ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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May 24, 2019

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

Attn: Chris Petrie, Chief Counsel

Docket No. 20000-545-ET-18
Record No.15133

RE: IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED CONTRACT TERM OF PURPA POWER PURCHASE AGREEMENTS WITH QUALIFYING FACILITIES – Rebuttal Testimony

Dear Mr. Petrie:

Rocky Mountain Power hereby submits for electronic filing the rebuttal testimony as required by the Scheduling Order issued on February 19, 2019. An original and four copies are being provided for the docket.

All formal correspondence and staff requests regarding this matter should be addressed to:

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

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Please contact Stacy Splittstoesser, Wyoming Regulatory Affairs Manager at (307) 632-2677 if you have any questions or would like additional information.

Sincerely,

Joelle R. Steward
Vice President, Regulation

Enclosure

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that on May 24, 2019, I caused to be served, via Email and/or Overnight Delivery a true and correct copy of Rocky Mountain Power's **Rebuttal Testimony** to the following service list:

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Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Docket No. 20000-545-ET-18
Witness: Daniel J. MacNeil

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Daniel J. MacNeil

May 2019

Q. Are you the same Daniel J. MacNeil who presented direct testimony in this proceeding?

A. Yes.

<u>PURPOSE OF TESTIMONY AND RECOMMENDATION</u>

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to the direct testimony filed on April 19, 2019 by Belinda J. Kolb for the Wyoming Office of Consumer Advocate ("OCA"), Kevin C. Higgins for the Wyoming Industrial Energy Consumers and Two Rivers Wind, LLC, Kenneth G. Lay for the Northern Laramie Range Alliance ("NLRA"), John Lowe, Ted Sorenson, and Trent Reed for the Renewable Energy Coalition ("Coalition"), Hans Isern and Mark Klein for the Rocky Mountain Coalition for Renewable Energy ("RMCRE"), and Dr. Marc Hellman and Dr. Lance Kaufman for the Coalition and RMCRE.

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

A. My testimony focuses on the methodology for accurately determining avoided costs for inclusion in qualifying facility ("QF") contracts. The first sections of the Company's filing included three proposed changes directly related to avoided costs:

- Modifying the avoided cost pricing methodology for large QFs under Schedule 38;
- Adopting the same methodology used for large QFs under Schedule 38 to set published Schedule 37 avoided cost prices; and
- Changes to the on-peak and off-peak definitions contained in Schedule 37 to better differentiate between periods of higher and lower avoided cost.

Q. Is the accurate determination of avoided costs also a factor in other issues raised by Parties?

A. Yes. Avoided costs go up and down over time as a result of changes in the Company's portfolio; resource options, costs, and characteristics; and forecasted load and market prices. The following issues raised by parties impact the time at which avoided costs would be calculated, and thus indirectly impact avoided cost pricing:

- Contract term limit
- Maximum time from execution to commercial operation date ("COD")
- Contract price updates before execution
- Schedule 37 resource cap and tariff updates

Q. What are Parties' positions on the avoided cost methodology for Schedule 38?

A. OCA supports the proposed changes to the Schedule 38 avoided cost methodology, while Mr. Higgins indicates the proposed methodology is reasonable under some circumstances, and proposes some additional modifications. Mr. Higgins and the witnesses for the Coalition and RMCRE propose changes to the Schedule 38 methodology that fall into three categories:

- Mr. Higgins, Mr. Lowe, and Dr. Hellman/Dr. Kaufman oppose limiting deferral to "like" renewables.
- The Coalition proposes that all renewable QFs have the option to be paid either a renewable avoided cost rate or a non-renewable avoided cost rate.
- Several parties make claims and/or propose changes to the GRID model or the avoided cost calculations:
    - Mr. Isern claims that avoided cost pricing takes into account any

increased or decreased access to or opportunities in the energy imbalance market ("EIM").

- Dr. Hellman/Dr. Kaufman propose several changes:
  - Use of monthly capital costs from the lowest cost capacity resource, such as a simple cycle combustion turbine ("SCCT"), to set the price of front office transactions ("FOTs").
  - Only 75 percent of QFs with executed contracts that are not yet operational should be assumed to reach operation. This issue is also identified by Mr. Lowe.
  - Remove the Foote Creek replacement project from both base and avoided cost GRID runs
  - Allow coal units to cycle
  - Escalate coal prices consistent with historic increases
  - Allow sales to entities in Wyoming and east of Wyoming

Each of these categories is addressed in a separate section of my testimony.

Q. What are Parties' positions on the Company's proposed avoided cost methodology for Schedule 37?

A. OCA and Mr. Higgins support the Company's proposal to apply the Schedule 38 methodology to Schedule 37 rates. The Coalition proposes that the existing Schedule 37 methodology be retained. Dr. Hellman/Dr. Kaufman propose certain changes related the Schedule 37 assumptions, but do not appear to have raised specific objections to the use of the Schedule 38 methodology.

Q. What are Parties' positions on the Company's proposed changes to on-peak and off-peak definitions and price shaping?

A. OCA and Mr. Higgins support the Company's proposed changes to on-peak and off-peak definitions and price shaping. Mr. Lowe and Dr. Hellman/Dr. Kaufman object to the proposed changes to on-peak and off-peak, suggesting that additional analysis or methodology changes would be required. Dr. Hellman/Dr. Kaufman also suggest that a generic process is the appropriate forum to examine peak hour definitions.

Q. Generally, what are Parties' positions on contract term limits, the maximum time from execution to COD, pricing updates prior to execution, and the Schedule 37 resource cap?

A. Mr. Higgins, the Coalition, RMCRE, and Dr. Hellman/Dr. Kaufman generally advocate that avoided costs be establish earlier relative to the contract delivery period.

Q. Please summarize your conclusions.

A. The Company's proposed Schedule 38 methodology is clearly defined and relatively straightforward to implement, and produces a reasonable estimate of the Company's avoided costs. As such, the proposed Schedule 38 methodology should be approved by the Commission. The current Schedule 37 methodology is less accurate and does not capture any characteristics specific to small QFs, so the Commission should also approve the use of the Schedule 38 methodology to set Schedule 37 rates. In addition:

- Deferring like-for-like resources using the specific rules described in my direct testimony produces the most accurate avoided costs by maintaining a reasonable balance of cost and risk consistent with the integrated resource plan ("IRP") preferred portfolio.

- The Schedule 38 avoided cost methodology is designed to be straightforward to implement so as to provide a reasonable estimate of avoided costs to all parties requesting pricing within the required timelines of the Schedule 38 process. The methodology is necessarily simplified and cannot account for all of the effects of portfolio changes with the granularity of the IRP models used by the Company for non-QF resource procurement. Given the limitations of the Schedule 38 methodology, it is appropriate to help maintain customer indifference by ensuring as much information as possible is included in avoided costs. A reduced contract term limit, lower maximum time from execution to COD, and contract price updates up to the time of execution all help ensure customer indifference by setting avoided costs closer to the expected time of delivery.
- The Coalition's proposal to allow Wyoming QFs to choose between renewable and non-renewable avoided cost rate options is not consistent with the Public Utility Regulatory Policies Act of 1978 ("PURPA") regulations and Federal Energy Regulatory Commission's ("FERC") precedent and should be rejected.
- Mr. Isern's conclusion that the effects of EIM are already accounted for in avoided costs is incorrect. The GRID model does not account for sub-hourly dispatch, EIM transfers, or negatively priced intervals. As a result, the value of EIM-participating resources is understated and the avoided costs associated with must-take QF output are overstated.
- Dr. Hellman/Dr. Kaufman's proposed changes to GRID model inputs are generally inconsistent with assumptions used in the IRP, rate cases, and actual

operations and in some cases the description does not accurately represent the current assumptions used to determine avoided costs. These proposed changes should be rejected.

- The Company's proposed changes to the on-peak and off-peak definitions are a significant improvement over the current definitions in Schedule 37. Dr. Hellman/Dr. Kaufman's objections related to the on-peak definitions in other rate schedules are unfounded since the existing definitions are already inconsistent, and the QF contracting process is distinct from retail rates. Furthermore, the alternative on-peak and off-peak definitions proposed by Dr. Hellman/Dr. Kaufman result in only minor differences from the Company's proposal. Dr. Hellman/Dr. Kaufman's suggestion that price shaping during the winter and summer periods should be revenue neutral is reasonable during the resource sufficiency period and the Company has prepared avoided cost prices reflecting this change. The Company also notes that it is willing to entertain project-specific on-peak and off-peak proposals during contract negotiations under Schedule 38.
- The current Schedule 37 modeling assumptions and capacity cap are reasonable to ensure accurate avoided costs and retail customer indifference; however, the Company is willing to clarify the triggers and tariff update process. The Company proposes that, when 10 megawatts ("MW") of Wyoming Schedule 37 contracts have been signed at the published prices, the prices would be suspended for QFs in excess of 100 kilowatts ("kW"), and the Company would be required to file updated Wyoming Schedule 37 prices within 30 days. Until

the Commission acts on the Company's proposal, QFs larger than 100 kW would receive project-specific prices calculated using the current assumptions under the Schedule 38 methodology. Each time new published prices are approved, the cap would be reset to zero.

DEFERRAL OF LIKE RENEWABLES

Q. Please summarize the Parties' positions on the Company's proposed Schedule 38 methodology.

A. OCA generally supports the Company's "like for like" Schedule 38 methodology, which assumes renewable resources defer renewable resources of the same type in the preferred portfolio, or if no renewable resources of that type remain in the preferred portfolio during the contract term, renewable resources defer thermal resources. Mr. Higgins suggests that the Company's "like for like" methodology is reasonable unless the timing of wind and solar resources begins to diverge and that "like for like" restrictions may not be appropriate for baseload QFs. Mr. Lowe and Dr. Hellman/ Dr. Kaufman propose that resource deferral should be calculated solely based on capacity contribution, without regard to resource type.

Q. What evidence does Mr. Lowe provide in support of the proposed deferral methodology?

A. Mr. Lowe provides no evidence beyond statements about his perception of the accuracy of the Company's proposal, Dr. Hellman/Dr. Kaufman's proposal, and the simple proxy method currently used for Schedule 37.

Q. What evidence do Dr. Hellman/Dr. Kaufman provide in support of the proposed deferral methodology?

A. Dr. Hellman/Dr. Kaufman provided a single example of a QF and deferred a resource of a different type, with a baseload QF resource assumed to defer a wind resource.

Q. Can a new resource defer resources of other types?

A. Yes.

Q. Ideally, how would the Company determine what resource options would be deferred?

A. The tools and models developed in the IRP are employed in major non-QF resource decisions, such as the evaluation of bids submitted in response to requests for proposals ("RFPs"). These models dynamically account for the Company's needs in each geographic location, and the costs and characteristics of various resource options across the system that could meet those needs. The portfolio optimization accounts for the changing needs and options over time and evaluates all resource options in combination. This is a lengthy process which is not suitable for QF pricing given the volume of requests the Company receives each year.

Q. Please illustrate that maintaining an equivalent capacity contribution is insufficient to maintain the least-cost, least-risk characteristics of the preferred portfolio.

A. The 2017 IRP preferred portfolio included a range of resource types, which indicates that the specific characteristics of a combination of different resources together supports least-cost, least-risk outcomes. This is because a resource's impact on the portfolio is based on more than just capacity equivalence, otherwise there would be no need to run portfolio optimization models at all, as we would merely pick the lowest cost capacity resource available. As shown in Table 4 below, based on costs used in the development of the 2017 IRP preferred portfolio, while an SCCT may provide the lower-cost capacity, the other characteristics of combined cycle combustion turbines ("CCCTs"), solar, and wind resources make them valuable components of a portfolio optimized to serve customers in all hours of the year, rather than just during peak conditions. As a result all of these resource types were included in the 2017 IRP preferred portfolio.

Table 4: Capacity-Equivalent Cost by Resource Type

		2029 SCCT	2030 CCCT	UT Solar	DJ Wind
Fixed Cost ($/kw-year, 2017$)	a	$84	$146	$164	$164
Capacity Contribution (%)	b	100%	100%	59.7%	15.8%
Capacity-Equivalent Cost ($/kw-year, 2017$)	c = a / b	$84	$146	$275	$1,037

Q. Are a range of resources included in the preferred portfolio from the 2017 IRP Update, rather than just the lowest-cost source of capacity?

A. Yes. The 2017 IRP Update preferred portfolio contains both wind and solar resources, which have very different capacity values as previously indicated, along with energy efficiency and demand response. This combination of resources with the Company's existing portfolio and expected requirements produced the least-cost, least-risk outcomes when evaluated using the IRP tools when the 2017 IRP Update was prepared in early 2018.

Q. What do you conclude based on the range of resources selected in the 2017 IRP and 2017 IRP Update?

A. The presence of a range of resource types that are not strictly related to capacity-equivalent cost demonstrates that there are other factors involved. These factors include seasonal variations in output, the types of resources in the Company's existing portfolio, geographic diversity and resource potential, among others. A methodology which fully accounted for all of these factors would need to be as complex as the IRP modeling that the PDDRR avoided cost methodology is intended to streamline for the purposes of producing avoided costs.

Q. Is a methodology based on generic capacity-equivalence likely to produce stable results over time?

A. No. Table 5 shows the assumed capacity contribution values for east-side solar and wind resources from the 2015 IRP, the 2017 IRP, and from results presented in the ongoing 2019 IRP public-input process. Also shown are the relative capacity contribution values between solar, wind, and baseload resources.

Table 5: Solar and wind capacity contribution assumptions through time

	Tracking Solar (a)	Wind (b)	Solar to Wind Capacity Ratio = (a) / (b)	Baseload to Solar Capacity Ratio = 100% / (a)	Baseload to Wind Capacity Ratio = 100% / (b)
2015 IRP	39.1%	14.5%	2.7	2.6	6.9
2017 IRP	59.7%	15.8%	3.8	1.7	6.3
2019 IRP	12.2%	26.1%	0.5	8.2	3.8

Q. Do parties agree that capacity contribution values can change over time?

A. Yes. In response to RMP data request 1.34 Dr. Hellman/Dr. Kaufman agree that the capacity contribution values for a given resource may change over time.

Q. Given that one megawatt of wind has recently been considered to have capacity equivalent to anywhere between 0.5 and 3.8 megawatts of solar, and between 3.8 and 6.9 megawatts of baseload resources, is it reasonable to base capacity deferral solely on capacity equivalence?

A. No. The range of the recent results indicates that other factors besides capacity values are important when establishing a least-cost, least-risk preferred portfolio in the IRP.

Ignoring these other factors unnecessarily introduces risks that updates to capacity value over time would lead to inaccurate avoided cost prices.

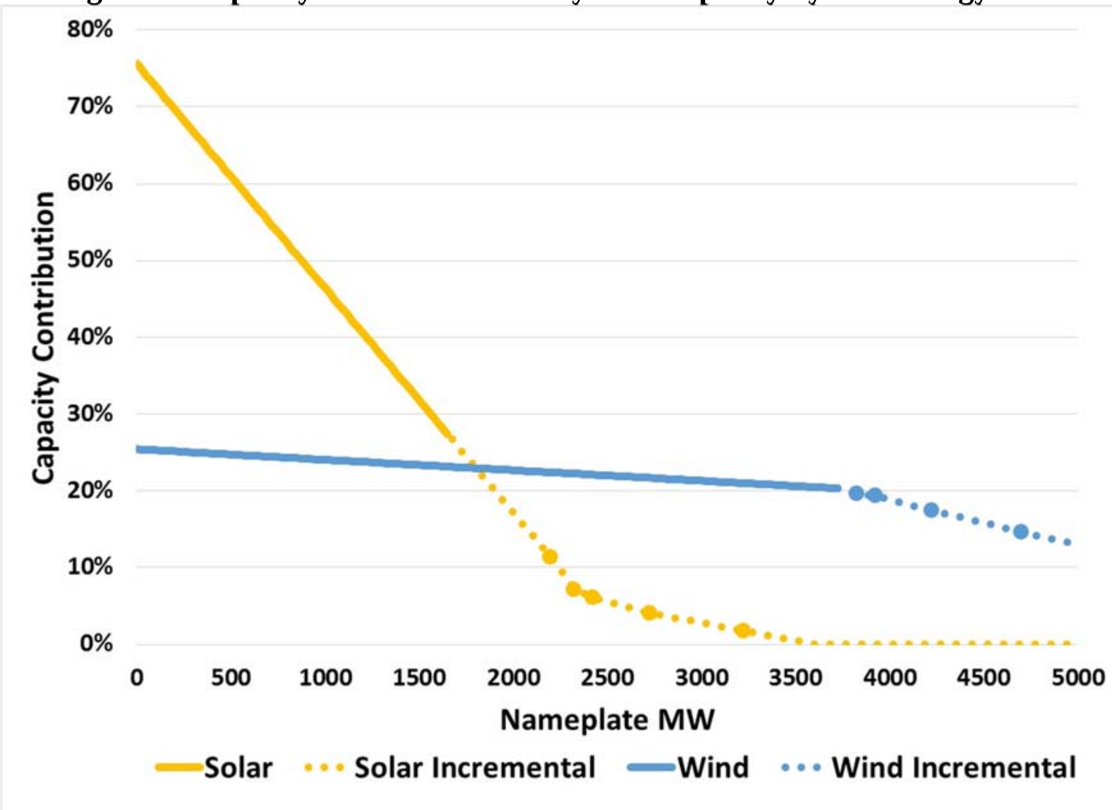
Q. Has the Company quantified any factors that contribute to changes in wind and solar capacity contributions over time?

A. Yes. The Company has identified that increasing penetration of wind and solar resources results in declining capacity contribution values. The results shown in Figure 6 below were presented to stakeholders as part of the 2019 IRP public-input process.[1] Similar relationships have previously been identified in a variety of studies performed

[1] Presentation from the September 27-28, 2018 IRP Public Input Meeting. Slide 94. Available online: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_September_27-28_2018_Public_Input_Meeting.pdf.

by other utilities and industry groups.[2]

Figure 6: Capacity Contribution vs. System Capacity by Technology



Q. Does the Company's proposal help account for those other factors?

A. Yes. By limiting deferral to resources of the same type, the QF and the deferred resource will have more of the characteristics accounted for in the IRP modeling in common, beyond equivalent capacity values.

Q. Please summarize your basis for supporting the like for like resource deferral methodology for pricing of QFs under Schedule 38.

A. The PDDRR methodology relies on the GRID model to forecast the avoided cost of energy, not the avoided cost of capacity or the composition of a least-cost, least-risk resource portfolio. The Company's position is that the GRID model, when properly

[2] Ibid. Slide 95.

applied, produces a reasonable estimate of avoided energy costs. It is necessary, however, to calculate the avoided cost of capacity by deferring like-for-like resources because doing so maintains a reasonable balance of cost and risk that is consistent with the least-cost, least-risk IRP preferred portfolio.

Q. What is the overarching principle behind the Company's position?

A. The overarching principle is the customer indifference standard.[3]

Q. Does the proposal by Mr. Lowe and Dr. Hellman/Dr. Kaufman provide sufficient information for the Company to implement it?

A. No. While Dr. Hellman/Dr. Kaufman provide one example of a baseload QF resource deferring a wind resource, it is unclear what specific algorithm they propose to use to account for signed contracts and determine the next deferrable resource.

Q. Has the Company prepared data illustrating the range of possible outcomes under the proposal supported by Mr. Lowe and Dr. Hellman/Dr. Kaufman?

A. Yes. Table 6 provides 10-year levelized avoided cost prices starting in 2030 for various combinations of solar, wind, and baseload resources. For comparison, Table 6 also provides resource costs from the supply-side tables used to develop the 2017 IRP Update and the ongoing 2019 IRP. 2030 is used as a starting point because it allows for a direct comparison with the Company's filing, which included solar and wind resources in that year. Based on the 2017 IRP Update preferred portfolio after accounting for signed contracts since it was prepared, the first resources remaining in the preferred portfolio are in 2030, so the change in resource deferral assumptions proposed by Mr. Lowe and Dr. Hellman/Dr. Kaufman would not impact avoided costs

[3] MacNeil Direct at 4, fn 2 & 3.

prior to 2030.

Table 6: 10 year levelized prices starting 2030

QF Type	Company "Like for like"	Deferring Solar	Deferring Wind	2017 IRP Update Resource Cost	2019 IRP Resource Cost
Baseload	$46.82	$53.24	$59.63	n/a	n/a
Solar Tracking	$49.34	-	$66.46	$46.90	$40.92
Wind	$48.52	$40.79	-	$44.84	$37.00

Q. What can you conclude from these results?

A. There are three main takeaways from this table. First, the results vary by a significant amount, depending on the type of resource deferred. This is further evidence that capacity equivalence is not sufficient basis for developing avoided costs. For instance, based on these results, the value of solar tracking resources replacing wind are substantially higher. Yet this result is contrary to the conclusion of the 2017 IRP preferred portfolio, which still included wind resources and did not conclude the solar resources alone would produce a least-cost, least-risk portfolio. This also highlights the need for a more specific deferral algorithm, as the results are highly sensitive to this assumption.

Second, the Company's "like for like" proposal results in avoided costs for wind and solar resources that are higher than the cost of comparable resources from the 2017 IRP Update supply-side table. This is an indication that the Company's relatively simple "like for like" proposal may be producing avoided costs that are too high. For instance, the IRP models evaluated and opted not to include east side tracking solar resources in the preferred portfolio in 2030, indicating that their benefits were not sufficient to justify their cost at that time.

Third, the cost of comparable wind and solar resources from the ongoing 2019

IRP is significantly lower than resource costs from the 2017 IRP Update. This is an indication of the risk customers may face by being forced to commit to QF pricing well in advance of COD and well in advance of the identified 2030 resource needs from the 2017 IRP Update.

Q. What do you conclude with regard to Parties proposed changes to the resource deferral methodology for pricing of QFs under Schedule 38?

A. Parties have not provided evidence that their proposed changes would result in more accurate avoided costs, nor have they provided sufficient detail for the Company to clearly identify resource deferrals for QF pricing. Resource deferral is a complicated and involved problem and while it is somewhat simplified, the like for like methodology proposed by the Company maintains a reasonable balance of cost and risk that is consistent with the IRP preferred portfolio. The Commission should adopt the like for like resource deferral methodology proposed by the Company.

<u>RENEWABLE AND NON-RENEWABLE AVOIDED COST OPTION</u>

Q. The Coalition proposes that a renewable QF should have the option to choose between either a renewable or non-renewable avoided cost rate.[4] How do you respond?

A. Avoided cost rates must meet the customer indifference standard. FERC has established precedent for states implementing multi-tiered avoided cost rates. In an order dated January 20, 2011, FERC held that "the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular resources of energy for a long duration."[5] Renewable Portfolio Standards

[4] Lowe Direct at 8, lines 100-105.
[5] 134 FERC ¶ 61,044 at 18 (Jan. 20, 2011).

("RPS") are one example of such obligations. Because the Company does not have an RPS or any other obligation to procure renewable resources in Wyoming, there is no basis for implementing a renewable resource option for Wyoming QFs.

Q. Does this mean that avoided cost rates cannot be based on the cost of renewable resources?

A. No. The Company isn't obligated under PURPA to pay more for renewable resources in Wyoming than the costs it would otherwise incur, but the costs it would otherwise incur could include acquisition of cost-effective renewable resources. The corollary is also true, that the Company would not pay less for renewable resources than it would otherwise incur. Thus, in the absence of state obligations requiring specific resource types and justifying multi-tiered rates, a single rate is established that is equal to the avoided costs.

Q. How are renewable avoided cost rates typically implemented?

A. Generally, renewable avoided cost rates are paid based on the incremental value of RECs transferred from a QF to the utility, based on the value of those RECs for RPS compliance.

Q. Does REC ownership impact the capacity and energy value associated with a QF?

A. No. REC ownership has no impact on the Company's treatment of QF output when calculating avoided energy and capacity costs because system operations and dispatch would be the same for a given project regardless of REC ownership.

Q. Mr. Lowe suggests that renewable avoided cost rates could be higher or lower than non-renewable avoided cost rates. How do you respond?

A. I have already established above why the capacity and energy provided by a given QF project in Wyoming has a single avoided cost. To the extent renewable generation costs are less than the costs of equivalent non-renewable resources, after accounting for differences in operational characteristics including capacity and energy value, then those renewable resources should be present in the Company's preferred portfolio. This is exactly the situation in the 2017 IRP Update preferred portfolio, which includes two different kinds of renewable resources. To the extent substantial opportunities exist to acquire renewable resources at costs lower than those identified in the 2017 IRP Update preferred portfolio, the customer indifference standard would dictate that the Company seek competitive bids to acquire the lowest cost opportunities, as it is has recently completed for both wind and solar resources.

Q. The Coalition indicates that some QFs may wish to retain the RECs they produce. Is this issue pertinent to QF avoided costs?

A. Not necessarily. The disposition of RECs produced by Wyoming QFs is clearly within the jurisdiction of the Wyoming Commission, as is compensation insofar as it impacts avoided costs. The Wyoming Commission has already established that the Company receives the RECs produced by Wyoming QFs for the benefit of retail customers.[6] To the extent a QF wished to retain the RECs it produces, at least two potential avenues are available. First, the Company routinely sells RECs to interested parties, and a Wyoming QF can already offer to buy back RECs it generates. Second, a non-QF PPA could be negotiated wherein the RECs remain with the resource owner. Neither of these outcomes require modifications to QF pricing or contracting requirements.

[6] *See,* Docket No. 20000-388-EA-11 (Record No. 12750).

Q. What is your conclusion with regard to the Coalition's proposal to allow Wyoming QFs to choose between renewable and non-renewable avoided cost rates?

A. The Coalition's proposal to allow Wyoming QFs to choose between renewable and non-renewable avoided cost rates is not consistent with PURPA, is not consistent with FERC precedent, and should be rejected.

ON-PEAK AND OFF-PEAK PRICE SHAPING

Q. Please summarize Parties positions on the Company's proposed changes to the seasons and on-peak and off-peak definitions in Schedule 37.

A. OCA and Mr. Higgins generally support the Company's proposed changes to the seasons and on-peak and off-peak definitions in Schedule 37. Dr. Hellman/ Dr. Kaufman oppose the changes and recommend that if the Commission wishes to consider these changes it should do so in a separate proceeding that involves all peak price definitions that impact cost of service customers. Dr. Hellman/Dr. Kaufman's objections fall into two categories: the relationship between different time of use definitions customers may be subject to, and the design characteristics that should be reflected in a price shaping proposal. I will address these two categories of objection.

Q. Please summarize Dr. Hellman/Dr. Kaufman's objections related to other peak price definitions customers are already subject to.

A. Dr. Hellman/Dr. Kaufman claim that RMP should utilize similar peak price definitions across all filings and that all customers involved in time of use should be involved in a proceeding where changes are considered.

Q. Is it necessary to use similar peak price definitions in all filings?

A. No. In developing a peak definition it is appropriate to consider metering capabilities, customer sophistication, and interactions with other customer requirements, along with the accuracy of representing the avoided cost, which I address later.

Q. Are metering capabilities a concern for setting peak definitions in Schedule 37?

A. No. For time of use programs that impact large numbers of customers, the capabilities of existing metering equipment and existing Company processes may restrict the range of feasible peak price definitions. To qualify as a QF, a resource must have metering equipment capable of providing data to support the Company's proposal, so this issue is not a concern in this instance.

Q. Is customer sophistication a concern for setting peak definitions in Schedule 37?

A. No. Time of use programs can provide two key benefits: they can improve cost allocation and they can incent changes in customer behavior that reduce system costs. Customers do not need to be aware that they are subject to time of use rates for those rates to more accurately allocate costs relative to a uniform rate. To the extent customers do change their behavior in response to pricing signals in time of use rates, they reap the benefits of lower rates while at the same time reducing system costs by a related amount. Overly complicated or overlapping time of use definitions could result in customer fatigue and lost benefits, wherein less sophisticated customers give up because identifying changes and keeping tracking of the schedule becomes too complicated.

When considered in the context of QFs, the more accurate allocation of avoided costs is the primary goal of the Company's proposal and as in the time of use example, a QF's ability to respond is secondary. To the extent QFs do respond to variations in avoided cost across a day, the intent of the proposed definition is to ensure that the compensation they receive is commensurate with the benefits they provide. Relative to the current requirements, the Company's proposal is slightly more complex by having distinct winter and summer peak definitions, but is less complex by removing distinctions based on day of the week. Regardless, QF developers are more sophisticated than typical customers, as their stated intent is earning revenue from the long term operation of energy generating equipment, whereas customers are more focused on lighting, air conditioning, refrigeration, and so on, rather than their impact on generation requirements.

Q. Are interactions with other customer requirements a concern for setting peak definitions in Schedule 37?

A. Not at this time. First, the other peak definition identified by Dr. Hellman/Dr. Kaufman is in Schedule 46, and it is not the same as the current definition in Schedule 37. Moreover, that definition applies to on-peak demand charges, rather than energy charges, so it is unclear how that would conflict with the payments for energy output under Schedule 37. Second, most QF contracts are for stand-alone resources without other onsite load beyond offline station service. While offline station service may be provided by the Company at retail rates, the amounts are generally minimal relative to generation output such that any interaction between peak definitions would be insignificant. Furthermore, if QF output can be controlled by the owner, it can operate in whatever manner it desires, and if it is not dispatchable, it will be subject to the prevailing avoided costs and retail rates regardless of any peak definition.

Q. Can other retail customers be harmed by inconsistent peak definitions?

A. Possibly. For example, consider a cogeneration customer with a partial requirements contract that pays retail rates with an on-peak definition from Monday through Friday and avoided cost rates with an on-peak definition that applies every day. Retail rates will be lower on the weekend, whereas for simplicity, the avoided cost price on the weekend will reflect an average of all days, even though avoided costs are typically lower on the weekend. This customer might be incented to generate relatively more on the lower-value weekend periods. For a Schedule 38 QF, the Company would likely negotiate a time of use definition that more closely aligned with the elements of the retail definition. For a Schedule 37 QF, the impact would be unlikely to significantly impact retail customers and would be outweighed by the benefits of applying a more accurate peak definition to other Schedule 37 QFs. Such trade-offs are unavoidable with a standard published rate, regardless of whether it is for QF avoided costs or for retail electric service.

Q. Please summarize Dr. Hellman/Dr. Kaufman's objections related to the design characteristics that should be reflected in a price shaping proposal.

A. Dr. Hellman/Dr. Kaufman claim that:

- Rather than using Palo Verde market prices as in the Company's proposal, Mid-C market prices or avoided costs from the GRID model are a more appropriate source for differentiating on-peak and off-peak pricing.
- The methodology should be revenue neutral within the summer and winter months.

Q. Does using avoided costs from the GRID model instead of Palo Verde market prices appreciably change the on-peak and off-peak definitions?

A. No. Workpapers prepared by Dr. Hellman/Dr. Kaufman indicate that the summer on-peak and off-peak definitions could be unchanged if based on avoided costs from the GRID model for 2019 rather than Palo Verde market prices. The winter on-peak definition would be unchanged in the evening, and would be one hour shorter in the morning, extending from 6:00 a.m. to 8:00 a.m. rather than starting at 5:00 a.m.[7] The data by Dr. Hellman/Dr. Kaufman assumed that periods that were in excess of 110 percent of the monthly average were considered on-peak, whereas the Company's proposal used a cut-off of 100 percent of the monthly average.

Q. Does using Mid-C market prices instead of Palo Verde market prices appreciably change the on-peak and off-peak definitions?

A. No. Using 2019 Mid-C market prices and the 110 percent cut-off described above results in no changes in the summer on-peak and off-peak definitions. In the winter, the morning on-peak period extends from 6:00 a.m. to 8:00 a.m., the same as with the GRID-derived results above. In addition, the evening on-peak period is one hour shorter, extending from 5:00 p.m. to 10:00 p.m. rather than until 11:00 p.m. in the Company's proposal.

Q. Is the Company opposed to using these alternative on-peak and off-peak definitions?

A. No. While the Company believes that its proposal is reasonable, the minimal difference in the definitions will produce largely the same outcome – a significant improvement relative to the current definition which extends from 6:00 a.m. to 10:00 p.m. and includes all hours during the middle of the day. The Company would also note that the

[7] See confidential workpaper "On-Off Peak Designation (1806 OFPC) Decrement CONF.xlsx" provided in response to RMP data request 1.1.

change in the definition will slightly impact the pricing, as the volumes and relative prices between on-peak and off-peak will be different.

Q. Do you have any additional concerns with use of the GRID-model results to shape avoided cost prices?

A. Yes. Besides requiring an additional GRID run, the GRID results can reflect multi-hour changes that aren't specifically tied to conditions in a particular hour. For instance, a gas plant that commits up or down will impact a block of hours, and while economic for the block as a whole may include additional hours to meet minimum up time or down time requirements. As a result, the reported cost impact in those hours is not solely related to the marginal resource added in that hour, but rather can reflect impacts based on multiple hours. This can produce strange results. For example, there are negative marginal prices in some months of Dr. Hellman/Dr. Kaufman's analysis, despite positive avoided costs for those months. While this did not appear to be a significant issue in the 2019 data used to estimate the on-peak and off-peak periods, it does impact the shaping for future periods.

Q. Do you have any additional concerns about the shaped avoided cost prices reported by Dr. Hellman/Dr. Kaufman?

A. Yes. In addition using skewed marginal costs for some periods as described above, Dr. Hellman/Dr. Kaufman appear to have neglected to modify the on-peak and off-peak volumes for the change in the on-peak and off-peak definitions. The Company's methodology is intended to ensure that the seasonal on-peak and off-peak prices and expected generation are equal to the calculated avoided cost, which requires that the forecast volumes during each pricing period be accurate.

Q. Should avoided cost pricing be revenue neutral within summer and winter periods?

A. During the sufficiency period, when avoided costs are based on GRID results and deferral of FOTs, it is reasonable for avoided cost pricing to be revenue neutral within the summer and winter periods as the costs and benefits are entirely reflected within the respective periods. During the deficiency period, when avoided costs include deferral of a proxy resource, the Company's calculation currently assumes that the QF receives one-twelfth of the annual revenue requirement associated with the deferred resource in each month. While this cost may realistically compare to the expected recovery, the benefits of a QF resource will be tied to its performance in months with the highest avoided costs and the months with the highest loss of load probability, and not more or less flat across the year. As a result, during the deficiency period it is still appropriate for avoided cost pricing to be revenue neutral within the year, and not revenue neutral within the summer and winter periods. The resulting higher prices during summer periods incentivizes QFs to maximize output during a period that provides the greatest benefits to customers.

Q. Have you prepared updated avoided cost prices reflecting revenue neutrality in the summer and winter months during the sufficiency period?

A. Yes. Because there are no deferrable thermal resources under the Company's proposed rates, this change impacts baseload QF prices throughout the study period. Because wind and solar resources are each assumed to defer proxy generation resources starting in 2030, this change only impacts wind and solar QF prices through 2029. Table 7 shows the impact on baseload QF pricing.

Table 7: Revenue Neutral Baseload QF Pricing Impact by Season

Deliveries During Calendar Year	On-Peak Energy Prices ($/MWh) Winter	On-Peak Energy Prices ($/MWh) Summer	Off-Peak Energy Prices ($/MWh) Winter	Off-Peak Energy Prices ($/MWh) Summer
2019	(3.52)	8.08	(1.93)	3.78
2020	(3.50)	8.01	(1.94)	3.83
2021	(4.09)	8.93	(2.23)	4.55
2022	(2.36)	5.15	(1.28)	2.61
2023	(1.99)	4.36	(1.08)	2.20
2024	(3.02)	6.70	(1.65)	3.35
2025	(3.72)	8.19	(2.04)	4.14
2026	(3.35)	7.30	(1.83)	3.75
2027	(2.46)	5.36	(1.35)	2.76
2028	(1.06)	2.31	(0.58)	1.19
2029	(1.94)	4.22	(1.07)	2.19
2030	(2.97)	6.44	(1.64)	3.37
2031	(2.82)	6.10	(1.55)	3.19
2032	(2.85)	6.17	(1.57)	3.24
2033	(2.12)	4.59	(1.17)	2.41
2034	(2.59)	5.59	(1.43)	2.94
2035	(2.92)	6.30	(1.61)	3.31
2036	(2.57)	5.57	(1.42)	2.94
2037	(2.75)	5.92	(1.52)	3.13
2038	(3.01)	6.49	(1.66)	3.42
2039	(3.05)	6.59	(1.69)	3.47
2040	(3.47)	7.48	(1.92)	3.95

	On-Peak Energy Prices ($/MWh) Winter	On-Peak Energy Prices ($/MWh) Summer	Off-Peak Energy Prices ($/MWh) Winter	Off-Peak Energy Prices ($/MWh) Summer
20-year (2019-2038) Nominal Levelized	(2.87)	6.33	(1.58)	3.20

Q. What do you recommend with regard to on-peak and off-peak definitions and seasonal price shaping?

A. The Company's proposed on-peak and off-peak definitions are comparable to that derived from the alternative hourly sources identified by Dr. Hellman/Dr. Kaufman and all of the options are a dramatic improvement relative to the existing definition and it is unnecessary to modify the Company's proposal. With regard to seasonal price shaping, it is only reasonable to make the price shaping revenue neutral within the summer and winter seasons of each year prior to the assumed deferral of a generation resource. Because the assumed avoided costs of a deferred generation resource are uniform across the year, they do not reflect the associated variation in benefits and do not sufficiently incent QFs to perform during periods with the greatest benefits to customers. The Commission should adopt the Company's proposed on-peak and off-peak definitions and its modified proposal to reflect revenue-neutral pricing by season during the sufficiency period only.

GRID MODEL AND AVOIDED COST INPUT CHANGES

Q. Please summarize the issue raised by Mr. Isern related to the GRID model and avoided cost inputs.

A. Mr. Isern claims that avoided cost pricing takes into account any increased or decreased access to or opportunities in the EIM.

Q. Is this accurate?

A. No. There are three key elements related to EIM that are absent in GRID, such that the effects of EIM on avoided costs are understated. These elements are: sub-hourly dispatch, inter-regional transfers, and negatively-priced intervals.

Q. Please describe how sub-hourly dispatch relates to the GRID model.

A. In every interval of every hour, the Company must maintain the balance between loads and resources in its balancing authority areas ("BAAs") within specified bounds. The GRID model has hourly granularity and does not account for changes in loads and resource dispatch on a sub-hourly basis. While balancing average load and average resources provides a reasonable estimate, it fails to account for variations in marginal costs and resource constraints that can become relevant within an hour despite not being an issue on average. The GRID model accounts for operating reserve requirements for resources available within 10 minutes to meet contingency reserve requirements and resources available within 30 minutes to meet regulation reserve requirements, but resources that are allocated reserves in GRID are never called upon to dispatch in response to contingency or imbalance events, because neither of these occur within the GRID model. As a result, because EIM dispatch is only related to balancing within the hour, the GRID model is not accounting for EIM dispatch.

Q. Please describe how inter-regional transfers relate to the GRID model.

A. In addition to economically balancing the load and resources within each BAA, the EIM also optimizes dispatch by transferring energy between adjoining BAAs. The GRID model does not account for the volume and available pricing of energy available from other EIM entities, as it only includes hourly market prices. In addition, the GRID model reflects PacifiCorp Energy Supply Management's ("ESM") transmission rights, whereas in EIM, all unused transfer capability is made available for EIM transfers. The potential volume of EIM transfers can thus be well in excess of that reflected in the GRID model. Most importantly, only EIM participating resources can be dispatched to take advantage of the economic benefits of EIM transfers, and the resulting benefits are not captured within the current avoided cost methodology.

Q. Please describe how negatively-priced intervals are handled within the GRID model.

A. The current version of the GRID model does not support market prices or resource dispatch prices that are negative. This was rarely a concern in the past as negative market prices were uncommon, and typically occurred only as a result of relatively abnormal conditions, such as a very wet hydro year, which would not be appropriate to use as the basis of a long term forecast. Because of the significant resource congestion in eastern Wyoming, particularly when additional QFs are added, the current avoided cost methodology uses the GRID model to account for all positive-cost dispatch options in eastern Wyoming (including exports to other areas, coal backdown, and curtailment of wind resources that do not qualify for production tax credits ("PTCs")) and then assigns the cost associated with lost PTCs to any remaining volume in that area in excess of load. While this reasonably accounts for the Company's avoided costs associated with resources in eastern Wyoming, it fails to account for negatively-priced intervals that are a result of system-wide conditions, such as when other EIM participants experience renewable resource over-supply conditions.

Q. Why can renewable resource over-supply lead to negative pricing?

A. Renewable resources have expanded significantly over the past few years and the wind and solar resources that comprise the bulk of the recent renewable resource additions across the west generally have no fuel or variable costs. However, the dispatch price for these resources can be negative if they are wind resources that qualify for PTCs or if the RECs generated have high value. Because of RPS requirements and demand for RECs, renewable resources within the CAISO often have dispatch prices well below zero, as off-takers would rather pay to generate rather than forego PTCs and/or RECs. As a result of participating in EIM, the Company has the opportunity to be paid to take negatively-priced energy within the hour if it has EIM-participating resources available to back down.

Q. Do QFs impact the Company's ability to take negatively-priced energy within the hour?

A. Yes, in two ways. First, the current avoided cost pricing methodology accounts for the fuel cost savings associated with backing down the Company's coal and gas resources to maintain the load and resource balance inclusive of the output of a QF. In reality, those resources also have the opportunity to back down within the hour to take advantage of lower-cost energy available within EIM. But to the extent they have already backed down to accommodate a QF they will no longer be able to respond to lower-cost opportunities within EIM. While the Company has measured the benefits of its existing EIM-participating resources and estimated the value of intra-hour dispatch for other resource types, it has not determined how the EIM benefits from its existing portfolio would be impacted as a result of the re-dispatch required to accommodate additional QF resources.

Second, while the portfolio-wide effects are uncertain, to the extent a QF is assumed to defer a dispatchable proxy resource from the IRP preferred portfolio, it is clear that whatever benefits the proxy resource would have provided will be lost, and that the QF will not be able to provide them. The lost EIM benefits associated with the proxy resources in the IRP preferred portfolio are not accounted for within the current avoided costs, which further discredits Mr. Isern's claim that the inability to dispatch QFs is already reflected in the current avoided cost pricing.

Q. Could avoided cost pricing be adjusted to better reflect the impact of EIM?

A. Yes. Because the GRID model does not contain system-wide negative price intervals, it is appropriate to make an adjustment to account for the impact of the negative price intervals that are expected to occur. The best information currently available on negative price intervals is historical EIM results, and the Company identified intra-hour flexible resource credits which identify these values for specific resources as part of the ongoing 2019 IRP public process.[8] Curtailing wind or solar resources at a price of zero provides benefits by avoiding the cost of negative price intervals. QF resources cannot be curtailed, and thus do not avoid the cost of negative price intervals. Because the GRID model does not contain negative price intervals, this cost is incremental to the current avoided cost calculation.

Q. Are the costs of negative price intervals technology-specific?

A. Yes. Technology-specific historical results from the 12 months ending June 2018 are shown in Table 8 below. The results vary by technology-type due to differences in hourly output patterns. For instance, more negatively-priced intervals occur during the day, so the impact is higher for solar resources.

Table 8: Negatively-Priced Interval Costs by Resource Type (2018$)

Resource/Bid Price	Cost ($/kw-year)	Cost ($/MWh)	% of annual output during negatively-priced intervals
Baseload/$0	2.16	0.25	2.6%
Solar/$0	1.22	0.47	5.6%
Wind/$0	0.87	0.27	2.9%

Q. Are the costs of negative price intervals in EIM likely to change over time?

A. Yes. The continued expansion of zero or negative-cost renewable resources and tightening state RPS requirements across the west is likely to increase some EIM participants' willingness to generate even though prices are negative. As a result, the

[8] October 9, 2018 Public Input Meeting, slide 12. Available at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_October_9_2018_Public_Input_Meeting.pdf.

cost of negatively-priced could be higher in the future.

Q. What are your conclusions with regard to the impact of EIM on avoided cost pricing?

A. Mr. Isern's claim that interactions with EIM are already accounted for in avoided costs is incorrect. While some of these effects have not been quantified, there is sufficient evidence to justify an adjustment to the Company's current QF avoided cost methodology to account for the effect of negatively-priced intervals that are not currently accounted for within the GRID model.

Q. Please summarize the issue raised by Dr. Hellman/Dr. Kaufman related to the GRID model and avoided cost inputs.

A. Dr. Hellman/Dr. Kaufman propose several modifications to inputs within the GRID model or the avoided cost calculation:

- Use monthly fixed costs from the lowest-cost capacity resource, such as a simple cycle combustion turbine ("SCCT"), to set the price of front office transactions ("FOTs").
- Only 75 percent of QFs with executed contracts that are not yet operational should be assumed to reach operation. This issue is also identified by Mr. Lowe.
- Remove the Foote Creek replacement project from both base and avoided cost GRID runs.
- Escalate coal prices consistent with historic increases.
- Allow coal units to cycle.
- Allow sales to entities in Wyoming and east of Wyoming.

Q. What do Dr. Hellman/Dr. Kaufman propose with regard to the cost of FOTs?

A. Dr. Hellman/Dr. Kaufman propose that FOTs should be priced using monthly fixed costs from the lowest-cost capacity resource, such as an SCCT. They further propose that months of deferred FOTs should include all months with loss of load probability absent FOTs and payment based on deferral of an SCCT.

Q. How did Dr. Hellman/Dr. Kaufman propose to implement this change?

A. Dr. Hellman/Dr. Kaufman used the same GRID model results presented by the Company and added six months of capacity costs based on an SCCT, adjusted for a QFs capacity contribution.

Q. What is the source of the assumed six month requirement for FOTs?

A. It is not apparent from testimony, but Dr. Hellman/Dr. Kaufman indicate it could be determined by calculating the number of months with loss of load probability greater than zero absent market purchases.[9]

Q. Has the Company previously identified the loss of load probability by month?

A. Yes. The capacity contribution values that are currently being used to set avoided costs come from the 2017 IRP and are derived from a loss of load probability study.[10] The monthly LOLP was shown in Figure N.2 from that study, and is also provided in Figure 7 below.

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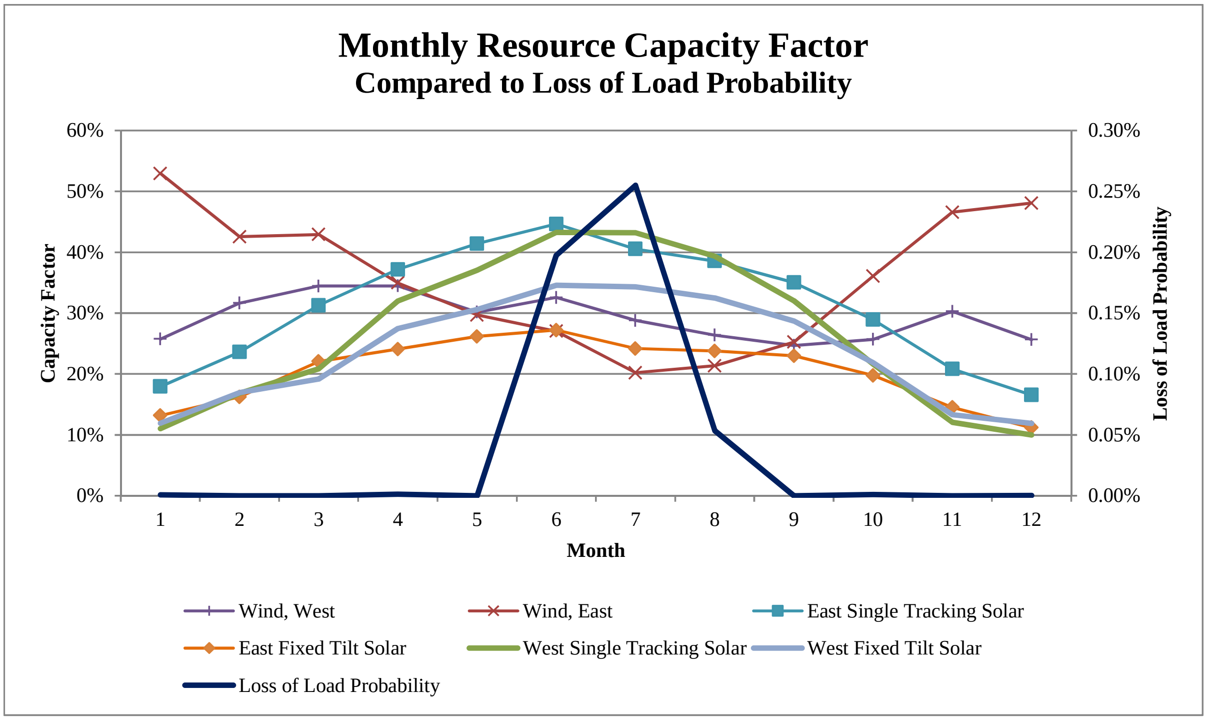
[9] REC 600/RMCRE 700 p. 43, footnote 35.

[10] 2017 IRP. Volume II, Appendix N: Wind and Solar Capacity Contribution Study. Available online: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.

Figure 7: Monthly Resource Capacity Factor Compared to Loss of Load Probability



Q. What does this figure indicate?

A. This figure indicates that the Company's loss of load probability is negligible outside of the months of June through August. As a result, this study would not support the number of months of FOTs for the purpose of setting capacity payments as identified by Dr. Hellman/Dr. Kaufman.

Q. What is the avoided cost of an FOT under the proposal of Dr. Hellman/Dr. Kaufman?

A. It is not clear. In response to RMP data request 1.36, Dr. Hellman/Dr. Kaufman responded that "We do not propose to set avoided costs of FOTs equal to the market price of electricity plus the cost of a SCCT." The GRID model already includes deferral of FOTs in December and July that reflect heavy-load hour products priced at market with an adder of approximately $1/MWh. Within the workpapers provided by

Dr. Hellman/Dr. Kaufman, there are no changes to the assumptions within the GRID model and the cost of an SCCT is added to prior GRID results. As a result, in July and December, the avoided cost appears to be market price, plus the adder, plus the cost of an SCCT. In four other months, which are not specifically identified, the avoided cost of FOTs is apparently just the cost of an SCCT.

Q. Would the Company's IRP preferred portfolio be as reliant on FOTs if the associated cost included the fixed costs of an SCCT?

A. No. Any increase in the cost of a resource will make it less likely to be included in the preferred portfolio. In addition, an SCCT is dispatchable, and can provide flexibility and operating reserve benefits that a typical market purchase cannot. To the extent the model was going to incur the cost of an SCCT regardless, it would be more economic to do so while also receiving the additional benefits an SCCT can provide.

Q. Does the Company reasonably expect to be able to purchase FOTs at its forecasted market prices, without incremental costs such as those proposed by Dr. Hellman/Dr. Kaufman?

A. Yes. This is a fundamental assumption in the IRP, and the basis for this assumption is detailed in the Company's Western Resource Adequacy Evaluation in Volume II of the 2017 IRP. When changes to this assumption are incorporated in future IRPs, the IRP filing will include a preferred portfolio and other related assumptions which are consistent with that change. Since the avoided cost methodology is based on the most recently filed IRP or IRP Update, all of the associated impacts will be incorporated at the same time.

Q. Have you identified any issues with the calculation of the SCCT cost adjustment proposed by Dr. Hellman/Dr. Kaufman?

A. Yes. The key inputs related to the fixed cost of an SCCT are the capital cost, the payment factor, fixed O&M cost, and fixed pipeline cost. Dr. Hellman/Dr. Kaufman have applied the costs for an Oregon SCCT resource from the 2017 IRP in their proposal, as it has the lowest cost per kW because maximum SCCT output is highest at sea level. However, their proposal used the payment factor[11] applicable to wind resources, rather than the slightly higher value applicable to the Oregon SCCT. Their proposal also neglected to account for fixed pipeline costs. These corrections increase the cost of the SCCT, and the size of the adjustment, by approximately 64 percent.

Q. Is the impact on avoided costs identified by Dr. Hellman/Dr. Kaufman applicable to all resource types?

A. No. Based on assumptions used in the 2017 IRP and 2017 IRP Update, wind resources have a low capacity contribution and relatively high capacity factor. In contrast, baseload resources have equivalent capacity contribution and capacity factor, while solar resources have a capacity contribution that is well in excess of their capacity factor. As a result, on a dollar per megawatt-hour basis the impact of the proposed adjustment would be significantly higher for baseload and higher still for solar resources as shown in Table 9.

[11] The payment factor spreads the capital cost over the life of the asset on a real-levelized basis, after accounting for the cost of capital.

Table 9: 6-Month SCCT Cost Adder by Resource Type

Resource	Capacity Contribution %	Capacity Factor %	SCCT Adder $/kw-yr	SCCT Adder $/MWh
Baseload	100%	100%	45	5.18
Solar Fixed	37.9%	26.8%	17	7.32
Solar Tracking	59.7%	31.0%	27	9.96
Wind	15.8%	39.8%	7	2.06

Q. What do you recommend with regard Dr. Hellman/Dr. Kaufman's proposal to add the cost of an SCCT to avoided costs?

A. Dr. Hellman/Dr. Kaufman have not demonstrated that the Company actually pays the cost of a SCCT when it acquires FOTs, and they certainly have not demonstrated that the Company incurs six months of SCCT costs each year due to reliance on FOTs.[12] The proposal is also grossly out of step with assumptions used to prepare the 2017 IRP Update preferred portfolio, which forms the basis for avoided costs. To the extent these costs were realistic, the IRP preferred portfolio would be less likely to select FOTs and more likely to select other resources. In particular, if the IRP selected a SCCT, the dispatch benefits of that resource would provide value to customers which would partially offset its cost under the PDDRR methodology. Under Dr. Hellman/ Dr. Kaufman's proposal, customers would have to pay for half of a SCCT and would receive no dispatch benefits. For those reasons, this proposal should be rejected.

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[12] *See*, Response to Company's Data Request to the Coalition and RMCRE 1.36 (stating that SCCTs are one of many resources that influence the market rate for FOTs).

Q. Does the Company assume that 100 percent of QFs with executed contracts that are not yet operational will reach operation?

A. No. The Company monitors project development progress and contractual milestones for QFs that are not yet operational. To the extent specific information exists which indicates a counterparty will fail to perform in accordance with its commitments, the size or expected COD may be modified, or a resource may be removed in its entirety.

Q. Dr. Hellman/Dr. Kaufman cite RMCRE data request 2.19 for statistics on the QFs that have executed PPAs that have yet to commence operations. Can you provide more details on the treatment of these resources within the avoided cost calculation?

A. Yes. In response to RMCRE data request 2.19, the Company identified seven QF contracts that had been executed but have yet to commence operations. None of these seven QF resources is currently included in the determination of avoided costs.

Q. Is there a chance that any of these resources will commence operations?

A. Yes. Four of the resources that have yet to commence operations are Wyoming wind QFs that are the subject of a complaint in Docket No. 20000-541-EC-18. Depending on the outcome of that docket, there is the potential for these resources to be brought online, but this outcome is not reflected in the current avoided cost pricing.

Q. What do you recommend with regard to Dr. Hellman/Dr. Kaufman's recommendation that only 75 percent of signed QF contracts that are not online be assumed to reach operation?

A. The Company already uses the best information available to inform the inputs to avoided costs related to signed QF contracts that are not online. Furthermore, based on the information in RMCRE data request 2.19, the Company would be required to add resources that it does not believe will reach commercial operation in order to comply with this proposal. It is inappropriate to use a static assumption that embeds QF failure to perform within avoided costs, particularly since this issue is highly project-specific. As with many issues, the QF contractual performance generally becomes clearer as the scheduled commercial operation date approaches, so continuing to incorporate the best information available for each project will lead to the most accurate avoided costs. For that reason, Dr. Hellman/Dr. Kaufman's proposal should be rejected.

Q. What is the current assumption for Foote Creek I within the GRID model?

A. Currently, Foote Creek I is assumed to continue operating at its existing level of output indefinitely.

Q. What is the basis for this treatment of Foote Creek I?

A. The assumptions for Foote Creek I are consistent with those used in the development of the 2017 IRP Update preferred portfolio. To the extent the Foote Creek I resource was not included, the 2017 IRP Update preferred portfolio would have been different as the energy and capacity provided by that resource would need to have been provided by another source.

Q. Does Dr. Hellman/Dr. Kaufman's proposed change account for changes in the preferred portfolio?

A. No. The impacts cited show a slight increase in avoided costs based on the removal of the Foote Creek I resource without identifying any resources to replace it. A replacement wind resource in a nearby location would be expected to have a higher capacity factor using modern turbine technology, which would tend to reduce avoided costs relative to the current modeling.

Q. Will the assumptions for the Foote Creek I resource change as a result of the Company's next IRP filing?

A. Yes. The Company's 2019 IRP is currently under development, and is anticipated to be filed on August 1, 2019. The baseline assumption for Foote Creek I within the 2019 IRP is retirement in 2029. Because avoided cost pricing is based on the most recently filed IRP preferred portfolio, the Foote Creek I retirement date would be applied to avoided cost pricing starting on August 1, 2019. Alternatively, if the 2019 IRP preferred portfolio includes a repowered Foote Creek I resource, that assumption would be applied to avoided cost pricing starting on August 1, 2019.

Q. Is there another way in which the assumptions for the Foote Creek I resource could change?

A. Yes. The Company's "signed contract queue" accounts for changes to all resources, including non-QF PPAs and owned assets, as well as QF PPAs. While the Company has filed a CPCN application requesting permission to repower the Foote Creek I resource, at this time it has not yet signed contracts committing to do so. When the associated contracts are signed, the updated characteristics of the repowered Foote Creek I resource would be incorporated in avoided costs.

Q. Is a change to Foote Creek I necessary at this time?

A. No. The Company's avoided cost methodology is tied to the most recent IRP preferred portfolio, updated to reflect committed, well-documented changes that are not subject to varying interpretations of expected outcomes. This helps ensure the avoided cost methodology requires as little interpretation of inputs as possible.

Q. What do you recommend with regard to Dr. Hellman/Dr. Kaufman's recommendation for Foote Creek I?

A. The existing avoided cost methodology will incorporate changes to Foote Creek I in due course, so no specific adjustment is necessary or appropriate at this time.

Q. What do Dr. Hellman/Dr. Kaufman propose with regard to forecasted coal costs?

A. Dr. Hellman/Dr. Kaufman propose that modeled coal costs be assumed to increase by a fixed percentage each year from 2019 forecasted levels.

Q. What coal costs are currently reflected in avoided cost modeling?

A. The coal costs in the Company's filing are based on a long term coal cost forecast prepared in August 2018. This forecast reflects the Company's current long term coal contracts and best estimate of the cost of additional coal supply to meet requirements and extends 10 years into the future. After the forecast ends in 2028, coal costs are escalated at inflation.

Q. Are there any additional nuances to coal costs?

A. Yes. The Company coal supply forecast identifies both average and incremental costs. Coal contracts can include minimum take volumes and pricing that varies with annual volume. As a result, average and incremental costs vary depending on plant dispatch. Importantly, for the purposes of avoided costs, the value of the incremental change in coal plant dispatch based on the addition of QF output is estimated based on incremental coal costs, not average costs.

Q. Is the difference between incremental and average coal costs relevant to Dr. Hellman/Dr. Kaufman proposal?

A. Yes. The source data used to calculate historical coal cost price increases is based on the change in average coal costs between 2010 and 2018. During this time, the Company's total annual coal generation declined significantly. Because coal cost tiers typically have the lowest prices for the highest volumes, declining volumes will drive up average costs. This does not indicate that the savings from displacing coal generation will be higher, in fact, as coal volumes drop further, the incremental savings is likely to continue to decline.

Q. Are the coal costs proposed Dr. Hellman/Dr. Kaufman significantly different from the Company's forecast?

A. Yes. By 2036, the last year of the Company's preferred portfolio from the 2017 IRP Update, Dr. Hellman/Dr. Kaufman's proposal would result in coal costs that are more than twice the Company's forecast. Were coal costs to vary to that extent, the Company's IRP would identify a significantly different preferred portfolio, with a greater emphasis on alternative low-cost energy sources.

Q. Can the QF avoided cost methodology on its own reasonably be expected to account for such a dramatic changes in assumptions?

A. No. The identification of a preferred portfolio in the IRP is an extensive process and the IRP models accounts for many inter-related factors and options, both in the year a change occurs and over time. The QF avoided cost methodology only allows for a one for one replacement of IRP preferred portfolio resources by suitable QFs, and cannot account for the range of more cost-effective portfolio options that would be suitable under those conditions. To the extent more cost-effective options are available, avoided costs would be overstated as a result of Dr. Hellman/Dr. Kaufman's proposal.

Q. What do you recommend with regard Dr. Hellman/Dr. Kaufman's proposal to escalate coal costs based on history?

A. Dr. Hellman/Dr. Kaufman have provided evidence of differences in historical coal costs over time but have provided no basis to include that their simplistic escalation is more accurate than the Company's current coal cost forecasts. The magnitude of the proposed change in the absence of considering other portfolio, such as through the IRP process, also makes the results questionable. In light of these issues, this proposal should be rejected.

Q. What do Dr. Hellman/Dr. Kaufman propose with regard to allowing coal units to cycle off and on?

A. Dr. Hellman/Dr. Kaufman suggest that transmission congestion in Wyoming could be relieved by allowing coal units to cycle (economically shutdown), but provide no details on their proposal in testimony. In response to RMP data request 1.55 Dr. Hellman/Dr. Kaufman clarified that their proposals is that "coal units be allowed to cycle in a manner consistent to that used in Pacific Power's filings for the Oregon Transition Adjustment Mechanism."

Q. What is Pacific Power's Oregon Transition Adjustment Mechanism ("TAM") filing?

A. The Oregon TAM is primarily an annual forecast of net power costs for the following calendar year, which are used to adjust retail rates for energy supply and certain related rate schedules. The forecast of net power costs in the TAM is also developed using the GRID model.

Q. What assumptions are used for coal units cycling in the Oregon TAM?

A. In the Oregon TAM, the Company models the ability to cycle coal plants that are majority-owned by the company, that are not participating in the EIM, and that are not under operational constraints that would preclude an economic shutdown. The economic cycling period is also limited to the spring season, from February 1 to May 31, which corresponds to the spring run-off period when loads are generally lower, weather is typically mild, market prices are lower, and solar imports from California are increasing.[13]

Q. How many coal units were allowed to cycle in the 2019 Oregon TAM?

A. Three. Cholla 4, Hunter 1, and Hunter 2.

Q. Are any of these units located in Wyoming?

A. No. As a result, the proposed change would not impact transmission congestion in Wyoming and would not be expected to have a significant impact on Wyoming avoided cost rates.

Q. Are there any other factors which would impact the avoided cost results?

A. The Oregon TAM is primarily a one year forecast and current assumptions may not be applicable over the longer term. For example, Cholla 4 is already assumed to be retiring at the end of 2020 in the 2017 IRP Update preferred portfolio, making cycling at this unit irrelevant thereafter. Similarly, both Hunter 1 and Hunter 2 are jointly owned units with contractual arrangements that complicate EIM participation. The Company

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[13] Oregon Docket No. UE 339. 2019 TAM Direct Testimony of Michael Wilding. PAC/100/Wilding 35.

expects to continue working with its co-owners to explore ways of enabling EIM participation at these units in the future.

Q. What do you recommend with regard Dr. Hellman/Dr. Kaufman's proposal to allow coal units to cycle?

A. The proposed coal unit cycling would not impact the transmission congestion that it is ostensibly intended to address and could be irrelevant as a result of changes at the currently applicable units over the next few years. In light of this I would recommend that the Commission reject Dr. Hellman/Dr. Kaufman's proposal to modify the GRID model to allow coal unit cycling.

Q. What do Dr. Hellman/Dr. Kaufman claim with regard to wholesale sales to entities in Wyoming and east of Wyoming?

A. Dr. Hellman/Dr. Kaufman claim that Rocky Mountain Power has transmission connections from Wyoming east to the Craig and Hayden units and that moving energy east from Wyoming would reduce trapped energy and renewable curtailment.[14]

Q. Is this representation accurate?

A. No. The energy from the Company's resources in Wyoming must be transferred using transmission reservations held by the Company's Energy Supply Management ("ESM") function. PacifiCorp ESM does not have long term transmission rights to transfer from Wyoming to Craig and Hayden. To do so would require transmission rights from multiple transmission providers, which would incur a significant cost. Moreover, firm transmission rights may not be available in the sizeable quantities required, which can exceed the Company's share of the Craig and Hayden plants.

[14] REC 600/RMCRE 700 p. 75, 14-16.

Q. Does the Company assume wholesale sales in eastern Wyoming in its IRP modeling or when evaluating non-QF resource decisions?

A. No. The Company's 2017 IRP Update, 2019 IRP, and recent resource evaluations do not assume any wholesale sales capability in eastern Wyoming. While Dr. Hellman/ Dr. Kaufman are correct that it would increase the value of resources in this area, the price and volume for such sales are highly uncertain.

Q. Is the inclusion of assumed wholesale sales at illiquid points in eastern Wyoming consistent with Dr. Hellman/Dr. Kaufman discussion of the risk-reducing benefits of QFs?

A. No. To the extent avoided cost prices are established based on assumed wholesale sales revenue from illiquid points, retail customers would face higher risks that market price and volume would vary.

Q. Are retail customers required to compensate QFs for potential wholesale sales revenue?

A. Not necessarily. The Idaho Commission has established an avoided cost methodology based on the highest displaceable incremental cost in each hour, not on the value of potential market sales.[15] This reduces the risk to retail customers as QFs are paid based on the avoided cost of resources that are expected to be used to serve load, rather than the less certain value of forecasted market prices.

Q. What do you recommend with regard Dr. Hellman/Dr. Kaufman's recommendation to allow wholesale sales in eastern Wyoming?

A. Allowing wholesale sales in eastern Wyoming is contrary to the assumptions used in

[15] Idaho Public Utilities Commission. Order No. 32697 at 21.

the 2017 IRP Update that forms the foundation of the avoided cost methodology and places inappropriate risk on retail customers. Therefore this proposal should be rejected.

<u>TIMING OF AVOIDED COST CALCULATIONS</u>

Q. Do avoided costs change over time?

A. Yes. The fact that forecasted avoided costs calculated today will be different from avoided costs calculated at the time of delivery is inherent in the pricing options PURPA makes available to QFs. Forecasts of avoided costs will also vary over time as a result of changes in the Company's portfolio; resource options, costs, and characteristics; and forecasted load and market prices.

Q. When are avoided costs the most accurate?

A. Avoided costs are not known for certain until the time of delivery.

Q. Is the avoided cost pricing ultimately reflected in a QF PPA impacted by contract terms and negotiating requirements?

A. Yes. Increasing the maximum contract term limit or time from execution to COD, restricting contract price updates prior to execution, or removing the Schedule 37 resource cap will result in avoided cost prices set using less up-to-date information.

Q. Can you provide an example illustrating current QF contract timelines?

A. Yes. At present a Schedule 38 QF can request a COD 36 months in the future, and a 20 year contract term with pricing calculated shortly prior to execution. As a result, a Schedule 38 QF contract signed today could have prices calculated in 2019, a start date in 2022, and an expiration date in 2042.

Q. How do these dates compare to the study period in the IRP?

A. The Company's current preferred portfolio from the 2017 IRP Update only extends through 2036, while the upcoming 2019 IRP will only extend through 2038. As a result, more than 25 percent of a current QF term reflects pricing that is not based on concurrent assumptions from the IRP. Instead, prices beyond the end of the IRP study period are assumed to escalate at inflation.

Q. How certain are the resources in the IRP preferred portfolio?

A. Not very, as the preferred portfolio can change dramatically over a short time period. For instance, the 2015 IRP preferred portfolio included no renewable resources beyond those required for state mandates. For the first time, the 2017 IRP preferred portfolio included solar resources, and the 2017 IRP Update preferred portfolio included no new thermal resources. The 2019 IRP preferred portfolio is likely to contain battery and/or pumped storage resources for the first time.[16] By making long-term commitments based on needs as of the time of the 2015 IRP, customers would have forgone the opportunity to take advantage of solar, energy storage, or other future alternatives that were not contemplated or economic at that time.

Q. How would the contract expiration date in the previous example be impacted by the proposed changes in contract terms and negotiating requirements?

A. The Company has proposed a seven year maximum contract term, which would result in a contract expiration date in 2029. OCA supports a maximum contract term of 10-15 years, which would result in contract expiration dates between 2032 and 2037.

[16] See slide 5 from April 25, 2019 IRP Public Input Meeting presentation. Available online: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_April_25_2019_PIM.pdf.

Mr. Lowe proposes that QFs be allowed to select a COD up to four years from execution, or the amount of time needed to complete interconnections. This would extend the contract expiration date to at least 2043, and potentially many years beyond that, depending on the time required to complete interconnections. The corollary is that the Company's forecast of avoided cost prices must also extend to 2043, 24 years in the future.

Q. What do you recommend with regard to maximum contract term limits and the maximum time from execution to COD?

A. In determining these contract terms, I would ask that the Commission take into account the uncertainty in avoided cost pricing far in the future, the absence of expected customer benefits at avoided cost prices that are only intended to be no worse than the utility's estimated costs, and the simplicity of the avoided cost methodology relative to the tools developed in the IRP.

Q. How would the vintage of avoided cost pricing in the previous example be impacted by the proposed changes in contract terms and negotiating requirements?

A. Allowing QFs to specify CODs that are 48 months in the future would result in pricing that has inputs that are 18 months out of date, relative to the Company's proposal of a 30 month limit. Restricting the Company's ability to update Schedule 38 avoided costs prior to execution could result in prices calculated using assumptions that are several months out of date. Based on the Company's current proposal to update Schedule 37 prices annually and the current review process, published Schedule 37 prices will always be 9-21 months out of date. Removing the resource cap would result in additional QFs contracted at these outdated prices, once the current cap is exceeded. Under the Company's proposal, Schedule 37 QFs in excess of the 10 MW cap would receive pricing using current assumptions.

Q. Do avoided cost prices change significantly from month to month?

A. Sometimes. Absent an update in inputs, avoided cost prices will not change at all. But updates to key inputs can have a dramatic impact on avoided costs in a short time. The key input changes that impact avoided cost prices are:

- The IRP preferred portfolio, including resource cost and performance assumptions, which are updated annually.
- Forward market prices for electricity and gas, which are updated quarterly.
- Newly signed contracts and committed owned resources, which are updated whenever necessary.

Q. Is it reasonable to require the Company execute QF PPAs with pricing that ignore the latest available information?

A. No. The Company would be deemed imprudent if it executed a non-QF PPA or committed to acquire an owned resource without accounting for current information as of the time of the decision. Customer indifference requires that QF PPAs be held to a comparable standard.

<u>USE OF SCHEDULE 38 METHODOLOGY FOR SCHEDULE 37</u>

Q. Please summarize Parties positions on the Company's use of the Schedule 38 methodology to calculate Schedule 37 rates.

A. OCA and Mr. Higgins generally support the Company's proposal to use the Schedule 38 methodology for Schedule 37 rates. Dr. Hellman/Dr. Kaufman identify several changes to the Schedule 37 pricing methodology, but appear to generally support resource-specific avoided cost pricing for Schedule 37 using a methodology comparable to that which they propose for Schedule 38 QFs. Mr. Lowe recommends that the current Schedule 37 pricing methodology be retained because he claims that avoided cost prices are already too low and that there aren't many Schedule 37 QFs in Wyoming. Mr. Lowe also proposes the creation of separate renewable and non-renewable pricing options under Schedule 37, which I have previously addressed.

Q. What is the most important characteristic of avoided cost rates?

A. Customer indifference.

Q. Does the Coalition provide any evidence that the current Schedule 37 methodology produces a more accurate forecast of avoided costs than the Schedule 38 methodology?

A. No.

Q. Does the Schedule 38 methodology inherently reduce Schedule 37 rates?

A. No. In fact, as I identified in my direct testimony, the proposed rates for baseload resources are higher using the Schedule 38 methodology than using the current Schedule 37 methodology. As a result, the small hydro resources Mr. Lowe and the Coalition represent would be paid more under the Company's proposal than if the simplified Schedule 37 methodology currently in place continued to be applied.

Q. Do you have specific examples of how the current Schedule 37 methodology is less accurate than the current Schedule 38 methodology?

A. Yes. First, during the sufficiency period the current Schedule 37 methodology calculates a single monthly avoided cost based on the generation of a baseload resource.

This does not accurately reflect the generation profiles of wind and solar resources. Because the existing solar resources in the Company's portfolio already avoid the highest cost resources during the day, avoided costs for new solar resources delivering at the same times are necessarily reduced. The baseload resource used to determine the single monthly avoided cost value in GRID/Proxy reflects an equal weighting of day and night that is inappropriate for solar. The proposed changes to on-peak and off-peak periods help to address this, but two prices per day are still not sufficient to distinguish between the output of baseload, wind, and solar resources.

Second, during the deficiency period the current Schedule 37 methodology calculates avoided costs based on the fixed and variable costs of a thermal proxy. This methodology fails to account for the benefits associated with dispatching the thermal resource up or down in response to resource needs and market prices. For instance during the spring run-off period, a CCCT may be taken offline to allow for lower cost market purchases. The current Schedule 37 methodology assumes that QF output during the spring will have value equal to the variable cost of the thermal proxy–even if that resource was expected to be offline during that period.

Q. Are there any specific characteristics of small QFs that are captured in the Schedule 37 methodology that are not captured in the Schedule 38 methodology?

A. No.

Q. Is the current number of Wyoming Schedule 37 QFs an appropriate basis for continuing to use less accurate avoided cost pricing?

A. The current number of Wyoming Schedule 37 QFs is no indication of future interest. To the extent any QFs receive pricing which is not consistent with the Company's avoided cost, it would be contrary to the customer indifference standard. Furthermore, the Company is required to publish avoided cost prices, and publishing less accurate prices would be contrary to PURPA.

Q. What is your conclusion with regard to the Schedule 37 pricing methodology?

A. The Schedule 38 pricing methodology provides a more accurate avoided cost than the current Schedule 37 methodology. After incorporating any modifications to the Schedule 38 methodology it deems appropriate, the Commission should approve its use to set Schedule 37 rates.

<u>SCHEDULE 37 RESOURCE CAP</u>

Q. Please summarize the issues raised by Parties relating to the Company's Schedule 37 resource cap.

A. OCA generally support the Company's proposal. Parties generally indicate that the language and process regarding the resource cap in Schedule 37 are unclear and should be modified or clarified. Mr. Higgins suggests that the 10 MW resource cap should be eliminated, as rates are expected to be updated annually, or that Schedule 37 should be updated as soon as the cap is reached. Mr. Lowe suggests that the resource cap should be increased to 100 MW. Dr. Hellman/Dr. Kaufman also support a 100 MW cap.

Q. What is the current tariff on the current Schedule 37 resource cap?

A. The current tariff says: "These prices will only be applied to Qualifying Facility resources over which the Commission has jurisdiction that enter into contracts with the Company until 10 megawatts of system resources are acquired."

Q. How has the Company interpreted the current Schedule 37 resource cap?

A. The Company has assumed that the published rates would be applicable until 10 MW of new or renewed Wyoming Schedule 37 contracts were signed. The sum of the signed Schedule 37 contracts resets to zero each time new published rates are approved.

Q. Has the current Schedule 37 resource cap ever been applied?

A. No.

Q. What happens if the Schedule 37 resource cap is reached?

A. It is unclear.

Q. What is the ideal outcome?

A. Customer indifference is best protected by having avoided rates which reflect the best available information at the time a QF contract is entered.

Q. Can the process for updating Schedule 37 rates hamper that outcome?

A. Yes. The current process for updating Schedule 37 rates is slow, for instance the Company's proposed change to Schedule 37 rates is not yet effective and now reflects data which is more than six months out of date. Parties also appear to be concerned that the Company may not file to request updates to Schedule 37 pricing, and may require Schedule 38 to be used indefinitely.

Q. Is the Company willing to commit to a timeline for filing a request to Schedule 37 updates?

A. Yes. The Company is willing to file updated Schedule 37 rates within 30 days of the contract cap being reached, the same timeline applicable to Schedule 38 indicative pricing requests. The Company would also support a more streamlined review process such that the rates could become effective more quickly.

Q. Mr. Lowe indicates that the Schedule 37 resource cap is unique to Wyoming.[17] Is this correct?

A. No. The Company's Utah Schedule 37 tariff contains published avoided cost prices for small QFs and uses a 25 MW resource cap, comparable to that applicable in Wyoming given the relatively larger load in Utah.[18]

Q. Will annual updates ensure that customer indifference will be maintained in the absence of a Schedule 37 resource cap as suggested by Mr. Higgins?

A. No. Given the duration of the current review process for Schedule 37, the Company will need to file updated Schedule 37 rates a few months after its previous filing is approved. Even if the Company filed immediately after an influx of QF resources, the updated rates would not become effective for many months pending Commission action. In the interim, the Schedule 37 resource cap ensures that rates for resources in excess of 100 kW will be consistent with avoided costs, whereas under Mr. Higgins' proposal the obsolete Schedule 37 prices would continue to be available to QFs for many months.

Q. Dr. Hellman/Dr. Kaufman support a 100 MW cap on the basis that this provides symmetry with the 50 MW resource used to calculate Schedule 37 rates. Is this reasonable?

A. No. There is nothing symmetrical about Dr. Hellman/Dr. Kaufman's proposal. The Company has calculated Schedule 37 avoided costs based on an assumed 50 MW resource of each type. The avoided costs for an additional 50 MW resource would be

[17] Coalition/600. p. 5, lines 97-99.
[18] *See*, Rocky Mountain Power, Electric Service Schedule No. 37, State of Utah, at the last sentence in the section entitled "Applicable" ("A cumulative cap of 25,000 kW shall apply to new resources contracted under this schedule.").

lower as the highest cost resources would be displaced by the first 50 MW resource.

Q. Why does the Company use a 50 MW resource to calculate Schedule 37 rates?

A. The Company's current and proposed application of the Schedule 37 resource cap only accounts for the quantity of signed Wyoming Schedule 37 resources. The resource cap does not account for: Wyoming Schedule 38 QFs, QFs in other states, non-QF PPAs, committed owned resources. Using a 50 MW resource to calculate Schedule 37 rates helps account for those other potential changes while the Schedule 37 rates are in effect.

Q. Are changes in other resources likely to occur?

A. Yes. Since the Company filed its proposed Schedule 37 avoided cost rates, which have not yet taken effect, it has signed a non-QF PPA for a 120 MW wind resource in eastern Wyoming, Cedar Springs III, and has signed contracts with 15 MW of QF PPAs in other states. The Wyoming wind resource would have an appreciable impact on avoided costs under the Company's proposed methodology due to its size and location. The other contracts would also influence avoided costs by reducing capacity needs and marginal energy costs.

Q. Will QFs in excess of 100 kW be harmed by the requirement to be priced in accordance with the Schedule 38 methodology?

A. Not necessarily. The Company endeavors to supply indicative Schedule 38 prices within 30 days of receiving a completed request. Contract negotiation typically is longer than this, even for small projects which do not take choose to negotiate changes to the standard contract terms. Moreover, the Company has proposed adopting the Schedule 38 methodology for Schedule 37, so the assumptions will be largely the same as what they would have otherwise received. The only differences between Schedule

37 and Schedule 38 in the Company's proposal are: Schedule 38 incorporates the latest available information and incorporates project-specific characteristics, rather than generic assumptions for that resource type. Neither of these are necessarily to a Schedule 37 QF's detriment.

Q. What is your conclusion with regard to the Schedule 37 resource cap?

A. The current Schedule 37 modeling assumptions and capacity cap are reasonable to ensure accurate avoided costs and retail customer indifference; however, the Company is willing to clarify the triggers and tariff update process. The Company proposes that, when 10 MW of Wyoming Schedule 37 contracts have been signed at the published prices, the prices would be suspended for QFs in excess of 100 kW, and the Company would be required to file updated Wyoming Schedule 37 prices within 30" days. Until the Commission acts on the Company's proposal, QFs larger than 100 kW would receive project-specific prices calculated using the current assumptions under the Schedule 38 methodology. Each time new published prices are approved, the cap would be reset to zero.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED CONTRACT TERM OF PURPA POWER PURCHASE AGREEMENTS WITH QUALIFYING FACILITIES	))))))))))	DOCKET NO. 20000-545-ET-18 (RECORD NO. 15133)

AFFIDAVIT, OATH AND VERIFICATION

Daniel MacNeil (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is a Resource and Commercial Strategy Adviser for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Resource and Commercial Strategy Adviser.

Further Affiant Sayeth Not.

Dated this 24th day of May, 2019

Daniel L. MacNeil

Daniel MacNeil
Resource & Commercial Strategy Adviser
825 NE Multnomah Ave, Ste 600
Portland, OR 97232

STATE OF Oregon)
) SS:
COUNTY OF Multnomah)

The foregoing was acknowledged before me by Daniel MacNeil on this 24th day of May, 2019. Witness my hand and official seal.

OFFICIAL STAMP
KELLY ANN WIGGINS
NOTARY PUBLIC-OREGON
COMMISSION NO. 968113
MY COMMISSION EXPIRES OCTOBER 26, 2021

K Wiggins

Notary Public

My Commission Expires: 10/26/2021

Docket No. 20000-545-ET-18
Witness: Mark P. Tourangeau

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Mark P. Tourangeau

May 2019

Q. Are you the same Mark P. Tourangeau who previously submitted direct testimony in this proceeding on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes. I filed direct testimony supporting the Company's application ("Application") to modify certain commercial aspects of Wyoming's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA").

<u>PURPOSE AND SUMMARY OF TESTIMONY</u>

Q. What is the Company asking the Commission to approve in this proceeding?

A. The Company seeks several changes to PURPA implementation, including; a reduction in the maximum allowable contract term for qualifying facility ("QF") power purchase agreement ("PPA") contracts from 20 years to seven years, improvements to the language and process for QFs under the Company's Schedules 37 & 38 tariffs, and improvements to the avoided cost pricing methodology.

Q. Please summarize your initial direct testimony.

A. My initial testimony presented and supported the Company's proposed modifications to Schedule 37, Avoided Cost Purchases from Qualifying Facilities, and Schedule 38, Avoided Cost Purchases from Non-Standard Qualifying Facilities. These modifications improve the implementation of PURPA Schedule 38 in a number of ways while reducing risk to the Company's customers.

First, a reduction in the fixed price contract length for non-standard QF PPAs under the Company's Schedule 38 tariff and Firm Power Time of Delivery QF PPAs under the Company's Schedule 37 tariff will mitigate risk to customers. I provided supporting evidence and discussed why a shorter term length for QF PPAs is fairer to the Company's customers, consistent with PURPA's customer indifference standard, while remaining consistent with PURPA's requirement that QF developers have a reasonable opportunity to attract capital for their Wyoming projects.

Second, clarifying the processes, procedures and language in the Company's proposed revisions to Schedules 37 & 38 will provide greater transparency in avoided cost pricing requests and PPA negotiation and execution procedures. The proposed clarifications to the processes and procedures in the Company's Schedules 37 & 38 will minimize confusion among potential QFs.

Q. Which witnesses' testimony are you responding to in your rebuttal testimony?

A. My rebuttal testimony focuses on the following testimonies: a) Kevin Higgins, who provided testimony jointly for the Wyoming Industrial Energy Consumers ("WIEC") and Two Rivers Wind, LLC ("Two Rivers Wind") (collectively "WIEC/Two Rivers"); b) John Lowe who provided testimony for the Renewable Energy Coalition ("REC"); c) The joint testimony of Drs. Marc Hellman and Lance Kaufman who provided that testimony on behalf of both REC and the Rocky Mountain Coalition for Renewable Energy ("RMCRE"); and d) The testimonies of Hans Isern and Mark Klein, each provided for RMCRE.

Q. After reading intervenors' direct testimony in this docket, what are your general observations?

A. Much of the REC, RMCRE, and the WIEC/Two Rivers testimonies cover common themes in response to the Application. Generally speaking, the witnesses allege that the true goal of the Application is to severely limit QF development. This is not true, the Company understands its obligations to purchase QF power under PURPA's rules as promulgated by the Federal Energy Regulatory Commission ("FERC") and the Public Service Commission of Wyoming ("Commission"). At the same time, the Company's central obligation is to provide its customers with safe, reliable and affordable power. The Application represents the Company's continuing efforts to balance these two, at times competing, obligations.

Q. Please summarize your understanding of the REC and RMCRE testimony with respect to the points raised concerning your initial testimony.

A. RMCRE is an un-incorporated, informal coalition that was formed with the sole purpose of opposing the Company's efforts in this proceeding. The current supporters of RMCRE are sPower, VK Clean Energy, and Chevron Power and Energy Management Co. REC is a trade group that was established in 2009 and is comprised of members that develop, own and operate QFs in the western United States. In their testimony, RMCRE's and REC's representatives make the following high level points:

RMCRE and REC both argue the Commission should reject the reduction of the QF PPA contract term for any period of time less than 20 years. They claim that QFs cannot obtain financing with seven year fixed price contracts, and that limiting contracts to seven years would be anti-competitive. RMCRE witnesses Mr. Isern and Mr. Klein claim that the shorter terms would impair QFs' ability to achieve financing/capital and discourage QF development.

At the same time, the witnesses solely testifying for REC appear to represent smaller scale QFs, and decry the lack of financing for their projects. These witnesses completely ignore the USDA financing programs identified in my direct testimony. Mr. Klein for RMCRE, on the other hand identifies the USDA programs but disregards them as more applicable to small QFs. REC's witnesses also claims that shorter term contracts make it difficult to operate small hydro facilities and to plan for maintenance capital and spend time and money on re-negotiation of PPAs. The Company is interested in speaking with the owners and operators of small hydro generating resources that can deliver to its service areas to see if there are mutually beneficial solutions for them outside of QF contracts. As is clear from my discussion on PURPA's must take obligation as it relates to the non-dispatchable nature of QFs, PURPA's limited flexibility may be leaving potential value on the table for both the Company and these small hydro resources.

Q. Please summarize your understanding of Kevin C. Higgins' direct testimony for WIEC/Two Rivers with respect to the points raised concerning your initial testimony.

A. While Mr. Higgins' testimony makes many of the same points as those made by RMCRE and REC, he also raises a couple of unique points worth addressing here individually.

Q. How is your rebuttal testimony organized?

A. My testimony focuses on rebutting several topics that REC, RMCRE, and WIEC/Two Rivers each provided testimony on, and then it rebuts two issues raised only by WIEC/Two Rivers' witness Mr. Higgins.

THE RISKS OF OVERLY LONG QF PPA TERMS

Q. Did the REC, RMCRE, and WIEC/Two Rivers testimonies properly characterize the discussion of risks associated with entering into long term PPAs with QFs?

A. No. Direct testimony from each of these parties missed the point the Company made regarding long-term QF PPA risk, economic dispatch vs uneconomic dispatch, and the harm that such long term QF contracts can cause our customers. Instead of taking these arguments head on, these parties attempted to confuse the issue by focusing much of their testimony on the Company and its return on invested capital. QFs cause more risk to our customers, and mitigating this risk is at the heart of the Application's proposal to shorten the maximum QF PPA term length. By shortening the term length the Company seeks to restore the balance between the principle inherent to PURPA that customers should be no worse off buying from a QF than they would be buying the same amount of energy from their utility (the "customer indifference principle"), and the Company's strict adherence to PURPA's other requirements. This case does not present the Commission with a decision about how the Company may or may not generate return on invested capital. Instead, the Application asks this Commission to determine whether shorter term QF contracts reduce risks to customers while still allowing QFs a reasonable opportunity to attract capital.

Q. Are fixed price contracts the only way to reduce risk?

A. No. After providing an elaborate description in testimony of the ability of fixed price QF contracts to reduce risk,[1] witnesses Hellman and Kaufman admitted, in response to RMP data request 1.20, that options also reduce risk. The ability to economically

[1] REC & RMCRE, Direct Testimony of Dr. Marc Hellman and Dr. Lance Kaufman, at pp. 8-12.

dispatch is an option available only with Company owned resources and non-QF PPAs that reduces risk. Over the longer term, Company owned resources give the Company the option to change its portfolio in response to changes in resource costs and expected future conditions, which is also hindered by long term, non-competitive fixed price contracts like 20 year QF PPAs.

Q. How do you respond to the assertions from REC and RMCRE witnesses Hellman and Kaufman that shorter term contracts increase risks for customers rather than mitigate them?

A. Witnesses Hellman and Kaufman assert that long term fixed price QF contracts are less risky because they lock in prices for the Company's customers and thus reducing price variability. They note that our customers only pay for the power that is generated. They claim that there is no risk to the Company or our customers when a QF defaults under its PPA or when it experiences operational issues. Hellman and Kaufman further claim that customers will never have to worry about the impacts from a QF coming online past its contractual commercial operation date ("COD") or shutting down prior to the expiration of its contract.

One of the purported risks referred to repeatedly by REC, RMCRE, and WIEC/Two Rivers stems from comparing the Company's ability to recover capital investments in owned-resources vs how QFs operate. However, this comparison is neither apt, nor does it address the evidence the Company has put forth in favor of a reduction to the maximum QF contract term. In my direct testimony I refer to the price risk to our customers from 20 year QF contracts. The price risk comes from two areas.

The first is that these long term contracts are not based on a competitive procurement.[2] This risk accrues to the customers through net power costs in the variance between the prices of these contracts versus other power costs over the term of the contract. Of course this risk applies to both QF and non-QF long term contracts but the difference is that non-QF contracts are typically priced through a competitive process. The resulting positive variance between the PPA and net power costs are reduced, or even go negative compared to an avoided cost based QF PPA that generally has a higher absolute price.

The second risk stems from the must-take obligation in these contracts.[3] When the Company refers to impacts to net power costs in the EIM relative to the "must-take" provision of a QF, what we are referring to is the opportunity to displace a higher cost resource with a lower cost import. For example, if prices in the EIM are $10/MWh and a thermal unit has a cost of $18/MWh, that unit can be decremented from its original schedule and displaced with the $10/MWh import at a benefit to customers of $8/MWh. Similarly, if the QF contract states that PacifiCorp must pay it $35/MWh for every MWh, but prices in the EIM are $5/MWh, PacifiCorp does not have the opportunity to displace the QF schedule for the cheaper import. Due to the fact that the EIM is only a within-hour market, these intra-hour EIM prices are not included in the avoided cost pricing model, which is an hourly model. Even if the model was an intra-hour model, the Company does not currently have an "EIM" price curve since it is within-hour opportunities that are primarily related to imbalances across the system (e.g. solar over-

[2] Rocky Mountain Power, Direct Testimony of Mark P. Tourangeau, at p. 14 lines 4-7.
[3] *Id.*, at pp. 12-13, lines 22-23 & 1-13.

producing in the real-time market versus forecast on a day-ahead basis, or lower loads versus day-ahead forecasts).

Avoided cost models are forecasting models and cannot measure what the impact to market prices are when forecasts are wrong. The imbalances that result when forecasts are wrong in real-time can create opportunities to monetize benefits in the EIM using resources that the Company has the ability to dispatch up and down for our customers' benefit. These opportunities do not exist with QFs due to their must-take provisions, which ultimately harms the Company's customers.

Q. Can you provide a specific example of how these benefits are forfeited due to a QF must-take contract?

A. Yes. In 2017 and 2018, a 140.7 MW nameplate capacity QF in Wyoming experienced 6,519 and 2,163 five minute intervals of negative pricing respectively. Due to the project being a QF, the resource was required to be dispatched during these intervals instead of being decremented to allow lower-priced resources or transactions to be used to serve the Company's customers. The total cost to customers due to this must-take obligation over the two years was $327,506. This is the cost to our customers in 2017 and 2018 associated with just one of the 166 QFs on PacifiCorp's system, totaling almost 2,000 MWs of nameplate capacity. These are real costs that increase customers' rates vs what they could be, and demonstrate the harm to customers from the lack of dispatchability associated with the Company's must-take PURPA obligations.

The negative impacts of QF non-dispatchability hits customer prices in our 6 states through various net power cost adjustment mechanisms such as the Energy Cost Adjustment Mechanism and Energy Balancing Account, and impact customer rates. By shortening the terms of QF contracts, improvements in avoided cost calculations to better account for the impact of the EIM market and other factors can be incorporated when a contract is renewed, reducing the absolute difference between the PPA prices and actual avoided costs.

Using the definition of risk from REC's witnesses Hellman and Kaufman, which is stated as variance,[4] shortening fixed price QF contract lengths –will increase the Company's options to respond to changing future conditions and reduce risk for customers. Having more options reduces the risk to the Company's customers and better aligns the allocation of risk between QFs and customers in accordance with PURPA's customer indifference principle.

Q. Do REC and RMCRE witnesses' discussion of risks associated with QFs miss any key risks?

A. Yes. RMCRE and REC's witnesses contend that QFs are less risky than utility owned resources since QFs can only receive pricing based on avoided costs of the utility. They claim that QFs bear all costs of project development including cost overruns, that, should a QF be decommissioned early, ratepayers do not continue to pay, and that if a QF comes online late the developer must pay delay damages. All of these claims ignore a key point—that if a QF defaults due to any of the reasons above and fails to come online or ceases operations early, it is the Company and its customers who will bear the risk of replacing the defaulted QF capacity.

[4] *See*, Direct Testimony of Marc Hellman, Ph.D. and Lance Kaufman Ph.D. on behalf of Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy, at pp. 9-11, lines 15-19, 1-17, and 1-5 respectively.

Q. What other key QF risks does the REC, RMCRE, and WIEC/Two Rivers testimony fail to fully account for?

A. REC, RMCRE, and WIEC/Two Rivers witnesses each claim that the Company's concerns over the "must take" obligation and "economic dispatch" costs borne by our customers are incorrect and irrelevant to the contract term length. RMCRE's witness Mr. Isern claims that my testimony seeks to create an "apples to oranges" comparison between utility owned generation and the Company's return on capital vs. QFs, while totally ignoring the impacts to our customers. In fact, my testimony stresses the "apples to apples" comparison of costs to our customers in a given settlement period on the system. This comparison demonstrates the risks associated with the must take obligation that causes higher priced QF energy to be used in a given period versus the low to negative price alternatives available from company owned resources, contracted resources, or transactions available in the EIM.

Testimony from REC, RMCRE, and WIEC/Two Rivers repeatedly fails to address non-dispatchability, and their witnesses instead attempt to re-direct the Company's arguments about "must-take" and "economic dispatch" into a discussion on capital recovery for company-owned resources. These are diversionary tactics, not evidence that counters the Company's concerns about QF non-dispatchability. The Company consistently points to the risk to our customers that stems from PURPA's must take obligation, and our efforts to reduce the risks to our customers via the proposals made in the Application. These parties instead point to unrelated issues, versus squarely addressing the real risks that the Company has identified.

<u>PROCURMENT USING IRP PROCESSES AND TOOLS YEILDS POSITIVE BENEFITS TO CUSTOMERS, QFS ARE ONLY INTENDED TO MAKE CUSTOMERS NO WORSE OFF</u>

Q. Did the REC, RMCRE and WIEC/Two Rivers testimonies properly describe how the Company identifies and selects new non-QF energy resources?

A. No. Testimony from each of these parties shows a basic lack of understanding of the procurement process for non-QF resources, all while trying to conflate this process with the QF process. Company resource procurement, and the QF PPA process exist under entirely different regulatory regimes that were established for distinct purposes. The Company's non-QF procurement process results in significantly lower risk for the Company's customers, in part because the Company risks cost disallowance if its procurement of non-QF resources—either owned or contracted—do not result in customer benefits and are not implemented and maintained prudently.

Q. Are there other differences between the Company's non-QF resource procurement and QFs?

A. Yes. As I have noted, the Company has an obligation to provide its customers with safe, reliable and affordable power. It uses several tools through its IRP processes to identify its customers' needs and the best resources and opportunities to meet those needs. The non-QF procurement process generally arises from the Action Plan part of the Company's IRP, and, at times, outside of the Action Plan to take advantage of significant market opportunities, which opportunities the Company uses IRP tools to evaluate customer benefits. In contrast, the QF PPA process, mandated by PURPA, effectively provides non-utility generators that meet the law's qualifications a "put" option to utilities with little to no ability on the part of utilities to plan in advance to acquire QF resources based on customer needs. While the Company understands PURPA's federal mandate is ongoing, the law initially sought to alleviate issues in the US energy market that no longer exist. These changed circumstances are among the reasons why the Company has asked the Wyoming Commission to use its authority under PURPA to modify its implementation so that it better reflects the current environment.

Q. What is your response to the assertion from REC, RMCRE, and WIEC/Two Rivers witnesses that non-QF procured resources result in more risk to customers than QF procured resources?

A. This is an area where the witnesses mischaracterize or willfully ignore the scope of the Company's non-QF resource procurement processes. My initial testimony described at a high level the IRP process and resulting resource acquisition strategy traditionally followed by the company.[5] REC, RMCRE, and WIEC/Two Rivers witnesses pointed out different occasions where the Company procured resources outside of this process —for example, the Cedar Creek III wind PPA. The Company acknowledges that the IRP Action Plans are not always followed systematically with respect to non-QF resource acquisitions, and the Company, at times, must act quickly to take advantage of time-limited opportunities to generate benefits for customers. However, the Company also evaluates the customer benefits associated with such opportunities using the IRP information and tools.

[5] Tourangeau Direct, at pp.9-11, lines 17-22, lines 17-22, 1-24, and 1-21 respectively.

With respect to the Cedar Creek III PPA, the Company acted on the opportunity to acquire an additional PPA for 120 MW of capacity in Wyoming as a result of the Energy Vision 2020 2018R RFP. In early November 2018, NextEra Energy Resources ("NextEra") approached PacifiCorp with an offer to engage in PPA discussions, with similar terms and conditions as contained in the Cedar Springs I PPA from Energy Vision 2020, for the incremental 120 MW Cedar Springs III opportunity.

Cedar Creek III must be in service by December 31, 2020 to qualify for federal production tax credits ("PTCs"). To achieve this in-service date, construction activities must begin no later than May 2019, which required a PPA to be executed quickly. Executing the PPA enabled NextEra to finalize certain contractual arrangements (i.e., turbine-supply agreements and engineer, procurement and construction agreements) that were required to achieve a commercial-operations date of no later than December 31, 2020. Failure to execute the Cedar Springs III PPA within this time frame risked forgoing the opportunity to secure a low-cost wind resource that will provide a unique value for customers. Signing this PPA will result in anywhere from an estimated $38m to $84m in net present value revenue requirement benefits to the Company's customer from 2021 through 2038. This is in contrast to similarly long QF contracts that generate $0 forecasted economic benefits to customers due to their pricing at avoided costs, and provides another example of how a re-balancing of risk is necessary to ensure that customers remain indifferent to QF contracts.

Q. What are some other differences between Company procurement and the QF PPA process?

A. Another important point to consider when attempting to compare the Company's resource acquisitions to QFs is that, unlike QF developers, the Company faces significant scrutiny with respect to the prudency of these actions, and disallowance risk on capital investment or non-QF PPA acquisitions. Commission scrutiny provides a strong disincentive against unnecessary investments or contractual commitments.

The witnesses also try and frame the operations and credit risks as the same or less for QFs vs company-owned or non-QF PPAs, but here we disagree as well. The Company faces the same types of disallowance risks for cost-overruns and performance issues for these contracts as they do for initial approvals to treat them as system resources. Contrast this with QFs, who face the same sort of operational and environmental risks as a company owned or non-QF PPA asset.

REC, RMCRE, and WIEC/Two Rivers witnesses are correct that these are borne by the QF owners. But only up to a certain point. In response to Company discovery, Mr. Higgins responded that the customers would be indifferent to the choice of replacement, but that is only if avoided cost forecasts equal actual costs for energy and capacity at the time of the default.[6] Other witnesses did not directly answer. Isern stated that the relevant Commission would decide who bears the replacement cost and Hellman/Kaufman provided a similarly indirect answer.[7] In fact, the cost of the replacement capacity and energy would be borne by the Company's customers, and any variation vs the original avoided cost, or risk, would accrue to the customers. QFs are not subject to a prudency review on where their projects are sited, their proposed budgets vs what they actually spend, the quality of their construction and equipment,

[6] *See*, Response to Company's WIEC/Two Rivers Data Request 1.3.
[7] *See*, Response to Company's RMCRE Data Request 1.5; and Response to Company's REC & RMCRE Data Request 1.24.

or any other aspects of a normal prudency review faced by the Company for non-QF procured resources. And yet the ultimate risk of replacing the capacity and energy does not fall on the QF owner as it typically does for the Company, it accrues to the Company and ultimately its customers.

Q. Is it the Company's position that QFs are often more risky for customers than resources the Company contracts for through competitive solicitations?

A. Yes. While REC, RMCRE, and WIEC/Two Rivers would have you believe that there is less risk associated with QFs, in reality the requirements for non-QF resource providers are more stringent and ensure a lower risk profile for our customers.

QFS DO NOT PROVIDE MEANINGFUL COMPETITION TO COMPANY PROCURMENT

Q. Does PURPA introduce price competition into Wyoming's generation market?

A. No. REC, RMCRE, and WIEC/Two Rivers testimony all claim that PURPA introduces competition into the generation market in vertically integrated utility territories.[8] However, this is not competition from a price/customer risk perspective, because third party QFs are not required to provide energy at prices that are better than the Company's, they merely have to be viable at the Company's avoided costs. In other words, a QF will proceed and be paid for by customers if it can be developed at a price that is only "as good as" the price at which the Company estimates it could provide the same amount of energy to customers. Absent the risks inherent in such estimation, and the other risks discussed in my direct testimony, the "competition" cited by these parties provides zero price benefits to customers. Considering the other risks I have

[8] *Id.*, at pp. 36-37; and WIEC/Two Rivers, Direct Testimony of Kevin C. Higgins, at pp. 19 & 24.

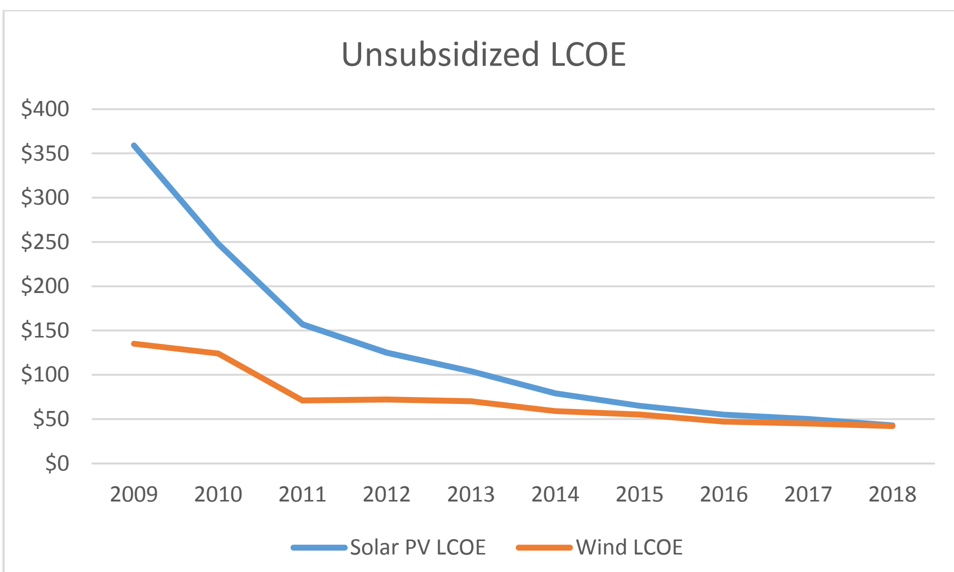
discussed surrounding long-term QF PPAs, and customers may actually end up worse off.

Instead of the creative interpretation of "competition" advanced by REC, RMCRE, and WIEC/Two Rivers, real competition with tangible benefits to customers comes through solicitations for resources and the competitive bidding process that ensues. Through the non-QF procurement process, the Company, and other stakeholders, have a much greater say over the caliber of developers who provide non-QF resources, and can better ensure higher levels of operational experience and creditworthiness to ensure that customers and the utility get the resources they are counting on. PURPA's 1978 mandates, which do not require QFs to demonstrate any net benefits to customers is not comparable.

Q. The intervenor witnesses talk about the benefits that QFs bring to customers via their direct competition with Company-owned resources. Is this competition beneficial for customers, and how does it compare to other means for procuring resources through the markets?

A. One of the basic goals of PURPA when it was passed in 1978 was to allow third party generators to install generation in vertically integrated utility territories, while ensuring that the utilities' customers were indifferent to the costs of either source of generation. This was the only way at the time, given the lack of deregulation in the electricity markets, to introduce competition into what had traditionally been considered a natural monopoly. It was akin to a centrally planned economy trying to introduce some initial free market concepts into the industry. This goal, combined with the other goals of PURPA to pursue energy independence and promote the growth or renewable energy, helped keep a check on utilities' costs of owning and operating generation 30 to 40 years ago.

In terms of true competition though, PURPA, as originally conceived, only goes part way. Given that the pricing construct for PURPA essentially puts a price floor on generation capacity and energy for QFs, ensuring they receive no less than what it costs a utility to buy or build their own generation, it allows the QFs to extract excess rents from the market if the utility's method for calculating avoided costs is not aligned with or keeping up with the market. The graph below, using data from Lazard investment bank, shows how the levelized costs of energy ("LCOE") for utility scale photovoltaic solar and wind technologies have changed over the last 10 years.[9] The values in the table reflect the *unsubsidized* values for each technology, meaning the costs for utility scale solar and wind are not reduced by the $/MWh value of the ITC and PTC respectively.



[9] https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

This situation has the following impacts on the Company's customers with respect to QFs. First, the biennial nature of the IRP process sometimes makes it impossible to keep up with the fast changes in the market, and second, by locking in avoided costs in 20 year contracts, our customers are subject to costs that do not reflect the market, even at the time the pricing was set, for many years into the future. The witnesses for RMCRE, REC, and WIEC/Two Rivers point out the benefits of the 'competitive' QF landscape, but this is a dated construct that does not recognize the further deregulation and evolving market dynamics that have revolutionized the United States electricity markets—even in vertically integrated utility territories. Perhaps these arguments were valid in 1979, or even in 1989, but they ring hollow 30 years later.

True competition for the utility comes from competitive solicitations that we issue to procure non-QF generation resources, and the recent success the Company had with the 2017R RFP demonstrates how this competition is benefitting our customers. This competition manifests itself even during the competitive solicitation process. During the 2017R RFP, the benefits to the Company's customers increased as the bidding progressed from the initial short list to the submission of best and final offers, as explained in Rick T. Link's testimony in Wyoming Docket No. 20000-520-EA-17.[10]

> The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct testimony. This profile shows that despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits, reduce the magnitude and shorten the duration over which costs increase after federal PTCs for new wind resources expire, and continue to contribute to customer benefits over the long-term.

[10] *See,* Supplemental Direct Testimony of Rick T. Link, Wyoming Docket No. 20000-520-EA-17.

In order to restore customer indifference to ensure the Company's customers are not subject to these ongoing higher costs for long periods of times versus other alternatives available in the competitive market, it is imperative to shorten the contract length to seven years.

Q. What mechanisms ensure that the Company will act in its customers' best interests when it comes to Company sponsored solicitations for new energy resources?

A. There are two key things that provide the Company with strong incentives to ensure that the resources it procures are least cost and least risk. First, the Company takes its duty to provide reliable and affordable power to its Wyoming customers very seriously. Second, the Company faces significant disallowance risk from regulators if it acts imprudently on behalf of its customers. The Company's service obligation when coupled with the scrutiny of regulators, which includes the risk of cost disallowance, provides very effective incentives to ensure the Company only devotes its capital to prudent projects that will be used and useful in service to its customers.

A SEVEN YEAR PPA TERM PROVIDES QFS REASONABLE OPPORTUNTIES TO ATTRACT CAPITAL

Q. After reading the witnesses' testimony, how do you respond to their assertions that seven year contracts are 'un-financeable'?

A. As FERC affirmed in *Windham Solar*, PURPA implementation by the states must allow reasonable access to capital for QFs.[11] Reasonable access does not mean that the implementation must guarantee financings at the best rates and terms possible. A seven

[11] 157 FERC 61,134 at P. 8.

year contract does not automatically make QFs un-financeable. Avoided cost pricing that is above competitive market pricing allows for economic rent extraction by QFs (a privilege not available to other market participants); in conjunction with a reasonable fixed term of seven years, this provides a sufficiently reasonable ability to attract capital. This ability is enhanced by the strong credit quality of the cash flows from these PPAs which are backed by the diversification benefit of millions of utility customers and regulated utilities' generally strong credit ratings, a fact that QF developers enjoy pointing out in their investor materials.[12]

Under the Company's proposed seven year term, these advantages to QFs, coupled with the nimbleness and flexibility of the capital markets, and the vast sums of money currently chasing renewables deals, will provide Wyoming QFs reasonable opportunities to attract debt financing that PURPA requires. While some QFs may not achieve the high leverage levels and or the same returns that they have enjoyed at 20 year terms, and project sponsors may have to put more of their own equity at risk, this is not unreasonable and therefore is not a violation of PURPA.

Q. What evidence can you cite to support the idea that the QF's concerns over financing are overstated?

A. The renewables industry is replete with examples of new financing structures being developed to adapt to changes in the industry. Tax equity financing is a great example.

[12] On February 7, 2018 sPower issued a press release stating they recently closed a $421.4 million 4(a)(2) private placement on a portfolio of 565 MW of utility scale solar and wind assets. sPower CEO Ryan Cramer is quoted as saying "This first-of-its-kind milestone is a testament to the quality of our operating portfolio, the relationships we have with our finance partners and the strength of our utility offtakers. This financing will benefit sPower for years to come by locking in predictable cash flows for almost two more decades." In December 2017, Project Finance International named this financing their "Deal of the Year" for the renewable energy category. Available at , http://www.spower.com/news_2018/news-2018-02-07.php (last accessed October 11, 2018).

Entities such as investment banks or large industrial conglomerates with the appetite for tax credits—used to offset earnings and allow them to pay lower federal and/or state income taxes—pay for those tax attributes, thereby providing funding for developers who don't have the same tax credit appetite due to a lack of earnings or a stockpile of existing credits that they cannot use in current or near future tax years. Given the copious Investment and Production Tax Credit ("ITC" and "PTC") incentives enjoyed by renewables developers, the tax equity market has been a key financing pillar in the growth of the industry. And when the developers began setting up YieldCos—an innovative financing structure mirrored off of master limited partnerships used by pipeline companies, which both take advantage of unique tax laws and ongoing streams of cash flows—they worked with tax equity partners to further refine the tax equity market through the use of pay as you go ("PAYGO") tax equity structures[13].

PAYGO tax equity structures are tax equity financings that provide cash flows over time to the developers and their YieldCo companies in exchange for tax attributes instead of a single upfront payment (thus the term PAYGO). Another example, referenced by Mr. Isern in his direct testimony, would be to package these deals as part of a syndicated financing with longer term PPAs from other markets to achieve a longer weighted average contract length.[14] While these syndicated loans may not achieve quite as favorable financing terms as would a structure with a longer weighted average contract length, the addition of PPAs with extremely secure cash flows due to the high

[13] NextEra Energy Partners Investor Presentation, page 23.
http://www.investor.nexteraenergypartners.com/~/media/Files/N/NEP-IR/news-and-events/events-and-presentations/2017/10-30-2017/nep-october-2017-investor-presentation-vfinal2.pdf.
[14] *See*, Direct Testimony of Hans Isern on behalf of Rocky Mountain Coalition for Renewable Energy, at pp. 12-13, lines 248-255.

quality of the underlying customer credit, would, I suspect, compete very well. And again, the purpose of PURPA is to allow access to capital markets, not to create the lowest cost debt, and therefore greatest profits possible, for QF developers.

There are yet other avenues for financing small QFs, as I pointed out in my direct testimony, including the USDA's Rural Development and Rural Energy for America Programs. In his testimony, RMCRE's Mr. Klein claimed that these programs are not available to QF developers, later in response to discovery he admitted that his point was really that they do not work for the sorts of QFs that his company develops, because his projects are utility scale solar sites developed on leased property.[15] In other words his testimony did not consider small QFs developed by farmers or ranchers on their own land and to supplement their cash flows and provide renewable energy to the grid.

Lastly, given that the federal tax incentives for wind and solar renewables assets are rolling off over the next couple of years via federal legislation passed in the Tax Extender bill in late 2015 (brokered by major renewables developers and equipment manufacturers) the importance of longer PPA terms required to enable tax-equity financings will no longer be needed. So while RMCRE's Isern and Klein point to the need for longer term PPAs to support these tax equity financing structures in their testimony, in reality once these incentives have rolled off, the market will likely return to a more traditional project financed or syndicated loan market with more flexible terms and conditions. And the developers will have access to this capital at good terms, even under seven year contracts. QF developers may just have to be a little more

[15] Response to Company's RMCRE Data Request 1.21.

creative and work a little harder to bring solid projects to the capital markets for financing.

The fact that a project with a 25 to 30 year life cannot be solely debt-financed for a seven year term without a meaningful equity stake is unsurprising. The Company's proposed seven year contract term accounts for the uncertainty and risk in future avoided costs and that uncertainty is well-known to capital markets. A 20 year contract term unfairly imposes that risk on customers who receive no expected benefits in return at the avoided cost price.

Q. Did REC, RMCRE, or WIEC/Two Rivers provide reliable evidence that a seven year term was insufficient to allow QFs a reasonable opportunity to attract capital?

A. No. RMCRE testimony sought to differentiate the types of financing available to utility-scale QF developers that bundle multiple 80 MW projects into mega renewables development sites versus the truly small power generation that PURPA was meant to support. None of these parties offered testimony disputing the fact that billions of dollars are available to renewables developers in the United States. Similarly, none of these parties countered the evidence presented in my direct testimony demonstrating that capital markets are creative and flexible, and will adjust to changes in underlying regulation and deal structures in order to continue to allocate capital to opportunities to earn returns.

Q. What is the fundamental difference between a 20 year contract term and the Company's proposed seven year contract term?

A. With a 20 year contract term, the Company's customers are guaranteeing a payment stream that reflects expected benefits far into the future and are thereby deprived the opportunity to pursue more cost-effective options. With a seven year contract term, a developer can still expect to receive benefits far into the future, but the exact benefits are not guaranteed. To the extent the avoided cost forecast is as accurate as possible, which is what the Application seeks to accomplish, developers should still have reasonable opportunities to attract capital without forcing retail customers to guarantee payments far into the future, because those estimates should give them a reasonable sense of expected earnings in subsequent contract terms.

Q. Does RMCRE's Mr. Isern accurately characterize your testimony regarding alternatives to 20 year contract terms?

A. No. Mr. Isern's direct testimony discusses PPAs signed by corporate buyers for sustainability goals that may be less than 20 years in length.[16] He claims that such contracts are not comparable to QF PPAs, stating, without any substantiation, that corporations must pay a premium for these agreements to facilitate the developer to signing a shorter term contract.

Mr. Isern also states that the PPAs cited in my testimony are all in organized markets where power can be freely liquidated and there are a "whole host" of contracting opportunities after the expiration of an initial PPA. In my prior role at NextEra Energy Resources managing over 40 utility scale wind assets in the organized markets of the Southwest Power Pool ("SPP") and the Electricity Reliability Council of Texas ("ERCOT"), I found the opposite to be absolutely true; attempting to re-contract a 15 to 25 year old renewable asset with obsolete technology was incredibly

[16] RMCRE, Direct Testimony of Hans Isern, at p. 11.

difficult in organized markets with competition from new technology with lower installed costs and better technology. In his testimony, Mr. Isern notes that lenders assign little to no value to an asset at the end of a 20 or 25 year contract term because of this fact. Yet, at the same time, Mr. Isern contradicts himself stating that there are a "whole host" of re-contracting opportunities. Mr. Isern ignores the legal realities, which is that a QF has a distinct advantage over renewable resources in organized markets. Under PURPA, a QF retains the right to put an asset with a 25 to 30 year life to the Company under additional long term contracts at avoided cost prices, even after earning most of their return during the initial contract term. This legal right to force utilities to enter into subsequent contracts once the initial term has expired is a huge advantage for QFs over merchant facilities in organized markets.

THE COMPANY'S 30 MONTH PPA EXECUTION POLICY IS REASONABLE, REGARDLESS OF WHY A QF'S COD MAY BE DELAYED

Q. Is the Company's application seeking any change to the QF interconnection process in Wyoming?

A. No. REC, RMCRE, and WIEC/Two Rivers witnesses all expressed disagreement with the Company's proposal in its revisions to Schedule 38, which commits to writing its long standing policy not to execute a QF PPA if a QF's COD is more than 30 months out. While these parties all point to the interconnection process and the time that process can take as a reason to either not adopt this restriction, or to modify the 30 month period, the policy arises out of considerations that are purely commercial.

There are a whole host of reasons that a QF developer may run into delays that require it to push out its COD. These reasons can include the timing of the interconnection study process, but they also include permitting, securing land rights, financing, and construction or equipment delays. With respect to the interconnection process, the Company has long understood that it can take a long time. It is for this reason that the current version of Schedule 38 contains the following exhortation to QF developers:

> It is recommended that the owner initiate its request for interconnection as early in the planning process as possible, to ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Wyoming Energy Service Schedule 38, Section II, ¶2. The Application's proposed revisions to Schedule 38 repeats this same language in the beginning of the tariff to better ensure that developers are made aware of the fact that the highly technical interconnection study process operates on a separate timeline from the commercial pricing and PPA negotiation process. Just as it is the developer's responsibility to have financing secured, permits in place, and construction and equipment supplies ready to meet its construction schedule, it is the developer's responsibility to ensure that its interconnection is well underway before seeking to finalize a PPA with the Company,

The 30 month policy is indifferent as to the cause of a delayed COD, and its focus is on customers who would otherwise be at risk of having to pay for QF PPAs at very stale prices if the company were to execute contracts with CODs too far into the future. The Company's policy, now proposed to be explicitly stated in Schedule 38, strikes a reasonable balance between the risk of stale pricing and the QFs need for time to build its project. In my 10 plus years of experience in the utility scale renewables markets, it is extremely rare for a site to require more than two years to achieve COD from the time of PPA execution, unless there were specifically negotiated reasons for the longer time frame.

Q. Can you comment on the recommendation of Mr. Klein with respect to the Company's proposed inclusion of this policy in Schedule 38?

A. Yes. Mr. Klein attacks the Company's proposal. He urges the Commission to instead increase the 30 month time period to fifty-one months to account for the long winters in Wyoming and to adjust that period based upon any interconnection study delays, or to account for the risk that QFs cannot achieve their environmental or other permitting on a timely basis. Mr. Klein also claims that RMP has not demonstrated the current practice of negotiating the COD is in need of reform. RMP agrees on the last point, the policy against executing a PPA more than 30 months prior to a QFs COD has been part of the Company's practice in Wyoming since at least 2014, and including explicit language in its tariff will not change that. The policy itself, as noted in response to the earlier question, is indifferent as to the cause of a delayed COD, and protects customers from stale pricing. The risks of development delays should not be borne by the Company's customers, and speculative behavior by a QF should not be rewarded at customer expense.

Q. Why might a QF not achieve COD?

A. QF developers may speculatively enter agreements in anticipation of technology cost declines. If as construction approaches those cost expectations do not occur, they may choose not to construct and default on their agreement. The associated cost to customers of replacement resources is unlikely to be fully covered by the contractual damage provisions. This is particularly true if the Company has foregone other more economic resource opportunities in the interim.

Q. What if technology costs decline?

A. If technology costs decline by more than the Company's forecast, avoided costs will be overstated relative to the non-QF resources the Company could acquire and customers will be worse off.

Q. What is the key link between these two negative outcomes?

A. Both of these situations are exacerbated by allowing for contract pricing and execution well in advance of COD. A QF project which is shovel-ready and commences construction soon after executing a PPA is much more likely to achieve COD than one which fully intends to gauge the market for a year or more before committing to construction.

<u>OTHER STATES' PURPA IMPLEMENTATIONS OFFER HELPFUL GUIDANCE, BUT WYOMING'S PARTICULAR NEEDS PREDOMINATE</u>

Q. Why do you think it is relevant to look to other states for their efforts to implement PURPA in a way that balances the requirements to purchase power from small power producers (as defined in PURPA) and the interests of customers?

A. It is instructive to look to other states to see how they have managed the influx of utility scale solar and wind generation under PURPA. Many states have seen large increases in installed capacity in their territories as their contract terms and avoided cost methodologies struggled to keep up with the rapid decrease in renewables LCOE's combined with the impacts of tax incentives. As I stated in my initial testimony, this has caused real costs and real operational issues for utilities as they seek to integrate these resources into their daily generation dispatch.

Wyoming's situation is unique, as are the situations in each state, and thankfully PURPA allows Wyoming to implement rules and procedures that are appropriate for its unique economic and regulatory circumstances. States such as Idaho, North Carolina, Alabama, and Montana have looked for various solutions to achieve the right balance for their particular circumstances. Other states' approaches can be instructive, even if those solutions would need tailoring to fit within Wyoming's broader economic and regulatory structures. For example, the Company is closely watching the legislative solution in North Carolina, as Duke Energy Carolinas recently concluded their first round of competitive RFPs under HB 589 and North Carolina's Competitive Procurement of Renewable Energy ("CPRE") program, where Duke awarded 14 solar contracts for 602 MWs[17] out of the 78 bids that were received. According to reports from the independent administrator, Duke's customers will see savings of around $375m over the 20 year contract period versus avoided costs.[18] While the Company would not necessarily propose the exact same process be implemented in Wyoming, a program that successfully delivers better value for Duke's customers could inform future changes to PURPA implementation in Wyoming.

Q. Are REC, RMCRE, and WIEC/Two Rivers witnesses consistent in their analysis of how other states have implemented PURPA?

A. Not at all. On the one hand, these parties' witnesses question the relevance of the Company's references to laws and regulations passed in other states that have led to

[17] https://www.elp.com/articles/2019/04/duke-energy-selects-14-solar-projects-602-mw-in-all.html.
[18] *Id.*

shorter contract terms and/or competitive bidding processes. These witnesses erroneously state that the Company's arguments in support of its Application rest heavily on these decisions. On the other hand, one of their strenuous objections to the current Company proposal is based on a recent Montana District Court ruling overturning the Montana Public Service Commission's recent decision to shorten contract terms and adjust avoided cost prices.[19]

These witnesses fail to fully describe the procedural reasons the court overturned the decision. The major findings of the Court, in overturning the Montana Public Service Commission, were grounded in procedural deficiencies in the cases below. The court found that the Montana PSC failed to provide adequate notice on certain key contract length issues, failed to follow its own precedents, exceeded its statutory authority, and failed to gather the evidence needed to determine that the term length met Montana standards as set forth in Montana's statutes. REC, RMCRE, and WIEC/Two Rivers testimony on the Montana case all ignore the fact that the Commission, in considering the Application, can avoid the administrative and procedural errors that contributed heavily to the decision by the Montana Eighth Judicial District Court. Their testimony also ignores the fact that, unlike in the Montana case, nothing requested in the Application is inconsistent with Wyoming's PURPA related precedents and statutes.

REC, RMCRE, and WIEC/Two Rivers cannot have it both ways, how other states have implemented PURPA is not relevant when it favors one's position, and

[19] Montana Eighth Judicial District Court, *Vote Solar, Montana Environmental Information Center, Cypress Creek Renewables, LLC, and Windata LLC v. The Montanta Department of Public Service Regulation, Montana Public Service Commission, and Northwestern Corporation,* BDV-17-0776, 2019.

irrelevant when it does not. Instead, the policies of other states can provide the Commission useful information as to how particular policies have worked in other places, understanding that, before adoption, any such policies would need to be tailored to fit Wyoming's particular regulatory and economic circumstances, Even mistakes made in other states' implementation of PURPA can be useful counterexamples. The Montana case, for example, provides this Commission with an example of procedural deficiencies it should seek to avoid in this or future PURPA proceedings.

Q. Would it be appropriate for Wyoming to adopt the changes suggested by REC witness John Lowe, which would make Wyoming's Schedule 37 more consistent with Oregon's approach to small QFs?

A. No. Mr. Lowe points out that the equivalent to Schedule 37 is handled differently in other states where the Company serves customers, such as Oregon. However, Mr. Lowe provides no context to justify why Wyoming should make the same PURPA policy choices as Oregon, a state with a very different regulatory and economic environment than Wyoming. Wyoming has the right to implement PURPA in a manner that best balances the law's mandates against the needs and policies that are most likely to serve the interests of Wyoming customers.

MISCELLANEOUS REBUTTAL POINTS

Q. Is Mr. Higgins' testimony for WIEC/Two Rivers on the Company's ability to refresh avoided cost pricing any time prior to PPA execution consistent with Commission precedent?

A. No. Mr. Higgins objects to the Company's inclusion a provision in its proposed revisions to Schedule 38 stating that the company has the right to update QF pricing any time prior to PPA execution. While the language is certainly new, the right is not. In a recent case involving a developer named Trireme Energy Development II, LLC, the Wyoming Commission affirmed this right, and expressed its desire that the Company ensure QFs receive the most up-to-date pricing possible prior to executing a PPA.[20] The Commission's order makes clear that its goal was to preserve the customer indifference principle.[21] The Company's goal in proposing this new language for Schedule 38 was not to expand its ability to refresh its avoided cost pricing, but rather to make the Commission's existing policy on such repricing clear to prospective Wyoming QFs to help avoid unnecessary disputes.

Q. Should the Commission incorporate all of the testimony and information in the previous Wyoming PURPA case filed by the Company in Docket No. 20000-481-EA-15 as Mr. Higgins suggests?

A. No. Mr. Higgins makes this suggestion based on the claim that, during the Commission ordered collaborative, the Company only "recycled" its proposals from the docket itself. Mr. Higgins claim is not true, but that is beside the point. The Company's application in this docket is not intended to rehash arguments and solutions proposed in the prior case. The Company filed the application to incorporate the most recent, relevant information necessary for the Commission to make an informed decision regarding the Company's requests, so the closed docket is relevant only to the extent it

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[20] *See*, *In the Matter of the Amended Joint Complaint Filing by Trireme Energy Development II, LLC; Pryor Caves Wind Project LLC; Mud Springs Wind Project LLC; and Horse Thief Wind Project LLC Against Rocky Mountain Power and PacifiCorp Regarding the Avoided Cost Pricing for the Bowler Flats Wind Qualifying Facilities Power Purchase Agreements*, Docket No. 20000-505-EC-16 (Record No. 14579), Commission Order at ¶ 63 (Dec. 31, 2018).

[21] *Id.*

provided the Company the impetus to take a harder look at changes needed to PURPA implementation in Wyoming. The Application itself can and does stand on its own.

CONCLUSION

Q. Please summarize your recommendations based on your experience in the energy markets and your testimony?

A. I recommend the Commission approve the Company's request to adopt a seven year maximum contract term length for Wyoming QFs offering firm energy and capacity. This change will bring Wyoming's implementation in-line with the current economic and regulatory environment, and better balance PURPA's requirement for customer indifference against its requirement that QFs will have reasonable opportunities to attract capital from potential investors.

I further recommend that the clarifying changes the Company proposes for Schedules 37 and 38 be approved. These changes will improve the Company's process for PPA negotiations with QFs, and help to reduce QF complaints, which often include claims resulting from QFs' misunderstanding or misinterpreting the current versions of those schedules. Finally, I recommend that the items presented by Company witness Mr. MacNeil be adopted. The proposed refinements to the PDDRR methodology will improve the accuracy of avoided costs in Wyoming, and thereby reduce risks to customers. Using that improved PDDRR methodology to determine the Schedule 37 avoided costs will likewise improve the accuracy of those prices. Similarly, the change to Schedule 37's on-peak and off-peak definitions will more accurately reflect high price hours on the Company's system, and more fairly reflect when QFs should also receive higher prices.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED CONTRACT TERM OF PURPA POWER PURCHASE AGREEMENTS WITH QUALIFYING FACILITIES	DOCKET NO. 20000-545-ET-18 (RECORD NO. 15133)

AFFIDAVIT, OATH AND VERIFICATION

Mark Tourangeau (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Vice President of Customer Solutions and Business Development for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Vice President of Customer Solutions and Business Development.

Further Affiant Sayeth Not.

Dated this 24th day of May, 2019

Mark Tourangeau
VP Customer Solutions & Business Development
1407 W. North Temple, Suite 310
Salt Lake City, UT 84116

STATE OF Utah)
) SS:
COUNTY OF Salt Lake)

The foregoing was acknowledged before me by Mark Tourangeau on this 24 day of May, 2019. Witness my hand and official seal.

CAROL SABOL
NOTARY PUBLIC - STATE OF UTAH
My Comm. Exp. 07/12/2019
Commission # 684199

Notary Public

My Commission Expires: 07/12/2019