Witness OCS – 4D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	))))))	**Docket No. 20-035-04** **Direct Testimony of Philip Hayet For the Office of Consumer Services**

PUBLIC REDACTED VERSION

September 2, 2020

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I. INTRODUCTION AND SUMMARY OF POSITIONS

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Philip Hayet and I am a Vice President and Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. PLEASE PROVIDE A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. I have included a summary of my education, experience, and expert testimony appearances in Exhibit OCS 4.1D.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Utah Office of Consumer Services ("OCS").

Q. HAVE YOU PREPARED ANY OTHER EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I have prepared Exhibit OCS 4.2D, which contains responses to data requests referenced in this testimony and the attached exhibits. I am also providing electronic copies of GRID Model databases and spreadsheet workpapers that were used to derive adjustments based on OCS's recommendations. These electronic files are confidential as they include information that Rocky Mountain Power identified as being confidential.

Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommended adjustments are as follows:[1]

1. I recommend that the Utah Public Service Commission ("PSC") should require Rocky Mountain Power ("RMP") to remove market depth constraints from the High Load Hours ("HLH") in the GRID model. These limits were originally intended to eliminate excess coal generation in Low Load Hours ("LLH") and are not applicable to HLH. This adjustment lowers Net Power Costs ("NPC") by $26.5 million on a total PacifiCorp basis or approximately $11.5 million on a Utah allocated basis.

2. The Energy Balancing Account ("EBA") true-up process reduces the need for further GRID adjustments. However, the OCS does not necessarily accept or endorse all other GRID modeling assumptions and methodologies used by RMP. The OCS reserves the right to challenge GRID modeling issues in additional testimony in this proceeding, as well as in other proceedings.

3. RMP experienced an outage at [redacted] Ratepayers should not be held responsible for the costs of [redacted] that may be the fault of RMP or a third party. The OCS recommends a permanent disallowance of any resulting repair related costs or capital investments. This adjustment lowers NPC by approximately [redacted] million on a Utah allocated basis.[4]

4. RMP experienced an outage at [redacted]

[1] The revenue requirements adjustments I present in this testimony are for illustrative purposes and are based on the RMP's requested rate of return, capital structure and other ratemaking conventions as applicable. OCS witness Ramas will input all of the pertinent data into the JAM model to develop the OCS' final recommended revenue requirements.

[2] OCS Confidential DR 17.5(e). This amount was associated with costs incurred during the test period. OCS Confidential DR 19.1 indicated that the total cost to repair the unit, which was completed in [redacted] was $[redacted] million.

[3] Confidential Attachment to DR OCS-3.2. Included in Confidential Exhibit OCS 4.2D, at page 4.

[4] OCS Confidential DR 17.5(e).

[5] Confidential Attachment to DR OCS-3.2. Included in Confidential Exhibit OCS 4.2D.

[6] OCS Confidential DR 19.2(c).

[redacted][7] Ratepayers should not be held responsible for the costs of [redacted][8] which appears to be the fault of RMP or a third party vendor. The OCS recommends a permanent disallowance of any resulting repair related costs or capital investments. This adjustment lowers NPC by approximately $[redacted] million on a Utah allocated basis.[9]

5. RMP has included costs of substantial new investments in repowered and new wind projects. Except for three projects, all of the others were pre-approved in Docket Nos. 17-035-39 and 17-035-40. Consequently, the OCS does not contest the rate treatment of the pre-approved projects. The three projects that were not pre-approved and the OCS rate treatment recommendations on the three projects are as follows:

a. Leaning Juniper: RMP's request for approval of the Leaning Juniper repowering project in Docket No. 17-035-39 was rejected by the PSC as "not being in the public interest" due to the questionable economic benefits of the project.[10] The PSC did not object to RMP proceeding with the project subject to it demonstrating prudence at the time it sought ratemaking approval. According to RMP witness Rick Link, in an August 2018 updated analysis the capital cost to repower the Leaning Juniper project turned out to be $[redacted] million less than the amount estimated by RMP in its February 2018 analysis in Docket No. 17-035-39.[11] RMP also increased its capacity factor estimate from [redacted] percent in its February 2018 analysis to [redacted] percent in its August 2018 analysis.[12] The OCS takes no position regarding the rate treatment of Leaning Juniper at this time.

b. Foote Creek I Repowering: RMP also requests rate recovery of the Foote Creek I repowering project, which was never considered as part of the 2017 repowering proceeding, Docket No. 17-035-39. Foote Creek I cost approximately [redacted] million[13] and required a pair of complicated transactions with the Eugene Water and Electric Board ("EWEB") and BPA. The project

[7] Confidential Exhibit OCS 4.2D, pdf page 10.
[8] OCS Confidential DR 17.5(d). This amount was associated with costs incurred during the test period. OCS Confidential DR 19.2(a) indicated that the total cost to repair the unit as of June 30, 2020 is $[redacted] million, and that final costs are still being determined.
[9] OCS Confidential DR OCS 17.5(d).
[10] PSC Order, May 25, 2018, Docket No. 17-035-39, Voluntary Request of Rocky Mountain Power for Approval of Resource Decisions to Repower Wind Facilities.
[11] Rick Link Direct Testimony at line 111.
[12] Id. at line 114.
[13] Confidential DR UAE 3.5.

uses wind turbine generators purchased from another Berkshire Hathaway affiliate. The project was not considered or approved in Docket No. 17-035-39 and its cost is [redacted] percent more on a dollars per kW basis than the PSC approved new wind projects from Docket No. 17-035-40 and [redacted] percent more than the PSC approved cost of repowered wind projects from Docket No. 17-035-39. Given RMP's failure to prove the project is the least cost alternative, the OCS recommends removal of the Foote Creek repowering costs from the test year and exclusion of Foote Creek repowering costs from RMP's rate base. This adjustment lowers NPC by approximately $[redacted] million on a Utah allocated basis.[14]

c. Pryor Mountain is a 240 MW wind project located in Montana that cost [redacted] million to build.[15] This project has not been approved in any prior PSC proceeding and was not a part of Docket No. 17-035-40. The project also uses wind turbine generators purchased from a Berkshire Hathaway affiliate. The overall project cost is more than [redacted] percent greater on a dollars per kW basis than the PSC approved new wind power projects. Given RMP's failure to prove the project is the least cost alternative, the OCS recommends removal of Pryor Mountain costs from the test year and exclusion of Pryor Mountain from RMP's rate base. This adjustment lowers NPC by approximately $[redacted] million on a Utah allocated basis.[16]

6. The OCS recommends the PSC reject RMP's proposal to include a true-up of PTCs in the EBA. The OCS believes this would further expand the scope of the EBA and establish the wrong incentives for RMP.

II. GRID MODEL – NPC BASELINE ISSUES

Q. SINCE THE EBA TRUE-UP PROCESS IS ULTIMATELY USED TO DETERMINE HOW MUCH RATEPAYERS WILL HAVE TO PAY FOR NET POWER COSTS, WHY SHOULD THE GRID MODEL RESULTS BE REVIEWED IN THIS PROCEEDING?

[14] See Hayet Workpapers.
[15] Robert Van Engelenhoven Confidential Direct Testimony at line 75.
[16] See Hayet Workpapers.

A. There are two reasons. First, while the EBA true-up does eventually correct under or over-collections relative to the GRID model NPC baseline, it is not reasonable to think there should be no limit to allowable GRID forecast errors. Large NPC forecast errors amount to a forced loan from ratepayers to RMP (or vice-versa). Second, it is normal to expect that existing customers will move out of RMP's service territory or go out of business, and that new customers will move in and create new businesses. It is simply a matter of fairness that GRID modeling and data issues should be kept to a minimum so as not to provide an advantage to existing customers at the expense of new ones, or vice-versa. Finally, the GRID model is used by RMP for other regulatory purposes such as computing avoided costs and it has also been proposed for use in setting distributed solar export credit rates. Consequently, ensuring that GRID is properly tuned has value beyond the general rate case setting. It has been many years since RMP's last GRC and it has changed many elements of its GRID modeling. Consequently, Kennedy and Associates conducted a limited examination of the GRID model in this proceeding.

Q. IN YOUR SUMMARY YOU MENTIONED MARKET DEPTH CONSTRAINTS. WHAT IS THE PURPOSE OF THESE CONSTRAINTS?

A. In the mid-2000 time period, RMP introduced market depth constraint modeling (also referred to as "market caps") as a means of forcing GRID to limit energy sales to market hubs in an attempt to bring GRID results more in line with actual operational results.

Q. HAS THE PSC EVER RULED ON MARKET DEPTH CONSTRAINTS?

A. Yes, in an avoided cost proceeding in 2005, the PSC agreed with PacifiCorp and issued an order in which it noted that market cap modeling was necessary to ensure coal units would back down to their minimum operating levels overnight instead of making excessive market sales during those night-time hours. In that Order the PSC stated:[17]

> We are persuaded by the evidence that coal resources are backed down in some hours and use of a production cost model, including market caps, is necessary to accurately identify the production costs avoided by a QF and thereby maintain ratepayer neutrality.

PacifiCorp contended at the time, that such constraints were necessary to prevent coal units from operating excessively in LLHs (also referred to as graveyard shift hours).[18] The input market caps essentially acted as another transmission limit and prevented sales to the market hubs during the low load night-time hours.

Q. DID YOU CONDUCT ANY ANALYSIS FOCUSED ON MARKET CAPS?

A. Yes. As discussed above, market caps were originally justified on the basis of needing to limit coal-fired generation during the LLH (the so-called "graveyard shift"). Even if market caps are appropriate they should only be modeled during LLHs, as the PSC originally authorized. As such, we performed a GRID run in which we removed the market caps at all markets during the HLHs but left them in place during the Low Load Hours. This adjustment lowered NPC by $26.5 million on a total PacifiCorp basis or approximately $11.5 million on a Utah allocated basis.

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[17] PSC Order, October 31, 2005, Docket No. 03-035-14, pgs. 12 and 13.

[18] Graveyard shift hours are discussed in Mr. Gregory Duvall's rebuttal testimony for PacifiCorp, Docket 09-035-23, November 12, 2009 at ln. 174.

We believe this is a reasonable modeling adjustment and recommend that RMP also be required to include it in its export credit analysis.

Q. ARE YOU RECOMMENDING REMOVAL OF ALL CONSTRAINTS ON MARKET SALES IN THE HLHS?

A. No I am not. Transmission limits often constrain the actual operation of PacifiCorp's generation resources and can limit off system sales. These constraints are already reflected in the GRID model and are not impacted by my recommended modeling.

Q. DID YOU IDENTIFY ANY OTHER GRID MODELING CONCERNS?

A. Yes, we identified one other issue related to RMP's GRID modeling, which is its proposed adjustment "to more accurately model system balancing transactions."[19] RMP asserts that it was necessary to adjust system balancing transactions to reflect the fact that GRID does not necessarily capture cost impacts that occur in system operations caused by PacifiCorp purchasing and selling energy in markets on a forward basis using standard block products (e.g. "7x24" or "6x16" transactions), but then balancing loads and resources on an hourly basis in real-time markets. RMP also claims this adjustment is necessary because without it, GRID's average purchase cost would be too low, and average sales revenue would be too high compared to actual results. RMP claims this causes GRID to understate NPC by $[redacted] million. RMP addressed its concern by deriving different forward market prices for purchases versus sales at the same GRID market hubs. In addition, RMP

[19] David G. Webb Direct Testimony beginning at ln. 348.

made a second GRID adjustment to increase the volume of system balancing transactions that were modeled in an attempt to align GRID results with historical actual operations.

Q. WHAT DID YOU CONCLUDE REGARDING RMP'S SYSTEM BALANCING TRANSACTION ADJUSTMENTS?

A. RMP's adjustments seem overly complex, and possibly over-reaching. As mentioned, to address this issue RMP made two adjustments to market cost inputs and purchase and sales volumes. The adjustments were intended to produce a [redacted] million increase in NPC based on a four-year historical average of actual and market index price differentials for system balancing sales and purchases. The ultimate result of RMP's modeling adjustment is that net power costs increased by $44 million,[20] which exceeded its [redacted] million goal by $[redacted] million. An interesting result of this adjustment, which overshot RMP's goal, is that coal and gas generation and costs increased, which is opposite the outcome RMP is trying to achieve by using market caps in the GRID model.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING RMP'S SYSTEM BALANCING TRANSACTION ADJUSTMENT?

A. RMP has not adequately justified its system balancing transaction adjustment and the OCS recommends that RMP should present an analysis in its rebuttal testimony justifying the nearly [redacted] million in "additional costs" that resulted from the system balancing transaction adjustment. It should also explain why it is appropriate to

[20] David Webb Direct Testimony at line 348.

include both a system balancing adjustment and a market cap adjustment, whose intended impacts on coal and gas generation directly conflict with one another. Furthermore, it should explain why it is necessary to add the additional complexities in its adjustment instead of possibly just using the [redacted] million figure as a line item adjustment based on historical data. Simply stated, RMP should provide additional clarification and supply reasonable and adequate justification for the adjustment, particularly in light of the conflicting impacts of this adjustment and the market cap adjustment.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE GRID MODEL?

A. Yes, there were also other issues that we examined (for example, RMP's solar profile modeling) that we determined would not have a substantial impact on net power costs in this case, particularly in light of the EBA true-up mechanism, but could have a more significant impact in other situations. Should GRID be utilized in other proceedings, the OCS reserves the right to revisit any GRID modeling issues that may arise at that time.

III. TWO MAJOR GENERATOR OUTAGE ISSUES

Outage 1

Q. PLEASE DESCRIBE THE FIRST OUTAGE, WHICH AFFECTED THE [redacted] UNIT.

A. [redacted] During the July 10 Technical Conference RMP indicated the unit has now been returned to service.

Q. HOW DID YOU BECOME AWARE OF THIS OUTAGE?

A. The GRID Minimum Filing Requirements ("MFRs") provide the data for all unit outages for the 48-month period that ended on December 31, 2019. As part of the GRID model overview, we submitted discovery requests related to unusually long outages as well as outages related to RMP or contractor errors. Based on this review and additional discovery, we found this outage was a major event resulting in substantial lost generation.

Q. DID RMP PERFORM A ROOT CAUSE ANALYSIS TO DETERMINE THE CAUSE OF THIS OUTAGE?

A. Yes. [redacted] assisted RMP to perform a Root Cause Analysis ("RCA"),[21] which is provided as part of Confidential Exhibit OCS 4.2D. The RCA report examined a number of possible causes for the failure, [redacted]

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[21] Confidential Attachment to DR OCS-3.2. Included in Confidential Exhibit OCS 4.2D.

[22] Confidential Exhibit OCS 4.2D, at page 4.

Q. DID RMP MAKE ANY FURTHER EFFORTS TO FIND THE CAUSE OF THE OUTAGE?

A. Yes. RMP has since contracted for another RCA which was initially expected to be completed by the end of August 2020 but is now expected to be completed in the first part of October 2020.[23] The report should be provided to OCS pursuant to OCS 3.2. The OCS reserves the right to further address this issue when this information becomes available.

Q. DOES THE RCA PROVIDE SUPPORTING EVIDENCE THAT A [redacted]

A. Yes. The RCA report identifies that there were [redacted]

Q. WHAT IS YOUR RECOMMENDATION?

A. Given that RMP [redacted] this outage should result in a disallowance of the resulting repair and replacement power costs. Ratepayers should not be held responsible for the costs of an [redacted]

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[23] Email from Jana Saba with PacifiCorp on August 19, 2020.
[24] Confidential Exhibit OCS 4.2D, at page 22.
[25] Id. at page 28.

[redacted] PacifiCorp may still be able to offset some or all of the costs that it wants to collect from ratepayers by receiving an insurance payout or by pursuing litigation with the manufacturer. Even if there is no avenue for recovery via insurance or litigation, ratepayers should not be held responsible for paying the costs of the outage that resulted from negligence on the part of RMP and/or a vendor.

Q. HAS THIS TYPE OF PROBLEM OCCURRED BEFORE AT ONE OF THE [redacted] GENERATORS?

A. Yes. The RCA identifies similar outages that occurred at the same type of [redacted] That event occurred in [redacted] and the RCA describes it as follows:[26]

[redacted]

Q. WOULD THE [redacted] BE CONSIDERED A SERIOUS EVENT?

A. Yes. [redacted] Given the extremely high cost and other consequences, utilities

[26] Id. at page 4.
[27] Confidential Exhibit OCS 4.2D, at page 4. Also, page [redacted]

typically go to great lengths to ensure that such situations do not occur, and it does not appear that PacifiCorp took sufficient precautions to ensure that it did not occur [redacted]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the PSC disallow any costs related to this outage event including all repair costs and replacement power costs. I have provided OCS witness Ramas with the information necessary to remove the repair related costs from the Test Year. The replacement power costs should be addressed in the appropriate EBA proceedings that cover the years 2019 and 2020.

Outage 2

Q. PLEASE DESCRIBE THE SECOND OUTAGE, WHICH AFFECTED THE [redacted] UNIT.

A. [redacted] Confidential Exhibit OCS-4.2D contains the RCA report[28] regarding the [redacted] outage.

> [redacted] (Emphasis added)

The report states:

> [redacted]

[28] Confidential Attachment to DR OCS-3.2. Included in Confidential Exhibit OCS 4.2D.
[29] Confidential Exhibit OCS 4.2D, pdf page 4.

[redacted][30]
(Emphasis added)

The report further states:

[redacted] (Emphasis added)

The unit returned to operation on August 2, 2020.

Q. WHAT WAS THE SEQUENCE OF EVENTS?

A. [redacted][32] The RCA report explained the sequence of events as follows:

[redacted]

[30] Id. at pdf page 5.
[31] Id. at pdf page 7.
[32] Id. at pdf page 5.
[33] Id. at pdf page 10.

[redacted]

Q. [redacted]

[redacted] [redacted]

Q. WHAT ARE YOUR CONCLUSIONS?

A. Since the damages resulted from [redacted], RMP appears negligent in [redacted]

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[34] Id. at pdf page 43, which is part of the [redacted] PacifiCorp states at pg. 9 of the pdf file that [redacted]

[35] Id. at pdf page 43.

[36] Id. at pdf page 10.

[redacted] PacifiCorp may still be able to offset some or all of the costs that it had hoped to collect from ratepayers by receiving an insurance payout or by pursuing litigation with the manufacturer. Even if there is no avenue for recovery via insurance or litigation, ratepayers should not be held responsible for paying the costs of the outage that resulted from negligence on the part of RMP and/or a vendor.

Q. WHAT DO YOU RECOMMEND REGARDING THIS OUTAGE EVENT?

A. Ratepayers should simply not be held responsible for the costs of an error of this magnitude. I recommend the PSC disallow any costs related to this outage event including all repair costs and replacement power costs. I have provided OCS witness Ramas with the information necessary to remove the repair related costs from the Test Year. The replacement power costs should be addressed in the appropriate EBA proceedings that cover the years 2019 and 2020.

Q. IT MAY BE ARGUED THAT MISTAKES OR ERRORS HAPPEN, DESPITE THE BEST EFFORTS OF RMP TO AVOID THEM. GIVEN THE SIZE OF THIS ADJUSTMENT, IS IT APPROPRIATE TO MAKE A DISALLOWANCE IN A SITUATION SUCH AS THIS?

A. Yes, it is. In this case RMP had to replace the [redacted] due to an avoidable [redacted] in relation to the overall Utah rate base, that may not always be the case.[37] It might not be out of the question in another similar situation with another unit that damage could amount to $100 million or more. It is a matter of negligence to fail to detect and correct an avoidable programming mistake that could destroy an entire turbine generator no matter how small it may be. RMP should be put on notice that it will not be able to pass on the costs of errors of this nature to ratepayers.

IV. WIND POWER PROJECTS

Q. ARE WIND GENERATION PROJECTS A SIGNIFICANT DRIVER OF THIS GENERAL RATE INCREASE?

A. Yes. RMP has made capital investments of approximately $3.5 Billion (Total PacifiCorp wide) in new and repowered wind generation and related transmission projects, which it proposes to recover in customer rates.[38] RMP proposes recovery of the costs of wind repowering projects that were approved in Docket No. 17-35-39, referred to as the Repowering docket, and the costs of new wind and related transmission projects that were approved in Docket No. 17-035-40, referred to as the New Wind/New Transmission docket.

Given the history of those projects and the PSC's prior approval, the OCS does not contest the ratemaking treatment of the approved new wind projects and repowering project costs. Irrespective of any disagreements that the OCS had in

[37] This amount was associated with costs incurred during the test period. OCS Confidential DR 19.2(a) indicated that the total cost to repair the unit as of June 30, 2020 is $[redacted] million, and that final costs are still being determined.
[38] RMP Technical Conference, July 10, 2020, pg. 4.

Docket Nos. 17-035-39/40, pre-approval of major generation projects is a vital part of the current regulatory process and should be honored in subsequent proceedings, absent evidence that costs were incurred imprudently, or that material facts were not revealed.

Q. HAS THE PSC PREAPPROVED ALL OF THE WIND PROJECTS THAT RMP SEEKS RECOVERY OF IN THIS PROCEEDING?

A. No. RMP seeks recovery of the costs of the Leaning Juniper repowering, which the PSC specifically did not approve in Docket No. 17-035-39, and two projects that were never a part of those, or any, proceedings: the Foote Creek I Repowering and the Pryor Mountain Project.

Q. PLEASE DISCUSS THE LEANING JUNIPER REPOWERING PROJECT.

A. The PSC denied the Leaning Juniper repowering project in Docket No. 17-035-39 because it believed it carried "a materially higher risk than the other eleven projects and that it will not be cost effective if energy production falls short of forecasts."[39] However, the PSC did not order RMP to abandon the project:

> *"We decline to approve the voluntary request for resource decision for the Leaning Juniper project. This decision does not mean PacifiCorp may not still pursue that project. It means that the Leaning Juniper repowering project will not have the protections afforded by Utah Code Title 54, Chapter 17, Part 4. If PacifiCorp chooses to implement the project, the project will be subject to a standard prudence review in future general rate cases. Our order declining to approve the project in this docket may not be interpreted to pre-judge that issue in any way."*[40]

[39] Report and Order Docket No. 17-035-39, May 25, 2018, page 20.
[40] Id.

Q. DOES OCS CONTEST THE PROPOSED RATE TREATMENT OF THE LEANING JUNIPER REPOWERING PROJECT?

A. No. According to the testimony of Mr. Link[41] the cost of the repowering project was [redacted] million, which was about [redacted] million less than the amount estimated by RMP in Docket No. 17-035-39. RMP also estimated that the expected gain in generation from the project [redacted][42] According to the information provided by RMP at the July 10, 2020 Technical Conference, the Leaning Juniper repowering was completed by the end of 2019, and the resource has been included in RMP's dispatch since that time. Therefore, it appears that the costs referenced above have been realized and are not simply estimates.

In this instance, the OCS believes the PSC's order provided the impetus for RMP to find ways to reduce the cost and improve the performance of the Leaning Juniper repowering project. Consequently, the OCS does not oppose nor endorse RMP's request. We do, however, have a concern that the benefits of Leaning Juniper, while now positive, appear to be small, and we share the PSC's concern that Leaning Juniper carries a higher risk that it will not be cost effective if energy production falls short of forecasts. Therefore, we reserve the right to reconsider our position at a later point in the proceeding, after reviewing other parties' testimony.

Q. PLEASE DISCUSS THE FOOTE CREEK I REPOWERING PROJECT.

[41] Direct Testimony of Rick Link at line 111.
[42] Id.

A. RMP requests rate treatment of the "repowering" costs of the Foote Creek project. This project was not considered in Docket No. 17-035-39 and apparently originated only *after* the PSC issued its decision in that proceeding. Consequently, RMP lacks any regulatory pre-approval from the PSC for this project.

Q. WAS THIS "REPOWERING" A MINOR UNDERTAKING?

A. No. This project cost approximately $[redacted] million[43], which is quite expensive for just a 41 MW project, and on a cost per kW basis it amounts to about [redacted]/kW ([redacted]). The project also required a pair of complicated transactions to be completed with EWEB[44] and BPA[45]. Furthermore, the use of the term "repowering" in the case of Foote Creek is also rather misleading. In fact, the project really amounts to the complete construction of new wind power turbines at the Foote Creek I site. The "repowering" project retains little but the land and some transmission infrastructure from the original project. The foundations, towers, generators, and energy collector-circuits all had to be replaced.[46]

According to RMP, the project was made possible because it was able to acquire the EWEB ownership share of the prior resource providing PacifiCorp full ownership of the Foote Creek I installation. In the end, RMP decided to replace the much older, smaller generators at the Foote Creek I site with newer, larger turbines (requiring all new generation related equipment at the site – turbines,

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[43] Hemstreet Confidential Exhibit TJH-1
[44] Eugene Water and Electric Board. EWEB was a part owner of Foote Creek and had to be bought out.
[45] Bonneville Power Administration. BPA has a contract to purchase power from Foote Creek until 2024 which had to be terminated, resulting in a buyout.
[46] Direct Testimony of Timothy Hemstreet, line 435.

towers and even the foundations.) In effect, RMP mostly built a new project after it demolished an older wind farm. This would not be terribly different from RMP building a new generator at the site of an older steam plant on its own initiative without any regulatory approval, and this should be viewed no less critically by the PSC.

Q. ARE THERE OTHER ASPECTS OF CONCERN REGARDING THIS PROJECT?

A. Yes. RMP witness Hemstreet states that the turbines were purchased from Berkshire Hathaway Energy Renewable ("BHER"), an affiliated company to PacifiCorp. Ultimately, when the Foote Creek project is complete, it will not use current 2020 model year WTGs, but instead will use older turbines as BHER originally purchased the turbines in 2016 from Vestas.[47] Mr. Hemstreet also explained that unless the turbines could be installed by December 31, 2020 the full production tax credits would have been in doubt at the time the project was being evaluated.[48] Foote Creek appears to have been expedited to meet the PTC deadline, even though it is expensive on a dollar per kW basis, and is projected to have small economic benefits.

The project also seems unusual in that some of the wind turbine generators ("WTGs") are sized at 2.0 MW, while others are 4.2 MW. In my experience it is usually the case that wind farms use multiple copies of the same turbine. It is easier and less costly to maintain and operate a fleet of turbines that are identical rather

[47] Id. at line 551.
[48] Id. at line 529.

than one that is an odd collection of more than one size design. The parts would not be interchangeable and maintenance procedures would differ between the different sized turbines. The reasons for using two different sized turbines are puzzling because Mr. Hemstreet testified the new project would not use all of the land available.[49] Consequently space constraints do not appear to have forced the selection of two different turbine sizes.

Q. ARE YOU CONCERNED ABOUT ANYTHING ELSE BESIDES THE USE OF DIFFERENT TURBINE TYPES AND SIZES?

A. Yes. I am concerned about the fact that this repowering project raises some troubling questions. The first is whether RMP acted in ratepayers' or shareholders' best interests when it moved forward with the project. It seems plausible that unless BHER could find a way to dispose of some of the "left over" turbines it bought in 2016, the market value of the turbines would (at the time) have been expected to drop after the December 31, 2020 expiration date for receiving full PTC benefits.[50] The second question is whether the transaction was priced at the lesser of cost or fair market value. The final question is why RMP chose to use four-year-old turbines when newer models would likely have been even more efficient. The ultimate question really is – was there any compelling need to rush into this project in 2019? This is particularly relevant, given RMP knew that it would likely propose to add even more renewable resources based on a competitive solicitation process

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[49] Id. at line 618.
[50] The IRS extended the expiration date by one year on May 27, 2020 due to the COVID-19 pandemic.

when it filed its 2019 IRP in October 2019, just a short period of time after it made its decision to repower Foote Creek 1 in June 2019.[51]

Q. HAVE COVID-19 RELATED ISSUES IMPACTED THE PROJECT?

A. Mr. Hemstreet acknowledges that impacts are possible but as yet unknown. He also indicated that contractors have issued force majeure notices that have the potential to impact equipment supply and transport logistics.[52] Consequently, there is some uncertainty as to the final in service date for the project and possibly the final cost. At this time, we cannot be certain whether the project will be completed by the start of the 2021 test year or not.

Q. DID RMP PRESENT ANY EVIDENCE REGARDING THE ECONOMICS OF THE FOOTE CREEK I REPOWERING PROJECT?

A. Yes. RMP presented economic analyses of the project, circa August 2019, that showed a very modest benefit of the project (less than [redacted]) under the Low Natural Gas, Zero Carbon scenario.[53] However, RMP did not present any updated analyses showing the current economics of the project or more importantly, showing that the project is among the least cost options that could have been acquired. As mentioned, RMP's economic results are modest to begin with, and given the severity of the COVID-19 pandemic and the ensuing economic recession, it is likely the benefits of the project would be even smaller. These economic issues are also relevant to the Pryor Mountain project that is discussed

[51] Direct Testimony of Timothy Hemstreet, line 497.
[52] Id. at line 909.
[53] Link Confidential Testimony, line 230.

next. The implications of these issues and ratemaking treatment recommendations will be discussed there.

Q. PLEASE DISCUSS THE PRYOR MOUNTAIN PROJECT.

A. According to RMP witness Mr. Robert Engelenhoven, Pryor Mountain is a 240 MW wind project that is projected to cost approximately $[redacted] million[54] and is located about 60 miles south of Billings, Montana. Mr. Engelenhoven describes the project as follows:

> The project consists of 57 Vestas Model V110-2.0 MW safe harbor, 21 Vestas Model V110-2.2 MW safe harbor, four General Electric Model 2.3-116 MW safe harbor, and 32 Vestas model V110-2.2 MW follow-on wind turbine generators ("WTGs").[55]

All but the four General Electric WTG's were acquired from BHER. The four GE turbines were purchased directly by RMP in 2016.[56] A unique feature of the project is that a Facebook subsidiary, Vitesse, LLC, has contracted to purchase all RECs from the project for 25 years under Oregon PUC Schedule No. 272.[57]

Q. DO YOU HAVE ANY CONCERNS REGARDING THE PRYOR MOUNTAIN PROJECT?

A. Yes, the acquisition of this project and its use of disparate types of WTG's acquired from both RMP's affiliate BHER and PacifiCorp, has the appearance of having being negotiated so that BHER could use its and PacifiCorp's remaining WTG equipment stocks before the PTC's started phasing out and before BHER and

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[54] Engelenhoven Confidential Testimony at line 75.
[55] Id at line 52.
[56] Id. at line 95.
[57] Joelle Steward Direct Testimony at line 241.

PacifiCorp's pre-purchased inventory of WTGs started losing significant value. Ratepayers should not be expected to provide a return on such high cost assets so that a Berkshire Hathaway affiliate and PacifiCorp itself could avoid a loss.

Q. WAS PRYOR MOUNTAIN EXAMINED IN EITHER DOCKET NO. 17-035-40 OR IN PACIFICORP'S 2019 IRP?

A. No.

Q. HOW DOES RMP EXPLAIN NOT SEEKING PRE-APPROVAL OF THE FOOTE CREEK I AND PRYOR MOUNTAIN IN UTAH?

A. RMP stated at the July 10 Technical Conference that the projects were time limited opportunities which precluded obtaining regulatory approval. I am aware of at least one other case in which RMP identified a time limited opportunity and brought it to the PSC's attention to seek approval.[58] The PSC ultimately issued an order just four short months after RMP filed its application seeking approval of its request. This demonstrates that in the past regulators have been willing to work with RMP in such situations and it does not appear there is a good reason RMP could not have made a similar request for these projects.

Q. DOES RMP CONTEND THE PRYOR MOUNTAIN PROJECT PROVIDES ECONOMIC BENEFITS?

A. Yes. However, those benefits are negligible in relation to the project cost under the Low Gas Zero Carbon scenario.[59]

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[58] PSC Order, August 1, 2008, Docket No. 08-035-35, Acquisition of the Chehalis Combined Cycle Plant, In Re: In the Matter of the Request of Rocky Mountain Power for a Waiver of the Solicitation Process and for Approval of Significant Energy Resource Decision.

[59] Link Confidential Direct Testimony, line 306.

Q. WHY DO YOU REFERENCE THE LOW GAS ZERO CARBON SCENARIO RESULTS RATHER THAN OTHER SCENARIOS?

A. It is widely believed that the current economic conditions with high levels of unemployment ranks as one of the worst recessions since the Great Depression of the 1930's. Whether or not it lasts as long, it is clear that current economic activity continues to be greatly depressed, and the current pandemic may contribute to the acceleration of a move away from fossil fuels to more renewables. In turn, that will likely continue to cause oil and gas commodity prices to remain relatively low. Also carbon taxes are nowhere on the horizon at the present time and continue to be highly uncertain. Consequently, the Low Gas Zero Carbon scenario is the scenario that should receive considerable attention and is the one most likely aligned with current conditions. Furthermore, PacifiCorp and other utilities have modeled the imposition of carbon taxes for many years now, only to continually delay the forecast implementation dates.

Q. ARE THERE ANY OTHER REASONS THAT CARBON TAX SCENARIOS SHOULD BE DISCOUNTED IN THE ECONOMIC ANALYSIS OF FOOTE CREEK I AND PRYOR MOUNTAIN?

A. Yes. While it is appropriate to include consideration of the possibility of a Congressional response to climate change, that does not imply that carbon taxes are the only means by which Congress could take action to address this issue. There are also other means by which Congress could act including tax credits, direct subsidies, or government loan guarantees. Some if not all of these have been used by Federal and/or State governments. For example, residential customers have received tax credits for purchase of electric cars, solar panels, energy efficient heating systems and insulation. At least one utility I know of received Federal loan guarantees to support construction of a new nuclear plant. As regards to wind power, PTC's have been in place since 1992. PTC's have been extended twelve times after having originally been scheduled to terminate in 1999.[60]

This is a classic "carrot or stick" situation. Incentives to implement CO_2 mitigation technologies are the carrot, while carbon taxes are the stick. It should be clear by now that Congress prefers the "carrot" approach to dealing with the issues of renewable resources and global climate change rather than the "stick" - carbon taxes.

Instead of a carbon tax intended to increase the costs of CO_2 emissions, Congress has implemented Production Tax Credits ("PTC's") to encourage development of more renewable resources. RMP has assured us that these projects will in fact be eligible for PTC's. Consequently, the environmental benefits of these projects already are embedded in the actual PTC's and are already being modeled by RMP. Inclusion of hypothetical carbon taxes could be viewed as a double counting of the CO_2 mitigation benefits of these wind projects.

Q. IN TERMS OF A CARBON TAX EQUIVALENT, HOW MUCH IS THE CURRENT 2.5 CENTS PER KWH PTC WORTH TO THE PRYOR MOUNTAIN OR FOOTE CREEK I PROJECTS?

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[60] The Renewable Electricity Production Tax Credit: In Brief, Congressional Research Service, April 29, 2020, at pg. 3, https://crsreports.congress.gov/product/pdf/R/R43453/19.

A. For PacifiCorp, much of the energy offset by new wind projects would otherwise be generated from coal. The PTC incentive of $25/MWH (or 2.5 cents per kWh) for wind resources roughly equates to a carbon tax of approximately $23/Ton[61] applied to the CO_2 emissions at a typical coal unit. This assumes use of a typical coal unit average heat rate of 10.5 MBTU/MWH, and an assumed 210 pounds per MBTU CO_2 production rate. In effect, a production tax credit can be seen as a rather large carbon reduction credit, or in other words, an indirect application of a carbon tax.

Q. PLEASE SUMMARIZE THIS POINT.

A. RMP's estimate of the benefits of the Foote Creek I and Pryor Mountain projects are rather low when PTC benefits are considered, and low gas and no CO_2 taxes are assumed. If history is any guide to what may happen in the future (PTCs extended 12 times already), then it is likely that PTCs will be extended again, and CO_2 taxes will not be imposed.[62] PacifiCorp's assumptions of the disappearance of PTC's and the subsequent appearance of carbon taxes serve to make the decisions about these projects appear to be more urgent than they really are. The point of this is not to suggest that PacifiCorp should overhaul its IRP processes on the basis of this rate case, but to indicate that it has not demonstrated that Foote Creek 1 and Pryor Mountain are the least cost resources available, and that in order to show any demonstrable benefits PacifiCorp has to rely on unrealistically high CO_2 and gas

[61] $25/MWH equates to a $23/Ton CO_2 tax based on this calculation. ($25/MWH * 2000 lbs/Ton) / (10.5 MBTU/MWH * 210 lbs/MBTU) = 23 $/Ton

[62] Even during the Obama Administration when the Democratic party held a majority in both houses, Congress was unable to pass a Carbon Tax.

price forecasts, which are inconsistent with current economic conditions. Based on the more realistic low gas, zero CO_2 forecasts, Utah customers will pay [redacted] million[63] more in costs during the test year period, when the net power cost savings are netted against the higher capital costs that customers will incur, and it will be years before customers will begin to see even a small benefit from the Foote Creek I and Pryor Mountain projects.

Q. ARE THERE OTHER REASONS WHY YOU BELIEVE THAT FOOTE CREEK I AND PRYOR MOUNTAIN SHOULD BE REJECTED?

A. Yes. It is likely these projects would not have been found to be least cost if evaluated within a competitive solicitation process. Based on the confidential information contained in the testimonies of Messrs. Hemstreet (See TJH-1 and TJH-3) and Engelenhoven, the approved capital cost of new wind resources (Cedar Springs II, Ekola Flats and TB Flats) is approximately $[redacted]/kW.[64] The approved cost of the repowered wind projects was $[redacted]/kW.[65] In contrast the capital cost of Pryor Mountain is [redacted]/kW[66] and Foote Creek is [redacted]/kW[67]. The approved projects were acquired based on RMP's solicitation for new wind resources. Pryor Mountain and Foote Creek I cost [redacted] percent and [redacted] percent more per unit of capacity respectively than the approved new wind projects. If Foote Creek I is viewed as a repowering project, its cost is [redacted] percent more than the PSC approved

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[63] See Hayet Workpapers.
[64] $[redacted]

repowering projects. I think this is clear evidence that a solicitation is a far lower cost mechanism for resource acquisition than buying older technology WTG's from an affiliate with a need to find a place to use them before having to write down their value due to the loss of PTCs.

Q. FROM A POLICY PERSPECTIVE WOULD IT BE WISE FOR THE PSC TO APPROVE RATE RECOVERY FOR FOOTE CREEK I AND PRYOR MOUNTAIN?

A. No. The Foote Creek I and Pryor Mountain projects amount to a proposal for a departure from the regulatory practices that have been in place in Utah for many years now. These practices were implemented to avoid some of the problems of the previous utility regulatory paradigms and practices. Integrated Resource Planning ("IRP") and pre-approval of new power plants have become standard practices within the industry. In Utah, utilities were provided the ability to request advanced PSC approval of resource projects when the Energy Resource Procurement Act ("the Act"), 54-17-402 was codified in 2005. This legislation has allowed utilities to obtain pre-approval of major projects, which has lowered risks for the benefit of both utilities and customers. In the instant case of Foote Creek I and Pryor Mountain, RMP simply went back to the old paradigm: *build first and answer questions later.* RMP bought the Pryor Mountain project from a third party developer and acquired most of the WTG's from affiliates, which raises numerous questions about PacifiCorp's motives as discussed above.

Also, as discussed above, the Foote Creek Project is expensive, its projected economic benefits are expected to be fairly small, and RMP has failed to demonstrate that the Foote Creek project is the least cost alternative available. In failing to meet its burden of proof, this project, which relies significantly upon affiliate acquisitions, should be rejected and should not be eligible for cost recovery in this case. Furthermore, RMP is now dealing with force majeure claims by vendors, which may impact the cost and schedule of the projects. Approving these projects under these circumstances would amount to encouraging similar resource acquisition practices by RMP in the future.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend disallowance of RMP's request to recover costs of the Foote Creek I repowering project and the Pryor Mountain project from ratepayers. I estimate the Foote Creek disallowance to be [redacted] million on a Utah Allocated basis. For Pryor Mountain the disallowance would be [redacted] million on a Utah Allocated basis.[68] Both figures are net of NPC benefits as computed in the GRID model. As mentioned previously, the revenue requirements adjustments I present in this testimony are for illustrative purposes and are based on the RMP's requested rate of return, capital structure and other ratemaking conventions as applicable. OCS witness Ramas will input all of the pertinent data into the JAM model to develop the OCS' final recommended revenue requirements.

Q. DOES THIS MEAN RMP COULD NEVER GAIN RATE TREATMENT FOR THESE PROJECTS?

[68] See Hayet Workpapers.

A. No. RMP could prove the need for additional resources as part of its IRP and bid them into the next wind resource solicitation, or even include them in the on-going 2020 All Source RFP if the projects were able to meet all eligibility requirements. RMP could also sell the output of these resources to other utilities or to RMP under its approved avoided cost tariff.[69]

V. PROPOSAL TO EXPAND THE EBA TO INCLUDE PTCS

Q. DO YOU AGREE WITH RMP'S PROPOSAL TO INCLUDE A TRUE-UP OF PTC'S IN THE EBA?

A. No. This proposal is problematic because it expands the scope of the EBA beyond power costs and provides yet another true-up mechanism to insulate RMP from regulatory lag. Further, it would create a further disincentive for RMP to maximize the output of renewable projects. For example, WTG O&M costs are not pass-through items while PTC's would be under RMP's proposal. This creates a perverse incentive for RMP to save money by deferring maintenance because it would not be penalized by the loss of PTC's should WTG output fall as a result.

Likewise, this policy would protect RMP from construction delays on approved wind projects. Should the projects not be in service for the entire year, ratepayers would have paid the full annual revenues requirements for the WTG's, but the true up would deduct any PTC's that would have otherwise been generated

[69] Note that while there is an 80 MW size limit to qualify as a QF, the prior developer that sold the Pryor Mountain development project to PacifiCorp had originally structured the project as three 80 MW projects for a total of 240 MWs.

during the delay. This is not the same as PTC variances due to variances in wind levels, which should be part of any true-up. Indeed, if the PSC adopts RMP's PTC proposal, wind generation (and PTCs) during any construction delay should be imputed in the EBA. In summary, OCS recommends rejecting RMP's request to expand the EBA to include PTCs.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.