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March 19, 2018

Via Electronic Filing and U.S. Mail

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER,
Application for Approval of Final Draft 2017R Request for Proposals
Docket No. UM 1845

Dear Filing Center:

Please find enclosed the redacted version of the Comments of the Industrial Customers of Northwest Utilities ("ICNU") on PacifiCorp's Request for Acknowledgement of Final Shortlist of Bidders.

The confidential portion of ICNU's comments is being handled in accordance with Order No. 17-218 and will follow via U.S. Mail.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portion of the **Comments of the Industrial Customers of Northwest Utilities on PacifiCorp's Request for Acknowledgment of Final Shortlist of Bidders** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 19th day of March, 2018

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1845

In the Matter of PACIFICORP, dba PACIFIC POWER, Application for Approval of Final Draft 2017R Request for Proposals.	))))))))	COMMENTS OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES ON PACIFICORP'S REQUEST FOR ACKNOWLEDGEMENT OF FINAL SHORTLIST OF BIDDERS

I. INTRODUCTION

Pursuant to the Administrative Law Judge's March 7, 2018 Ruling in the above-referenced docket, the Industrial Customers of Northwest Utilities ("ICNU") files these Comments on PacifiCorp's (or the "Company") Request for Acknowledgement of Final Shortlist of Bidders in 2017R Request for Proposals ("Request") and the Oregon Independent Evaluator's Final Report ("IE Report").

ICNU recommends that the Oregon Public Utility Commission ("Commission") decline to acknowledge the Company's final shortlist. The Company ran an accelerated request for proposals ("RFP") that was riddled with errors and questionable modeling assumptions and, ultimately, proved to be fundamentally unfair to third-party bidders. These bidders had the rug pulled out from under them at the last minute when they learned that the Company's changes to its transmission planning eliminated their bids before they were even prepared. Even so, lower cost and lower risk solar resources may still be available through a separate RFP the Company has issued. Given both the procedural concerns with its wind RFP and the potential existence of lower cost resources, the final shortlist does not "seem reasonable" based on current information.

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As the IE concludes, the final shortlist bids are "not the best the market could provide based on cost or risk."[1/] If nothing else, then, PacifiCorp's RFP demonstrates the difference between what the market can offer and what the Company is prepared to provide to its customers. This will only increase the discrepancy between the Company's rates and those available to market customers and will continue to increase customers' desire for alternatives to the Company's service.

II. BACKGROUND

The Aeolus-to-Bridger/Anticline transmission line is part of PacifiCorp's Gateway West transmission project.[2/] This project as a whole consists of approximately 1,000 miles of high-voltage transmission in the Company's eastern control area and has been planned since 2008.[3/] The Aeolus-to-Bridger/Anticline line is a section of Segment D ("Section D.2"), which runs from the Windstar Substation in Wyoming to the Populus Substation in Southeastern Idaho.[4/] As late as March 31, 2016, when PacifiCorp filed its 2015 Integrated Resource Plan ("IRP") Update, the Company was projecting an in-service date for Segment D anywhere between 2021 and 2024, indeed had *extended* the earliest potential completion date from 2019 to 2021 in this IRP update.[5/]

Three months before this IRP Update, at the end of 2015, Congress extended the production tax credit ("PTC") through the Consolidated Appropriations Act of 2016, the latest in a series of at least ten such reauthorizations since 1992.[6/] On April 11, 2016, just over three

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1/ Revised Independent Evaluator's Final Report on PacifiCorp's 2017R Request for Proposals ("IE Report") at 35.

2/ Docket No. LC 67, PacifiCorp 2017 IRP at 61.

3/ http://www.pacificorp.com/tran/tp/eg/gw.html. PacifiCorp is also planning an extension of this project to Boardman, Oregon. PacifiCorp 2017 IRP at 71.

4/ PacifiCorp 2017 IRP at 71.

5/ Docket No. LC 62, PacifiCorp Integrated Resource Plan Update at 21 (Mar. 31, 2016).

6/ http://nationalaglawcenter.org/wp-content/uploads/assets/crs/R43453.pdf.

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months after the PTC reauthorization, and less than two weeks after it filed its 2015 IRP Update, PacifiCorp issued simultaneous RFPs, one seeking renewable resources and the other seeking renewable energy credits ("RECs").[7/] The Company did not follow the competitive bidding guidelines for these RFPs, arguing that the combination of the recent passage of SB 1547 with the PTC extension presented a time limited opportunity of unique value to customers.[8/]

Through this RFP process, however, PacifiCorp determined that purchasing RECs in lieu of physical resources resulted in the least-cost, least-risk outcome for its customers.[9/] PacifiCorp presented the results of its RFPs to the Commission at a July 26, 2016 special public meeting. In this presentation, PacifiCorp stated that the results of its REC RFP would allow it to defer its initial shortfall of RECs from 2025 to 2028.[10/] In the meantime, it would "continue to test REC market through future RFPs, thereby taking advantage of dollar-cost averaging" and would "pursue bi-lateral renewable resource opportunities if cost effective for customers."[11/]

As PacifiCorp conducted its 2016 RFPs, it was also engaged in its integrated resource planning process. Its kick-off meeting was held on June 21, 2016, three months after its 2015 IRP Update, and before it reported the results of its 2016 RFPs to the Commission. Monthly IRP meetings continued through March of 2017. These meetings did not, however, disclose the Company's final action plan, including accelerated completion of the D.2 Section. As Commission Staff described it:

> [T]he Company essentially completed the public input process of seven public meetings, beginning in June 2016 and going through the end of the year. The

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7/ http://www.pacificorp.com/sup/rfps/2016-renewables-rfp.html; http://www.pacificorp.com/sup/rfps/2016-rec-rfp.html.

8/ Docket Nos. AR 598 & UM 1771, PacifiCorp's Opposition to Petition for Temporary Rulemaking and Investigation (May 6, 2016).

9/ PacifiCorp Presentation at Commission Special Public Meeting at 3 (July 26, 2016), available at: http://oregonpuc.granicus.com/GeneratedAgendaViewer.php?view_id=1&clip_id=110.

10/ Id. at 20.

11/ Id. at 33.

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> Company then produced a draft Action Plan reflecting no new resource acquisition, as the Company's analysis projected no need for additional resources in order to serve load reliably.
>
> It was only at the end of this process that the Company drastically altered its Action Plan to include both the repowering of 905 MW of existing Company-owned wind resources … and the purchase of 1,100 MW of new wind with the associated new transmission line … that would enable transport of the New Wind power …. [S]takeholders had little to no time to review because it was brought to the table at the very end of the process.[12/]

As the Commission reviewed the Company's IRP, PacifiCorp was simultaneously pursuing the RFP at issue here. The RFP was approved on September 26, 2017 and issued to the market on September 27, 2017.[13/] The Commission acknowledged PacifiCorp's IRP Action Plan at a Special Public Meeting held on December 11, 2017, nearly two months after RFP bids were due, and a month-and-a-half after the initial shortlist was developed.

The highly accelerated schedule for PacifiCorp's RFP (now its second to capture the PTC) resulted in modeling errors that needed to be resolved at the last minute, including inflated energy values for bids and the failure to include sales tax for one bid.[14/] The RFP did, however, yield a substantial quantity of potential resources – nearly 4,900 MW of eligible bids and approximately 3,100 MW selected to the initial shortlist.[15/] From the initial shortlist, PacifiCorp identified a final shortlist consisting mainly of Company-owned resources.[16/] As the IE notes, however, this portfolio won out only because of modeling assumptions that favored PacifiCorp's resources. Despite levelizing all other costs and benefits, PacifiCorp applied the benefits of the PTC on a nominal basis, which favors owned resources.[17/] By levelizing the PTC,

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12/ Docket No. LC 67, Staff Initial Comments at 1 (June 23, 2017).
13/ Order No. 17-367 (Sept. 27, 2017); http://www.pacificorp.com/sup/rfps/2017-rfp.html.
14/ Utah IE Report at 60, available at: https://pscdocs.utah.gov/electric/17docs/1703523/300621IERedacFinRep2-27-2018.pdf.
15/ IE Report at 11, 19.
16/ Id. at 27.
17/ Id. at 29-30.

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a portfolio consisting mainly of PPAs showed $161 million of net benefits as compared to only $95 million over a 20-year period.[18/] Additionally, PacifiCorp applied a terminal value to its owned resources, which made Company-owned resources appear competitive over the period through 2050. In fact, "the only reason the PacifiCorp portfolio was even close in net benefits over the entire time period was due to [this] large terminal value applied to company-owned bids totaling about $374 million in 2050. Without the terminal value the PPA portfolio produced a net cumulative benefit of $219 million versus $185 million for PacifiCorp's chosen portfolio."[19/]

Unfortunately, this information proved to be useless. Because of PacifiCorp's last-minute change to its IRP Action Plan to include a massive new wind procurement enabled only by bringing the D.2 Section online earlier than planned, the Company's transmission section had to restudy the interconnections of proposed generators in the queue.[20/] This interconnection restudy process showed that there would be insufficient capacity on the new transmission segment to accommodate projects below queue number 712.[21/] Thus, any such projects would need additional transmission infrastructure to enable delivery, which would not be available in time to ensure that the full value of the PTC is captured. One consequence of this change is that every single bid on the final shortlist that only offered a PPA was disqualified from consideration, while every bid on the final shortlist with a Company ownership option save one (McFadden Ridge) remained viable.[22/] As the IE Report puts it, the consequence of PacifiCorp's interconnection restudy process was that "this entire RFP really boiled down to two

18/ Id. at 31.
19/ Id. at 32.
20/ PacifiCorp Request at 14-15; IE Report at 32-33.
21/ PacifiCorp Request at 16.
22/ IE Report at 33-34.

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viable benchmarks and two third-party offers, meaning a lot of the analysis presented here was of questionable value."[23/]

Another consequence of PacifiCorp's transmission restudy is that the only Company-owned project that was disqualified was replaced by a different Company ownership option (Ekola Flats) because the interconnection restudy process somehow revealed that D.2 Section would have more capacity than originally anticipated (by 240 MW).[24/] There is no explanation in either the IE Report or PacifiCorp's Request as to why this occurred, and the Utah IE states that "PacifiCorp did not provide technical studies that support the additional capacity of the [D.2 Section].[25/]

It is worth noting that, according to the IE Report, PacifiCorp said nothing about its transmission restudy process until it became apparent that the IE was going to recommend selection of the PPA-heavy portfolio.[26/] Had PacifiCorp's modeling choices won out and influenced the IE to recommend the Company-owned portfolio, it is unclear whether PacifiCorp would have said anything at all about its updated transmission planning.

In any event, the resources that PacifiCorp selected to the final shortlist following its RFP process are:

(1) TB Flats I and II (a 500 MW benchmark resource);

(2) Ekola Flats (a 250 MW benchmark resource);

(3) Uinta (a 161 MW project that will be sold to PacifiCorp under a build-transfer agreement ("BTA")); and

(4) Cedar Springs (a 400 MW project, half of which will be through a PPA and half of which will be sold to PacifiCorp through a BTA).

23/ Id. at 35.
24/ Id. at 34.
25/ Utah IE Report at 82 & 83-84.
26/ IE Report at 32.

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These results, in which 85% of the 1,311 MW selected will be Company-owned, are "not surprising given the fact that there were so few bids to choose from …."[27/] The IE recommends acknowledgement on the basis that these are "the top offers that are viable under current transmission planning assumptions."[28/] The highly confidential information, however, reveals that one of these offers provides only marginal net benefits to customers over its life and is a net cost in many of those years.[29/] The IE also recommends three conditions on acknowledgement: first, that the Company-owned resources be held to a "hard cap" on costs based on cost projections included in the bids; second, that PacifiCorp provide an unconditional guarantee that customers will receive the full value of the PTC; and third, that the Company be held to its cost projections for the D.2 Section.[30/]

In addition to the wind RFP, PacifiCorp issued a second RFP for solar resources at the request of the Utah Public Service Commission.[31/] This solicitation resulted in bids totaling over 1,600 MW, none of which would require new transmission and all of which were PPAs.[32/] PacifiCorp has not yet identified a final shortlist from the solar RFP, but its Request purports to show lower net benefits to customers if solar resources are selected in lieu of its wind bids, but greater net benefits if the solar resources are combined with its wind bids.[33/] This analysis has been questioned in other states.[34/]

27/ Id. at 36.
28/ Id. at 2.
29 IE Report, Highly Confidential Attachment 5.
30/ Id. at 4-5.
31/ PacifiCorp Request at 26.
32/ Id. at 27.
33/ Id. at 28, 30.
34/ See, e.g., Wyoming Public Service Comm'n Docket No. 20000-520-EA-17, Redacted Supplemental Resp. Test. & Exhibits of Nicholas L. Phillips (WIEC Exh. No. 304) (March 2, 2018), included as Attachment A.

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III. COMMENTS

The Commission's competitive bidding guidelines provide it with 60 days to review a utility's final shortlist.[35/] Following this review, the Commission can either acknowledge or decline to acknowledge the shortlist.[36/] Presumably, the Commission also could adopt a middle ground in which it acknowledges the shortlist with conditions, although ICNU is unaware of a circumstance in which conditional acknowledgement has occurred.

Acknowledgement of the final shortlist of bidders means "that the final short-list seems reasonable, based on the information provided to the Commission at that time."[37/] To make this determination, the Commission has evaluated three factors: (1) that the utility conducted its RFP fairly and properly; (2) that the utility selected the best bids for the final shortlist based on overall system cost and risk and the decision criteria used to develop the utility's acknowledged IRP action plan; and (3) that continued utility negotiation with the final shortlist of bidders is reasonable based on the information provided to the Commission.[38/]

Based on this evaluation, ICNU recommends that the Commission decline to acknowledge the final shortlist. PacifiCorp did not conduct a fair and proper RFP and, at best, it is uncertain based on current information whether it selected the best bids and whether continued negotiation is reasonable.

A. PacifiCorp did not conduct a fair and proper RFP.

ICNU has two concerns related to this criterion. One is that PacifiCorp modeled the bids in a manner that even the IE disagrees with. As the IE Report explains, the Company's

35/ Docket No. UM 1182, Order No. 14-149 at 14 (Apr. 30, 2014).
36/ Id.
37/ Docket No. UM 1182, Order No. 06-446 at 15 (Aug. 10, 2006)
38/ Docket No. UM 1429, Order No. 09-492 at 2 & Appen. A at 2 (Dec. 14, 2009).

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modeling significantly favored its own resources by applying a “large terminal value” and by levelizing all of the costs and benefits of the bids *except* for the PTC.[39/] PacifiCorp explains that this is appropriate because it is “consistent with how PTC benefits flow into customer rates.”[40/] But as the IE notes, PacifiCorp levelized the *costs* of its owned resources even though that is also inconsistent with how such costs flow into customer rates.[41/] Notably, even with these favorable modeling assumptions, the PPA portfolio was competitive with the Company-owned portfolio.[42/]

Another modeling issue the IE does not address is that, while PacifiCorp updated the bids to account for the newly passed Tax Cuts and Jobs Act, the Company did not update its forward market price curves. The Company’s modeling of net benefits is based on its December 2017 official forward price curve, which was developed before passage of the new tax law.[43/] If forward market prices have declined as a consequence of this new law, the net benefits to customers from the final shortlist are likely exaggerated.

The other issue – the bigger issue – is that none of this modeling even mattered. The Company’s last-minute changes to its transmission planning assumptions drastically limited the pool of eligible resources, including what the IE found to be lower cost resources.[44/] PacifiCorp blames Utah for the fact that these bidders spent time and money putting together the lowest cost bids available only to find out later that their bids never had a chance of winning in the first place. It notes that the Utah IE and other Utah parties requested that it “remove a requirement that bidders submit a completed interconnection system-impact study.”[45/] But as the

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39/ IE Report at 29-32.
40/ PacifiCorp Request at 14.
41/ IE Report at 30.
42/ Id. at 28-29.
43/ Attachment B (PacifiCorp Response to UAE DR 3.2 in Docket No. 17-035-040); Utah IE Report at 57.
44/ IE Report at 32; Utah IE Report at 78 (“a few PPA options actually did have higher net benefit values. However, these proposals were not selected to the final shortlist due to the project queue position”).
45/ PacifiCorp Request at 15.

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IE notes, such a requirement would not have mattered: "The fact is that even for projects that had completed system impact studies at the time of bid submission, those studies needed to be redone to account for the accelerated completion schedule for the D2 Segment."[46/] The Utah IE even notes that it encouraged PacifiCorp to hold a transmission workshop with bidders at the beginning of the process, which "may have shed light for bidders on their chances of success."[47/] Despite agreeing to this recommendation, PacifiCorp never held this workshop.[48/]

The IE nevertheless recommends acknowledgement of the final shortlist because it represents the lowest cost resources that are "viable under current transmission planning assumptions."[49/] The IE expresses frustration with the result, but ultimately lays blame on the idea that "PacifiCorp's procurement (in the form of this RFP) got out ahead of its resource and transmission planning."[50/]

Whether that is the case or not is an issue that must await a prudence review. For now, it is worth recalling the circumstances in which this procurement occurred. In the IRP, the Company claimed that it waited so long to change its action plan from acquiring no new resources to acquiring over *1,000 MWs* of new resources and building a new transmission line because it was continuously refining its modeling, which did not identify this opportunity until the end of the process.[51/] But the PTC was extended at the end of 2015, the most recent in a string of reauthorizations of this tax credit. PacifiCorp was actively testing the market through a renewable RFP by the spring of 2016. The D.2 Section is part of PacifiCorp's Gateway West transmission project, which has been in the works since at least 2008. It seems incredible to

46/ IE Report at 34.
47/ Utah IE Report at 69, 83.
48/ Id. at 83.
49/ IE Report at 2.
50/ Id. at 35.
51/ Docket No. LC 67, PacifiCorp Reply Comments at 11-14 (July 28, 2017).

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believe that PacifiCorp did not identify the opportunity its RFP pursues until April of 2017 – indeed, had explicitly told stakeholders it was not seeking new resources – when it had: (1) been studying the Gateway West transmission project for almost a decade; (2) been aware of the PTC's extension and sunset date for nearly a year and a half; and (3) had even gone to the market a year earlier to identify resources that could claim this PTC. And this scenario becomes even more incredible when it is understood that the Company had secured positions for its own resources in its transmission queue early enough to ensure they remained eligible under its updated transmission planning assumptions.

The limited transmission availability identified through this RFP process is a major issue because it means that PacifiCorp's "competitive solicitation" was not really competitive at all. It was a *de facto* solicitation of its own resources. This is not a "fair and proper" RFP.

B. It is unclear whether PacifiCorp selected the best bids and should continue to negotiate with the final shortlist bidders

While PacifiCorp selected the only "viable" bids, that does not mean that all of them should have been selected. PacifiCorp's modeling shows that one of the final shortlist bids provides marginal net benefits to customers, and is a net cost in many years of its assumed life.[52/] Neither PacifiCorp's Request nor the IE Report adequately explains the rationale for this selection.

Moreover, the fact that the Company selected the only viable bids does not end the inquiry, and certainly does not indicate that the Company should proceed with negotiations (mostly with itself). For one, last-minute modeling errors occurred, including overstated energy

[52/] IE Report, Highly Confidential Attachment 5 at 4.

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outputs and the failure to incorporate sales tax for one bid, that raise questions about whether PacifiCorp has accurately reflected net benefit assumptions under the rushed timeframe of the RFP.[53/] One of the final shortlist bids may require installation of a synchronous condenser at the Aeolus Substation, an issue that appears yet to be resolved, and which could cost customers between [redacted], an estimate that is based solely on "PacifiCorp's judgment."[54/]

Further, there are resources that can still compete with those on the final shortlist – those from its solar RFP. The Company presents a high-level analysis in its Request that purports to show that the solar bids provide fewer net benefits to customers than the bids on its final shortlist from the wind RFP, but this analysis necessarily lacks the more rigorous analysis applied to final shortlist bids because no final shortlist has been selected in the solar RFP.[55/] As the Utah IE states, "it is not possible to determine if the wind-only resources offer the lowest reasonable cost without an integrated resource procurement and evaluation process that also includes solar and potentially other resources."[56/] At a minimum, it would be useful to understand what the total net benefits to customers would be if PacifiCorp substituted the final shortlist bid with marginal net benefits for one or more solar bids.

PacifiCorp's modeling of the solar bids has been questioned in other states. Testimony before the Wyoming Public Service Commission, for instance, argues that, when analyzed on a nominal revenue requirement basis, the solar bids provide more net benefits to customers.[57/] Notably, one of the justifications PacifiCorp gives for selecting its resource

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53/ Utah IE Report at 60.
54/ IE Report at 36-37.
55/ PacifiCorp Request at 27-28.
56/ Utah IE Report at 68.
57/ Attachment A at 14-27.

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portfolio over the PPA-heavy resource portfolio in the wind RFP is that the PPA portfolio "produced higher *nominal* costs when compared to the economic analysis of the 2017R RFP final shortlist."[58/]

The solar bids are also significantly less risky because, among other things, they do not require new transmission to deliver to PacifiCorp's system.[59/] By contrast, with the Company's final shortlist from the wind RFP, customers will assume the risk of construction cost overruns, both for the generation resources and the transmission line, and construction delays that prevent acquisition of the full value of the PTC. The IE has recommended conditions to mitigate these risks, but such conditions are unnecessary to attach to the solar bids because customers will not assume such risks. Accordingly, there remain significant unresolved questions over whether PacifiCorp has selected the best bids and should continue negotiating with them.

C. The Commission should not adopt the IE's recommended conditions at this time.

While the IE recommends acknowledgement of the final shortlist, it does so with three conditions. First, "all selected resources to be owned by the Company (i.e., BTAs and Benchmark resources) be held to their capital and operations and maintenance … cost projections as provided with the bid. These amounts should be considered a 'hard' cap, meaning that there will be no opportunity for the Company to collect additional costs even if they believe such expenditures were prudent."[60/] Second, "PacifiCorp should provide an unconditional guarantee (i.e., not subject to force majeure or change in law) that ratepayers will receive the full

58/ PacifiCorp Request at 14 (emphasis added).

59/ Attachment A at 14-27.

60/ IE Report at 4. The Utah IE raises specific concerns with the low capital cost of PacifiCorp's benchmark bids. Utah IE Report at 69, 71, 82.

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projected value of the [PTC]. This includes situations where (a) PacifiCorp cannot claim the full PTC value or (b) PacifiCorp does not have the taxable income to use the full PTC."[61/] Finally, PacifiCorp "should similarly be held to their cost projections for the [D.2 Section]."[62/]

To be clear, *if* PacifiCorp ultimately proceeds with its wind solicitation, and *if* the Commission ultimately determines that it acted prudently in a subsequent rate review, then ICNU will likely support inclusion of these conditions as part of such a prudency determination. ICNU would add another: that if the D.2 Section is not completed on time, PacifiCorp will not only credit customers with the full value of the PTC it was unable to claim, but also the lost energy value from these resources. ICNU does not support acknowledging the final shortlist with these conditions, however, because it does not agree that acknowledgement under any conditions is appropriate under the Commission's Guidelines.

ICNU's purpose in these comments is not to argue that the Company necessarily would be imprudent in going forward with its final shortlist of bids. But just as the utilities are always quick to point out that acknowledgement does not guarantee cost recovery, neither does lack of acknowledgement guarantee disallowance. PacifiCorp may ultimately have reasonable justifications for everything it did, but at this point in the process, the question is only whether the final shortlist it has brought to the Commission "*seems reasonable*, based on the information provided …."[63/] From the criteria the Commission has used to conduct this evaluation in the past, analyzed above, there is little doubt that the final shortlist does not warrant acknowledgement. Even with the IE's recommended conditions, it remains unclear at this point whether PacifiCorp should pursue the bids from its wind RFP, those from its solar RFP, or

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[61/] IE Report at 4-5.
[62/] Id. at 5.
[63/] Order No. 06-446 at 15 (emphasis added).

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neither. The Commission should not signal that the Company has made a reasonable decision in selecting its final shortlist when it does not have the information to make this finding.

IV. CONCLUSION

Ultimately, there is little doubt that PacifiCorp rushed this RFP. The Company, of course, has a reason for its haste – to capture the PTC – but the consequence remains that the process resulted in errors that required last-minute changes, included incomplete analysis of alternative resource options, such as through the solar RFP, and resulted in after-the-fact changes to the Company's transmission planning that fundamentally altered the nature of the RFP. This RFP was unfair, incomplete, and potentially inaccurate. Its final shortlist should not be acknowledged.

Dated this 19th day of March, 2018

Respectfully submitted,

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<u>/s/ Tyler C. Pepple</u>
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BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND NONTRADITIONAL RATEMAKING FOR WIND AND TRANSMISSION FACILITIES	**DOCKET NO. 20000-520-EA-17** **(Record No. 14781)**

REDACTED SUPPLEMENTAL RESPONSE TESTIMONY

AND EXHIBITS

OF

NICHOLAS L. PHILLIPS

On Behalf of

Wyoming Industrial Energy Consumers

March 2, 2018

Exhibit No. 304

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Nicholas L. Phillips. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and an Associate with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. ARE YOU THE SAME NICHOLAS L. PHILLIPS WHO PRE-FILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF THE WYOMING INDUSTRIAL ENERGY CONSUMERS ("WIEC")?

A. Yes, I am.

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

A. I address Rocky Mountain Power's ("RMP" or "the Company") updated proposal to construct or procure four new Wyoming wind resources with a total capacity of 1,311 megawatts ("MW") (the "Wind Projects"), and the Company's proposal to construct the Aeolus-to-Bridger/Anticline Line and the 230 kV Network Upgrades (the "Transmission Projects"). Throughout my testimony, I refer to the Transmission Projects and the Wind Projects collectively as the "Combined Projects."

Q. PLEASE PROVIDE A SUMMARY OF YOUR SUPPLEMENTAL RESPONSE TESTIMONY.

A. First, I will describe some of the background of this proceeding leading up to this supplemental response testimony. Second, I will discuss issues associated with how the

Company changed its approach to modeling the Combined Projects, as well as the differences in the approaches to modeling used in this proceeding generally. Then I will describe issues associated with RMP's solar RFP (the "2017S RFP") and how the Company's own analysis of the benefits associated with new solar resources indicates that the Combined Projects likely are not the least-cost, least-risk plan for serving customers. Next, I will address the Company's updated economic analysis for the Combined Projects, based on the final shortlist resulting from the RFP for new wind resources (the "2017R RFP"). Finally, although I recommend that the Commission deny the requested certificate of public convenience and necessity ("CPCN") for the Combined Projects, I also recommend conditions that the Commission should include to protect ratepayers if it approves a CPCN for the Combined Projects.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS CONCERNING THE COMPANY'S REQUEST FOR A CPCN FOR THE COMBINED PROJECTS.

A. The results of RMP's updated analysis reaffirm my conclusion that the Combined Projects are simply too risky and should not be approved. Furthermore, assuming that the Company needs additional resources (an assumption with which I strongly disagree), RMP's updated analysis actually demonstrates that the Combined Projects likely are not the "least-cost, least-risk" plan to serve customers given the results of the 2017S RFP. Specifically, the Solar PPA Option (without any new wind or transmission facilities) provides [redacted] [redacted] in net benefits in the Medium Gas, Medium CO_2 scenario,

[1] RMP Witness Rick Link Confidential Workpaper, "EV2020 Second Supp Results Summary File – VOM adjusted CONF.xlsx" as referenced in response to WIEC Data Request 18.1(f).

<u>whereas the Combined Projects only result in $167 million of projected benefits.</u>[2] Consequently, if the Commission is inclined to approve any new resources acquisitions, instead of approving the Combined Projects, the Commission should invite RMP to demonstrate whether solar power purchase agreements ("PPAs") would provide greater customer benefits than the status quo. However, if the Commission ultimately decides that the Combined Projects should be approved, I offer certain conditions which should be included on such an approval in order to protect ratepayers. These conditions include:

1. Disallowing rate based recovery for any turbines that are not commercially operational in time to receive 100% of the Production Tax Credit ("PTC") benefits they are being constructed to capture, along with a capacity ratio share of any interconnection, transmission, distribution, and AFUDC costs.

2. Capping RMP's cost recovery on the capital cost of the Combined Projects from retail ratepayers, inclusive of the new generation and transmission facilities, as well as any interconnection costs, network upgrades, distribution costs, and AFUDC to $1,781.44 million installed cost; a reduction of $468 million, or approximately 21%, from the total cost of the Combined Projects.

3. Capping RMP's recovery of future O&M and capital expenditures related to the Combined Projects, QF project cost recovery, and net fixed system costs to those levels assumed in the Company's updated economic analysis.

4. Requiring RMP to include in its Base Rates and Net Power Costs, at minimum, the full (i) 10 years of PTCs, assuming, at minimum, a 21% federal corporate income tax rate, and (ii) energy benefits to customers for the life of the Wind Projects, both based on the assumed net capacity factors used in RMP's updated economic modeling.

5. Guaranteeing ratepayers receipt of the full grossed up value of the PTCs without having to compensate RMP for return on any deferred tax assets that may be created as a result of RMP's inability to contemporaneously monetize PTCs to full value.

6. Ensuring that if RMP ceases construction of the Combined Projects, for whatever reason, no costs incurred are recoverable from customers.

[2] RMP Witness Link's Confidential Workpapers [redacted]

II. RMP'S SUPPLEMENTAL AND SECOND SUPPLEMENTAL TESTIMONIES

Q. PLEASE DESCRIBE GENERALLY THE ROUNDS OF TESTIMONY THAT HAVE BEEN FILED IN THIS PROCEEDING SINCE YOU FILED YOUR DIRECT TESTIMONY.

A. WIEC filed its Direct Testimony in this proceeding on November 20, 2017, in response to RMP's initial application. On December 18, 2017, RMP filed its Rebuttal Testimony, and provided an additional round of Rebuttal Testimony on January 8, 2018.

On January 16, 2018, RMP filed its Supplemental Direct Testimony, generally for the purpose of updating its initial application to account for the results of its 2017R RFP and the Tax Cuts and Jobs Act that was passed in December 2017. In that testimony, RMP announced that the final shortlist of Wind Projects included TB Flats I and II, McFadden Ridge II, Cedar Springs, and Uinta. Certain portions of this testimony were subsequently corrected by the Company.

On February 16, 2018, RMP filed its Second Supplemental Direct Testimony, generally for the purpose of updating the 2017R RFP final shortlist to reflect the results of the interconnection restudy process and new system impact studies. With the Second Supplemental Direct Testimony, the Company removed the McFadden Ridge II project from its final shortlist, and replaced it with Ekola Flats (another Company-owned benchmark project). This change increased the capacity of the final shortlist Wind Projects from 1,170 MW to 1,311 MW.

After the Second Supplemental Direct Testimony was filed, the Company discovered that its Planning and Risk ("PaR") model had not accurately captured certain wind tax costs and wind integration costs, and, as a result, the benefits of the Combined

Projects reflected in the Company's Second Supplemental Direct Testimony were not accurate. Consequently, on February 23, 2018, RMP filed corrections to portions of Ms. Crane's Second Supplemental Direct Testimony and portions of Mr. Link's Second Supplemental Direct Testimony.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THE VARIOUS ITERATIONS OF RMP'S TESTIMONY?

A. Yes. I am very concerned that RMP is attempting to push through a $2.245 billion utility investment – one that carries with it very high risks that the Company is asking ratepayers to assume on its behalf – without providing intervenors such as WIEC sufficient time to fully evaluate and scrutinize the Combined Projects. I have attempted to evaluate RMP's proposal, as it evolved over time, to the best of my ability. However, RMP has modified and updated the details of its proposal more than once in recent weeks. Furthermore, RMP has also designated a fair amount of relevant information as "highly confidential," making it very difficult for parties to review and use that information. Not only does this give me concern that RMP has not thoroughly evaluated the Combined Projects for which it seeks approval, but it also inhibits intervenors' ability to fully vet the Combined Projects under the existing timeframe. To the extent that RMP continues to modify or correct its proposal, I may have additional testimony to provide.

Q. THROUGHOUT THESE ITERATIONS, DID RMP ALSO CHANGE THE WAY IT PERFORMED ITS ECONOMIC ANALYSIS?

A. Yes. In its Direct Testimony, RMP used a "levelized" approach to model capital costs and PTCs associated with project alternatives within the System Optimizer ("SO") and PaR models. This is consistent with the way RMP has performed its Integrated Resource

Plan ("IRP") analyses for many years. Once the SO model had selected a least-cost plan and PaR had performed additional production costs simulations, a full nominal revenue requirements analysis was performed spanning the full project life rather than just the first 20 years.

However, for its Supplemental Direct Testimony, the Company altered this methodology. Rather than using levelized costs for wind related PTCs, as it had originally, for the first time RMP modeled these nominally in the SO and PaR models. However, at the same time, RMP continued to model capital costs on a levelized basis in its Supplemental Direct Testimony. As a result, RMP mixed and matched its modeling methods in its Supplemental Direct Testimony. The result of this change in methodology is important because, holding all else equal, it makes self-build or build-transfer ("BTA") wind projects seem more economic compared to the original methodology. Consequently, the SO model will be more likely to include self-build/BTA wind projects in the "least-cost" portfolio. In other words, the change in modeling was self-serving. Once the least cost portfolio selected, the same full nominal revenue requirements analysis spanning the life of the projects was performed.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO BE AWARE OF THIS CHANGE?

A. What is important for the Commission to remember is that the levelized approach is used when modeling resource alternatives, specifically to allow for equitable comparison when the full life of the resource does not fit within the study horizon. However, it is the nominal revenue requirements that most closely depict how project costs and benefits will pressure customer rates. The Company is aware of this reality, and RMP performed a full nominal revenue requirements analyses over the full project lives. The nominal revenue requirements analyses provide a more reliable assessment of the impact of project costs on rates and the risks associated with the timing of costs and benefits compared to the levelized approach. Consequently, the Commission should weigh the results of the nominal revenue requirements analysis much more heavily than the results of a levelized approach.

Q. WHY DO THE RESULTS OF THE NOMINAL REVENUE REQUIREMENTS ANALYSIS MORE CLOSELY ALIGN WITH THE PRESSURE PLACED ON RATES BY NEW CAPITAL ADDITIONS TO RATE BASE?

A. Simply put, this is how the revenue requirements will actually occur and flow through to rates. The capital costs for self-build/BTA projects will not be recovered from ratepayers on a levelized basis. Instead, the revenue requirements are actually greatest when the asset(s) are first placed into service, and decline over time as the asset is depreciated. As I just mentioned, the levelization approach is merely a method used in economic models to compare assets when the full asset lives do not fit into the modeling horizon. This should not be mistaken for the reality of how rates will be affected.

Furthermore, there are different levelization methods, most notably uniform levelization and "real" levelized. The Company appears to have used the "real" levelized approach, which is actually completely opposite of how the project revenue requirements associated with a self-build/BTA project will actually affect rates. Figure NLP-SR-1 below illustrates this point, showing the increasing costs overtime via the levelization whereas the actual way these costs will affect the revenue requirements and rates are. What should be evident from this illustration is how the levelization of costs, though useful for economic modeling, in no way aligns with how new capital investments will affect rates. Additionally, Figure NLP-SR-1 shows how the shift in the levelization method with respect to PTCs has made these projects seem much more attractive to the SO model (which selects the least cost portfolio) when, in reality, the nominal project costs (which will influence rates) have not changed much.

As I indicated, the net effect of this change will result in a higher likelihood of self-build/BTA projects being selected by the SO model, an outcome that is highly favorable to the Company, as these are the projects will result in the highest financial reward to RMP and its shareholders through its rate of return. I will note that in the nominal project costs I have excluded the final year in order to make the plots easier to read and the corresponding net present values ("NPVs") listed in the legends are linked to the data shown in the plot.

CONFIDENTIAL FIGURE NLP-SR-1
Comparison of Changes to Economic Modeling Assumptions
for the Combined Project's Costs (Both Capital Costs and PTCs)

[redacted]

***Note that all costs associated with the projects (Wind, Transmission and Network Upgrade Capital as well as PTC benefits) are included in each plot. Given the virtually identical NPV associated with the nominal projects costs, one would expect the NPV of the levelized costs to also be virtually identical.**

Q. DOES THE COMPANY'S REVISED ECONOMIC MODELING BIAS THE ECONOMIC MODEL AND IN TURN THE LEAST-COST PORTFOLIO IT SELECTS?

A. Yes. Combining a levelized capital cost with a nominal PTC benefit distorts the value of the projects within the economic model that is tasked with selecting the least-cost portfolio. This is because the metric used by the SO model to determine the least-cost portfolio is to minimize the NPV of revenue requirements. The Company changed how PTCs were modeled in its analysis, moving from a levelized approach to a nominal approach. The Company claims that this will better reflect how the PTCs will affect rates, but this explanation it misleading because the *capital costs* will affect rates on a nominal basis, not a levelized basis. The Company has mixed and matched the modeling methodologies, and this mixing and matching will result in more emphasis being placed on self-build/BTA options rather than on PPAs. When levelizing costs, the NPV of the levelized cost should be equal to the NPV of the nominal costs.[3] An easy to understand example is a mortgage loan amortization, which is a cost levelization. The levelization (amortization) of the loan keeps the underlying NPV of the loan constant; it does not reduce it. But the Company's updated, or "hybrid," method has skewed the economics by reducing the NPV of the Combined Projects.

Q. HOW CAN WE TELL THAT THE COMPANY'S HYBRID APPROACH REDUCED THE NPV OF THE COMBINED PROJECTS COMPARED TO NOMINAL APPROACH?

A. In Figure NLP-SR-1 (above), I presented plots of the Combined Projects costs, as reported in the Corrected Second Supplemental Testimony, on both a levelized basis and a nominal basis.[4] The difference in the NPV over the first 20 years shows that the levelization has reduced the NPV of the nominal series by about 27%. Conversely, the levelization of the Combined Projects costs in the Company's Direct Testimony is within about 1% of the NPV of the 20 year nominal costs.

Similarly, for the Solar PPA Option (which I discuss below), the levelized costs are within less than 2% of the NPV of the 20 year nominal costs. Effectively, the

[3] This is a fundamental economic principle for expressing the same costs (or cash flows) in different ways, see for example "Engineering Economy", 6th Ed. by Blank & Tarquin at Chapter 2.

[4] Note that the "levelized" approach used by the Company in its updated analysis presented in its Supplemental Testimony is a hybrid of levelized and nominal project costs.

outcome of the Company's updated economic modeling is biased as the SO model picks resources based on lowest NPV and the Company's approach made the Combined Projects appear 27% cheaper to the model, when the reality is the NPV of costs over the life of the Combined Projects have hardly changed, as evidenced in the full nominal revenue requirements analysis.

Q. WITH THAT UNDERSTANDING, PLEASE DESCRIBE THE RESULTS OF THE 2017R RFP.

A. As I mentioned above, the Company announced the final shortlist of Wind Projects on January 16, 2018, and subsequently modified that final shortlist in its Second Supplemental Direct Testimony, provided on February 16, 2018. The modified final shortlist of Wind Projects is as follows:

- Ekola Flats, a 250 MW Company benchmark project;
- TB Flats I and II (combined into single project), a 500 MW Company benchmark project;
- Cedar Springs, a 400 MW third-party build-transfer project and PPA; and
- Uinta, a 161 MW third-party build-transfer project.

Q. THE VAST MAJORITY OF THE NEW CAPACITY WILL BE COMPANY-OWNED. WHAT RISKS DO COMPANY-OWNED PROJECTS POSE TO RATEPAYERS THAT PPAS WOULD NOT?

A. Only 200 MW of the total 1,311 MW of new wind capacity, or approximately 15%, will be purchased under a PPA with a third-party. The remainder of the capacity will come from the Company's benchmark projects and BTAs. When the Company acquires additional energy and capacity through PPAs, ratepayers are insulated from certain risks that they typically bear when RMP owns the generation. Specifically, when the Company enters into PPAs, the third-party provider takes on the capital cost risk, as well as the risk of changes in the cost of equipment, output, O&M costs, and PTCs through the life of the agreement, among other things. As the Company's *pro forma* PPA states:

> Seller shall bear all risks, financial and otherwise throughout the Term, associated with Seller's or the Facility's eligibility to receive PTCs, ITCs or other Tax Credits, or to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes. The obligations of the Parties hereunder, including those obligations set forth herein regarding the purchase and price for and Seller's obligation to deliver Net Output, shall be effective regardless of whether the sale of Output or Net Output from the Facility is eligible for, or receives, PTCs, ITCs or other Tax Credits during the Term.[5]

With Company-owned projects, on the other hand, ratepayers are expected to bear the burden of capital costs (including cost overruns) and O&M costs, to the extent that those costs are prudently incurred.[6] This is in contrast with the opportunity RMP identified to purchase solar power under PPAs as a result of the 2017S RFP, which I address next.

III. <u>THE POTENTIAL RISKS AND BENEFITS OF SOLAR PPAS</u>

Q. PLEASE PROVIDE SOME BACKGROUND INFORMATION ON THE COMPANY'S 2017S RFP.

A. RMP's 2017R RFP was subject to the approval of the Utah Public Service Commission ("Utah PSC").[7] After RMP filed its application for approval of its solicitation process on

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[5] The Independent Evaluator's Final Report On PacifiCorp's 2017R Request For Proposals, by Bates White Economic Consulting, Presented to the Oregon Public Utility Commission, dated February 16, 2018 at pp. 38-39 (available at: http://edocs.puc.state.or.us/efdocs/HAH/um1845hah121349.pdf).

[6] This is completely true for Company self-build projects. The capital cost risk could be reduced depending of the contractual structure associated with BTAs.

[7] Docket No. 17-035-23.

April 17, 2017, parties intervened and raised concerns that restricting the proposed RFP to wind projects would not produce results that would be the lowest reasonable cost to customers. Parties argued that the RFP should be opened up, and that RMP should solicit bids from a greater variety of resources.

RMP resisted efforts to expand the RFP to include non-wind and non-Wyoming resources, citing, in part, the results of the 2017 IRP and its concern that a broad RFP would impact the Company's ability to move forward with the Combined Projects. RMP asserted:

> While there may be opportunities to acquire new renewable resources that can be delivered into other parts of PacifiCorp's transmission system, the 2017 IRP did not identify these opportunities as part of PacifiCorp's least-cost, least-risk plan. All of the resource portfolios produced during the initial stages of the portfolio development phase of the 2017 IRP contained new Wyoming wind resources in 2021, which for modeling purposes was used as a proxy on-line date for PTC-eligible wind achieving commercial operation by the end of 2020. None of the resource portfolios developed during the initial stages of the portfolio development phase of the 2017 IRP indicated that renewable resources delivered into other parts of PacifiCorp's transmission system would provide the economic benefits that are expected with the new wind and transmission projects included in the preferred portfolio.
>
> …
>
> Consideration of this broader RFP can be vetted through the on-going review of the 2017 IRP, and if there is interest in pursuing a broader renewable resource RFP, a second solicitation process could be initiated in the first quarter of 2018. Because this broader solicitation would not be dependent upon a critical-path transmission investment, as is the case in the proposed 2017R RFP, a second RFP process initiated in early 2018 could target renewable resources that can be placed in service by the end of 2020, thereby maximizing opportunities to procure projects that can leverage federal income tax credits. The possibility of procuring additional renewable resources does not need jeopardize the significant opportunity that is being pursued through the proposed 2017R RFP. If additional renewable resources identified through a second solicitation process provide all-in economic benefits for customers, those opportunities can be

> pursued in addition to, not in lieu of, the wind resource procurement proposed in the 2017R RFP.[8]

Nevertheless, the Utah PSC issued an order approving the 2017R RFP, but also suggesting certain modifications. The order stated:

> We are recommending that the RFP be modified to include solar resources that can interconnect at any point in PacifiCorp's system, rather than accepting PacifiCorp's offer to execute a second RFP for solar resources. We find that a second and separate RFP for solar resources, based on modeling inputs that would assume the construction of the proposed wind resource, would not accomplish the objective of comparing the proposed solar resources against the wind resources on an equal basis. Simply put, the question is not whether solar resources should be built in addition to the proposed wind resources. Rather, we find that the more relevant question is whether solar resources should be built instead of, before, or in conjunction with the proposed wind resources. A separate, subsequent RFP cannot answer that question due to the dynamic nature of generation and transmission resource decisions. Ultimately, without the benefit of conclusive evidence regarding the current and actual costs to build and connect utility scale solar projects to PacifiCorp's system, we believe the market would provide the best comparative results. While we are not making that suggested modification mandatory for our approval of the RFP, PacifiCorp's decision about whether to accept the suggested modification will be relevant in any docket evaluating costs related to a winning RFP bidder. PacifiCorp must make an operational decision with respect to this issue and must be prepared to defend it.[9]

In response to this order, RMP filed a letter with the Utah PSC stating that, "In order to act expeditiously to issue the 2017R RFP, the Company has not adopted the Commission's suggested modification to expand the 2017R RFP to include solar resources. Instead, the Company is preparing to issue a separate solicitation for solar resources, the 2017S RFP, in November 2017."[10]

Q. DO YOU HAVE ANY OBSERVATIONS ON THE GENESIS OF THE 2017S RFP.

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[8] RMP's August 18, 2017 Reply in Support of Application for Approval of Solicitation Process at pp. 9-12.

[9] *Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources*, Docket No. 17-035-23, Order Approving RFP With Suggested Modifications at pp. 9-10.

[10] RMP's October 10, 2017 letter in Utah PSC Docket No. 17-035-23.

A. Yes. Absent the Utah PSC's order, I do not believe that RMP would have issued the 2017S RFP. In other words, absent the Utah PSC's order, I do not believe RMP would have looked into a solar option to assess whether the Combined Projects actually presented the least-cost, least risk portfolio. And, in light of the results of the 2017S RFP, RMP's assertion that the 2017 IRP did not identify any non-wind non-Wyoming opportunities as part of RMP's least-cost, least-risk plan raises serious concerns about the integrity of the 2017 IRP, which is the foundation of the Company's Energy Vision 2020 project.

Q. DID RMP ADDRESS THE RESULTS OF THE 2017S RFP AS PART OF THE COMPANY'S SUPPLEMENTAL AND SECOND SUPPLEMENTAL TESTIMONY?

A. Yes. In his Supplemental Direct Testimony and Second Supplemental Direct Testimony, Mr. Link described sensitivity studies that RMP performed to analyze the impact of the solar bids received in the 2017S RFP.[11] In this sensitivity, the SO model selected 1,122 MW of solar PPA bids in the Low Gas, Zero CO_2 scenario and 1,419 MW of solar PPA bids in the Medium Gas, Medium CO_2 scenario (the "Solar PPA Option").[12] The selected sizing of these projects is approximately the same as the 1,311 MW of the Wind Projects proposed by the Company. However, the Company failed to discuss the *true results* of its analysis of the Solar PPA Option in its testimony. In contrast to the information discussed by Mr. Link as part of the "solar sensitivity" analysis, the Company's workpapers and discovery responses provide more compelling evidence

[11] Supplemental Direct Testimony of Rick T. Link at pp. 33-36; Second Supplemental Testimony of Rick T. Link at pp. 20-24.

[12] Second Supplemental Testimony of Rick T. Link at p. 21, ll. 2-5.

demonstrating the Combined Projects are not in the public interest, but instead serve as a vehicle to increase investor earnings by forcing ratepayers to compensate investors for an inferior project.

Q. WHAT DID THE COMPANY REPORT AS THE RESULTS OF THE SOLAR SENSITIVITY IN ITS SECOND SUPPLEMENTAL TESTIMONY?

A. The Company claims that, when analyzed in isolation, the Solar PPA Option produced net benefits that are lower than those expected from the Combined Projects under the Medium Gas, Medium CO_2 scenario and approximately the same net benefits as the Combined Projects under the Low Gas, Zero CO_2 scenario.[13] The Company also argues that pursuing the Solar PPA Option would leave significant benefits on the table, which includes building the proposed Aeolus-to-Bridger/Anticline Line.[14] These arguments are misleading.

Q. PLEASE EXPLAIN.

A. Earlier in my testimony I explained how the Company's revised modeling (*i.e.*, the hybrid levelized capital/nominal PTC approach) distorts the levelized NPV of the Combined Projects and why the most relevant analysis is the nominal revenue requirements analysis. Again, the nominal revenue requirement analysis most closely aligns with how costs/(benefits) will impact rates, and it has not been skewed by the Company's revised levelization method. While the Company presented the results of the nominal revenue requirements analysis for the Combined Projects, the Company did not report these results for the Solar PPA Option, even though it performed this analysis and

[13] Second Supplemental Testimony of Rick Link at p. 21, l. 17 - p. 22, l. 9.
[14] *Id*.

provided the results in its workpapers. Notably, the results of this nominal revenue requirement analysis tell a much different about the Solar PPA Option and how it compares to the Combined Projects.

Q. WHAT DO THE COMPANY'S WORKPAPERS SHOW IF THE REVENUE REQUIREMENTS FOR THE SOLAR SENSITIVITY ARE SHOWN ON A NOMINAL BASIS?

A. The results tell a completely different story with respect to the Solar PPA Option and the resulting economics. This nominal revenue requirements analysis, which spans the year from 2017 through 2050, shows that <u>the [redacted] Solar PPA Option (without any new wind or transmission facilities) provides [redacted] in net benefits in the Medium Gas, Medium CO_2 scenario, whereas the Combined Projects only result in $167 million of projected benefits.</u>[15] This is a difference of [redacted], or about a [redacted] increase in net benefits over the Combined Projects.[16]

Q. HOW DID THE BENEFITS OF THE SOLAR PPA OPTION COMPARE TO THE PROJECTED BENEFITS FROM THE COMBINED PROJECTS IN THE LOW GAS, ZERO CO_2 SCENARIO?

A. The contrast is even greater under the Low Gas, Zero CO_2 scenario. In this scenario, which WIEC believes represents the status quo, the Solar PPA Option provides [redacted] in net benefits, whereas the Combined Projects actually result in a [redacted] *increase* in costs to customers.[17]

[15] RMP Witness Rick Link Confidential Workpaper, "EV2020 Second Supp Results Summary File – VOM adjusted CONF.xlsx" as referenced in response to WIEC Data Request 18.1(f).
[16] *Id.*
[17] *Id.*

Q. HOW DO THE RISKS OF THE SOLAR PPA OPTION COMPARE TO THE RISK OF THE COMPANY-OWNED COMBINED PROJECTS?

A. First and foremost, there is no transmission cost risk because the Solar PPA Option does not require the proposed Aeolus-to-Bridger/Anticline Line. Second, because the Solar PPA Option is not dependent on PTCs, there is no PTC risk borne by customers. Third, because the solar resources would be acquired through PPAs, customers will only pay for power and energy actually produced, rather than being held at risk for underperformance. This is a significant difference, given that the Company has not presented and quantified the risk assessment associated with wind variability. And, unlike the Combined Projects, the Solar PPA Option does not require variable and output-dependent PTCs in order to make the Transmission Projects economic.

Figure NLP-SR-2 compares the expected incremental revenue requirements associated with the Combined Projects and the Solar PPA Option under the Medium Gas, Medium CO_2 scenarios. Similarly, Figure NLP-SR-3 contains the same information under the Low Gas, Zero CO_2 scenario.

CONFIDENTIAL FIGURE NLP-SR-2
Solar PPA Option vs Combined Projects (Mid Gas, Mid CO2)
(Benefit)/Cost ($ millions of 2016 Dollars)

[redacted]

CONFIDENTIAL FIGURE NLP-SR-3
Solar PPA Option vs Combined Projects (Low Gas, Zero CO2)
(Benefit)/Cost ($ millions of 2016 Dollars)

[redacted]

Q. PLEASE DISCUSS FIGURES NLP-SR-2 and NLP-SR-3.

A. These figures show both the annual and cumulative NPV of incremental revenue requirements resulting from the nominal revenue requirements analysis associated with the Combined Projects and the Solar PPA Option under the Medium Gas, Medium CO_2 and Low Gas, Zero CO_2 price-policy scenarios.

The final value of the cumulative NPV in green (read from the left axis) aligns with the NPVs the Company has been reporting to assess the projects. The Annual NPV in red (read from the right axis) added together year by year over time make up the cumulative NPV and provide additional insight on the timing of the costs and benefits. The horizontal blue line shows the crossover point of the cumulative NPV, which represents when the project is expected to break even. Overall, these figures provide additional insight into the projects and the risks embedded in each approach.

When inspecting these figures, a few facts become clear. First, the Solar PPA Option does not have near the variability in costs. Second, the Solar PPA Option produces net benefits in both price-policy scenarios. Third, in the Medium Gas, Medium CO_2 scenario, when both projects produce net benefits, the breakeven occurs at near similar times, but the Solar PPA Option has *more than double the expected benefit* and does not include the large, risky, and speculative benefit in 2050 (which I address below). Fourth, the Solar PPA Option produces greater benefits with lower upfront costs, leading to a lower risk project. Finally, in the Low Gas, Zero CO_2 scenario, the Combined Projects never breakeven, resulting in increased cost to ratepayers, whereas the Solar PPA Option still breaks even at approximately the same time it did under the Medium Gas, Medium CO_2 scenario, resulting in over [redacted] in net benefits by the end of the project life.

[18] RMP Witness Rick Link Confidential Workpaper, "EV2020 Second Supp Results Summary File – VOM adjusted CONF.xlsx" as referenced in response to WIEC Data Request 18.1(f).

It is worth noting that the cost to customers for the Solar PPA Option is approximately [redacted] (with less than [redacted] in upfront capital) as compared to the $2.245 billion for the Combined Projects (which requires over [redacted] in upfront capital).[19] As I just mentioned, for the roughly [redacted][0] price tag, RMP's own analysis shows more customer benefits compared to the Combined Projects (for less capital expenditure) and the Solar PPA Option contains far less risk. The risk reduction manifests in the plots above via the consistent breakeven point across both the low gas and medium gas scenarios and less variable annual NPV of incremental revenue requirements. There are a number of reasons why the Solar PPA Option is less risky for customers.

Q. WHY IS THE SOLAR PPA OPTION LESS RISKY FOR CUSTOMERS COMPARED TO THE COMBINED PROJECTS?

A. Simply put, the Solar PPA Option does not require any upfront investment from RMP. Consequently, all the risk associated with the completion of the project remains with the project developer rather than RMP and its customers. Unlike the Combined Projects, if the solar projects are not completed in time to secure tax credits, RMP's customers are indifferent. If the projects fail to generate electricity in the amounts assumed, RMP's customers do not pay both rate base costs and replacement energy costs like they would with the Combined Projects. Furthermore, the solar projects do not require the Aeolus-to-Bridger/Anticline Line or the transmission upgrades associated with the Wind Projects, completely alleviating the risk associated with constructing and placing into

[19] *Id.*
[20] *Id.*

service a new transmission line in time to secure PTCs (which RMP admits are required to make the transmission line economic). And, because the Company would not receive PTCs from the solar PPAs, there is no risk associated with the possibility of RMP not being able to monetize the PTCs contemporaneously when they are produced.

Q. HAVE YOU PREPARED A NOMINAL REVENUE REQUIREMENTS COMPARISON BETWEEN THE COMBINED PROJECTS AND THE SOLAR PPA OPTION?

A. Yes. This is presented below in Figures NLP-SR-4 and NLP-SR-5. As I have mentioned, this method is the more realistic, and therefore preferred, way to understand how the two project alternatives will impact customer rates.

FIGURE NLP-SR-4 Solar PPA Option vs Combined Projects (Mid Gas, Mid CO2) (Benefit)/Cost ($ million)

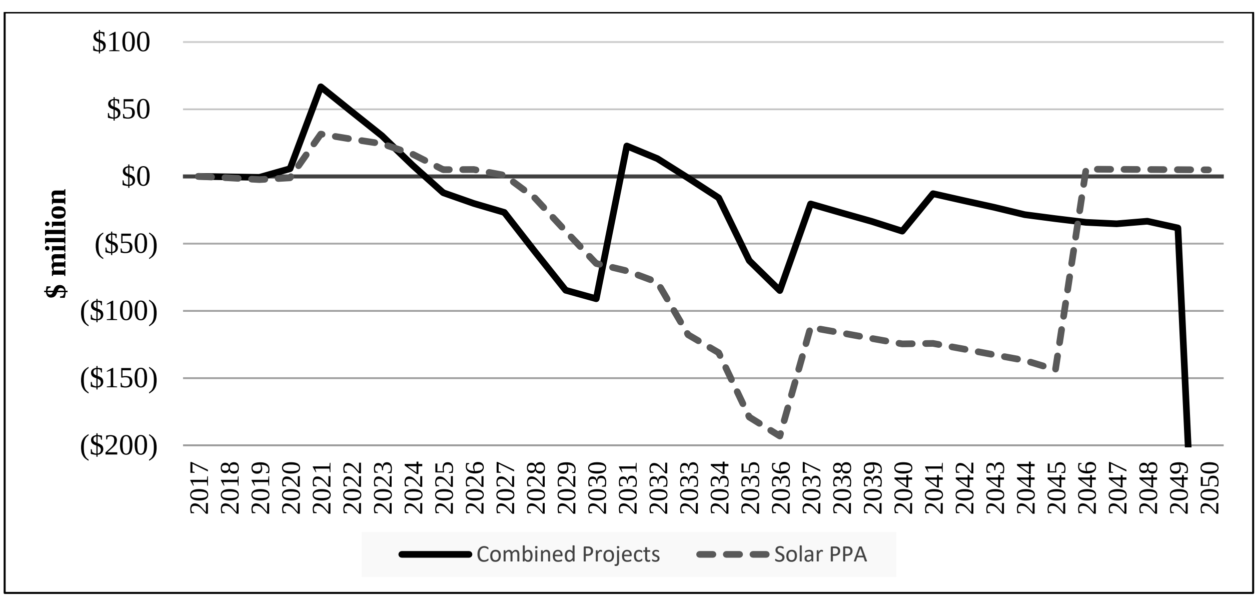
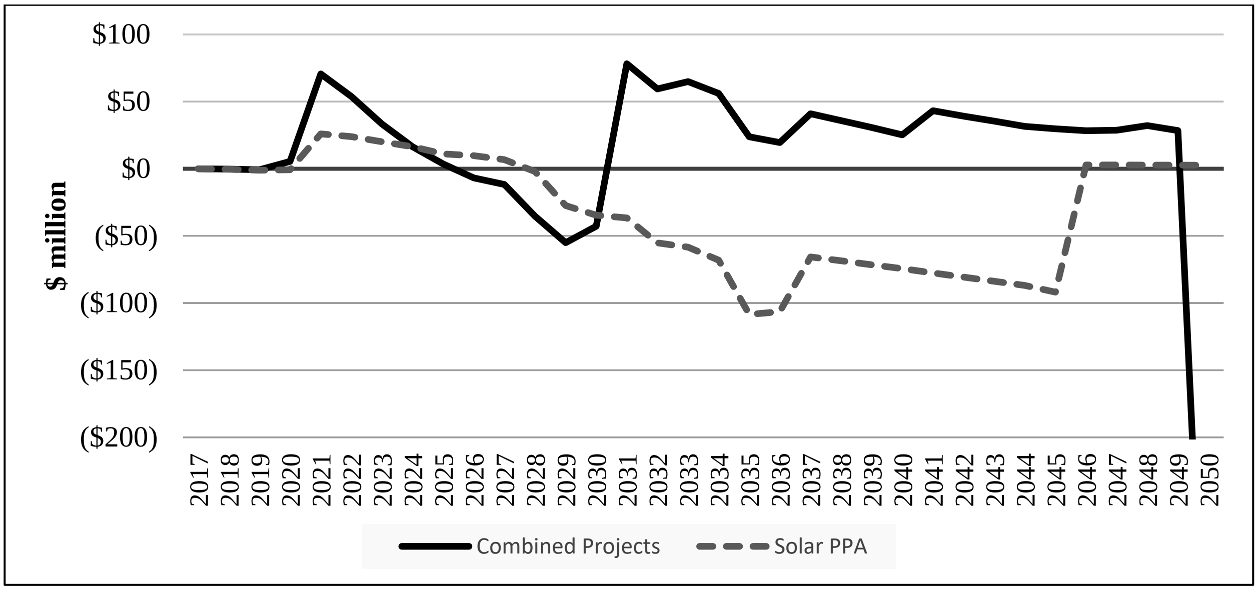


FIGURE NLP-SR-5 Solar PPA Option vs Combined Projects (Low Gas, Zero CO2) (Benefit)/Cost ($ million)



Q. PLEASE DISCUSS HOW RMP'S SHAREHOLDERS STAND TO BENEFIT UNDER THE COMBINED PROJECTS AS COMPARED TO THE SOLAR PROJECTS.

A. Under the Combined Projects, the Company would own the new transmission assets as well as the vast majority of the new wind capacity. Accordingly, the Company would be allowed the opportunity to earn a return on these new Company-owned assets. In contrast, the Solar PPA Option is an all-PPA option that does not allow for the Company to earn a return.

Q. HAVE YOU QUANTIFIED THE VALUE OF EQUITY RETURNS THE COMPANY EXPECTS TO REALIZE FROM THE COMBINED PROJECTS?

A. Yes. In response to WIEC Discovery Request 18.1(c) and (d),[21] RMP provided the expected equity returns for its shareholders with respect to the Combined Projects and Solar PPA Option, respectively. In those responses, the Company stated the following: "Total equity returns are approximately $1.9 billion over the life of the assets" for the Combined Projects and "There are no equity returns for a solar PPA."[22]

Q. HOW DO THESE RETURNS TO SHAREHOLDERS COMPARE WITH THE PROJECTED BENEFIT TO CUSTOMERS?

A. By comparison, under the Medium Gas, Medium CO_2 case, the Company only expects $167 million in NPV benefits for customers. As I discussed in my direct testimony, WIEC is especially concerned about the level of customer risk embedded within RMP's proposal. WIEC believes that the risks borne by the customers outweigh those borne by the Company, particularly in light of the significant benefits to RMP's shareholders from the Combined Projects. This risk is evidenced in Figures NLP-SR-4 and NLP-SR-5, where one can see how the Combined Projects result in a net cost to customers in the Low Gas, Zero CO_2 scenario. And, unlike the potential benefits for customers, the benefits to RMP's shareholders do not depend on the output from the Wind Projects, or future gas, power, or CO_2 prices. By contrast, the Solar PPA Option provides significantly greater benefits to customers in both scenarios, but yields no equity returns to RMP.

[21] WIEC Exhibit No. 304.1.

[22] The Company indicated there is no clear convention on the appropriate discount rate for equity return but WIEC could perform its own calculation. Using the same discount rate as used by RMP in its economic analysis, the NPV of the equity returns is approximately $741 million.

Q. ARE YOU SAYING THAT THE COMPANY SHOULD PURSUE THE SOLAR PPA OPTION?

A. No. WIEC is not convinced that RMP needs to acquire *any* new resources at this time. Additionally, WIEC disagrees with RMP's position that the question is whether the Company should consider both opportunities (consistent with the Utah PSC's decision, quoted above). Furthermore, the Company did not request the Commission's approval to enter into any solar PPAs in this proceeding. The key takeaway is that RMP's own analysis raises legitimate doubts regarding whether the Combined Projects truly are the least-cost, least-risk resource portfolio to serve customers given the updated economic analysis provided in this proceeding. For that reason, the Commission should deny RMP's request for a CPCN for the Combined Projects.

IV. THE POTENTIAL RISKS AND BENEFITS OF THE COMBINED PROJECTS

Q. HAS RMP UPDATED ITS ECONOMIC ANALYSIS TO SUPPORT THE COMBINED PROJECTS?

A. Yes. RMP has updated its economic analysis to reflect the costs obtained via the 2017R RFP, along with revising the analysis to reflect updated load, commodity, and tax information.

Q. HAS ANY OF THE INFORMATION CONTAINED WITHIN RMP'S SECOND SUPPLEMENTAL TESTIMONY AND UPDATED ECONOMIC ANALYSIS CAUSED YOU TO CHANGE ANY OF YOUR DIRECT TESTIMONY RECOMMENDATIONS?

A. No. In fact the results of the updated analysis reaffirm my direct testimony recommendation that the Combined Projects are simply too risky and should not be approved.

Furthermore, while RMP is still characterizing the Combined Projects as the least-cost, least-risk plan, I just described information that RMP provided with its updated economic analysis which demonstrates that they likely are not the least-cost, least-risk resources. Simply put, the facts contained within RMP's own filing contradict the premise for its requested CPCN and there is no way the Commission can approve the CPCN consistent with the public interest without imposing concrete ratepayer protections to ensure the projected benefits actually materialize.

Q. PLEASE SUMMARIZE THE CHANGES REFLECTED IN RMP'S UPDATED ANALYSIS.

A. There were four broad categories of updates incorporated into RMP's updated analysis. The models were updated to reflect: (1) cost-and-performance assumptions for the Wind Projects consistent with the winning bids selected to the 2017R RFP final shortlist as summarized earlier in my testimony; (2) current load-forecast projections; (3) current price-policy scenario assumptions; and (4) recent changes in federal tax rate for corporations.[23]

In addition to updating the models with revised capital cost assumptions and net capacity factors sourced to the specific RFP responses selected, RMP also added a new "benefit" that was not included in its original modeling: terminal value benefits from projects that will be owned by the Company.

[23] Supplemental Direct Testimony of Rick Link at p. 17.

Q. DID THE COMPANY ALSO CHANGE THE WAY IT MODELED PTC BENEFITS IN THIS PROCEEDING?

A. Yes. As I discussed earlier in this testimony, in its original filing, the Company modeled these benefits on a levelized basis over the life of the asset. This is the same way PTCs were modeled in the Company's 2017 IRP. In its updated model, the Company modeled the PTCs on a nominal basis. That is, the PTCs are modeled for 10 years until they expire.

Q. WHAT DOES THE COMPANY CLAIM THE RESULTS OF ITS UPDATED ECONOMIC ANALYSIS SHOW?

A. RMP claims the results of its updated economic analysis demonstrate that the Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.[24] The Company further claims that the customer benefits increase to $167 million in the Medium Gas, Medium CO_2 case through 2050 (as compared to $137 million in the original filing), and range from $357 million to $405 million in the Medium Gas, Medium CO_2 case through 2036.[25]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM WITH RESPECT TO THE UPDATED ECONOMIC ANALYSIS?

A. No. The results stated by the Company are erroneous and misleading. When inspected more closely, the economics of the Combined Projects are actually no better than originally presented, and are arguably worse than what the Company originally claimed. Furthermore, the Company fails to discuss the fact that the updated economic analysis

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[24] Second Supplemental Direct Testimony of Rick Link at p. 2.
[25] *Id*.

reveals that the level of risk embedded within the Combined Projects is greater than originally reported in its original filing. Finally, the Company failed to disclose to the Commission that, using the same nominal revenue requirements analysis over the period from 2017-2050 which it uses to support the Combined Projects, the Solar PPA Option results in a superior economic benefit at a lower cost and with less customer risk compared to the Combined Projects. Consequently, the Company's proposal suffers from the same deficiencies I discussed in my direct testimony, and now contains new pitfalls.

Q. PLEASE EXPLAIN.

A. First, the Company claims that the results of its updated economic analysis demonstrate that the Combined Projects provide net customer benefits under all scenarios studied through 2036 and that these benefits range from \$357 million to \$405 million in the Medium Gas, Medium CO_2 case. These claims are based on the Company's SO and PaR modeling, which incorporate *levelized capital costs* for the Combined Projects and *nominal PTC cash flows*. I have already discussed the reasons why this approach is flawed. While levelization of capital costs when done correctly can be a reasonable method when selecting economic resource alternatives with different lives and in-service dates, it does not accurately reflect how these costs will flow through to customers. As a result, the benefits produced from these analyses are contradicted by the Company's updated nominal revenue requirement analysis. The updated nominal revenue requirement analysis produced the \$167 million in NPV customer benefits in the Medium Gas, Medium CO_2 case (and the \$137 million in NPV benefits claimed in the original filing). This analysis more accurately reflects the way the actual costs and revenues of the projects will flow through to customers.

Q. WHAT ARE THE 20 YEAR NPV SAVINGS THAT RESULT FROM THE NOMINAL REVENUE REQUIREMENT MODELING?

A. The Medium Gas, Medium CO_2 price policy scenario actually shows only $51 million NPV of estimated customer benefits. Said another way, only 30% of the total claimed benefits for this scenario occur in the first 20 years, while the remaining estimated benefits occur in years 21-35. Furthermore, two of the scenarios actually result in increased costs to customers. Table NLP-SR-1 below presents the 20 year and 35 year NPV benefits for all nine price-policy scenarios resulting from the updated nominal revenue requirements analysis.

Table NLP-SR-1
2017 Wind RFP Nominal Revenue Requirement
PVRR(d)
Updated Economic Analysis
(Benefit)/Cost ($ million)

Price-Policy Scenario	20 Yr	35 Yr
Low Gas, Zero CO2	156	184
Low Gas, Medium CO2	127	127
Low Gas, High CO2	(30)	(147)
Medium Gas, Zero CO2	(13)	(92)
Medium Gas, Medium CO2	(51)	(167)
Medium Gas, High CO2	(141)	(304)
High Gas, Zero CO2	(262)	(448)
High Gas, Medium CO2	(297)	(499)
High Gas, High CO2	(388)	(635)

Q. HOW DOES THIS COMPARE TO THE COMPANY'S ORIGINAL ECONOMIC ANALYSIS?

A. In the Company's original analysis, the Medium Gas, Medium CO_2 scenario resulted in a 20 year NPV benefit of $93 million, which was 68% of the total 35 year estimated benefit. Additionally, compared to the Company's original analysis, seven of the nine scenarios included in the updated analysis result in *less favorable* economics over the first 20 years. For convenience, Table NLP-SR-2 below presents that 20 year and 35 year NPV benefits for the nine price policy scenarios that resulted from the original analysis.

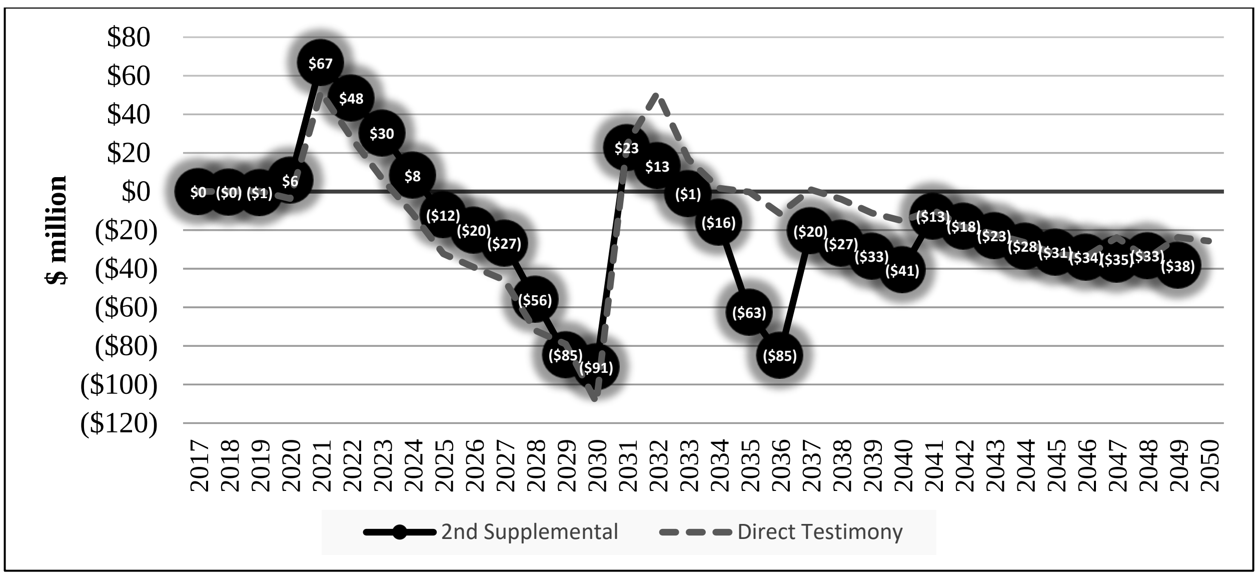
Table NLP-SR-2
2017 Wind RFP Nominal Revenue Requirement
PVRR(d)
Original Economic Analysis
(Benefit)/Cost ($ million)

Price-Policy Scenario	20 Yr	35 Yr
Low Gas, Zero CO2	96	174
Low Gas, Medium CO2	51	93
Low Gas, High CO2	(114)	(194)
Medium Gas, Zero CO2	(38)	(53)
Medium Gas, Medium CO2	(93)	(137)
Medium Gas, High CO2	(205)	(317)
High Gas, Zero CO2	(241)	(341)
High Gas, Medium CO2	(253)	(351)
High Gas, High CO2	(390)	(595)

Q. WHAT DOES THIS IMPLY ABOUT THE RISK OF THE COMBINED PROJECTS?

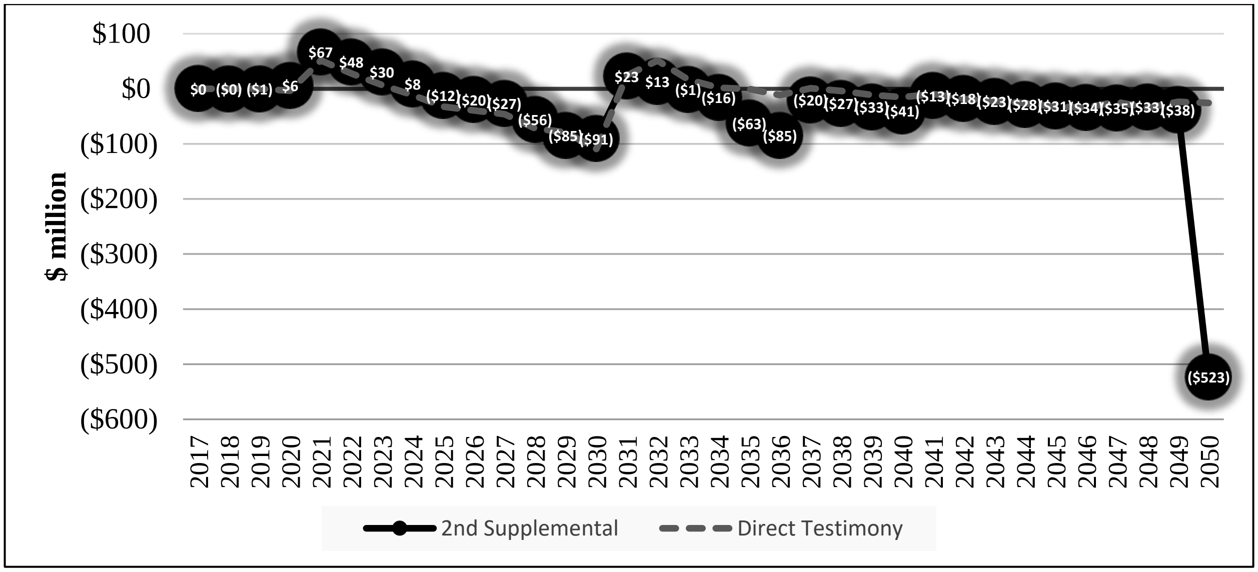
A. This reveals that the Combined Projects are actually more risky for customers than the Company's original analysis indicated. This is because, originally, the majority of the benefits accrued earlier. This can be seen by inspecting CORRECTED Figure 5-SD in the Company's Supplemental Direct Testimony, which I have included below for convenience (updated with the revised revenue requirements contained in the Company's Second Supplemental Direct Testimony). Notice the revenue requirements associated with the updated economic analysis contained with the Second Supplemental filing are higher in the earlier years and lower in the later years.

CORRECTED Figure 5-SD Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



Additionally, the Company also failed to plot an important data point, the 2050 year, for its updated economic analysis. The NPV of the plot above, as presented by RMP, is only $113 million, not the $167 million referenced by the Company. To get to the $167 million referenced by the Company, it needs to include a large, terminal value benefit in 2050, which I will discuss later. In Figure NLP-SR-6 below, I have updated the Company's CORRECTED Figure 5-SR below to include the 2050 year.

FIGURE NLP-SR-6 Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



As can be seen, the Company is relying heavily on the 2050 year to demonstrate positive economic benefit, in turn, placing significant risk exposure on the ratepayers. It is well understood that the further out in time an economic model extends, the more uncertain it becomes.[26] In the case of the Combined Projects, during the first 10 years of the Wind Projects, an additional benefit (the PTCs) is realized. After the PTCs expire, the remaining benefits are primarily driven by energy savings, which in turn depend heavily on commodity forecasts. In my direct testimony, I discussed the problems RMP has had accurately forecasting commodity prices, and particularly its tendency over the last eight years to overestimate future gas and power prices. If the commodity prices are overstated in the economic modeling for the Combined Projects, customer benefits are

[26] As the Company said in its application in Docket No. 20000-481-EA-15 (Record No. 14220): "While the Company's planning process is robust and designed to reasonably capture a wide range of uncertainties, the magnitude of various planning uncertainties grows further out into the IRP 20-year planning horizon."

overstated and the likelihood that customers will experience higher costs as a result of the proposed project increases.

Q. WHAT CHANGES CAN EXPLAIN THE INCREASED RISK IN THE COMBINED PROJECTS?

A. The primary driver of the increased risk is the change in the federal corporate tax rate. While the lower tax rate has made utility capital cheaper, it has also reduced the value of the PTCs generated by the Wind Projects. The PTCs are only generated during the first 10 years of eligible wind projects, and reducing the value of the PTCs directly translates into higher initial revenue requirements relative to the original analysis.

In addition to the reduced value of the PTCs, there are other changes which make the Combined Projects more risky. The Company reduced its load forecast and its commodity forecasts, which also reduce the value of the proposed projects.

Finally there is the issue of the newly assumed terminal value of the Wind Projects.

Q. PLEASE ELABORATE ON THE ISSUE WITH TERMINAL VALUE.

A. As I mentioned earlier, the terminal value is a new benefit not previously modeled by the Company. [redacted], [redacted].[27] RMP argues that remaining life of transmission assets required for interconnection could be reused to reduce costs to interconnect new projects that are developed at these existing

[27] WIEC Exhibit No. 304.1 (RMP Response to WIEC Data Request 12.5, Confidential Attachment Page 11 of 20).

sites in the future.[28] Consequently, the value of this is very speculative. In order for the value to be realized, a new project must be built at this site, which in turn would have additional costs which are not included in the Company's analysis. The Company does not state why this benefit was left out of the original analysis, but now the Company is claiming a [redacted][29] (nominal) benefit for all of its price-policy scenarios. Absent this previously unquantified benefit, the updated analysis would result in [redacted][30] less benefits in the 35 year NPV for the Medium Gas, Medium CO_2 scenario compared to the original analysis provided by RMP. In total, seven of the nine price-policy scenarios would actually result in less favorable economics relative to the original analysis filed by the Company when excluding the terminal value. The Commission should take extreme caution when considering the claimed additional benefits resulting from the updated economic analysis, because in large part they depend on an assumption about a benefit that occurs 35 years in the future. Table NLP-SR-3 below compares the updated economic analysis excluding the terminal value assumption to the original 35 year analysis present by RMP.

[28] Supplemental Direct Testimony of Rick Link at p. 17, l. 18 – p. 18, l. 9.
[29] RMP Witness Rick Link Confidential Workpaper, "EV2020 Second Supp Results Summary File – VOM adjusted CONF.xlsx" as referenced in response to WIEC Data Request 18.1(f).
[30] *Id.*

Table NLP-SR-3
2017 Wind RFP Nominal Revenue Requirement
PVRR(d)
Updated Economic Analysis Excluding Terminal Value
and Original Analysis
(Benefit)/Cost ($ million)

Price-Policy Scenario	35 Yr Excluding Terminal Value[31]	35 Year Original Analysis
Low Gas, Zero CO2	[redacted]	174
Low Gas, Medium CO2	[redacted]	93
Low Gas, High CO2	[redacted]	(194)
Medium Gas, Zero CO2	[redacted]	(53)
Medium Gas, Medium CO2	[redacted]	(137)
Medium Gas, High CO2	[redacted]	(317)
High Gas, Zero CO2	[redacted]	(341)
High Gas, Medium CO2	[redacted]	(351)
High Gas, High CO2	[redacted]	(595)

Q. DID THE COMPANY UPDATE ITS ANALYSIS TO ASSESS THE RISK ASSOCIATED WITH THE VARIABILITY OF WIND OUTPUT?

A. No. In WIEC Data Request 5.9, WIEC asked for a risk assessment related to the variability of wind output.[32] The Company objected and indicated it would instead perform this analysis later when the wind sites, equipment, and layout were more certain. However, the Company has yet to update its response and economic analysis to provide an assessment of this risk. In WIEC Data Request 18.2 WIEC again asked about a risk analysis surrounding the variability of wind output.[33] RMP responded stating that the

[31] *Id.*
[32] WIEC Exhibit No. 304.1.
[33] *Id.*

Company considered wind-performance risk by analyzing wind data for certain bids offered into the 2017R RFP however, the Company has still not quantified the economic risk associated with variable wind output. This is particularly concerning as the Combined Projects economics rely upon generating PTCs which, in turn, depend entirely upon the wind output in the first 10 years of operation. The Company admitted this is a risk to Customers in its response to WIEC Data Request 18.3 and also admitted that this risk is not present if a PPA based project was pursued and WIEC Data Request 18.4.[34]

Q. WHAT CAN CAUSE THE OUTPUT FROM THE FACILITIES, AND THUS THE AMOUNT OF PTCS, TO BE LOWER THAN WHAT THE COMPANY ASSUMED IN ITS MODELING?

A. A variety of factors, including curtailment. RMP stated in response to WIEC 17.7 that there is a Qualifying Facility ("QF") project with a cumulative total of 320 MW of new capacity that will interconnect to Segment D.2. However, RMP also stated that it has not reserved interconnection capacity for that 320 MW project on that line because the project needs additional transmission upgrades in order to come on line, which is scheduled to occur in 2024, according to RMP's interconnection queue. RMP's interconnection queue[35] indicates the project (Q0409A-D) has a signed interconnection agreement, and its power purchase agreements are executed.

If and when that project comes online, RMP must purchase its power because it is a QF. Additionally, RMP must curtail the Wind Projects before it curtails a QF, because QFs are "must take" resources that can only be curtailed in times of emergency. Thus,

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[34] WIEC Exhibit No. 304.1.
[35] Available at: http://www.oasis.oati.com/PPW/PPWdocs/pacificorplgiaq.htm

this additional 320 MW of QF capacity, for which RMP has not reserved interconnection capacity, may impact the generation of energy and PTCs from the Wind Projects.

Additionally, RMP has indicated that the Wind Projects are currently in various stages of assessing avian impacts, including data collection, initiation of discussions with the appropriate agencies, and development of mitigation plans.[36] Furthermore, bidders in the 2017R RFP did not submit a formal mitigation plan as part of their bid package. As a result, avian issues could require curtailment at any of the Wind Projects, causing the output and related PTCs to be lower than assumed in the Company's analyses.

Q. DID EITHER OF THE INDEPENDENT EVALUATORS EXPRESS ANY CONCERN REGARDING WIND OUTPUT?

A. Yes. The Utah Independent Evaluator ("Utah IE") stated in its conclusions:

> A common occurrence in the wind industry has been that the actual capacity factors of wind projects have been lower than the projected capacity factors. Such an occurrence for PPA options is not a major issues since the PPA project must conform to the contract requirements for meeting generation required levels or incur penalties. For BTA or benchmark options, failure to meet the target capacity factor is an issue. For one, the full PTC benefits may not be realized if generation is lower than projected. Failure to meet projected generation levels for these resources results in higher unit costs and raises the question of whether these projects would have been selected if realistic generation profiles were provided. While PacifiCorp retained Sapere to conduct such an analysis to ensure the generation levels and capacity factors are reasonable, the IE feels there is some risk associated with the [redacted] projects based on the Sapere analysis regarding wake losses. The IE feels that the generation levels of the benchmark and BTA options should be closely monitored to ensure they perform as proposed;[37]

[36] Supplemental Direct Testimony of Rick T. Link at p. 14, ll. 19-21 and RMP's Response to WIEC Data Request 14.27 (WIEC Exhibit No. 304.1).

[37] Confidential Exhibit No. 304.2.

Q. DID THE COMPANY ASSESS THE RISK OF CAPITAL COST OVERRUNS IN ITS UPDATED ECONOMIC ANALYSIS?

A. No.

Q. DID THE COMPANY PERFORM ANY SENSITIVITIES REGARDING ITS LOAD FORECAST USED IN ITS UPDATED ANALYSIS?

A. No.

Q. WHAT DO YOU CONCLUDE FROM THE COMPANY'S RISK ASSESSMENT?

A. The Company has not performed a reasonable assessment of projects risks that under its proposal will be borne by RMP customers. Absent this risk assessment, there is no reasonable way to grant the Company's request for a CPCN and preserve the public interest unless the Commission's order contains concrete ratepayer protections that address these risks.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE COMPANY'S UPDATED ECONOMIC ANALYSIS?

A. Nothing contained within the Company's updated economic analysis and supplemental testimony has changed the conclusion and recommendations presented in my direct testimony. In fact, when inspected more closely, the results show that the Combined Projects are more risky than the Company's direct testimony indicated. Furthermore, the Company has not performed any additional risk analysis even though it has had ample time to do so. Based on these facts alone, I recommend the Commission deny RMP's request for a CPCN.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE RISKS POSED TO RATEPAYERS BY THE COMBINED PROJECTS AND RATEPAYER PROTECTIONS?

A. Yes. In Oregon, the Independent Evaluator ("IE") issued a report on RMP's 2017R RFP and recommended, in part, certain ratepayer protections. Specifically, the Oregon IE stated:

> We have additional recommendations related to the RFP to help protect ratepayers from bearing undue risk. First, in order to protect ratepayers and ensure that they receive the benefits promised during this RFP we would recommend that all selected resources to be owned by the Company (i.e., BTAs and Benchmark resources) be held to their capital and operations and maintenance ("O&M") cost projections as provided with the bid. These amounts should be considered a "hard" cap, meaning that there will be no opportunity for the Company to collect additional costs even if they believe such expenditures were prudent. Doing so will help give the offers a risk profile much closer to that of a PPA, requiring the Company to take risks that typical wind developers take, and insulate ratepayers from the risk of cost overruns. Because the majority of construction costs will be covered under the BTA agreement or, in the case of Benchmarks, a negotiated engineering, procurement, and construction ("EPC") agreement, we feel this is a reasonable requirement.
>
> Second, ratepayers should not be harmed if either PacifiCorp or the project developers fail to acquire 100% of the value of the Production Tax Credit ("PTC"). PacifiCorp should provide an unconditional guarantee (i.e., not subject to force majeure or change in law) that ratepayers will receive the full projected value of the Production Tax Credit. This includes situations where (a) PacifiCorp cannot claim full PTC value or (b) PacifiCorp does not have the taxable income to use the full PTC value. Again, this is similar to what is expected of a third-party developer.
>
> Third, the Company should similarly be held to their cost projections for the Aeolus-to-Bridger D2 Segment. PacifiCorp's resource acquisition strategy here – which includes three projects that rely on the D2 Segment's construction for economic viability – is based on a certain cost

promise for this segment and the Company should be held to its promises.[38]

Q. WHAT IS YOUR RESPONSE TO THE OREGON IE'S RECOMMENDATIONS?

A. First, I think it is significant that the Oregon IE included these points in its evaluation at all. It is telling that the Oregon IE would recognize the risks the Combined Projects pose to ratepayers and recommend to the Oregon PUC that it take action to protect ratepayers.

That being said, I do not think the Oregon IE's recommendations go far enough. While of these protections align with those I recommended above and in my direct testimony, the Oregon IE's recommendations still leave ratepayers vulnerable to significant risk. This is particularly true, since the Oregon IE did not compare the Wind Projects against the potential benefits associated with the Solar PPA Option.

Q. GIVEN THE NEW INFORMATION REGARDING THE SOLAR PPA OPTION, ARE YOUR DIRECT TESTIOMNY RECOMMENDATIONS STILL SUFFICIENT TO PRESERVE THE PULIC INTEREST?

A. No. Given the new information and economic benefits presented by the Company with respect to the Solar PPA Option, I no longer believe the conditions I recommended in my direct testimony are adequate to protect ratepayers and maintain the public interest. Consequently, while I maintain the prudent action is for the Commission to deny RMP's request for a CPCN outright, should the Commission decide to approve RMP's request, I have a revised set of conditions that should be imposed upon RMP in order to preserve the public interest.

[38] Available at: http://edocs.puc.state.or.us/efdocs/HAH/um1845hah121349.pdf

Q. IS THERE ANY REASON TO CONSIDER PURSUING BOTH THE SOLAR PPA OPTION AND THE COMBINED PROJECTS TOGETHER?

A. No. The best case scenario stemming from the full nominal revenue requirements analysis as reported by the Company is an incremental $11 million in NPV benefits if the $2.25 billion Combined Projects are layered on top of the Solar PPA Option. On the other hand, in the worst case scenario, the $217 million in solar benefits are reduced by $424 million as a result of adding the Combined Projects, resulting in a *$208 million cost increase to customers*. Under no circumstances would pursuing both the Combined Projects and the Solar PPA Option be pursued simultaneously be in the public interest.

V. <u>RECOMMENDED CONDITIONS</u>

Q. WHAT CONDITIONS DO YOU RECOMMEND IF THE COMMISSION GRANTS A CPCN FOR THE COMBINED PROJECTS?

A. I recommend conditions similar to those identified in my direct testimony, updated in light of the results of the Solar PPA Option, which is less costly, less risky, and provides greater net benefits than the Combined Projects. Consequently, if the Commission approves the Combined Projects, it should only do so under the expressed conditions that ratepayers will be no worse off than if RMP were to actually propose and pursue the Solar PPA Option. Absent these conditions, a finding that the Combined Projects are in the public interest cannot be maintained. If the Commission grants a CPCN for the Combined Projects, such approval should include the following conditions:

1. Disallow rate based recovery for any turbines that are not commercially operational in time to receive 100% of the PTC benefits they are being constructed to capture, along with a capacity ratio share of any interconnection, transmission, distribution, and AFUDC costs.

2. Cap RMP's cost recovery on the capital cost of the Combined Projects from retail ratepayers, inclusive of the new generation and transmission facilities, as well as any interconnection costs, network upgrades, distribution costs, and AFUDC to $1,781.44 million installed cost; a reduction of $468 million, or approximately 21%, from the total cost of the Combined Projects.

3. Cap RMP's recovery of future O&M and capital expenditures related to the Combined Projects, QF Project cost recovery, and net fixed system costs to those levels assumed in the Company's updated economic analysis.

4. RMP should be required to include in its Base Rates and Net Power Costs, at minimum, the full (i) 10 years of PTCs, assuming at minimum a 21% federal corporate income tax rate, and (ii) energy benefits to customers for the life of the Wind Projects, both based on the assumed net capacity factors used in RMP's updated economic modeling.

5. Ratepayers should be guaranteed receipt of the full grossed up value of the PTCs without having to compensate RMP for return on any deferred tax assets that may be created as a result of RMP's inability to contemporaneously monetize PTCs to full value.

6. If RMP ceases construction of the Combined Projects, for whatever reason, no costs incurred are recoverable from customers.

Establishing the recoverable capital costs upfront, and capping future recovery of costs relating to the remaining assumptions used by RMP in its updated economic analysis, will increase the probability that customers will receive at least the same benefits and risk profile from the Combined Projects as they would from the Solar PPA Option (*i.e.*, what appears to be the truly least-cost, least-risk portfolio as evidenced by RMP's own nominal analyses). However, given customers cannot be protected from all of the risk of increased costs from the Company's proposal, it is essential that the Combined Projects be rigorously evaluated to determine whether there is a high probability that customers will be better off with the Combined Projects than without them.

VI. CONCLUSION

Q. AS CURRENTLY PROPOSED, CAN THE COMMISSION APPROVE RMP'S REQUEST FOR A CPCN WHILE PROTECTING THE PUBLIC INTEREST?

A. No.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE COMPANY REQUEST FOR A CPCN IN THIS PROCEEDING?

A. I recommend the Commission deny RMP's request for a CPCN. However, if the Commission believes that the Combined Projects should be undertaken, then conditions should be included on the Commission's approval to ensure the ratepayers are not burdened by paying for an inferior project. Absent these conditions, the public interest cannot be maintained.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL RESPONSE TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND NONTRADITIONAL RATEMAKING FOR WIND AND TRANSMISSION FACILITIES	**Docket No. 20000-520-EA-17 (Record No. 14781)**

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of Nicholas L. Phillips

Nicholas L. Phillips, being first duly sworn, on his oath states:

1. My name is Nicholas L. Phillips. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Wyoming Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Supplemental Response Testimony which was prepared in written form for introduction into evidence in the Public Service Commission of Wyoming, Docket No. 20000-520-EA-17.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

Nicholas L. Phillips

Nicholas L. Phillips

Subscribed and sworn to before me this 2nd day of March, 2018.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2021
Commission # 13706793

Maria E. Decker

Notary Public
Commission #: 13706793

My Commission Expires: May 5, 2021

UAE Data Request 3.2

Regarding PacifiCorp's Official Forward Price Curve (OFPC) issued in the 4th quarter of 2017 on or around December 29, 2017:

(a) Please provide a copy of the referenced price curve for gas and power markets where PacifiCorp transacts and for all years where a forecast was developed.

(b) Please provide a description of how the long-term natural gas price forecast (i.e. prices developed by 3rd party consultants used in the OFPC for periods extending beyond 72 months) was developed in the referenced OFPC.

(c) Please describe any changes to the long-term natural gas forecasting methodology that occurred in developing the referenced OFPC, relative to the OFPC that was used in the August 31, 2017 Supplemental Testimony of Rick T. Link in Docket No 17-035-23

(d) Please provide any memoranda or documentation in PacifiCorp's possession describing the methodologies the 3rd party consultants used to develop PacifiCorp's long-term natural gas price forecast in the referenced OFPC.

(e) Please state when the long-term natural gas price forecasts used in the referenced OFPC were developed by the 3rd party consultants.

(f) Please identify whether the long-term price forecasts used to develop the referenced OFPC include the impact of the passage of the Tax Reform Bill.

Response to UAE Data Request 3.2

The Company understands that the term "referenced OFPC" used throughout this request is intended to reference the Company's December 2017 official forward price curve (OFPC). Based on this understanding, the Company responds as follows:

(a) Please refer to Attachment UAE 3.2-1, which provides the Company's December 2017 OFPC.

(b) The December 29, 2017 OFPC was developed using 72 months of market forwards followed by 12 months (months 73 through 84) of a forwards-fundamentals blend that transitions to a pure fundamentals-based forecast starting in month 85. Blended prices for months 73 through 84 are calculated as an average of the preceding year's forward prices with the following year's fundamentals prices on a month-by-month basis.

The fundamentals-based portion of the OPFC, starting month 85, was developed by an expert third-party forecasting service and published in nominal dollars using PacifiCorp inflation indices. The expert third-party fundamentals forecast was supplied as part of the Company's ongoing subscription to receive multi-client "off-the-shelf" fundamentals-based forecasts on a regular basis.

(c) The long-term natural gas forecasting methodology used by PacifiCorp to develop the December 29, 2017 OFPC is unchanged relative to the OFPC that was used in the August 31, 2017 Supplemental Testimony of Company witness, Rick T. Link in Docket 17-035-23.

(d) Please refer to Confidential Attachment UAE 3.2-2.

(e) The long-term natural gas price forecast used in the December 2017 OFPC was produced by an expert third-party forecasting service, as part of its multi-client subscription service, on November 21, 2017.

(f) The impact of the Tax Reform Bill is not explicitly reflected in the gas price forecast, which was issued before the Tax Reform Bill was passed or signed, used in the December 2017 OFPC.

Confidential information is provided subject to Public Service Commission of Utah Rule 746-1-602 and 746-1-603.