ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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August 8, 2023

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

RE: Docket No. 17-035-40
Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision
Reply Comments on Report for Calendar Year 2022

On May 24, 2023, Rocky Mountain Power (the "Company") filed its New Wind and Transmission Report for Calendar Year 2022 ("Report") in compliance with the Public Service Commission of Utah ("Commission") June 22, 2018 Order and October 22, 2018 Order on Reporting Requirements (together, the "EV2020 Orders"). In accordance with the Amended Notice of Filing and Comment Period issued by the Commission on June 26, 2023, Rocky Mountain Power submits its reply comments in response to the comments filed by the Division of Public Utilities ("Division") and the Office of Consumer Service ("Office"). Overall the Division and the Office recommend that the Commission approve the Report as meeting the reporting requirements, offering a few comments and recommended changes. The Company submits these reply comments to address the comments and recommendations. Attached to these reply comments is a revised New Wind and Transmission Report for Calendar Year 2022 ("Revised Report") that incorporates some of the recommendations and corrections discussed below.

Confidentiality

The Division notes that the Company filed the entire Report as a confidential Excel file even though some of the tabs in the file were previously determined to be non-confidential. The Division states they are neutral on this practice, but recommends the Commission consider reviewing the confidential/non-confidential status of the Report.

In response to the Division, the Company revisited its practice of filing the entire Report as confidential although it contains tabs that have been designated as non-confidential. Since the Report is presented in an Excel spreadsheet, the Company believes that keeping the tabs in a single file is beneficial since it allows information to be linked among the tabs. To address the Division's concerns, the Company will continue to file the Report in its native form as a confidential Excel file with all the tabs; however, the Company will ensure that the non-confidential information is filed in a manner that makes it accessible to the public, such as a pdf of the non-confidential tabs.

The Company has reviewed the original confidential designations that were established in the Report template[1] and found two changes. Tab (ii) PTC benefits was originally designated as non-confidential, but since the Report now includes the PTC benefits on a turbine-by-turbine basis, the information is now confidential. Similarly, Tab (vi) has been expanded since the reporting template was approved to provide the 230kV network upgrade costs on a project-by-project basis. This information is now confidential. The Company revised the reporting requirements in Table 1 to reflect the updated confidentiality changes. As requested by the Division, the Company also added a new footnote to the Frequency column to memorialize the May 25 due date of the Report.

Table 1
Revised Reporting Requirements of the Combine Projects (Docket No. 17-035-40)

Required Information	Start Date	Frequency[1]	Duration	Confidentiality
(i) final project costs for each specific project	12 ME CY 2020, due 4/30/2021	annually	**10 years**	Confidential
(ii) realized PTC benefits	12 ME CY 2020, due 4/30/2021	annually	**10 years**	**Confidential**
(iii) realized energy benefits	12 ME CY 2020, due 4/30/2021	annually	**10 years**	Non-confidential
(iv) transmission costs of the Transmission Projects that are actually offset by revenues derived from wholesale transmission customers	12 ME CY 2020, due 4/30/2022	annually	**10 years**	Non-confidential
(v) payments for any damages, including liquidated damages	Included in annual reports, as applicable	annually	**10 years**	Confidential
(vi) contribution to the 230 kV Network Upgrades' total cost from interconnection customers	12 ME CY 2020, due 4/30/2022	annually	**10 years**	**Confidential**
(vii) annual revenue requirement associated with the Aeolus to Bridger/Anticline Line and the incremental transmission revenue resulting from the construction of the line	12 ME CY 2020, due 4/30/2022	annually	**10 years**	Non-confidential
(viii) wind operations and maintenance costs associated with the Wind Projects that PacifiCorp owns	12 ME CY 2020, due 4/30/2021	annually	**10 years**	Non-confidential
(ix) realized value of RECs sold	12 ME CY 2020, due 4/30/2021	annually	**10 years**	Confidential

Footnote 1: beginning 5/25/2023, the report will be due annually on May 25.

Report Corrections

The Company identified three corrections to the Report. First, the Division found a formula error in Tab (i) in cell C131 which was corrected in the Revised Report. Second, the Division and Office requested the Company explain why the actual production tax credits ("PTC") were significantly lower than projected at the time of the filing. In reviewing the inquiry, the Company discovered that the original PTC projections included in the Report were grossed up to account for tax impacts while the actual PTC amounts were not grossed up, making the two numbers not directly comparable. The Company has corrected the actual PTC information for calendar years 2020, 2021 and 2022 to gross up the PTCs for the tax impacts. Last, the Company updated the 230kV Network Upgrade costs on Tab (i) to reflect additional project costs that were booked during 2022, consistent with Tab (vi).

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[1] Docket No. 17-035-40, Rocky Mountain Power's Reply Comments Regarding Proposed Reporting System, October 15, 2018, p. 4.

Tab (i) Final Project Costs

Tab (i) of the Report included final project costs for the individual projects. With the exception of a $9.7 million adjustment to TB Flats and a $24k adjustment to the 230kV network upgrades, there were no changes to the final project costs from the CY 2021 report. The Company believes the project costs to be final at this time.

In its comments, the Division requested that the Company add the project costs that were included in the last general rate case ("GRC") to the Report as "the relevant point of comparison."[2] The Company respectfully disagrees with the Division that the project costs at the time of the last GRC should be added to the reporting requirements. The Company believes that expanding the Report to include GRC information is outside the scope of what the Report is intended to highlight and adds unnecessary complexity. When the Commission discussed the reporting requirements in its June 22, 2018 Order, it quoted the independent evaluator's testimony who stated that "the capital cost of PacifiCorp's benchmark resources should be closely scrutinized to ensure that the costs on which the economic evaluation was based are realistic."[3] Therefore, the Company interprets this to mean the purpose of the Report is to allow parties to evaluate and scrutinize the costs and benefits that were projected at the time of preapproval with those that actually occur. Therefore, the Report was designed to compare the costs and benefits projected at the time of preapproval with those that actually occur each calendar year. The Company understands that a party may want to compare the information in the Report to what was included in a GRC or other regulatory filing as a point of reference and does not object to a party performing that exercise. However, the Company strongly prefers that a party wishing to make such a comparison request the information in discovery.

Due to the timing of the GRC and the in-service dates of the projects, adding the project costs that were included in the case is likely to complicate the Report without providing a meaningful comparison. For example, the TB Flats wind project was not in service until July 2021 - the middle of the test period used in the GRC. Therefore, although the updated project costs at the time of the case was $633.4 million, it was only partially reflected in rates. Furthermore, the cost of the projects that was used for purposes of the GRC was just an updated forecast using a combination of actuals incurred during the base period of the 12 months ended December 31, 2019, and projected balances through the end of the CY 2021 test period. Adding even more complexity, rate base in a general rate case is based on a 12-month average for capital balances. The Company is unclear if the Division is asking the Company to include the updated projection of project costs, or the amount actually reflected in rates. Regardless, the Company asserts this is not appropriate to include in the reporting requirements.

The Office states that the Report lacks explanation for the variances on the project costs and requests that the Company further explain. The Office also suggests the Company be required to include the explanation for the variances in the Report going forward as part of an overall recommendation to include variance explanations for all tabs of the Report.

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[2] Docket No. 17-035-40, Division of Public Utilities Confidential Action Request Response, July 25, 2023, p. 5.

[3] Order page 35.

Table 2 below provides a summary of the final project costs compared to the projected project costs at the time of preapproval.

TABLE 2: Comparison of Final Project Costs to Projections at Time of Preapproval

Project	Final Project Costs	Projection	Variance $	Variance %	Date Used and Useful
Total Cedar Springs BTA	270,772,043	277,409,000	(6,636,957)	-2.4%	12/8/2020
Total Ekola Flats	328,898,207	314,478,919	14,419,288	4.6%	12/30/2020
Total TB Flats	627,885,760	597,284,147	30,601,613	5.1%	circuit by circuit, July 2021
Total 230kv Network Upgrades	93,850,070	92,200,000	1,650,070	1.8%	11/1/2020
Total Aeolus to Bridger/Anticline Line	646,876,562	679,214,938	(32,338,376)	-4.8%	11/4/2020
Total EV2020 Projects	1,968,282,642	1,960,587,005	7,695,637	0.4%	

As shown, the final project costs for each project were very close to the original projections. And in total the EV2020 projects were less than one half of a percent different from the original projections. The largest cost overage was for TB Flats wind project, which has been discussed in detail in Docket Nos. 20-035-04[4] and 21-035-42. For the variances on the other projects, all of the projects were reasonably close to their original projection, given the size and scope of projects constructed under the considerable challenges of the COVID-19 pandemic.

<u>Tab (ii) PTC Benefits</u>

As noted by the Division and the Office, the Report showed significantly lower PTC benefits than projected at the time of preapproval. After grossing up the actual PTCs to be comparable, the remaining difference in PTCs is approximately 11 percent lower than forecast, which is mostly attributable to Cedar Springs and TB Flats wind projects.

[redacted]

<u>Tab (iii) Energy Benefits</u>

The Office requested the Company provide an explanation for the increased energy benefits. Calendar year 2022 was impacted by extreme events such as the December winter cyclone, heat waves in July, August and September and the ongoing drought in the western United States. The conflict in Ukraine also impacted regional natural gas prices. These factors led to a significant increase in market prices as shown in the Report. For example, September and December heavy

[4] *See* Docket No. 20-035-04, Rebuttal Testimony of Timothy J. Hemstreet, October 5, 2020.

load hour $/MWh market prices were $238.38 and 234.24, respectively. In 2021, the $/MWh prices for September and December were $82.39 and $53.97. The higher market prices result in the value of the energy produced by the wind projects to increase substantially.

Tab (iv) Transmission Costs

The Office concluded that the percentage of revenues from third party wholesale transmission customers has increased from 12 percent at the time of preapproval to 20.3 percent in CY 2021 and 22 percent in CY 2022. The Office acknowledges that a higher percentage is a benefit to customers, but requested the Company provide an explanation for the increase.

The percentage of revenues from third party wholesale transmission customers has steadily increased in the recent past. There are many variables that impact the percentage of third-party long-term transmission revenue compared to the Company's own use of transmission including, but not limited to, unforeseen market and economic impacts, customers decisions to utilize PacifiCorp transmission and thus, termination of existing contract rights, future impacts of new generation interconnections and parties responsible for transmission, growth in retail customers for the Company that exceeds or is less than the growth for retail customers served by third-party transmission customers.

For the recent increase, the primary drivers include an increase in the percentage of third-party long-term point-to-point ("PTP") and network transmission revenues when compared to PacifiCorp's own use. Third-party, long-term PTP capacity increased almost 49 percent from 2017 to 2021, and the Company terminated approximately 24 percent of its long-term PTP capacity during that time. From 2021 to 2022, the Company terminated approximately 27 percent of its long-term PTP capacity, while third-party, long-term PTP capacity increased by almost 4.6 percent.

Tab (viii) – Wind O&M

The Report includes actual wind operations and maintenance ("O&M") expense for the wind projects. The Office requests that the Company include a baseline by which the actual expenses can be compared, suggesting either the original projections at the time of preapproval or the projections included in the last GRC. The Company agrees with the Office that a baseline would be a beneficial addition to the Report. The Revised Report includes the projections that were used at the time of preapproval.

Other Recommendations

The Division also recommends the Commission require the Company to include "more thorough footnotes or similar narrative tools to explain and clarify important numbers and labels and provide some insight into how crucial numbers are calculated. The report would be easier for all readers to understand and require fewer questions of RMP if the meaning and origin of numbers were clearer to the reader."[5]

The Company is committed to helping the Division and other parties in their review of the Report.

[5] Docket No. 17-035-40, Division of Public Utilities Action Request Response, July 25, 2023, p. 8.

When preparing the Report, the Company was mindful of areas where it anticipated questions may arise and included footnotes on many of the tabs of the Report. The Company attempted in good faith to provide adequate information in the Report. Due to the volume of information included in the Report, the Company asserts that trying to anticipate all areas that will be of interest to the parties and adding detailed explanations will be overly burdensome and nearly impossible to achieve without making the Report voluminous. Parties can request additional information to any aspect of the Report by contacting the Company informally or submitting discovery.

For example, the Company included a footnote in the Report on Tab (i) to explain why a $9.7 million reduction was booked to the plant balance for TB Flats during CY 2022. The Company then received an informal request from the Division for additional information on this reduction. The Company facilitated a meeting with its subject matter experts and the Division and Office where the topic was discussed in detail. The Company believes this process is efficient and preferrable over the Company attempting to include the requested level of detail within the Report.

The Company also attempted to include formulas, references to source documents and descriptive labeling within the Report to the extent possible. A large amount of information is provided in the Report, much of it directly from the Company's accounting records. Providing detailed calculations for all numbers would be challenging, and it is unclear to the Company what parts of the Report the Division would consider to be "important" and "crucial" numbers.

Similarly, the Office states that "the Report lacks explanations for variances (variances from originally forecasted amounts)"[6] and the OCS requests that the Company include explanations for project costs reflected in Tabs (i) through (ix) that vary from amounts in other dockets, such as in a GRC.

Since the reporting is required is for ten years, including cost and benefit information from all the general rate cases and other potential proceedings involving these projects (such as annual energy balancing account and renewable energy credit balancing account filings) would be burdensome and quickly make the Report extremely voluminous. For reasons described earlier, the Company urges the Commission to keep the Report focused on comparing the relevant cost and benefit projections from the time of preapproval to the actual costs and benefits instead of expanding the Report to be a repository for every time information on the EV2020 projects is included in a regulatory filing over a decade.

Conclusion

The Company remains committed to working with the Division, Office and other interested parties to provide additional information for any aspect of the Report through discovery and informal discussions and requests. The Company respectfully requests the Commission issue an order:

1. Acknowledging the Revised Report as complying with the relevant reporting requirements;

[6] Docket No. 17-035-40, Comments of the Office of Consumer Services, July 25, 2023, p. 2.

2. Reject the recommendations of the Division and the Office to expand the reporting requirements beyond what the Company has agreed to in these reply comments; and,
3. Approve the Company's request for a change in confidential designation from non-confidential to confidential for the information in Tabs (iv) and (vi).

Sincerely,

Joelle Steward
Senior Vice President, Regulation and Customer/Community Solutions

Report for Calendar Year 2022 – Non-Confidential Information

Energy Benefits (NPC)
12 Months Ended December 31, 2020 - Actuals - Note: resources were on-line in December 2020

Cedar Springs Wind II (BTA)

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Dec-20	36,603	$ 26.15	$ 0.39	$ 942,925	27,879	$ 25.84	0.39	$ 709,726	$ 1,652,651
12 Months Ended December 31, 2020				**$ 942,925**	12 Months Ended December 31, 2020			**$ 709,726**	**$ 1,652,651**

Energy Benefits (NPC)
12 Months Ended December 31, 2021 - Actuals

Cedar Springs Wind II (BTA)

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Jan-21	42,665	23.93	0.19	1,012,788	38,073	23.23	0.19	877,050	1,889,838
Feb-21	26,253	95.18	0.19	2,493,853	22,606	56.64	0.19	1,276,040	3,769,893
Mar-21	28,651	22.49	0.19	639,016	28,480	23.56	0.19	665,577	1,304,593
Apr-21	30,166	29.19	0.19	874,899	25,724	30.95	0.19	791,243	1,666,142
May-21	20,525	27.94	0.19	569,473	22,611	25.20	0.19	565,585	1,135,058
Jun-21	15,635	147.86	0.19	2,308,768	15,820	46.31	0.19	729,568	3,038,337
Jul-21	13,762	114.19	0.19	1,568,864	13,829	52.62	0.19	725,004	2,293,868
Aug-21	21,979	71.23	0.19	1,561,357	22,761	47.59	0.19	1,078,771	2,640,128
Sep-21	24,934	82.39	0.19	2,049,688	22,742	57.56	0.19	1,304,776	3,354,464
Oct-21	33,293	53.88	0.19	1,787,608	26,872	51.25	0.19	1,372,202	3,159,809
Nov-21	43,294	62.83	0.19	2,712,133	37,834	45.76	0.19	1,724,085	4,436,218
Dec-21	49,822	53.97	0.19	2,679,472	41,740	43.83	0.19	1,821,726	4,501,198
12 Months Ended December 31, 2021				**20,257,918**	12 Months Ended December 31, 2021			**12,931,628**	**33,189,546**

Energy Benefits (NPC)
12 Months Ended December 31, 2022

Cedar Springs Wind II (BTA)

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Jan-22	47,222	52.20	0.27	2,452,163	41,656	41.21	0.27	1,705,368	4,157,530
Feb-22	39,775	51.83	0.27	2,050,799	31,007	44.62	0.27	1,375,272	3,426,071
Mar-22	40,987	43.19	0.27	1,759,344	30,047	43.03	0.27	1,284,679	3,044,023
Apr-22	35,848	56.98	0.27	2,032,775	25,380	60.83	0.27	1,536,986	3,569,761
May-22	25,986	73.50	0.27	1,902,955	22,206	66.99	0.27	1,481,548	3,384,503
Jun-22	15,580	82.09	0.27	1,274,696	12,090	64.49	0.27	776,394	2,051,090
Jul-22	12,541	111.24	0.27	1,391,645	12,336	68.45	0.27	841,112	2,232,756
Aug-22	13,867	133.89	0.27	1,852,893	12,223	80.66	0.27	982,557	2,835,450
Sep-22	19,823	258.38	0.27	5,116,586	13,350	94.73	0.27	1,261,058	6,377,644
Oct-22	22,626	61.98	0.27	1,396,320	17,471	56.90	0.27	989,425	2,385,745
Nov-22	21,588	71.56	0.27	1,539,062	21,989	72.65	0.27	1,591,564	3,130,626
Dec-22	35,708	234.24	0.27	8,354,725	32,215	224.20	0.27	7,213,959	15,568,684
12 Months Ended December 31, 2022				**31,123,962**	12 Months Ended December 31, 2022			**21,039,921**	**52,163,884**

Notes:
HLH = heavy load hour
LLH = light load hour
MWh = megawatt-hours

Incremental Generation = Wind Plant Generation MWh – Base Wind Plant Generation MWh

$$NPC\ Incremental\ Savings = [Incremental\ Gen_{HLH} \times (Monthly\ Market\ Price_{HLH} - Integration\ Costs)] + [Incremental\ Gen_{LLH} \times (Monthly\ Market\ Price_{LLH} - Integration\ Costs)]$$

$$NPC\ Benefit = NPC\ Incremental\ Savings \times EBA\ Sharing\ Band, if\ applicable$$

Where:

Incremental Generation = The increase in generation at the wind plants due to the Wind Projects
Wind Plant Generation MWh = The wind plant generation associated with the Wind Projects
Base Wind Plant Generation MWh = The wind plant generation associated with the Wind Projects that is included in base rates.
$Incremental\ Gen_{HLH}$ *= The increase in generation at the wind plant due to the Wind Projects during heavy load hours*
$Incremental\ Gen_{LLH}$ *= The increase in generation at the wind plant due to Wind Projects during light load hours*
$Monthly\ Market\ Price_{HLH}$ *= Heavy load hour monthly market price*
$Monthly\ Market\ Price_{LLH}$ *= Light load hour monthly market price*
Integration Costs = Wind integration costs from the most recent IRP

Heavy load hours ("HHL") and light load hours ("LLH") are defined by the Western Electricity Coordinating Council ("WECC") as: HLH – 0600 through 2200 hours, Monday through Saturday, excluding North American Electric Reliability Corporation ("NERC") holidays, and LLH – 2200 through 0600 hours, Monday through Saturday, and all day Sunday and on the six NERC Holidays (New Year's, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas). For all hours, Pacific Prevailing Time is used.

Energy Benefits (NPC)
12 Months Ended December 31, 2020 - Actuals - Note: resources were on-line in December 2020

Ekola Flats Wind

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Dec-20	20,201	$ 26.15	$ 0.39	$ 520,406	15,853	$ 25.84	$ 0.39	$ 403,565	$ 923,971
12 Months Ended December 31, 2020				**$ 520,406**	12 Months Ended December 31, 2020			**$ 403,565**	**$ 923,971**

Energy Benefits (NPC)
12 Months Ended December 31, 2021 - Actuals

Ekola Flats Wind

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Jan-21	42,907	23.93	0.19	1,018,532	35,889	23.23	0.19	826,740	1,845,272
Feb-21	57,301	95.18	0.19	5,443,198	38,244	56.64	0.19	2,158,758	7,601,955
Mar-21	38,803	22.49	0.19	865,440	25,877	23.56	0.19	604,745	1,470,186
Apr-21	36,206	29.19	0.19	1,050,076	19,428	30.95	0.19	597,585	1,647,661
May-21	30,348	27.94	0.19	842,015	17,557	25.20	0.19	439,165	1,281,181
Jun-21	21,290	147.86	0.19	3,143,823	8,009	46.31	0.19	369,350	3,513,173
Jul-21	17,850	114.19	0.19	2,034,895	4,446	52.62	0.19	233,087	2,267,983
Aug-21	24,986	71.23	0.19	1,774,970	12,403	47.59	0.19	587,848	2,362,818
Sep-21	22,131	82.39	0.19	1,819,269	17,022	57.56	0.19	976,603	2,795,872
Oct-21	34,352	53.88	0.19	1,844,469	21,869	51.25	0.19	1,116,727	2,961,196
Nov-21	53,262	62.83	0.19	3,336,573	42,169	45.76	0.19	1,921,630	5,258,204
Dec-21	66,750	53.97	0.19	3,589,874	47,805	43.83	0.19	2,086,431	5,676,305
12 Months Ended December 31, 2021				**26,763,136**	12 Months Ended December 31, 2021			**11,918,668**	**38,681,804**

Energy Benefits (NPC)
12 Months Ended December 31, 2022

Ekola Flats Wind

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Jan-22	51,145	52.20	0.27	2,655,878	46,781	41.21	0.27	1,915,182	4,571,060
Feb-22	55,855	51.83	0.27	2,879,884	42,485	44.62	0.27	1,884,363	4,764,247
Mar-22	48,260	43.19	0.27	2,071,534	25,749	43.03	0.27	1,100,915	3,172,449
Apr-22	51,257	56.98	0.27	2,906,548	23,413	60.83	0.27	1,417,867	4,324,415
May-22	39,952	73.50	0.27	2,925,685	20,790	66.99	0.27	1,387,075	4,312,760
Jun-22	32,270	82.09	0.27	2,640,207	16,575	64.49	0.27	1,064,412	3,704,619
Jul-22	19,192	111.24	0.27	2,129,690	11,243	68.45	0.27	766,587	2,896,277
Aug-22	19,752	133.89	0.27	2,639,240	8,879	80.66	0.27	713,746	3,352,987
Sep-22	25,980	258.38	0.27	6,705,791	8,454	94.73	0.27	798,575	7,504,367
Oct-22	36,231	61.98	0.27	2,235,926	20,739	56.90	0.27	1,174,500	3,410,427
Nov-22	46,836	71.56	0.27	3,339,056	31,241	72.65	0.27	2,261,224	5,600,279
Dec-22	72,512	234.24	0.27	16,965,885	50,137	224.20	0.27	11,227,262	28,193,147
12 Months Ended December 31, 2022				**50,095,324**	12 Months Ended December 31, 2022			**25,711,707**	**75,807,032**

Notes:
HLH = heavy load hour
LLH = light load hour
MWh = megawatt-hours

Energy Benefits (NPC)
12 Months Ended December 31, 2020 - Actuals - Note: resources were on-line in December 2020

TB Flats Wind

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Dec-20	17,356	$ 26.15	$ 0.39	$ 447,116	12,761	$ 25.84	$ 0.39	$ 324,851	$ 771,967
12 Months Ended December 31, 2020				**$ 447,116**	12 Months Ended December 31, 2020			**$ 324,851**	**$ 771,967**

Energy Benefits (NPC)
12 Months Ended December 31, 2021 - Actuals

TB Flats Wind

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Jan-21	33,133	23.93	0.19	786,514	22,891	23.23	0.19	527,319	1,313,833
Feb-21	53,192	95.18	0.19	5,052,858	33,817	56.64	0.19	1,908,875	6,961,733
Mar-21	47,415	22.49	0.19	1,057,527	32,473	23.56	0.19	758,884	1,816,411
Apr-21	43,885	29.19	0.19	1,272,795	20,277	30.95	0.19	623,692	1,896,487
May-21	40,657	27.94	0.19	1,128,042	25,023	25.20	0.19	625,918	1,753,960
Jun-21	35,485	147.86	0.19	5,239,932	16,367	46.31	0.19	754,800	5,994,733
Jul-21	34,595	114.19	0.19	3,943,848	12,196	52.62	0.19	639,379	4,583,227
Aug-21	50,105	71.23	0.19	3,559,388	28,375	47.59	0.19	1,344,850	4,904,238
Sep-21	46,288	82.39	0.19	3,805,084	31,098	57.56	0.19	1,784,185	5,589,269
Oct-21	44,510	53.88	0.19	2,389,884	28,947	51.25	0.19	1,478,160	3,868,045
Nov-21	89,593	62.83	0.19	5,612,512	74,310	45.76	0.19	3,386,287	8,998,799
Dec-21	122,730	53.97	0.19	6,600,529	83,178	43.83	0.19	3,630,272	10,230,801
12 Months Ended December 31, 2021				**40,448,914**	12 Months Ended December 31, 2021			**17,462,621**	**57,911,535**

Energy Benefits (NPC)
12 Months Ended December 31, 2022

TB Flats Wind

	(a) HLH Generation (MWh)	(b) HLH Monthly Market Price ($/MWh)	(c) Integration Cost ($/MWh)	(d) HLH Energy Benefits (Loss) (a) x ((b) - (c))	(e) LLH Generation (MWh)	(f) LLH Monthly Market Price ($/MWh)	(g) Integration Cost ($/MWh)	(h) LLH Energy Benefits (Loss) (e) x ((f) - (g))	(i) Total Energy Benefits (Loss) (d) + (h)
Jan-22	93,163	52.20	0.27	4,837,806	81,903	41.21	0.27	3,353,052	8,190,857
Feb-22	101,682	51.83	0.27	5,242,724	77,550	44.62	0.27	3,439,623	8,682,346
Mar-22	93,009	43.19	0.27	3,992,360	51,409	43.03	0.27	2,198,025	6,190,384
Apr-22	111,036	56.98	0.27	6,296,339	49,569	60.83	0.27	3,001,846	9,298,186
May-22	73,867	73.50	0.27	5,409,280	45,722	66.99	0.27	3,050,497	8,459,778
Jun-22	55,683	82.09	0.27	4,555,769	30,734	64.49	0.27	1,973,673	6,529,442
Jul-22	39,384	111.24	0.27	4,370,348	22,762	68.45	0.27	1,551,993	5,922,341
Aug-22	36,348	133.89	0.27	4,856,779	19,294	80.66	0.27	1,550,966	6,407,745
Sep-22	48,310	258.38	0.27	12,469,468	15,632	94.73	0.27	1,476,618	13,946,086
Oct-22	61,761	61.98	0.27	3,811,461	34,034	56.90	0.27	1,927,428	5,738,890
Nov-22	84,028	71.56	0.27	5,990,566	57,863	72.65	0.27	4,188,124	10,178,690
Dec-22	117,191	234.24	0.27	27,419,586	87,052	224.20	0.27	19,493,699	46,913,285
12 Months Ended December 31, 2022				**89,252,486**	12 Months Ended December 31, 2022			**47,205,544**	**136,458,030**

Notes:
HLH = heavy load hour
LLH = light load hour
MWh = megawatt-hours

Transmission Costs

Adapted from the attachment included in PacifiCorp's response to data request DPU 11.6 in Docket No. 17-035-40. Formula rate references refer to the true-up.

Transmission Costs
12 Months Ended December 31, 2021

Line	Description/Source	Calculation	CY 2021[2]	CY 2022
1	**Annual Transmission Revenue Requirement**:			
	Formula rate Appendix A, Line 169 (Net Zonal Revenue Req.)[1]		505,859,967	515,421,550
2	**12 CP Monthly Peak** (MW):			
	Formula rate Appendix A, Line 170		14,400	14,468
3	**Rate** ($/MW-year)	[Line 1 / Line 2]	**35,129**	**35,626**
4	($/MW-month)	[Line 3 / 12]	2,927	2,969
5	**Total PacifiCorp ESM Network Load volume plus Behind-The-Meter**:			
	Formula rate Attachment 9b, cols. 'e' and 'Behind-the-Meter'		106,749	111,039
6	**Total Revenue from PacifiCorp ESM Network Load**	[Line 5 x Line 4]	312,500,264	329,654,028
7	As percent of all network and long-term point-to-point	[Line 6 / Line 1]	61.8%	64.0%
8	**PacifiCorp ESM long-term point-to-point volume**:			
	Formula rate Attachment 9b, column 'g1'		29,827	23,395
9	**Loss rate**:			
	PacifiCorp OATT Schedule 10		4.04%	4.07%
10	**PacifiCorp ESM long-term point-to-point volume with losses:**	[Line 8 x (1 + Line 9)]	31,032	24,347
11	**Total Revenue from PacifiCorp ESM long-term point-to-point**			
	(with losses)	[Line 10 x Line 4]	90,844,051	72,282,214
12	As percent of all network and long-term point-to-point	[Line 11 / Line 1]	18.0%	14.0%
13	ESM network and LT PTP as percent of total network and LT PTP	[Line 7 + Line 12]	79.7%	78.0%
14	**Percentage of revenues from third party wholesale transmission customers**	[1 - Line 13]	20.3%	22.0%

Footnotes:
1. does not include short-term revenue
2. information provided is estimated and is pending due to the Company's FERC formula rate filing

Annual Revenue Requirement - Aeolus to Bridger/Anticline Line and Incremental Transmission Revenue

			(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	$-Thousands		**2021 Energy Gateway**				**2022 Energy Gateway**			
Line No.		Reference	**Total Company**	**Factor**	**Factor %**	**Utah Allocated**	**Total Company**	**Factor**	**Factor %**	**Utah Allocated**
	Plant Revenue Requirement									
1	Capital Investment	Footnote 1	643,365,947	SG	44.1357%	283,954,064	646,337,400	SG	44.3158%	286,429,435
2	Depreciation Reserve	Footnote 1	(6,834,853)	SG	44.1357%	(3,016,610)	(18,006,041)	SG	44.3158%	(7,979,517)
3	Accumulated DIT Balance	Footnote 1	(8,848,578)	SG	44.1357%	(3,905,382)	(19,829,928)	SG	44.3158%	(8,787,787)
4	Net Rate Base	sum of lines 1-3	627,682,515			277,032,072	608,501,431			269,662,132
5	Pre-Tax Rate of Return	line 29	8.994%			8.994%	8.994%			8.994%
6	Pre-Tax Return on Rate Base	line 4 * line 5	56,451,708			24,915,357	54,726,624			24,252,528
7	Wholesale Wheeling Revenue	Footnote 2	(14,877,592)	SG	44.1357%	(6,566,329)	(15,782,708)	SG	44.3158%	(6,994,230)
8	Operation & Maintenance		-	SG	44.1357%	-	-	SG	44.3158%	-
9	Depreciation		11,147,247	SG	44.1357%	4,919,916	11,201,420	SG	44.3158%	4,963,996
10	Property Taxes	line 30 * prev. yr-end net plant	5,814,012	GPS	43.5941%	2,534,568	5,753,021	GPS	43.7963%	2,519,611
11	Wind Tax		-	SG	44.1357%	-	-	SG	44.3158%	-
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**58,535,375**			**25,803,511**	**55,898,357**			**24,741,906**
	Net Power Cost									
13	NPC Incremental Savings		-	SG	44.1357%	-	-	SG	44.3158%	-
	PTC Benefit									
14	PTC Benefit		-	SG	44.1357%	-	-	SG	44.3158%	-
15	PTC Benefit in Base Rates		-	SG	44.1357%	-	-	SG	44.3158%	-
16	Net PTC	sum of lines 14 and 15	-			-	-			-
17	Gross- up for taxes	line 16 * (line 28 - 1)	-			-	-			-
18	PTC Revenue Requirement	sum of lines 16 and 17	-			-	-			-
19	**Rev. Requirement**	sum of lines 12, 13, 18	58,535,375			25,803,511	55,898,357			24,741,906
	Adjustment for EBA Pass-through									
20	Wholesale Wheeling Revenue	line 7				(6,566,329)				(6,994,230)
21	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%
22	EBA Pass-through	line 20 * line 21				(6,566,329)				(6,994,230)
23	NPC Incremental Savings	line 13				-				-
24	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%
25	EBA Pass-through	line 23 * line 24				-				-
26	**Rev. Reqt. after EBA Pass-through**	line 19 - line 22 - line 25				32,369,840				31,736,135
27	Federal/State Combined Tax Rate		24.587%				24.587%			
28	Net to Gross Bump up Factor = (1/(1-tax rate))		1.3260				1.3260			
29	Pretax Return		8.994%				8.994%			
30	Property Tax Rate	Footnote 3	0.91%				0.91%			
31	Utah SG Factor	Footnote 4	44.1357%				44.3158%			
32	Utah GPS Factor	Footnote 4	43.5941%				43.7963%			

Footnotes:
1) Average Balances
2) Wholesale Wheeling Revenue = percentage of third-party transmission revenues from tab (iv) Transmission Costs, line 14 * Aeolus to Bridger/Anticline line revenue requirement
3) Calculated from Docket No. 20-035-04
4) Allocation factors are from the Company's Results of Operations reports for the respective filing periods.

Wind O&M Costs for PacifiCorp Owned Projects
12 Months Ended December 31, 202

Resource	Total O&M	UT Allocated	Months
Cedar Springs Wind II (BTA	103,17:	45,047	< 1 month
Ekola Flats Win	10,058	4,391	< 1 month
TB Flats Winc	997	435	< 1 month
TOTAL	114,22	49,874	

Wind O&M Costs for PacifiCorp Owned Projects
12 Months Ended December 31, 202

Resource	Total O&M	UT Allocated	Months
Cedar Springs Wind II (BTA	4,304,60:	1,899,86	12
Ekola Flats Win	2,849,11	1,257,47	12
TB Flats Winc	3,990,29	1,761,14	see fn1
TOTAL	11,144,00	4,918,48	

Footnote
1) TB flats was place into service on a circuit by circuit basis from December 2020 through July
as shown in tab (ii) PTC Benefits

Wind O&M Costs for PacifiCorp Owned Projects
12 Months Ended December 31, 202

	Actual			*Projected at Preapproval*
Resource	Total O&M	UT Allocated	Months	Total O&M
Cedar Springs Wind II (BTA	5,169,10	2,290,73	12	3,778,87
Ekola Flats Win	3,002,81:	1,330,72	12	6,029,31
TB Flats Winc	5,403,11:	2,394,43:	12	12,589,88
TOTAL	13,575,03	6,015,88		22,398,07

CERTIFICATE OF SERVICE

Docket No. 17-035-40

I hereby certify that on August 8, 2023, a true and correct copy of the foregoing was served by electronic mail to the following:

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