Docket No. UM 1802
Exhibit PAC/100
Witness: Daniel MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP

Opening Testimony of Daniel MacNeil

January 2017

OPENING TESTIMONY OF DANIEL MACNEIL

TABLE OF CONTENTS

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

A. My name is Daniel MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Resource and Commercial Strategy Adviser.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by PacifiCorp since 2008, first as a member of the Net Power Costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to PacifiCorp's resource portfolio and obligations.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony addresses whether the Company's non-standard avoided cost pricing[1] should include a renewable price option, and how that renewable price option should be calculated. Specifically, I address:

- When a non-standard renewable avoided cost price stream is appropriate.
- How non-standard renewable avoided cost prices should be calculated.

[1] In my testimony, non-standard avoided cost pricing refers to the Company's Non-Standard Avoided Cost Rates offering, formerly known as Schedule 38.

- Whether there is a systematic difference between avoided cost prices and market prices.

USE OF A RENEWABLE AVOIDED COST PRICE STREAM

Q. Should there be a non-standard renewable avoided cost price stream?

A. The Company understands the desire to have separate prices for renewable qualifying facilities (QFs) that could provide renewable energy certificates (RECs or Green Tags) to the Company and defer renewable portfolio standard (RPS) compliant resources. The Company acknowledges that the Public Utility Commission of Oregon (Commission) has established separate renewable and non-renewable pricing streams for standard QFs.[2] The Company agrees that renewable avoided cost pricing should be available for non-standard renewable QFs when: (1) the preferred portfolio in the Company's most recent Integrated Resource Plan (IRP) identifies the need for a renewable resource of the same type; and (2) the identified need exists during the term of the QF's PPA.[3] Renewable avoided cost prices for non-standard QFs would be calculated using limited modifications to the Partial Displacement Differential Revenue Requirement (PDDRR) methodology recently approved by the Commission.[4]

CALCULATION OF A RENEWABLE AVOIDED COST PRICE STREAM

Q. Why is the PDDRR method appropriate for calculating renewable avoided cost pricing?

A. The Commission has concluded that the PDDRR methodology "more accurately values

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[2] *See Disposition: Policies Adopted*, Docket No. UM 1396, Order No. 11-505 at 2 (Dec. 13, 2011). In my testimony, standard avoided cost pricing refers to the Company's Standard Avoided Cost Rates offering, formerly known as Schedule 37.
[3] The Company's IRP preferred portfolio identifies the costs, timing, and characteristics of the renewable resources it expects to incorporate in its portfolio.
[4] *In re Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 2 (May 13, 2016).

energy and capacity on PacifiCorp's system by taking into account the unique characteristics (including location, delivery pattern, and capacity contribution) for each QF."[5] The Commission also recognized that the PDDRR methodology "improves non-standard QF avoided cost pricing for QFs selling to PacifiCorp."[6]

The same reasons that supported use of PDDRR to defer non-renewable resources apply to renewable resources, and it can be easily tailored to reflect deferral of various resource types. The PDDRR method has the following benefits, which can be realized in the context of renewable avoided cost prices:

- Incorporates the unique characteristics of each QF resource and the Company's system by utilizing its Generation and Regulation Initiative Decision Tools model (GRID) to calculate the value of energy and capacity from QFs to directly measure the impact each QF facility has on the Company's power costs. This accounts for QF location, delivery pattern, and capacity contribution.
- Aligns with the Company's long term resource plan by incorporating the cost, timing, and characteristics of the preferred portfolio identified by the IRP.
- Captures the impact of individual and aggregate QFs on PacifiCorp's system, accounting for unique characteristics of each QF.
- Appropriately accounts for the seven factors identified in 18 CFR § 292.304(e)(2).

Q. How would a renewable PDDRR work?

A. QFs partially displace the next major thermal resource in the IRP based on their capacity contribution. The Company proposes that under a renewable PDDRR, renewable QFs

[5] *Id.* at 23.
[6] *Id.*

would instead defer the next major renewable resource of the same type in the IRP preferred portfolio, again based on equivalent capacity contributions. While the GRID PDDRR methodology can reasonably account for the differences in value between resources in two geographic locations, to maintain a consistent load and resource balance, it is important to maintain the total effective capacity contribution identified in the preferred portfolio.

Based on the capacity contribution study being prepared for the 2017 IRP, each megawatt of west-side tracking solar resources is estimated to provide approximately 109% of the capacity provided by each megawatt of east-side tracking solar resources.[7] As a result, a 10MW Oregon tracking solar QF would defer 10.9MW of an east-side tracking solar resource from an IRP preferred portfolio. The same capacity contribution study indicates that a west-side wind resource provides approximately 75% of the capacity provided by each megawatt of east-side wind. Consequently, a 10MW Oregon wind QF would defer 7.5MW of an east-side wind resource from an IRP preferred portfolio.[8] If the potential QF queue fully displaces the IRP renewable resources of a given type, pricing would revert to the current non-renewable avoided cost pricing methodology, with the QF partially displacing the next thermal resource (adjusted for the capacity contribution of the QF).

[7] 2017 Integrated Resource Plan. Public Input Meeting 7 Presentation, slide 56. Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM07_1-26-17_Presentation.pdf.
East Tracking Solar: 59.7%. West Tracking Solar: 64.8%. 64.8% / 59.7% = 109%
[8] East Wind: 15.8%. West Wind: 11.8%. 11.8% / 15.8% = 75%.

Q. Should additional aspects of the IRP analysis and preferred portfolio be taken into consideration?

A. Yes. The intent of the PDDRR method is to identify alternatives that achieve the same low-cost, low-risk planning objective as the preferred portfolio selected in the IRP. To the extent the IRP identifies additional resource selection constraints to ensure these objectives are achieved, those constraints should also be accounted for in the PDDRR. Such constraints could include geographic limits based on transmission availability or requirements for dispatchable resources. The resource-specific and location-specific capacity contribution values identified in the 2015 IRP, which are being updated for the 2017 IRP, are an example of a resource selection constraint that is already reflected in the PDDRR method.

Q. Why is it appropriate to limit deferral to renewable resources of the same type (i.e. solar for solar, wind for wind)?

A. Renewable resources have significant differences in their operational characteristics, and widely varying impacts on the Company's system. For instance, solar generation is more prevalent in the summer with diurnal and seasonal characteristics based on the position of the sun and the potential for cloud cover. On the other hand, wind output is more prevalent in the winter and while not as predictable as the rising of the sun, it is strongly correlated to the output of other wind resources in the vicinity. Despite some geographic differences, renewable resources of the same type are thus much more similar to each other than they are to renewables of other types. Maintaining capacity equivalence between resources with widely disparate capacity contributions could introduce unintended consequences and unreasonable results. With this in mind, the Company believes it appropriate to limit the deferral of renewable resource capacity to QFs of the same type.

Q. Doesn't deferral of non-renewable resources by a renewable QF also have disparate capacity contributions and unintended consequences?

A. Not to the same extent. First, the PDDRR methodology has already been shown to accurately value energy and capacity and has been adopted by the Commission. Second, because deferred thermal resources have capacity contributions of 100%, the resource being deferred is always equal in size or smaller than the resource being added, so the incremental impact on the system is relatively small. Based on the capacity contribution of solar and wind resources being prepared for the 2017 IRP, 10 megawatts of a west-side tracking solar resource would defer 55 megawatts of west-side wind capacity.[9] Because wind and solar have different seasonal and hourly shapes, this could rapidly create an imbalance. Deferring a smaller quantity of a thermal resource with little seasonality would create less of a potential mismatch.

Q. How would RECs be handled under a renewable PDDRR?

A. As is the case today, during the renewable resource sufficiency period, the QF would keep the RECs they generate; the Company would acquire the RECs during the renewable resource deficiency period.[10] QFs would also continue to keep the RECs they generate during the resource deficiency period if their avoided cost pricing was based on deferral of a non-renewable resource. However, if QF pricing included deferral of a

[9] West Tracking Solar: 64.8%. West Wind: 11.8%. 64.8% / 11.8% = 549%.
[10] *In re Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*, Docket No. UM 1396, Order No. 11-505 at 1 (Dec. 13, 2011). "*The renewable resource QF will keep all associated Renewable Energy Certificates (RECs) during periods of renewable resource sufficiency, but will transfer those RECs to the purchasing utility during periods of renewable resource deficiency….*"

renewable resource, the Company would receive the RECs generated during the resource deficiency period.

Q. Is the renewable resource deferral in the Company's proposal comparable to that in the non-standard avoided cost methodologies employed in its other jurisdictions?

A. Yes. In Utah, when there is a "like" cost-effective renewable resource in PacifiCorp's planned resources, that resource is displaced in the determination of a QF's avoided costs. When a "like" cost-effective renewable resource is not included in PacifiCorp's planned resources, the next deferrable thermal resource is displaced in the determination of a QF's avoided costs. This methodology has been employed in Utah since 2013, and is very similar to that proposed for use in Oregon.

In Wyoming, wind QFs displace wind resources from the IRP preferred portfolio while other QFs displace thermal resources from the IRP preferred portfolio. When the Wyoming methodology was developed in 2011 the potential presence of solar resources in the IRP preferred portfolio was not contemplated. One departure in the Wyoming methodology is that, when there are no wind resources in the IRP preferred portfolio, it does not allow wind QFs to displace thermal resources.

Q. Do the Utah and Wyoming methodologies have any other shared characteristics?

A. Yes. Both Utah and Wyoming develop avoided cost prices based on deferral of resources identified in the Company's most recent IRP or IRP Update. In addition, in both jurisdictions resource deferral is automatically determined based on QF type, and QFs do not have the option to choose between renewable and non-renewable price streams.

Q. Will resources in the Company's most recent preferred portfolio from an IRP or IRP Update be used to price non-standard QFs prior to IRP acknowledgement?

A. Yes. In Order No. 16-174, the Commission highlighted the PDDRR method's ability to accurately value energy and capacity on the Company's system by taking into account the unique characteristics of each QF. Accurately valuing energy and capacity also requires an up-to-date representation of the Company's system and resource costs. Accordingly, the Company's PDDRR proposal specified that all model inputs would be updated to reflect the best information available, and specifically identified new preferred portfolios from an IRP or IRP Update as an input to be updated.[11]

Since the Commission adopted the PDDRR methodology, the Company's pricing for non-standard QFs has included deferral of thermal resources from the preferred portfolio identified in the 2015 IRP Update filed on March 31, 2016. Using the Company's most recent preferred portfolio in the renewable PDDRR methodology is thus consistent with the non-renewable PDDRR methodology in Oregon as well as the PDDRR methodologies employed in both Utah and Wyoming, and appropriately accounts for the impact of the queue of potential QFs across the Company's system on avoided cost prices.

Q. If renewable QFs are allowed to choose between renewable and non-renewable avoided cost price streams, are there any additional considerations?

A. Yes. While automatic deferral of like renewables identified in the IRP preferred portfolio is likely to provide the most accurate evaluation of a QF's avoided cost, the Company is willing to provide a non-renewable avoided cost price stream if requested. However, for

[11] *In re Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, PAC/800, Dickman/26.

consistency with the queue methodology for potential QFs adopted by the Commission in Order No. 16-174 and used in the Company's PDDRR, QFs will need to specify either renewable or non-renewable prices at the time of their request. With the option to choose between renewable and non-renewable prices at any time, a single QF would need to be reflected in the queues for both renewable and non-renewable capacity. This double-count would misrepresent the Company's expected system conditions and avoided costs for later QF requests. To maintain consistency, a request to change from renewable to non-renewable prices would result in removal of the QF in question from the renewable queue and its inclusion at the end of the non-renewable queue. This would be applicable for pricing changes in either direction.

Q. Should renewable resources added to the IRP preferred portfolio for the purposes of state-level RPS compliance be treated differently from renewable resources added to satisfy capacity and energy needs for all state jurisdictions?

A. Yes. If the IRP preferred portfolio includes cost-effective system renewable resources added to meet the capacity and energy needs for all jurisdictions, the QF will defer the system resource and will be a system-allocated QF. If the renewables in the IRP are situs-assigned for Oregon RPS purposes, the QF will be a situs resource, with costs and benefits allocated to Oregon only. This is in accordance with the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol.[12] Because they are not the least-cost resource option,

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[12] *In the Matter of PacifiCorp's Petition for Approval of the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol*, Docket No. UM 1050, Order No. 16-319 at Appendix A page 6 of 64 (August 23, 2016). Section IV.A.2: *"Costs associated with Resources acquired to comply with a Jurisdiction's Portfolio Standard adopted, either through legislative enactment or a State's Commission, the portion of which exceeds the costs PacifiCorp would have otherwise incurred, will be assigned on a situs basis to the Jurisdiction adopting the Portfolio Standard."*

the Company requests that the acquisition of resources for Oregon RPS purposes be acknowledged by the Commission prior to deferral by potential QFs.

Q. Can you please reiterate the other key characteristics of the renewable PDDRR, which are consistent with the current non-renewable PDDRR?

A. Yes. The proposed renewable PDDRR methodology would ensure accurate avoided costs by incorporating the following relevant inputs:

- Signed and potential QFs (located anywhere on PacifiCorp's system) are accounted for in the GRID model when calculating avoided costs for the next QF.
- GRID model inputs are updated to reflect the latest system conditions and market prices
- Transmission constraints are modeled to appropriately reflect the impact of QF output on market transactions as well as existing resources
- Renewable integration costs are included in accordance with the latest integration studies (typically included in an IRP). Studies being prepared for the 2017 IRP now identify integration requirements and costs for solar.

Q. Do any elements of the current non-renewable PDDRR need to be revisited?

A. Yes. In Order No. 16-337, the Commission indicated that utilities should identify when they experience transmission constraints that prevent otherwise economic market sales of low cost energy.[13] At the end of 2016, 431MW of potential solar QFs in Oregon had requested pricing. This is in addition to the 891MW of solar resources across the

[13] *In re Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 23 (May 13, 2016). "*We are persuaded that the benefit of QF developers understanding the price floor outweighs the minimal risk described by PacifiCorp that avoided cost prices produced by the PDDRR method would be lower than market.*"

Company's system that have reached commercial operation as of December 31, 2016, and 261MW of signed contracts that have not yet reached commercial operation. The Company does not have unutilized transmission rights adequate to deliver all of these solar resources to market, and thus must back down its thermal generation instead of making incremental market sales. As a result, QFs that receive payments based on the market price floor will receive payments appreciably greater than the Company's avoided cost.

MARKET PRICES AND AVOIDED COST PRICES

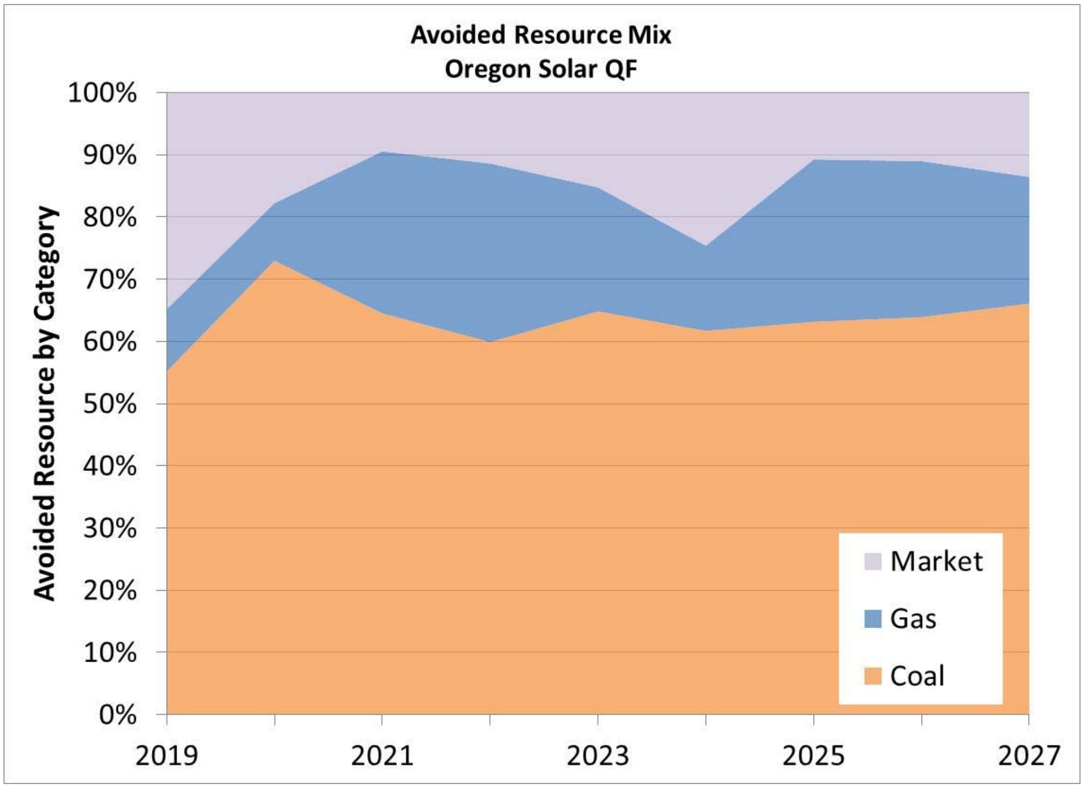
Q. Do transmission constraints in Oregon prevent the Company from making otherwise economic market sales of low cost energy as a result of incremental QF resources?

A. Yes. As described below, when incremental Oregon QF resources are included in the GRID model in accordance with the PDDRR methodology, a substantial portion of the output results in thermal backdown. Since the resulting thermal fuel cost savings are lower than the market price floor, it is clear that the displaced thermal resources would otherwise be economic relative to market.

Q. How much thermal backdown does the GRID model forecast as a result of incremental QF generation?

A. Through 2027, nearly two-thirds of the incremental solar QF generation resulted in avoided coal generation, while 20% resulted in avoided gas generation. As shown in Figure 1 below, market transactions (either avoided purchases or incremental sales), represent just 17% of the QF output.

Figure 1



Q. What is the impact of the market price floor on avoided cost pricing?

A. In the Company's most recent QF pricing request, the avoided cost calculated by the GRID model was 40% lower than the market price floor through the end of the sufficiency period in 2027. The market price floor exceeded the GRID-calculated avoided cost during the entire sufficiency period.

Q. What is the impact of the market price floor on retail customers?

A. As a result of the market floor, between 2018 and 2027 retail customers would pay $28 million more than the avoided costs calculated by GRID for the generation from an 80 MW solar QF. When the 431 MW of Oregon solar resources in the Company's QF queue are considered, the amount increases to $149 million. This corresponds to an increase in net power costs of approximately 1% on a total Company basis, or approximately 4% if the extra costs associated with the market floor are allocated specifically to Oregon customers.

Q. Have previous filings indicated that QF generation results in significant amounts of thermal backdown?

A. Yes. The most recent standard avoided cost[14] filing, from which the market floor is derived, includes a blended market price during the sufficiency period based on the market transactions modeled in GRID as a result of an incremental 50 MW resource. However, the Company's standard avoided cost calculations show that this resource results in approximately 30 MW of market transactions and 20 MW of thermal backdown.

Q. Is the difference in thermal backdown between standard avoided costs and the recent solar QF under non-standard avoided costs expected?

A. Yes. Thermal backdown for the solar QF under non-standard avoided costs is higher for two reasons. First, standard avoided cost prices do not incorporate the cumulative effects of the QF queue, and thus represents the potential thermal backdown resulting from the Company's existing resource portfolio. Second, due to a strong correlation between the output of the solar QF being priced under non-standard avoided cost rates and other solar resources on the Company's system, the solar QF being priced is more likely to deliver in periods when the Company's transmission system is congested and thermal backdown is necessary. A similar effect would be expected for wind generation, as wind speeds are often similar across a wide area. This effect for wind was accounted for through the adoption of the Company's hourly wind shaping methodology in Order No. 13-387 in UE

[14] Formerly known as Schedule 37.

264 (the 2014 Transition Adjustment Mechanism). Solar resources in GRID are modeled using a 24 hour shape by month, and as a result are correlated with each other due to the position of the sun. The standard avoided cost resource is flat across the year, and thus delivers in many periods where wind and/or solar output is low and thermal backdown may not occur.

Q. Is thermal backdown only an issue for wind and solar resources?

A. No. While wind and solar resources can be a driver for thermal backdown in certain hours, any resource that delivers in those hours contributes to thermal backdown.

Q. Is thermal backdown only dependent on resources in Oregon?

A. No. To the extent transmission is available, resources anywhere on the Company's system can make use of the Company's transmission rights in Oregon to reach market points when it is economic to do so. Regardless of the source of the generation, when the Company's transmission rights from Oregon to market points are fully utilized, incremental resources in Oregon will not result in incremental sales.

Q. Is thermal backdown as a result of renewables only an issue for the Company?

A. No. The California Independent System Operator has experienced a rapid increase in solar generation, and as a result its load net of renewables is now substantially lower during the day than it is in the morning and evening. During some times of the year, its load net of renewables during the day is even substantially lower than its load at night.[15] With the widespread expansion of solar, many other utilities are starting to experience this effect.

[15] CAISO Fast Facts, "What the duck curve tells us about managing a green grid" accessible at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

Q. Does thermal backdown at other utilities impact the Company?

A. Yes. Because the least-cost resources are deployed first, when the load net of renewables is lower, lower cost resources are available and market prices are lower. When renewable output is low, the load net of renewables is higher, and market prices will be based on higher cost resources. Even if the Company's excess resources can be delivered to a market point, there may not be any counterparties willing to take it, or they may only be willing to pay a lower price.

Q. Should the market price floor be eliminated from the non-standard avoided cost pricing methodology?

A. Yes. The Company currently experiences transmission congestion that prevents excess resources from being delivered to market. In the absence of transmission access, the Company is forced to back down low-cost resources, which lowers its avoided cost. Furthermore, even if resources can reach market points, willing buyers may not exist unless market prices are discounted from the average values upon which the market price floor is based. In both cases the market price floor exceeds the Company's avoided cost for renewable QF generation, resulting in higher costs for retail customers. Eliminating the market price floor would ensure that non-standard renewable QFs do not receive prices higher than the Company's avoided costs.

Q. Does this conclude your testimony?

A. Yes.