RPS compliance value effectuated by the current practice is thwarted by adoption of Staff's position in AR 617, then my proposal to use the RPS Adder calculated by the CPUC Energy Division to value the RECs freed up by PacifiCorp direct access customers should be adopted as an alternative.

Q. Does this conclude your opening testimony?

A. Yes, it does.

Docket No. UE 390

EXHIBIT

Calpine Solutions 101

Example Calculations

Schedule 30 (Secondary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
PacifiCorp's Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=Max of 20 55-22 88 or 0
2022	$21.96	$35.18	($13.22)	-	$26.45	-	$0.00
2023	$21.81	$35.24	($13.43)	-	$26.98	-	$0.00
2024	$22.86	$39.45	($16.59)	-	$27.52	-	$0.00
2025	$24.03	$43.05	($19.02)	-	$28.10	-	$0.00
2026	$25.04	$49.45	($24.41)	-	$28.72	-	$0.00
2027	$25.69	$55.77		($30.08)		$28.72	
2028	$29.98	$60.80		($30.82)		$28.72	
2029	$32.74	$66.52		($33.78)		$28.72	
2030	$33.61	$66.03		($32.42)		$28.72	
2031	$34.20	$67.49		($33.29)		$28.72	
10-Year Net Present Value (1)				($94.01)		$84.45	$0.00
5-year Nominal Levelized Payment				($22.88)		$20.55	$0.00

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 30 (Secondary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
Calpine Solutions' Example Calculation ($/MWh) - w/ Customer Opt-Out Credit

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		= 20 55-22 88
2022	$21.96	$35.18	($13.22)	-	$26.45	-	($2.33)
2023	$21.81	$35.24	($13.43)	-	$26.98	-	($2.33)
2024	$22.86	$39.45	($16.59)	-	$27.52	-	($2.33)
2025	$24.03	$43.05	($19.02)	-	$28.10	-	($2.33)
2026	$25.04	$49.45	($24.41)	-	$28.72	-	($2.33)
2027	$25.69	$55.77		($30.08)		$28.72	
2028	$29.98	$60.80		($30.82)		$28.72	
2029	$32.74	$66.52		($33.78)		$28.72	
2030	$33.61	$66.03		($32.42)		$28.72	
2031	$34.20	$67.49		($33.29)		$28.72	
10-Year Net Present Value (1)				($94.01)		$84.45	($9.55)
5-year Nominal Levelized Payment				($22.88)		$20.55	($2.33)

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 30 (Primary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
PacifiCorp's Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=Max of 20 90-22 53 or 0
2022	$22.32	$35.18	($12.86)	-	$26.90	-	$0.00
2023	$22.17	$35.24	($13.07)	-	$27.44	-	$0.00
2024	$23.23	$39.45	($16.22)	-	$27.99	-	$0.00
2025	$24.42	$43.05	($18.63)	-	$28.58	-	$0.00
2026	$25.44	$49.45	($24.01)	-	$29.21	-	$0.00
2027	$26.10	$55.77		($29.67)		$29.21	
2028	$30.46	$60.80		($30.34)		$29.21	
2029	$33.26	$66.52		($33.26)		$29.21	
2030	$34.14	$66.03		($31.89)		$29.21	
2031	$34.74	$67.49		($32.75)		$29.21	
10-Year Net Present Value (1)				($92.56)		$85.90	$0.00
5-year Nominal Levelized Payment				($22.53)		$20.90	$0.00

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 30 (Primary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
Calpine Solutions' Example Calculation ($/MWh) - w/ Customer Opt-Out Credit

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		= 20 90-22 53
2022	$22.32	$35.18	($12.86)	-	$26.90	-	($1.62)
2023	$22.17	$35.24	($13.07)	-	$27.44	-	($1.62)
2024	$23.23	$39.45	($16.22)	-	$27.99	-	($1.62)
2025	$24.42	$43.05	($18.63)	-	$28.58	-	($1.62)
2026	$25.44	$49.45	($24.01)	-	$29.21	-	($1.62)
2027	$26.10	$55.77		($29.67)		$29.21	
2028	$30.46	$60.80		($30.34)		$29.21	
2029	$33.26	$66.52		($33.26)		$29.21	
2030	$34.14	$66.03		($31.89)		$29.21	
2031	$34.74	$67.49		($32.75)		$29.21	
10-Year Net Present Value (1)				($92.56)		$85.90	($6.67)
5-year Nominal Levelized Payment				($22.53)		$20.90	($1.62)

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 47/48 (Secondary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
PacifiCorp's Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=Max of 20 61-22 87 or 0
2022	$21.97	$35.18	($13.21)	-	$26.53	-	$0.00
2023	$21.82	$35.24	($13.42)	-	$27.06	-	$0.00
2024	$22.87	$39.45	($16.58)	-	$27.60	-	$0.00
2025	$24.04	$43.05	($19.01)	-	$28.18	-	$0.00
2026	$25.05	$49.45	($24.40)	-	$28.80	-	$0.00
2027	$25.70	$55.77		($30.07)		$28.80	
2028	$30.00	$60.80		($30.80)		$28.80	
2029	$32.76	$66.52		($33.76)		$28.80	
2030	$33.63	$66.03		($32.40)		$28.80	
2031	$34.22	$67.49		($33.27)		$28.80	
10-Year Net Present Value (1)				($93.96)		$84.69	$0.00
5-year Nominal Levelized Payment				($22.87)		$20.61	$0.00

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 47/48 (Secondary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
Calpine Solutions' Example Calculation ($/MWh) - w/ Customer Opt-Out Credit

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		= 20 61-22 87
2022	$21.97	$35.18	($13.21)	-	$26.53	-	($2.26)
2023	$21.82	$35.24	($13.42)	-	$27.06	-	($2.26)
2024	$22.87	$39.45	($16.58)	-	$27.60	-	($2.26)
2025	$24.04	$43.05	($19.01)	-	$28.18	-	($2.26)
2026	$25.05	$49.45	($24.40)	-	$28.80	-	($2.26)
2027	$25.70	$55.77		($30.07)		$28.80	
2028	$30.00	$60.80		($30.80)		$28.80	
2029	$32.76	$66.52		($33.76)		$28.80	
2030	$33.63	$66.03		($32.40)		$28.80	
2031	$34.22	$67.49		($33.27)		$28.80	
10-Year Net Present Value (1)				($93.96)		$84.69	($9.27)
5-year Nominal Levelized Payment				($22.87)		$20.61	($2.26)

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 47/48 (Primary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
PacifiCorp's Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=Max of 19 82-23 83 or 0
2022	$21.03	$35.18	($14.15)	-	$25.50	-	$0.00
2023	$20.89	$35.24	($14.35)	-	$26.01	-	$0.00
2024	$21.89	$39.45	($17.56)	-	$26.53	-	$0.00
2025	$23.01	$43.05	($20.04)	-	$27.09	-	$0.00
2026	$23.97	$49.45	($25.48)	-	$27.69	-	$0.00
2027	$24.59	$55.77		($31.18)		$27.69	
2028	$28.70	$60.80		($32.10)		$27.69	
2029	$31.34	$66.52		($35.18)		$27.69	
2030	$32.17	$66.03		($33.86)		$27.69	
2031	$32.74	$67.49		($34.75)		$27.69	
10-Year Net Present Value (1)				($97.90)		$81.43	$0.00
5-year Nominal Levelized Payment				($23.83)		$19.82	$0.00

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 47/48 (Primary)
Schedule 390 - Five Year Cost of Service Opt-Out Program
Calpine Solutions' Example Calculation ($/MWh) - w/ Customer Opt-Out Credit

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		= 19 82-23 83
2022	$21.03	$35.18	($14.15)	-	$25.50	-	($4.01)
2023	$20.89	$35.24	($14.35)	-	$26.01	-	($4.01)
2024	$21.89	$39.45	($17.56)	-	$26.53	-	($4.01)
2025	$23.01	$43.05	($20.04)	-	$27.09	-	($4.01)
2026	$23.97	$49.45	($25.48)	-	$27.69	-	($4.01)
2027	$24.59	$55.77		($31.18)		$27.69	
2028	$28.70	$60.80		($32.10)		$27.69	
2029	$31.34	$66.52		($35.18)		$27.69	
2030	$32.17	$66.03		($33.86)		$27.69	
2031	$32.74	$67.49		($34.75)		$27.69	
10-Year Net Present Value (1)				($97.90)		$81.43	($16.48)
5-year Nominal Levelized Payment				($23.83)		$19.82	($4.01)

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 8.01%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 47/48 (Transmission)
Schedule 390 - Five Year Cost of Service Opt-Out Program
PacifiCorp's Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=Max of 18 65-23 64 or 0
2022	$19.74	$34.02	($14.27)	-	$24.01	-	$0.00
2023	$19.61	$34.08	($14.47)	-	$24.49	-	$0.00
2024	$20.55	$38.15	($17.60)	-	$24.98	-	$0.00
2025	$21.60	$41.63	($20.03)	-	$25.50	-	$0.00
2026	$22.50	$47.82	($25.32)	-	$26.06	-	$0.00
2027	$23.08	$53.93		($30.85)		$26.06	
2028	$26.94	$58.79		($31.85)		$26.06	
2029	$29.42	$64.33		($34.91)		$26.06	
2030	$30.20	$63.85		($33.65)		$26.06	
2031	$30.73	$65.27		($34.54)		$26.06	
10-Year Net Present Value (1)				($97.15)		$76.63	$0.00
5-year Nominal Levelized Payment				($23.64)		$18.65	$0.00

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 4.45%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Schedule 47/48 (Transmission)
Schedule 390 - Five Year Cost of Service Opt-Out Program
Calpine Solutions' Example Calculation ($/MWh) - w/ Customer Opt-Out Credit

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		= 18 65-23 64
2022	$19.74	$34.02	($14.27)	-	$24.01	-	($4.99)
2023	$19.61	$34.08	($14.47)	-	$24.49	-	($4.99)
2024	$20.55	$38.15	($17.60)	-	$24.98	-	($4.99)
2025	$21.60	$41.63	($20.03)	-	$25.50	-	($4.99)
2026	$22.50	$47.82	($25.32)	-	$26.06	-	($4.99)
2027	$23.08	$53.93		($30.85)		$26.06	
2028	$26.94	$58.79		($31.85)		$26.06	
2029	$29.42	$64.33		($34.91)		$26.06	
2030	$30.20	$63.85		($33.65)		$26.06	
2031	$30.73	$65.27		($34.54)		$26.06	
10-Year Net Present Value (1)				($97.15)		$76.63	($20.51)
5-year Nominal Levelized Payment				($23.64)		$18.65	($4.99)

Notes:
(1) 2022 through 2031 using a 6.92% Discount Rate
(2) Losses at 4.45%

Data Source:
1. PacifiCorp 30 Calendar Day CONFIDENTIAL Workpaper - 10 Yr Customer Opt Out

Docket No. UE 390

EXHIBIT

Calpine Solutions 102

PacifiCorp Responses to Data Requests Referenced in Testimony

Calpine Data Request 1.2

Please provide the following information regarding PacifiCorp's Oregon retail load in 2020, expressed in MWH, and indicate whether PacifiCorp's sales to Georgia Pacific-Camas are included in (a) and (b):

(a) Total Oregon retail load excluding direct access.

(b) Total Oregon retail load that was eligible for direct access.

(c) Direct access load differentiated into the categories of (i) annual, (ii) three-year opt out, (iii) five-year opt-out, and (iv) New Load Direct Access.

Response to Calpine Data Request 1.2

(a) Total Oregon retail load excluding direct access for 2020 was 12,993,459 megawatt-hours (MWh). There were no sales to Georgia-Pacific Camas (GP Camas).

(b) Non-residential retail customers are eligible for direct access. PacifiCorp's Oregon non-residential retail load for 2020 was 7,233,620 MWh. PacifiCorp had no sales to GP Camas.

(c) Please refer to the responses to subparts (i) through (iii) below:

PacifiCorp objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. Loads associated with specific customers are not relevant to this proceeding. Without waiving this objection, the company responds as follows:

i. Rounded to the nearest 15 average megawatts (aMW), the enrolled annual load is 10 aMW.

ii. No customers elected to participate in the three-year opt-out program.

iii. Rounded to the nearest 5 aMW, the enrolled load is 30 aMW.

Calpine Data Request 1.4

Please refer to TAM Support Set 4 (30-calendar day confidential work papers), specifically the confidential file "ORTAM22_10 Yr Customer Opt Out CONF" which provides the sample Schedule 296 calculation for Schedule 30-Secondary and Schedule 48-Primary.

(a) Please confirm that the sample calculations have been constrained such that the Customer Opt-Out Charge cannot be negative.

(b) Please explain the rationale for constraining the Customer Opt-Out Charge such that it cannot be negative.

(c) Please cite to any Settlement Agreements or Commission Orders requiring that the Customer Opt-Out Charge cannot be negative.

Response to Calpine Data Request 1.4

(a) Confirmed. The customer opt-out charge cannot be negative; the floor for the recovery of cost calculation is a positive value with a floor of zero.

(b) PacifiCorp objects to this request to the extent this response requires legal analysis and therefore beyond the scope of discovery in this proceeding. Without waiving the foregoing objection, PacifiCorp responds as follows:

The customer opt-out charge was designed as a charge to recover PacifiCorp's fixed generation costs, offset by the value of freed-up power made available by departing customers. If the value of freed-up power is greater than the fixed generation costs, then the customer opt-out is unnecessary and it should be eliminated (i.e. zeroed out), not converted into a credit. Such a credit would be inconsistent with a mechanism that protects non-direct access customers from cost-shifting.

(c) PacifiCorp objects to this request to the extent this response requires legal analysis and therefore beyond the scope of discovery in this proceeding. Without waiving the foregoing objection, PacifiCorp responds as follows:

Please refer to the Company's response to subpart (b), above.