REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-1SR)
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Rick T. Link

Oregon IE Report

May 2018

BATES WHITE
ECONOMIC CONSULTING

PUBLIC VERSION

THE INDEPENDENT EVALUATOR'S FINAL REPORT ON PACIFICORP'S 2017R REQUEST FOR PROPOSALS

Presented to:
OREGON PUBLIC UTILITY COMMISSION

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I. INTRODUCTION AND SUMMARY

A. INTRODUCTION

This is Bates White's Final Closing Report on PacifiCorp's 2017R Renewables RFP ("2017R RFP" or the "RFP"). Bates White served as the Independent Evaluator ("IE") for this RFP. The primary purpose of this report is to provide the Oregon Public Utility Commission ("Commission") with the IE's recommendation with respect to the acknowledgement of PacifiCorp's ("the Company's") selection of a Final Shortlist. This report is also intended to provide the Commission with a record of the development and evaluation process for both the Initial and Final Shortlists.

B. RECOMMENDATION REGARDING THE FINAL SHORTLIST

Bates White recommends that the Commission acknowledge the Final Shortlist as presented. Based on the results of portfolio optimization modeling, stochastic risk analysis, and review of viability factors, the Company has selected four projects for the Final Shortlist representing approximately 1,300 MW. These projects are

- TB Flats I & II – A proposed 500 MW wind project located in Carbon and Albany Counties, Wyoming. This project is to be developed by PacifiCorp's Benchmark team based on a site developed by Invenergy.

- Cedar Springs – A 400 MW wind project located in Converse County, Wyoming. This project is to be developed by NextEra Energy Acquisitions. Half of the project will be sold to PacifiCorp under a Build-Transfer Agreement ("BTA") while the other half will sell power to PacifiCorp under a Power Purchase Agreement ("PPA").

- Ekola Flats – a proposed 250 MW project located in Carbon County, Wyoming. This project is to be developed by PacifiCorp's Benchmark team based on a site developed by Invenergy.

- Uinta – A proposed 161 MW wind project located in Uinta County, Wyoming from Invenergy Wind Development. The project will be sold to PacifiCorp under a BTA Agreement. Unlike the top three projects this project does not require the completion of the Aeolus-to-Bridger/Anticline Segment ("D2 Segment") in order to be deliverable to PacifiCorp's system.

Our recommendation is based on the following points.

- The selected bids represent the top offers that are viable under current transmission planning assumptions and provide the greatest benefit to ratepayers as determined by the Company's System Optimizer ("SO") and Planning and Risk ("PaR") models.

- The selected bids represent the best viable options from a competitive process. The RFP received bids from 13 suppliers offering a total of 18 projects representing about 4,900 MW. Some of these projects offered multiple options. In total there were 59 bid options presented. Offers were received from projects both inside and outside the Company's constrained area in Wyoming and included variations in design such as different turbines and contract structures.

- Our independent analysis confirmed that the selected bids were reasonably priced and, while not the lowest-cost offers, were the lowest-cost offers that were viable under current transmission planning assumptions. Our analysis included the creation of our own cost models for each bid option, a review of PacifiCorp's models and a review of the terms and conditions of each bid.

- Two company-sponsored Benchmark bids were chosen and we took special care to confirm those selections. We confirmed the accuracy of the Benchmark costs and scoring and provided the Commission with a complete review of all costs of each project prior to bid receipt. We also confirmed the Benchmark's status by: (a) reviewing the project's Initial and Final Shortlist scores and models, (b) independently scoring the project's non-price characteristics, (c) comparing the cost and output of the project to recent third-party bids, and (d) evaluating the bid costs in our own cost model. The bids were also disciplined by the fact that a third-party bidder submitted a competing offer for a BTA for each project.

- To the best of our knowledge the RFP aligns with the Company's Integrated Resource Planning ("IRP") process, as well as its 2017 IRP Plan, which was filed on April 4, 2017 ("2017 IRP"). The Initial and Final Shortlist analyses used current assumptions from the IRP. The models used to select the Final Shortlist were the same models that the Company uses in its IRP process. While it is our understanding that the action plan from the 2017 IRP (which includes this resource acquisition strategy) is approved, we have yet to see a final approval order and are unaware of any potential conditions that may come with such an order. For the purposes of this report, we assume that the 2017 IRP will be approved without any conditions that may alter our recommendation here.

Additionally, we base our recommendation on our participation in the entire RFP process from design, through bid receipt and analysis, to selection of the Initial and Final Shortlists. During that time we:

1. Reviewed and commented on drafts of the RFP;
2. Attended the pre-bid conference;
3. Monitored bidder contact, including the answers to bidder questions;
4. Confirmed the assumptions used in the analyses;
5. Confirmed the initial qualification of bidders and the confirmation of proposal details;
6. Provided input with respect to bidder disqualifications;
7. Reviewed the price and non-price scores and models for the Company's Initial Shortlist process and confirmed the Company's selection of an Initial Shortlist; and

8. Reviewed the models for the selection of the Initial and Final Shortlist and confirmed the Company's selection of the Initial and Final Shortlist.

Throughout the process we were in constant contact with PacifiCorp's evaluation team. The Company was transparent in their discussions with us and provided all information that we asked within a reasonable timeframe.

We note that we will also be monitoring the negotiations of final contracts with the winning bidders to ensure that actual signed contracts match the offers submitted and evaluated. In the case of the Benchmark resources we will monitor the negotiation of EPC contracts for the facilities.

C. ADDITIONAL RECOMMENDATIONS TO PROTECT RATEPAYERS

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.

D. ADDITIONAL COMMENTS AND RECOMMENDATIONS

Based on our work in this RFP we have several observations and recommendations to assist parties moving forward. First, parties should make more effort in the future to align the RFP process with the IRP process. This process was rushed in order to meet deadlines for qualification for full value of the PTC. However, the PTC's sunset has been known since the end of 2015. We were not involved in the IRP process but are unaware of any reason why this fact could not have been incorporated into planning at an earlier time. Moreover, as of today there is still no written order approving the Company's IRP, which cast additional uncertainty over this RFP process.

Second, and related to the above point, transmission planning should better align with IRP planning. One troubling aspect of this RFP was that the initial system impact studies provided to bidders did not incorporate the early completion of the D2 Segment. After revisions to account for the earlier in-service date of the D2 Segment were incorporated it was determined that only projects with early queue positions could be deliverable to load without the completion of the entire Gateway South project in 2024. These evaluations by PacifiCorp's transmission group essentially left us with only about four potential offers in the transmission-constrained area served by the D2 Segment. We realize that there are functional separations within the Company but having alignment between the planning side and the transmission side will help make more informed decisions in the future.

Third, future RFPs using the Company's production cost modeling should examine (as a sensitivity) resource choice with levelized benefits as well as costs. While the issue ultimately had no impact on winning projects selected in this RFP due to the transmission issues noted above, the Company's modeling method, which levelized cost but not the benefits of PTC acquisition, could have biased the bid selection to less favorable offers.

Fourth, regarding the winning Cedar Springs project, which is 50% BTA and 50% PPA of 200 MW each (for a total of 400 MW), we note that the [redacted]. Additional analysis shows this option to be preferable to the selected option across several years, but slightly less preferable over the entire 30-year expected life of the facility. We believe the Company's selection of the 50-50 BTA/PPA option is reasonable, but note that the PPA option would also be a reasonable choice given its superior risk protections and additional portfolio flexibility.

Fifth, because the selected portfolio contains mostly options to be owned by the company, the selected portfolio generates significant PTC benefits within the first ten years of operation. These benefits credit against revenue requirements and serve to lower costs in this initial period. However, after the end of the ten-year PTC window these credits disappear and costs increase. PacifiCorp currently projects a $125 million cost increase in 2031. If the Commission believes such an increase would be unreasonable they should consider enacting some form of rate mitigation efforts in the future.

II. RFP ISSUANCE TO BID RECEIPT

PacifiCorp's RFP was approved by the Commission, with modifications, in a special public meeting on August 29, 2017. The Commission ordered modifications to the RFP regarding IRP acknowledgement, eligibility of existing resources, minimum bid requirements, credit requirements and terms in the *pro forma* PPA. PacifiCorp made the required changes to the RFP and provided a revised RFP to the IE prior to issuance of the final RFP to the market. We reviewed the changes made, had no objections, and the final RFP was approved by the Commission on September 26, 2017.

The final RFP was issued on September 27, 2017 and was subject to an accelerated schedule. The accelerated schedule was designed to allow winning bidders to capture the full value of the PTC by placing their projects into service prior to December 31, 2020,[1] and to align with the Company's Certificate of Public Convenience and Necessity ("CPCN") process to expand its transmission system in Wyoming in order to accommodate projects selected in this RFP.

Since PacifiCorp issued the RFP in late September the following steps have been completed:

Table 1: Milestone Events to Date

Milestone	Date
RFP Issued to Market	9/27/2017
1st Bidder's Conference	10/02/2017
Notice of Intent (NOI) to Bid Due	10/09/2017
Last Day for RFP Questions to IEs for Q&A	10/10/2017
Benchmark Bids Due	10/10/2017
RFP Bids Due – Wyoming Wind	10/17/2017
RFP Bids Due – Non-Wyoming Wind only	10/24/2017
Bid Eligibility Screening Completed	10/30/2017
Initial Shortlist (ISL) Evaluation/Scoring Completed	11/7/2017
Capacity Factor Evaluation on ISL started	11/12/2017
IEs' Review of ISL Completed	11/17/2017
ISL Price Update	11/22/2017
Capacity Factor Evaluation on ISL Completed	11/27/2017
Price update for Tax Reform Bill	12/21/2017
Final Shortlist Evaluation Completed	2/12/2018
IE Report submitted to OPUC	2/16/2018

Bates White has actively participated at each step of the RFP process. We have been in constant contact with the Company, Commission Staff and have had multiple discussions on many issues. In addition, throughout the process we have coordinated with Utah's independent evaluator to ensure that the rules of the RFP were applied consistently across both states.

PacifiCorp held a Bidder's Conference on October 2, 2017. The conference was simulcast in Portland, Salt Lake City, and online. Bates White attended the conference in

[1] RFP, page 1.

Portland. PacifiCorp personnel walked through the RFP process, including bid qualification and evaluation. Several questions were raised regarding a range of issues including bid fees, contract requirements, schedule, and submission requirements. PacifiCorp answered most of these questions at the conference and the reminder of the questions later via a posting on the RFP website. Bidders asked questions up until the final day for questions of October 9, 2017. Bates White reviewed all questions and answers prior to posting.

After the bid conference, PacifiCorp presented us with the assumptions to be used in bid evaluation. These included items such as cost of capital, asset lives, and forward market values. We reviewed the assumptions file and asked PacifiCorp questions in order to determine that the numbers used were consistent with the most recent IRP process or (for certain items) reflected the most recent Company forecasts.

Bidders were to submit NOIs by October 9, 2017. Submissions were made electronically and Bates White was copied on all submissions. In total, 19 companies indicated their intentions to bid by submitting NOIs. We received no indications that there were companies who wanted to submit an NOI but failed to do so. A list of those companies providing NOIs is presented in Table 2.

Table 2: Summary of NOI Submissions

Ownership of Bidders (Bidder name if different)[2]	State
[redacted]	Idaho
[redacted]	Wyoming
[redacted]	Wyoming
[redacted]	Montana
[redacted]	Idaho
[redacted]	Wyoming
[redacted]	Wyoming
[redacted]	Utah
[redacted]	Montana
[redacted]	Wyoming
[redacted]	Wyoming
[redacted]	Wyoming
[redacted]	Wyoming
[redacted]	Wyoming
[redacted]	Washington
[redacted]	Wyoming
[redacted]	Oregon
[redacted]	Wyoming
[redacted]	Wyoming

In the NOI bidders were asked to identify the types of proposals they might submit as well as the project size. Table 3 summarizes the indicated bids by state, type, (BTA or PPA) and size (in MW). The potential response was heavily weighted toward Wyoming wind offers and far in excess of the RFP's targeted solicitation of 1,270 MW.

Table 3: Summary of Indicated Bids

	PPA		BTA	
	Number of Proposals	MWs	Number of Proposals	MWs
ID	2	200	1	110
MT	3	400	-	-
OR	1	187	1	187
UT	2	180	1	100
WA	1	145	1	145
WY	21	6,194	12	3,365
Total	**30**	**7,305**	**16**	**3,906**

[2] Listing for ownership is name of entity providing credit support.

III. BENCHMARK BID ANALYSIS

On October 10, in accordance with the RFP timeline, PacifiCorp's Benchmark team submitted their offers to the IE and the PacifiCorp evaluation team. In total, there were four benchmark offers submitted. These projects are shown in Table 4.

Table 4: Benchmark Project Summary Data

Project Name	Nominal Capacity (MW)	Turbine Manufacturers	Number of Generators	Wyoming County	COD
Ekola Flats	250	[redacted]	[redacted]	Carbon	11/1/2020
McFadden Ridge II	110	[redacted]	[redacted]	Albany/Carbon	11/1/2020
TB Flats I	250	[redacted]	[redacted]	Carbon	11/1/2020
TB Flats I & II	500	[redacted]	[redacted]	Albany/Carbon	11/1/2020

Source: Project Applications, Appendix C

Bates White next undertook a review of the offers. In assessing a utility's own bids in response to the RFP, our greatest concern is that the utility will incorporate cost estimates that have been aggressively estimated and do not characterize the costs of the project accurately. To determine whether this had occurred, we looked at a detailed breakdown of each of the benchmarks costs to determine if any items have been improperly omitted from the cost calculation, and at overall capital cost levels by comparing them to publicly-available data on recent wind generation capital costs. Such a comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors.

We found that the Benchmarks were acceptable based on three items. First, the benchmarks were not deliberately underpriced through omission of any capital cost components. Second, the benchmark capital and operating costs appeared reasonable when compared with public data on U.S. wind projects. Third, the capacity factors of the benchmarks were reasonable when compared with public data and were supported by credible third-party analysis. Bates White's detailed assessment of the Benchmark bids is included as Appendix A to this report.

In addition, as required by the Oregon Competitive Bidding Guidelines, we reviewed PacifiCorp's price and non-price scoring of the benchmarks prior to receipt of third-party offers. The price score was based on a comparison of the bid's costs to the market value of the energy the bid would replace. The non-price score was based on criteria laid out in the RFP. Bates White confirmed the price scores by inputting key bid criteria into our own busbar levelized cost model. Additional details about all scores, as well as the actual scores, are provided later in this memo. All scoring was confirmed prior to the review of third-party offers, per Oregon's Competitive Bidding Guidelines.

IV. BID RECEIPT AND QUALIFICATION

Bids from third-party bidders were due on two separate dates. Wyoming project proposals were due on October 17. Non-Wyoming proposals were due a week later. Bates White suggested this bifurcation, noting that the original draft RFP did not allow bids from outside Wyoming. Only after a last-minute modification to the RFP were non-Wyoming bids allowed to participate. Our suggestion to allow non-Wyoming bidders an extra week to prepare their bids was meant to recognize the reduced notice afforded to them.

Bates White supervised in person in Portland the receipt and opening of the bids on both third-party bid receipt dates. No bids were rejected for being untimely and there was no indication that any bidder had offers they wished to submit but were unable to do so.

Ultimately, ignoring those who did not bid or whose bids were deemed to be non-compliant (discussed below), 13 suppliers submitted a total of 18 projects representing almost 4,900 MW—which is about 3.9 times the quantity solicited. The majority of these projects were Wyoming wind projects. Specifically, 14 projects representing around 4,400 MW were based in Wyoming while four projects representing 485 MW were located outside of Wyoming. Some projects contained several options, typically differences in project size, equipment, or transaction type (i.e., PPA versus BTA or a combination thereof). In total, bidders submitted 50 Wyoming bid options and nine non-Wyoming bid options.

One notable set of submissions came from Invenergy. These submissions were notable because they were third-party BTA offers for three of the four Benchmark sites (all sites except McFadden Ridge). Invenergy currently holds the development rights on these three sites and under their agreement with PacifiCorp's development team, both parties were free to offer bids into the RFP. We viewed this as a positive sign because it provides a transparent and above-board market offer to compare with the Benchmarks.

Fees for proposals were structured such that the bidder paid a fee of $10,000 covering a base proposal and two alternatives. Each bidder was permitted to offer up to three additional alternatives to the base proposal (maximum of six) at a fee of $3,000 per alternative. After the receipt of offers, PacifiCorp worked with bidders to confirm and collect bid fees. PacifiCorp and the bidders were able to come to agreement on fee amounts.

Upon final receipt of bids and bid fee confirmation, PacifiCorp went to work confirming bid details with bidders. Bidders provided and confirmed project information and provided update information where their original response was lacking. Bates White participated in calls with the bidders to make sure that all parties understood the terms and conditions of the bid and any deficiencies encountered.

Once the bids were confirmed, PacifiCorp and the IEs reviewed the offers for qualification purposes. Bids were held to several minimum requirements. Key requirements included: (a) being wind powered offers, (b) demonstrating that the project could be commercially operational by December 31, 2020, (c) being located in or demonstrating deliverability to PacifiCorp's system, (d) having requested interconnection with PacifiCorp's system or a third-party system and (at a minimum) having a feasibility study in progress, (e) compliance with and verification of major equipment availability (wind turbines), and (f) having one to two years of wind data from the site.

We discussed potential disqualifications with PacifiCorp and the Utah IE. Ultimately, four bidders had projects disqualified from consideration for the Initial Shortlist. The disqualified Wyoming projects were as follows:

1. [redacted] Farm was rejected for containing an unacceptable level of development risk. The project was still in the conceptual stage, the bidder did not have site control, and relied on "virtual" met tower data.
2. [redacted] withdrew its [redacted] proposal from consideration for the short-list because the project was proposing an unacceptable transmission structure. The project was located outside of PacifiCorp's system and proposed using a "pseudo-tie" for delivery rather than securing firm delivery to the system.

The rejected non-Wyoming projects were as follows:

1. Caithness Energy's Beaver Creek projects were disqualified as non-compliant as they did not offer a wind-only option as required by the RFP. Their offer was for a wind farm mixed with battery storage. In addition, their proposal presented issues with transmission service as their proposal required a third party to take title to the energy prior to receipt by PacifiCorp.
2. [redacted] project was rejected due to the fact that it was not a wind-only resource as required by the RFP. [redacted] had proposed a PPA from a pumped storage facility which might possibly be combined with wind and solar projects at a later date.

Bates White was consulted on the decision to remove each of these bidders and bid options and we agreed with the decision to remove them. Caithness pronounced themselves "very disappointed" that PacifiCorp did not accept their option, which they believed had real value for bidders. During discussions with the bidder PacifiCorp made clear that the failure to offer a wind-only option was the primary reason for the disqualification. [redacted] offer was also rejected due to the fact they did not offer a wind-only resource (though their project consisted of other resource types beyond storage).

In making the disqualification PacifiCorp had to point to a reference in the RFP that supported this decision. While the RFP, plainly read, asks only for "new wind resources", the closest specific language in the RFP document is Section 3.H.13 which states: "proposal presents an unacceptable level of development or technology risk." Caithness offered the argument, which has some validity, that their project did not, in fact, pose any technology risk. However, the fact remains that the offer was not a wind-only project and would not match the plan resulting from PacifiCorp's approved IRP. If the RFP was interested in dispatchable wind then it would have stated so clearly in the document.

It is true that PacifiCorp and the IEs could have decided to allow the offer. However, the issue with this decision is that other developers may have claimed – based on a clear reading of the RFP – that such an offer was not permitted and, had they known, they would have offered into the RFP in a different manner than they ultimately did. Yet another issue with granting the request is that the bid evaluation method would have to be re-examined in order to ensure it was capturing the full value of a dispatchable wind offer. In our experience these offers typically are not cost-competitive and only stand to succeed if the evaluation places a high value on the storage component.

Another factor is whether or not a storage-aided facility would truly count as a "renewable" resource. In California's Green Tariff Shared Renewable programs, which aim to bring renewables to those who want a larger share than under California RPS standards or who want to participate in community-based solar programs, storage is not allowed because it typically charges from the grid.

We note here that a cursory glance at Caithness offer prices, which ranged from around [redacted], would likely not have proven to be valuable when compared with the prices offered by other resources. PacifiCorp did tell the Caithness team that they were welcome to discuss the project in the context of a bilateral transaction and we share that sentiment. If the Commission is interested in pursuing more storage we would recommend that a separate procurement be held for such resources.

V. INITIAL SHORTLIST DEVELOPMENT

After the bids were received and bid details were confirmed, the Company began the Initial Shortlist evaluation. Per the RFP, each bid was scored on price and non-price factors. The total bid score was weighted at a maximum 80% for price and a maximum 20% for non-price factors. The non-price factors were defined as follows:

Table 5: Non-Price Factor Weighting

Non-Price Factor	Non-Price Factor Weighting
Conformity to RFP Requirements	4%
Project Deliverability	8%
Transmission Progression	8%

Price score was based on a comparison of the cost of the bid to the benefits of the bid. Costs differed based on the type of bid. For BTA bids the costs were:

(a) the revenue requirement needed to cover the project's capital cost (less the full Production Tax Credit),

(b) O&M costs, including maintenance capital and royalty payments,

(c) property tax,

(d) wind integration cost,

(e) network upgrade costs, and

(f) Wyoming generation taxes.

For PPA bids the costs included:

(a) the PPA price,

(b) network upgrades, and

(c) integration costs.

The major benefit for both types of offers was captured by the value of the energy replaced by the project. This value was based on one of three forecasts of benefits based on project location (Wyoming, Utah/Idaho, or Oregon/Washington). Each forecast was created by PacifiCorp's IRP team by running production costs models with and without proxy wind resources and measuring the increase in cost at each location. Energy benefits for each project were calculated based on the specific generation output of a given project. Beyond energy value, BTA bids were assigned a terminal value to account for the fact that PacifiCorp would own the site at the end of the project's useful life.

Bids were ranked in separate categories, "Wyoming Wind" and "Non-Wyoming Wind." In this context, "Wyoming Wind" meant projects whose deliverability was enabled by the D2 Segment. This was done because PacifiCorp's evaluation did not take into consideration the cost of the Aeolus to Bridger transmission expansion (a cost that was included in the Final Shortlist evaluation). We were concerned that ignoring this cost would place non-Wyoming offers at a disadvantage.[3]

A. RANKING THE BIDS

Bates White independently verified the rankings in three ways. First, we reviewed each model on a line-by-line basis to make sure that the details of the bids were properly input and that all bids used the same default assumptions. Second, we reviewed the terms and conditions of the bids and compiled our own non-price scores. Third, we tested PacifiCorp's models by inputting key costs of each bid option into our own cost model, which determined an annual $/MWh annuity cost for the bid option. After we reviewed the bids we conferred with both PacifiCorp and the Utah IE to come to a consensus on shortlist candidates.

Wyoming Wind

The ranking of all the Wyoming Wind bid options is shown in Attachment One. Our simplified cost models were able to match PacifiCorp's models reasonably well. On average PacifiCorp's models showed a higher cost by $0.27/MWh and in 46 out of the 50 cases the difference was less than a dollar per MWh.

The table below shows the offers for each project with the greatest net benefit, in other words, options proposed for the same project with lower net benefit are removed for clarity.

[3] Specifically, the Aeolus-to-Bridger transmission project – which has yet to be approved and built – will benefit all Wyoming-based bids, including the Benchmark bids. It is important for the RFP evaluation process to consider the cost of the transmission project in comparing bids, particularly in comparing Wyoming-based bids – which are most likely to benefit from the transmission project – to non-Wyoming bids, which are less likely to benefit from the transmission project.

Table 6: Best Offers from Each Wyoming Wind Project

[redacted]

Table 6 allows us to make a few observations. First, the offers were very close in value. Thirteen of the projects offered net benefits of between $25/MWh and $30/MWh. This bunching means that small assumptions can have a large impact on ranking. Second, we see that PacifiCorp's terminal value adders were fairly small, about $1.18/MWh on average. Third, term length does have an effect on the net benefits. The average energy benefit for projects with terms less than 30 years is $46.76/MWh while the average benefit for 30-year projects is $48.74/MWh. This difference is mostly driven by the fact that the value of energy replaced increases in later years. These latter two items give a small advantage to BTA bids (since all BTA offers are assumed to last for 30 years). Again, the difference is not vast, but it can have an impact when bids are bunched so close together. This is why the [redacted] BTA offers from [redacted] and [redacted] were ranked just ahead of the lower-cost [redacted] PPA offer from [redacted]. Finally, the Invenergy offers for the Benchmark sites were generally [redacted].

To translate these net benefits into a price score and create a final ranking, PacifiCorp utilized three scoring methods. First, the offers were "ranked' with the most beneficial bid receiving a score of 80 points, a breakeven bid (i.e., a bid with zero net benefit) receiving zero points, and any scores in between being interpolated. Second, the offers were "force-ranked," with the most beneficial bid receiving 80 points and the least beneficial receiving zero points, with in-between scores being interpolated. Finally, PacifiCorp used the "force ranking" concept, but used a "rank order" method to score all offers between the highest- and lowest-ranked offers. So, if there were nine bids, the best would receive 80 points, the second-best bid would get 70 points, the third-best bid would get 60 points, and so on, with the worst bid receiving 0 points).

In each method PacifiCorp combined their scores with the non-price score to get a final bid ranking. The results are shown in Table 7.

Table 7: PacifiCorp's Scores for Selected Projects

[redacted]

This table shows that regardless of the scoring system (e.g., "Cases" 1, 2, and 3) utilized, the actual project rankings did not change. This is an important point to underscore. Nevertheless, there are a couple other points to draw out from Table 7. First, there was a relatively big gap between the [redacted] project and the [redacted] project, which suggested a logical threshold for determining the shortlist. Second, under the first scoring method price scores were tightly bunched, with eight projects scored between 80 and 89 points. This meant that non-price factors could have a larger impact on bid selection. Having said that, non-price scores were relatively similar, with the exception of the [redacted], which were lower than those for other bidders.

In order to select bid options for the Initial Shortlist, PacifiCorp and the IEs proceeded with the following goals in mind:

1. Selecting the bids with the greatest net benefit in terms of price and non-price benefits,
2. A diversity of bidders and projects,[4]

[4] This can minimize the risk of relying on the success of one given project or a given bidder.

3. A mix of PPAs and BTAs,
4. A relatively clear split between the score of the last bid picked and the next bid that was not selected, and
5. The RFP goal that there be a minimum of 2,000 MW selected.

PacifiCorp's recommended Initial Shortlist relative to other top-performing projects is shown in [redacted].

[redacted]

[redacted]

Source: PacifiCorp, 2017R RFP – Wyoming Initial Short List Update – 2017-11-06 IE V4.pptx

The Initial Shortlist was comprised of nine projects including four PPAs, two BTAs, and one PPA/BTA combination. All three Benchmark projects were selected to the shortlist. (Figure 1 above omits the [redacted] because the [redacted] offer for the same site scored higher, but, as seen on Table 6, the [redacted] offer scored among the top offers, which earned it the right to move on to the next round.) If a project was selected, <u>all alternatives</u> for a given project were selected as well.

The nine projects represented a cumulative installed capacity of approximately 3,100 MW, significantly above the RFP's stated target shortlist size of 2,000 MWs. The reason for such a large selection of projects was the tight bunching of the offers. As noted above, when looking for a selection of projects we typically try to identify "gaps" in value. The first such gap appears between the [redacted] and [redacted] projects. This is shown on both figure one and above in Table 6.[5] While the [redacted] were also low scorers on the non-price side, the gap appears in the price score as well. As can be seen on Table 6 there is about a [redacted] gap between the [redacted] project and the [redacted] offer.

While we did consider imposing a stricter limit on the selection, ultimately, it was considered more advantageous to include more projects in the Final Shortlist evaluation. This is especially true given that all bids would be allowed to submit a best and final offer (BAFO) and the offers were so tightly bunched that any changes resulting from the BAFO could certainly alter the rankings. In addition, we did consider pushing for the exclusion of the McFadden Ridge project on the grounds that it would not be included in the shortlist without the assistance of the terminal value adder and the additional value resulting from its assumed 30 year operational life. We ultimately decided to allow it because (a) the bid was scored properly according to the rules of the RFP and (b) this was simply a selection to the Final Shortlist evaluation, not a selection for a winning bid.

Non-Wyoming Wind

As noted above, the Non-Wyoming Wind category received substantially fewer offers than the Wyoming category. This was not totally surprising since the category was added at the last minute per the decision of the Utah PSC. Only four qualified projects were submitted in this category. The table below shows all options considered in the evaluation

Table 8: Non-Wyoming Offers (All Qualified Options)

[redacted]

[5] Note that the values in Figure 1 differ slightly from the values in Table 6 above and in the Appendix. Figure 1 comes from PacifiCorp's presentation to the IEs and regulators while the numbers in the other sources are taken straight from PacifiCorp's cost models. In any case, the bid order is the same.

Table 8 makes it clear that these bids do not provide the same level of benefit as the Wyoming Wind offers. This is not unexpected given both (a) the quality of the wind resource in Wyoming and (b) PacifiCorp's projected energy market benefits – which are higher in Wyoming than elsewhere. Of course, the Wyoming bids did not include the cost of the proposed transmission upgrade— again, this was considered in the Final Shortlist evaluation.

The [redacted] was the only non-Wyoming project which provided positive net benefits. We note that this project is actually located in Southwestern Wyoming right near the Utah border. However, because it lies outside of the constraint that is alleviated by the Aeolus to Bridger transmission segment it was valued as a Non-Wyoming resource.

PacifiCorp scored these bids using the same methods as the Wyoming bids. The ranking of the offers did not change depending on the scoring method used and the non-price scores of the bids were not a factor (i.e., they did not change the ultimate project rankings).

In terms of bid selection, PacifiCorp recommended selecting all projects except the [redacted]. This selection is shown in Figure 2.

[redacted]

[redacted]

Source: PacifiCorp, 2017R RFP –Non-Wyoming Initial Short List Update – 2017-11-06 V6.pptx

PacifiCorp made this selection in order to achieve a balance of PPAs and BTAs. In addition, there was a reasonable gap between the last bid selected and the rejected [redacted] bid. We agreed with this conclusion.

B. INITIAL SHORTLIST

PacifiCorp placed the following projects and bidders on the Initial Shortlist. Again, if a project was selected to the Shortlist, then all bid options from a project were selected.

Table 9: Initial Shortlist

[redacted]

VI. BID REVIEW AND PRICE UPDATES

Best and Final Offers from all offers on the Initial Shortlist were due on November 22, 2017. Most bidders took advantage of the opportunity to adjust their pricing. Shortly thereafter it became clear that some form of tax reform legislation would soon be passed by the Federal Government. After discussions with the IEs, PacifiCorp sent a notice to all remaining bidders informing the bidders that, once tax reform legislation was finalized, bidders would be allowed a brief opportunity to refresh their offers to reflect any changes they felt necessary. This opportunity was extended to all bidders since parties could not be sure how the final law changes would affect each bidder.

On December 18th after conference committee approval of the "Tax Cuts and Jobs Act," PacifiCorp notified bidders that they could revise their offers by December 21 to reflect any changes they thought necessary as a result of the Act. Several bidders took advantage of the opportunity to adjust their offers.

PacifiCorp made other adjustments to the offers as well. As described in the RFP, PacifiCorp engaged a third-party consultant (Sapere Consulting) to review wind generation data from each offer in order to assess the reasonableness of data provided by the bidders. This was done in accordance with Guideline 10(f) in Commission Order 14-149. Evaluations were completed by November 17, 2017. Sapere Consulting found that most offers had reasonable output estimations. The exceptions were [redacted] and [redacted] bids, which each were subject to an 8% reduction in their net capacity factors based on the consultant's findings.

In addition, PacifiCorp found that the offers from [redacted] had mistakenly omitted Wyoming sales taxes in their offers. In order to perform production cost modeling the Company adjusted their levelized cost models to reflect these developments. Adjusting for (a) offer repricing, (b) capacity factor adjustments for [redacted] offers, (c) inclusion of sales taxes in [redacted] offers, and (d) some revisions in interconnection costs, resulted in the following changes in net benefits for all Wyoming shortlisted offers.

[redacted]

[redacted]

Table 10 shows that almost all bids saw the net benefits of their offer reduced. In some cases this was because the bidder raised their offer price. [redacted], for example, did this for several of their offers. In the case of BTAs, net benefits were reduced due to the lowering of the corporate tax rate, which lowered the value of the PTC. Other bidders, for example, [redacted]s [redacted] project and [redacted] [redacted] Project, left their offers relatively stable and saw little change in their valuations.

The non-Wyoming offers saw similar changes as shown in Table 11.

Table 11: Non-Wyoming Price Updates[6]

[redacted]

Putting together both lists, the table below shows the top offer for each project according to PacifiCorp's net benefits calculation.

Table 12: Top Offers for Each Project

[redacted]

The top offer, by net benefits, was the [redacted] PPA, followed by the [redacted] PPA, the [redacted] PPA, and the [redacted] and [redacted]. Note how close the offers are in price, with six projects net benefits in the $22-$27/MWh range.

One issue that we note here is that PacifiCorp initially requested letters of commitment from shortlisted bidders. During this process, PacifiCorp had objections to some of the forms of

[6] Note that two bid options for the [redacted] were removed from consideration due to the fact that the bidder was not able to hold to their promised on-line date as a result of delays in turbine manufacturing.

commitment provided by bidders, while some bidders' financial backers objected to providing such a letter of credit, since the letter compelled them to set aside collateral. Parties ultimately decided to interpret the RFP rules as requiring credit commitments only 20 days after selection to the Final Shortlist. We felt this was a reasonable compromise as it allowed PacifiCorp to continue with the evaluation and select the best offers from a wide range before getting into a discussion of what forms of collateral they would accept.

VII. FINAL SHORTLIST MODELING

A. INITIAL MODELING

To develop a Final Shortlist, bids on the Initial Shortlist were screened using the System Optimizer Model ("SO Model"). The SO analysis involved PacifiCorp creating a "base case" by dispatching the system without new wind additions and the D2 Segment over a 20-year time frame. The model added resources over the years in order to maintain a given reserve margin.

PacifiCorp then allowed the SO model to run again, this time allowing it to select a combination of bids from the shortlisted offers that would minimize costs, including the D2 Segment, to ratepayers. One key assumption here was the amount of new supply from inside the constrained area in Wyoming that would be enabled with the construction of the D2 segment. PacifiCorp initially assumed 1,030 MW would be available but ultimately, as discussed later in this report, decided that 1,270 MW could be incorporated onto the system with the addition of the D2 Segment.

The SO Model can only analyze the least-cost resource choice under one scenario or "path" of natural gas prices and CO_2 emissions costs at a time. PacifiCorp used three "paths" of natural gas prices (high, medium and low). Medium natural gas price assumptions were based on PacifiCorp's December forward price curve while high and low sensitivities were based on consultation with third-party experts. The SO model also used three "paths" of CO_2 costs (high, medium, and zero). The "medium" scenario started at $4.49/ton in 2030, rising to $7.95/ton in 2036 while the "high scenario" started at $3.62/ton in 2026 and rose to $19.23/ton in 2036.

Taken together these three gas and three CO_2 scenarios presented a total of nine specific "price-policy" scenarios.

These nine cases produced just two distinct portfolios. The full analysis provided to the IEs in January can be found in Attachment Two.

1. Under all scenarios the SO model selected the [redacted] bid, the [redacted] Bids, the [redacted] bid and the [redacted] bid. ("Portfolio A")[7]
2. In the medium gas, high CO2 case and in all three "high gas" cases the model also selected the [redacted] PPA. ("Portfolio B")

All selected portfolios showed net benefits as compared to the base case, ranging anywhere from $198 million to $782 million on a net present value basis. Benefits increased as gas prices and emission costs increased.

Once the SO Model was run, the Company passed along these two distinct portfolios to be assessed for stochastic risk. The term stochastic refers to assumptions being randomly varied along a given distribution using a Monte Carlo method. Assumptions for five factors were tested. Those five assumptions were load (electric demand), natural gas commodity prices, wholesale electricity prices, hydro generation availability, and thermal generation availability. Each portfolio was again assessed under the three CO_2 price cases and three gas price paths.

The stochastic analysis was performed with the Planning and Risk ("PaR") Model. The assumptions were randomly varied to result in 100 model runs for each case. This resulted in 100 different estimates of the cost –as measured by the present value of the revenue requirement, or PVRR, over 20 years – for each case. The average (mean) of these 100 estimates was provided as was the "risk-adjusted" mean which was equal to the average value plus the cost for the case at the 95th percentile times 5 percent.

[7] Note that this run was prior to the discovery that [redacted] offer had omitted Wyoming sales taxes. Subsequent analysis incorporated this cost and resulted in the selection of the [redacted] offer.

Table 13: Modeling Results

Natural Gas Cost	CO2 Cost	Portfolio	SO Model PVRR(d) (Benefit)/Cost ($m)	PaR Mean PVRR(d)	PaR Risk-adjusted PVRR(d)
Low	Zero	A	($198)	($153)	($161)
Low	Medium	A	($229)	($162)	($170)
Low	High	A	($347)	($306)	($323)
Medium	Zero	A	($372)	($319)	($335)
Medium	Medium	A	($399)	($349)	($367)
Medium	High	B	($493)	($445)	($467)
High	Zero	B	($704)	($572)	($601)
High	Medium	B	($720)	($604)	($634)
High	High	B	($782)	($689)	($724)

Table 13 above shows that the stochastic analysis reduces benefits somewhat, but benefits remain in each case.

The third step in the selection of the Final Shortlist was to use the SO Model to assess how the cost of the two portfolios from the stochastic risk assessment vary with different assumptions about fuel price and CO_2 compliance costs. Recall that, unlike the PaR model, the assumptions in the SO Model are defined outright, not varied along a distribution. Unlike the first step, where the SO Model was allowed to pick the ideal portfolio, in this analysis, each portfolio is fixed, allowing the model to dispatch the resource as part of the portfolio. The purpose of this step is to gather another data point regarding the risk of each portfolio. The result is an estimate of how much a portfolio costs under less than ideal circumstances (i.e., when key risk factors do not move in its favor). The results of this analysis are presented in Table 14. Note that table this does not include some costs for transmission improvements for Portfolio B that PacifiCorp added after the fact, such costs tilted the selection to Portfolio A in the low and medium gas scenarios.

Table 14: Scenario Modeling Results

Natural Gas Cost	CO2 Cost	Portolio A Benefits ($m)	Portfolio B Benefits ($m)
Low	Zero	($198)	($170)
Low	Medium	($229)	($216)
Low	High	($347)	($359)
Medium	Zero	($372)	($379)
Medium	Medium	($399)	($407)
Medium	High	($493)	($493)
High	Zero	($692)	($704)
High	Medium	($709)	($720)
High	High	($770)	($782)

This table shows that both portfolios produce positive benefits but that the portfolio with more wind is slightly more beneficial in higher gas price scenarios. This outcome make sense since the cost of wind stays the same but the cost of other resources increases. Therefore, more wind would generally be preferable in high gas price scenarios.

B. IE SENSITIVITY

We were somewhat surprised by the fact that the SO model would choose projects that had lower net levelized net benefits than other resources. Typically, we would expect resource selection to mirror the levelized cost analysis and, therefore, expected to see the [redacted] and [redacted] PPAs selected before the Benchmark projects.

We questioned PacifiCorp regarding this outcome. One item that they identified as a possible driver in the bid selection was the fact that, in order, to create the inputs for the SO model, bid costs were levelized but any PTC benefits were not—that is, these credits were flowed through as they were earned. Moreover, the SO Model covers the time period through 2036. Combined, these two factors meant that the SO Model spread the PTC benefits within the period of study, instead of over a 30-year period as is done in the Company's levelization models. This means that any offers earning PTCs would look more attractive than a levelized cost model would otherwise indicate.

To see if this was the case, we asked the Company to run the SO Model with medium gas price and CO_2 inputs and levelize PTCs over the 30-year life of BTA and Benchmark bids, instead of treating them as earned. The results were more in line with the levelized cost models. The SO model selected the [redacted] PPA, the [redacted] PPA, and the [redacted] project.

At this point, PacifiCorp made the observation that the non-levelized PTC selection would more closely reflect how they planned to pass PTC benefits through to ratepayers. While this was a reasonable assertion, we also noted that we had some concern that costs for their selection would not be levelized in real life but would, in fact, be front-loaded as well due to the way in which the costs for rate-based assets are recovered. Therefore, we had some concern that the front-loaded nature of rate recovery would cancel out the front-loaded benefits of the PTC recovery, and that the PPA-heavy portfolio was truly a better selection.

In response to this concern PacifiCorp produced an analysis looking at the actual flow of cost recoveries, treating both PTCs and costs as incurred. The table below compares the two portfolios, PacifiCorp's selected offers (PAC Portfolio) versus the PPA-heavy portfolio. Even though the SO Model only covers through 2036 PacifiCorp extended the analysis out through the 2050 – the end of the BTA project's useful life – by assuming market energy prices would simply increase with inflation each year after 2036. Note that PacifiCorp did not assume that any new supply replaces expiring contracts.

Table 15: Comparison of benefits ($m)

	Annual Benefit		Cumulative Benefit	
Year	PAC Portfolio	PPA Portfolio	PAC Portfolio	PPA Portfolio
2017	($0)	($0)	($0)	($0)
2018	$0	$0	($0)	($0)
2019	($0)	($0)	($0)	($0)
2020	$7	$13	$5	$10
2021	$58	$46	$46	$42
2022	$40	$38	$73	$68
2023	$22	$31	$87	$87
2024	$1	$20	$88	$98
2025	($17)	$5	$78	$101
2026	($25)	$4	$65	$103
2027	($34)	($3)	$49	$102
2028	($57)	($20)	$24	$93
2029	($88)	($52)	($13)	$71
2030	($96)	($78)	($51)	$41
2031	($0)	($79)	($51)	$12
2032	($4)	($82)	($53)	($16)
2033	($19)	($97)	($59)	($48)
2034	($31)	($109)	($68)	($80)
2035	($41)	($141)	($80)	($120)
2036	($56)	($156)	($95)	($161)
2037	($30)	($108)	($102)	($188)
2038	($36)	($114)	($110)	($214)
2039	($42)	($120)	($119)	($240)
2040	($49)	($126)	($129)	($265)
2041	($20)	$39	($133)	($258)
2042	($25)	$37	($137)	($251)
2043	($30)	$35	($142)	($245)
2044	($34)	$34	($147)	($240)
2045	($38)	$32	($153)	($236)
2046	($41)	$31	($158)	($231)
2047	($42)	$30	($163)	($228)
2048	($40)	$30	($168)	($224)
2049	($46)	$28	($173)	($221)
2050	($484)	($28)	($223)	($224)

While the PPA portfolio is more expensive in the early years, as we might assume since the value of the PTC in a PPA is spread out over a longer period of time, by 2034 it has greater cumulative benefits than PacifiCorp's selected portfolio. Even over the entire lifetime of all projects, the PPA portfolio produced more net benefits. Note also that the only reason the PacifiCorp portfolio was even close in net benefits over the entire time period was due to a 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.

C. INTERCONNECTION ANALYSIS

At this point we believed that the PPA-heavy portfolio should be the top choice. However, when we voiced this opinion to the Company they claimed that they had concerns regarding interconnection costs for some of the offers.

Specifically, the original system impact studies for most bids assumed completion of Gateway West and South projects by 2024. Because the Company had decided to move up the completion date for the D2 Segment they had a concern that projects located farther back in the interconnection queue would only be feasible to come online with the entire Gateway West and South projects complete.

As background, PacifiCorp's transmission arm, which assesses interconnection costs, must, by law, assume that each queue project is interconnected in order received so each project assumes that all projects ahead of it in the queue are interconnected. As more projects in the Wyoming area are interconnected it puts more strain on the transmission system until eventually major upgrades such as the Gateway West and South projects are needed.

Based on this analysis PacifiCorp believed it was highly unlikely that projects higher up in the queue would be able to interconnect with the D2 Segment alone. [redacted] was one such project, as was PacifiCorp's McFadden Ridge Project. The [redacted], and [redacted] projects were noted to have low queue positions and would likely be safe.

The Company said that PacifiCorp transmission was in the process of restudying interconnection costs assuming the accelerated completion schedule for the D2 Segment. At the end of January PacifiCorp transmission issued revised system studies. PacifiCorp transmission found that the Project with Queue number 713 triggered the need for major upgrades, stating: "Additionally, the Q0713 project triggers the need for the Transmission Provider's planned Energy Gateway South project. This project consists of a new 400 mile 500 kV transmission line from the planned Aeolus substation in Wyoming to the Transmission Provider's existing Clover substation in central Utah, with ancillary improvements." (See Attachment Three, page 8)

This meant that, in effect, any bid within the constrained area in Wyoming with a higher queue number than 712 would require extensive new transmission investment to be deliverable and likely would not be deliverable by the end of 2020. To see the effect on bids we can return to our earlier table showing the best offers from each project. Again, any offers higher than 712 located in the constrained area in Wyoming would need the completion of the Gateway South Project.

[redacted]

[redacted]

From this table we see that based on this analysis a majority of offers are no longer viable without major transmission investment. The [redacted], [redacted] and [redacted] projects are only viable because they are outside the constrained area in Wyoming. Inside the constraint only three projects – [redacted], [redacted], and [redacted] – are viable.

PacifiCorp claimed that this was why they proposed in their initial RFP that bids must have a completed system impact study; however, such a requirement would not have solved this issue. 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. And, once those studies were redone, the same result would have occurred: projects with queue positions above 713 would have been effectively eliminated from further consideration.

To its credit, PacifiCorp dropped pursuit of McFadden Ridge after this analysis. However, these restudies showed more transfer capability from the constrained area than PacifiCorp had been assuming. Earlier studies assumed about 1,030 MW of new supply was enabled by the D2 Segment but PacifiCorp revised the number to 1,270 MW based on the sum of the wind projects in the constrained area that could be accommodated prior to Gateway South improvements.[8] With this revision, PacifiCorp stated that the larger Ekola Flats project was now selected as part of the optimal portfolio in the SO Model. Prior to this revision Ekola was not selected because, at 250 MW, there was not enough transfer capability to accommodate it.

The net result of these adjustments calls for consideration of the overall context of the RFP. Recall that in its RFP as originally drafted, PacifiCorp proposed to select only projects from the constrained area and offered three Benchmark projects. Based on the final analysis laid out above, only one other third party bid on the shortlist (the [redacted] project) could even compete with these offers. In fact, only one other Wyoming wind offer – the [redacted]

[8] Specifically, the company assumed Q542 (240 MW), Q706 (250 MW), Q707 (250 MW), Q 708 (250 MW), Q 712 (520 MW) could be accommodated for a total of 1,510 MW of interconnection capability. PacifiCorp then subtracted 240 MW to account for a customer that already has an executed interconnection agreement, leaving a total of 1,270 MW.

wind proposal – had a high enough queue position to be viable. So this entire RFP really boiled down to two viable benchmarks and two third-party offers, meaning a lot of the analysis presented here was of questionable value.

To be clear, the remaining viable offers were competitive offers, but were not the best the market could provide based on cost or risk, but for the transmission constraint issue. We understand and appreciate PacifiCorp's position and do not disagree with their transmission department's findings (beyond noting the obvious fact that many projects will likely drop out of the queue and that actual interconnection costs will differ from projected). To go forward with projects that cannot meet the proposed online date without major accelerated transmission investment would not seem to be the wisest course of action

The real issue here is that PacifiCorp's procurement (in the form of this RFP) got out ahead of its resource and transmission planning. If PacifiCorp had identified this plan earlier, then all aspects of this work (IRP, transmission planning and resource acquisition) could have worked together in a more coherent fashion.

D. REVISED FINAL SHORTLIST ANALYSIS

Based on these findings PacifiCorp completed additional analysis to confirm the Final Shortlist selection. PacifiCorp updated their analysis to remove all non-viable offers, update interconnection costs, increase transfer capability from the D2 Segment and adjust the Invenergy offer to include Wyoming sales taxes. The updated presentation is included here as Attachment Four.

With these revisions, the SO Model selected a portfolio that included the Benchmark TB Flats I and II bid, the Ekola Flats benchmark, the Cedar Springs BTA/PPA, and the Uinta BTA. Benefits generally increased due to the larger amount of total supply selected (as the 109 MW McFadden project was replaced by the 250 MW Ekola Flats project).

Again, the outcome was not surprising given the fact that there were so few bids to choose from and that, with the revised and increased costs for the Invenergy bid options, the Benchmark options generally were lower cost.

E. OTHER SENSITIVITIES

Along with the analysis described above PacifiCorp also provided additional sensitivities, including a solar sensitivity and a wind repowering sensitivity. The goal of each analysis was to ensure that other procurement activities did not lessen the benefits of this procurement.

For the solar sensitivity PacifiCorp ran the SO Model for two scenarios: (a) medium gas and medium CO_2 prices and (b) low gas no CO_2 prices. PacifiCorp looked at value of adding about 1,000 MW of new solar PPAs (a) instead of the shortlisted bids from the RFP and (b) along with the shortlisted bids. Prices and quantities were based on initial results from PacifiCorp's current solar RFP.

In all cases the combination of solar and shortlisted resources provided more net benefits. For example, in the medium gas medium CO_2 scenario benefits of just solar were $343 million on net whereas solar and the shortlisted bids provided $647 million of net benefits in the SO Model. In the low gas zero CO_2 scenario solar PPAs alone provided $196 million of net benefits but $312 million when combined with the shortlisted offers.

In the wind repowering scenario PacifiCorp allowed additional repowering of existing units up to their large generator interconnection agreement ("LGIA") limits. Running the same scenarios as with the solar sensitivity PacifiCorp found that benefits increased when repowering was added to the shortlisted bids. For example, in the medium gas medium CO_2 scenario benefits increase to $608 million on net versus $405 million with just the Final Shortlist offers alone.

PacifiCorp also provided a sensitivity which tried to account for the fact that the turbines used by the [redacted] might require the installation of a synchronous condenser or other equipment at the Aeolus substation to address performance issues. PacifiCorp ultimately determined that upgrade costs would have to be in the [redacted]

[redacted]. It was PacifiCorp's judgment that costs would not be higher than this level.

Finally, per our request, PacifiCorp looked at the as-earned costs and benefits of the Final Shortlist portfolio versus a portfolio in which the Cedar Springs PPA/BTA bid was replaced [redacted]. Our reason for requesting this was that we wanted to see if, as we found before, the actual recovery of costs and benefits truly favored the full PPA option.

PacifiCorp calculated costs and benefits under the medium-gas medium CO_2 cost scenario for each portfolio as they had done before, looking at as-earned costs and benefits and extending the analysis out to 2050 by assuming that energy benefits increase with inflation. They found that their preferred portfolio had a cumulative net benefit of $298 million on a net present value basis and the portfolio with [redacted] had a value of $280 million on a net present value basis. Removing the terminal value brings the numbers closer together, but the company's preferred portfolio still has a greater net benefit, $255 to $250 million on a net present value basis.

We do note that the portfolio with [redacted] has a lower cumulative net benefit from about 2033 through 2048, better risk protections, and offers the Company future flexibility, making it a reasonable choice. However, given the fact that the total net benefits favor PacifiCorp's selection we cannot conclude that the selection of the BTA/PPA bid is unreasonable.

VIII. CONCLUSIONS AND RECOMMENDATIONS

We recommend that the Commission acknowledge PacifiCorp's Final Shortlist. The bids do represent the top viable offers and are projected to provide net benefits. With proper risk mitigation the offers can provide value to ratepayers. While it is our understanding that the 2017 IRP is approved, we have yet to see a final approval order and are unaware of any potential conditions that may come with the approval order. For the purposes of this report, we assume there are no conditions that alter our recommendation here.

A majority of the selected offers here are BTAs and Benchmark resources. These bids offer at least two risks that are not generally present in power purchase agreements: (a) the risk of capital and operating cost overruns and (b) failure to claim the full value of the Production Tax Credit. Some of these risks can and will be managed in the BTA and EPC contracts the company will sign, but the protection will not be as strong as in a PPA. Developers can promise to deliver PTC complaint equipment and install by a certain time, but, several of these projects are dependent on PacifiCorp's transmission arm completing the D2 Segment in order to achieve deliverability.

In order to achieve a level of risk protection similar to a PPA for ratepayers, PacifiCorp must guarantee that capital and O&M costs will not exceed the amounts forecasted here and that ratepayers will be credited the full PTC values projected here as well regardless of whether or not PacifiCorp has the taxable income to utilize the credits. For reference, we include the final cost projections for each resource from the Company here as Attachment Five.

To be clear these should be "hard" guarantees as would be found in a commercial contract. PacifiCorp should not be permitted to recover additional costs or not credit full value of the PTC due to force majeure or change in law events. The risk regarding the PTC is exceptionally important. As we have just seen with corporate tax reform (and the debate that took place prior to the law's passage in which the PTC was considered briefly for major overhaul), the value of the credit can change rapidly.

Again, the reason that the Company should take this risk without exception is that a commercial developer will take this risk in a PPA. By way of example, the *pro form*a PPA in this RFP has this to say about tax credits:

ii. "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."[9]

A related risk that was not analyzed is the risk of cost overruns for the D2 Segment. Because there is no real competition for this service it is more likely that cost overruns would occur here. These cost projections are important because they are a major driver of selection in this RFP. If actual costs are higher it may turn out that a better solution would have been to select more supply from outside the constrained area in Wyoming. Therefore, PacifiCorp should also be held to its cost projection for the D2 Segment. The revenue requirement numbers used in this analysis are included in Attachment Six.

In addition, the selected portfolio contains mostly options to be owned by the company. As a result PTC benefits are projected to flow to customers for the first ten years of operation as incurred. However, after the end of the ten-year PTC window these credits disappear and costs increase. PacifiCorp currently projects a $125 million cost increase in 2031. If the Commission believes such an increase would be unreasonable they should consider enacting some form of rate mitigation efforts in the future.

Going forward, many of the issues in this RFP were primarily caused by the resource acquisition function getting ahead of the resource planning and transmission planning function. Soon after the PTC sunset was established at the end of 2015, PacifiCorp's IRP team should have begun to consider if this change would drive them to pursue more renewable supply. Earlier consideration of this fact could have spurred debate about the proposal and possibly achieved earlier IRP approval as well as earlier revision of transmission planning in system impact studies. As it was the process was rushed and ultimately very few bids could be called viable.

In the future parties should seek better alignment of all these functions. Other tax credits (e.g., the Investment Tax Credit) are also planned to sunset and PacifiCorp has more transmission investment planned. As the next IRP process gets started parties should be asking what schedule PacifiCorp plans to pursue. Will they pursue additional solar with the sunset of

[9] Draft PPA section 2.8

the ITC? Would it make sense to accelerate any other portions of the Gateway project? Earlier consideration of these questions can lead to better and more transparent outcomes for all.

Finally, from a bid analysis standpoint any future modeling should at least consider the effect of unleveling of tax credit benefits. As demonstrated in our requested sensitivities if the production cost modeling does not consider the entire life of an asset then leveled benefits can force a choice of a suboptimal offer.

Attachment One

Qualified Wyoming Wind Options

Attachment One contain commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request.

The Company requests special handling. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Attachment Two

INITIAL FINAL SHORTLIST MODELING

Attachment Two contains confidential and commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request.

The confidential information is available to parties who have signed a confidential agreement in this docket.

The Company requests special handling of the commercially sensitive information. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Attachment Three

INTERCONNECTION ASSESSMENT

Large Generator Interconnection
System Impact Restudy Report

Completed for

("Interconnection Customer")
Q0713

Proposed Point of Interconnection

Yellowcake – Antelope Mine 230 kV transmission line
(POI at approx.43.113 N, 105.425 W)

January 29, 2018

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1.0 DESCRIPTION OF THE GENERATING FACILITY

(“Interconnection Customer”) proposed interconnecting 350 MW of new generation to PacifiCorp’s (“Transmission Provider”) Yellowcake – Antelope Mine 230 kV transmission line (Point of Interconnection at approx. 43.113 N, -105.425 W) located in Converse County, Wyoming. The project (“Project”) will consist of one hundred forty (140) GE 127 2.5 MW wind turbines for a total output of 350 MW. The requested commercial operation date is December 31, 2020.

The restudy of this Project is performed due to the staging of the Energy Gateway West project. Specifically, while the entire Gateway West project has a longer development timeline, the Aeolus-Bridger/Anticline D.2 segment of the project (500 kV segment from the planned Aeolus substation to the planned Anticline substation) now has an expected 2020 in-service date. The earlier availability of the D.2 segment materially changes certain modeling assumptions that could impact the cost or timing of the interconnection of certain projects whose previous studies depended on Gateway West in its entirety.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the Project “Q0713.”

2.0 SCOPE OF THE STUDY

The interconnection system impact restudy shall evaluate the impact of the proposed interconnection on the reliability of the transmission system. The interconnection system impact study will consider Base Case as well as all generating facilities (and with respect to (iii) below, any identified network upgrades associated with such higher queued interconnections) that, on the date the interconnection system impact study is commenced:

(i) are directly interconnected to the transmission system;
(ii) are interconnected to Affected Systems and may have an impact on the interconnection request;
(iii) have a pending higher queued interconnection request to interconnect to the transmission system; and
(iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

This interconnection system impact restudy will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The study will also provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of the cost responsibility and a non-binding good faith estimated time to construct.

Based on the engineering judgement, the stability results for this project are not expected to change and hence the restudy of stability analysis was not performed.

3.0 TYPE OF INTERCONNECTION SERVICE

The Interconnection Customer has selected *Energy Resource (ER)* interconnection service.

4.0 DESCRIPTION OF PROPOSED INTERCONNECTION

The Interconnection Customer’s proposed Generating Facility is to be interconnected through a new Point of Interconnection (“POI”) substation between Yellowcake and Antelope Mine 230 kV substations. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Generating Facility to the Transmission Provider’s system.

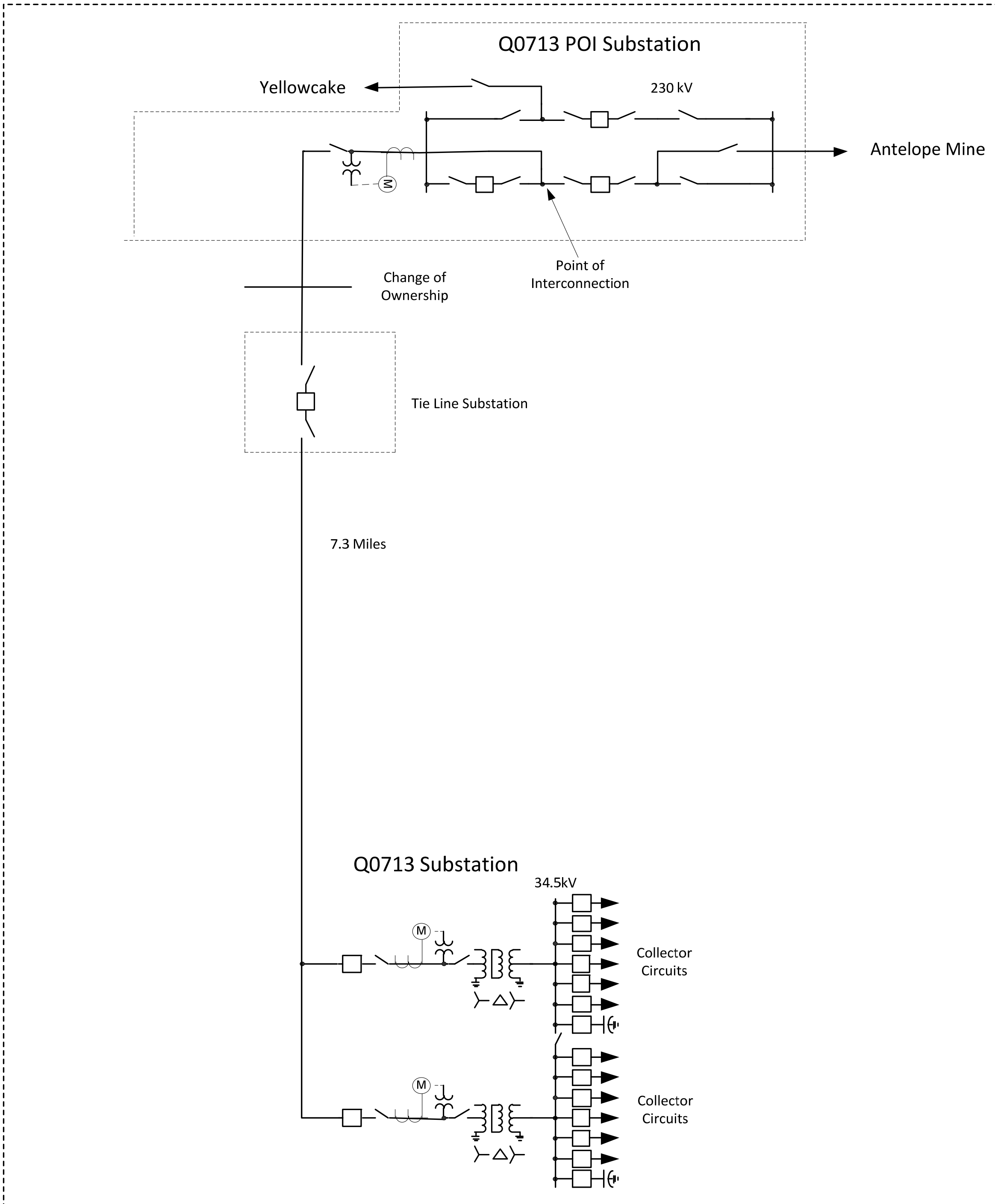

Figure 1: Simplified System One Line Diagram

5.0 OTHER OPTIONS CONSIDERED

The following alternative options were considered as potential points of interconnection for this Project: None

6.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests with an in-service date of December 2020 or earlier will be considered in this study and are listed in Appendix 1. If any of these requests are materially modified or withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: Interconnection Facilities associated with higher queued interconnection requests with an in-service date of December 2020 or earlier will be modeled in this study.
- The Interconnection Customer's request for energy or network resource interconnection service in and of itself does not convey transmission service. Only a Network Customer may make a request to designate a generating resource as a Network Resource. The provision of transmission service may require additional studies and the construction of additional upgrades.
- Under normal conditions, the Transmission Provider does not dispatch or otherwise directly control or regulate the output of generating facilities. Therefore, the need for transmission modifications, if any, which are required to provide Network Resource Interconnection Service will be evaluated on the basis of 100 percent deliverability (i.e., no displacement of other resources in the same area).
- This study assumes the Project will be integrated into the Transmission Provider's system at agreed upon and/or proposed POI.
- The Interconnection Customer will construct and own any facilities required between the Point of Change of Ownership and the Project unless specifically identified by the Transmission Provider.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and the Transmission Provider's performance and design standards.
- The Energy Gateway West, Aeolus-Bridger/Anticline D.2 500 kV line from the proposed Aeolus substation to the proposed Anticline substation and ancillary projects are assumed in service in 2020.
- All system improvements associated with the prior queued projects are in service before Q0713. This includes a new Aeolus – Shirley Basin #2 230 kV line with 2x1557 ACSR (Q0707), rebuild of the Standpipe-Freezeout-Aeolus 230 kV line to 2x1272 (Q0712), and rebuild of the Aeolus – Shirley Basin #1 230 kV line with 2x1557 ACSR (Q0712).
- All existing and proposed Remedial Action Schemes ("RAS") associated with prior queue generation facilities are assumed to be in service for this study.

- A RAS that will arm approximately 640 MW of generation for the Energy Gateway D.2 outages was assumed to be in-service.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Transmission Provider's web site regularly for Transmission System updates at http://www.pacificorp.com/tran.html

7.0 ENERGY RESOURCE (ER) INTERCONNECTION SERVICE

Energy Resource Interconnection Service allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System and to be eligible to deliver electric output using firm or non-firm transmission capacity on an as available basis.

7.1 Requirements

7.1.2 GENERATING FACILITY MODIFICATIONS

All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.

For synchronous generators, the power factor requirement is to be measured at the Point of Interconnection. For asynchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Generating Facility must provide dynamic reactive power to the system in support of both voltage scheduling and contingency events that require transient voltage support, and must be able to provide reactive capability over the full range of real power output.

If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the Generating Facility must be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization from the Grid Operator is given to operate in other control mode (e.g. constant power factor control). The control mode of the generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the Point of Interconnection. In general, Generating

Facilities should be operated so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Transmission Provider, between 1.00 per unit to 1.04 per unit. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions. Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among generation facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.

For areas with multiple generating facilities additional studies may be required to determine whether or not critical interactions, including but not limited to control systems, exist. These studies, to be coordinated with Transmission Provider, will be the responsibility of the Interconnection Customer. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generating Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

To facilitate collection and validation of accurate modeling data to meet NERC modeling standards, PacifiCorp, as the Planning Coordinator, requires Phasor Measurement Units (PMUs) at all new Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater. In addition to owning and maintaining the PMU, the Generating Facility will be responsible for collecting, storing and retrieving data as requested by the Planning Coordinator. Data must be collected and be able to stream to Planning Coordinator for each of the Generator Facility's step-up transformers measured on the low side of the GSU at a sample rate of at least 30 samples per second and synchronized within +/- 2 milliseconds of the Coordinated Universal Time (UTC). Initially, the following data must be collected:

- Three phase voltage and voltage angle (analog)
- Three phase current (analog)

Data requirements are subject to change as deemed necessary to comply with local and federal regulations.

All generators must meet the Federal Energy Regulatory Committee ("FERC") and WECC low voltage ride-through requirements as specified in the interconnection agreement. As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

Based on the turbine specification data provided by the Interconnection Customer, the wind turbines do not have the capability to deliver 100% of the power to the Point of Interconnection within the range of +/- 0.95 power factor. The data provided indicates that the wind turbines have a power factor capability of 0.98 capacitive and 0.96 inductive at rated power.

The study showed that the collector system injects approximately 17.2 MVAr (see Figure 3 in Appendix 3) when it is connected to the transmission system without the wind turbines being online. The Interconnection Customer will be required to ensure that there is minimum reactive interchange under these conditions and that the collector system of the Project is not contributing excessive reactive power into the system increasing voltage under light load conditions. Failure of the Project to minimize the reactive interchange under these conditions may result in the opening of the POI breakers for the Project by the grid operator.

At low output level, the Project needs to ensure that it maintains the power factor within +/- 0.95 at the POI and minimize the reactive power flow towards the transmission system to prevent high voltages. PacifiCorp has experienced high voltages in the Wyoming area when the transmission system is lightly loaded with low wind conditions. With low wind conditions the wind farms tend to supply reactive power into the transmission system increasing the voltage.

The Interconnection Customer is responsible for the protection of the transmission line between the Generating Facility and the Point of Interconnection substation. In order to provide this protection the Interconnection Customer shall construct and own a tie line substation to be located at the change of ownership (separate fenced facility adjacent to the Transmission Provider's Point of Interconnection substation) and include an Interconnection Customer owned protective device and associated transmission line relaying/communications. The ground grids of the Transmission Provider's Point of Interconnection substation and the Interconnection Customer's tie line substation will be connected to support the use of a bus differential protection scheme which will protect the overhead bus connection between the two facilities

7.1.3 TRANSMISSION SYSTEM MODIFICATIONS

- Construct a new POI substation with 3-breaker ring bus configuration between Yellowcake and Antelope Mine substations (refer to Figure 1).
- Expansion of the Windstar 230 kV substation with a new 230 kV bus.
- Addition of two new 230 kV breakers at Windstar substation.
- A new line termination at Windstar substation.
- A new line termination at Shirley Basin substation and one 230 kV circuit breaker.
- Construction of a new, 60-mile Windstar – Shirley Basin 230 kV line with 2-1272 ACSR (Aluminum Conductor Steel Reinforced).

Additionally, the Q0713 project triggers the need for the Transmission Provider's planned Energy Gateway South project. This project consists of a new 400 mile 500 kV transmission line from the planned Aeolus substation in Wyoming to the Transmission Provider's existing Clover substation in central Utah, with ancillary improvements.

7.1.4 TRANSMISSION REQUIREMENTS

Construct approximately 1,200 feet of 230 kV transmission line to loop-in the existing Antelope-Yellowcake 230 kV line to the Q0713 POI substation. This will require two guyed wood pole main line structures near structure 1/33 and a new guyed wood pole structure at each end of the POI sub.

Construct approximately 60 miles of 230 kV transmission line from Windstar substation to Shirley Basin substation. Conductor shall be double bundle 1272 ACSR "Bittern" Conductor.

The Interconnection Customer shall construct the tie line from the collector substation to the tie-line substation.

The Interconnection Customer is required to build tie-line substation adjacent to the new POI substation which will house the tie-line circuit breaker. The Transmission Provider shall review the design of the tie-line span between the tie-line substation deadend tower and the new POI substation deadend tower. The Interconnection Customer shall coil conductor, OPGW, shield wire, and line hardware with sufficient quantities to span between the tie-line substation tower and the POI substation tower.

The Transmission Provider will construct the span between the tie-line substation tower and the new POI substation tower.

If any Transmission Provider lines are crossed by Interconnection Customer tie-line, the Interconnection Customer line will cross under Transmission Provider's line with at least NESC plus 3 foot clearance under all sag conditions of both lines.

7.1.5 EXISTING CIRCUIT BREAKER UPGRADES – SHORT CIRCUIT

The increase in the fault duty on the system as a result of the addition of the Generating Facility with 140 GE 127 2.5 MW wind turbine generators fed through 140 – 2600 kVA 34.5 kV – 690 V transformers with 9.0% impedance then fed through two 230 – 34.5kV 120/115/200 MVA step up transformers with 8.0% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

7.1.6 PROTECTION REQUIREMENTS

The installation of protective relays for line fault detection will be required at the Transmission Provider's new 230 kV POI substation for the protection of the line to the Interconnection Customer's collector substation and the lines to Windstar and Teckla substations.

The ground mats of the tie-line substation and the Q0713 POI substation must be tied together so that metallic control cables can be used between the two facilities. Bus differential relays will be applied to detect faults on this connection. With this arrangement the Interconnection Customer must install line relays systems that will detect and clear all faults on the tie lines in 5 cycles or less. A set of non-pilot step distance line relays that will detect faults on the tie-line will also be applied at the Q0713 POI substation. Should the Interconnection Customer desire a potential alternative to the tie line substation in order to provide adequate protection to its tie-line, the Interconnection Customer may petition the Transmission Provider for an exemption to this arrangement. The Transmission Provider must review and approve the Interconnection Customer's proposed alternative. Without approval of the proposed alternative the tie-line substation configuration will be required. The Interconnection Customer will need to supply and maintain sets of line relays to be installed at Q0713 collector substation that will detect faults on the 230 kV line back to the Q0713 POI substation. These line relays can be time coordinated with the relays detecting faults on the transmission network and will not communicate with the line relays to be installed at the Q0713 POI substation for the tie-line.

Protective relay elements in the line relays at the Q0713 POI substation will monitor voltage and frequency. If the voltage, magnitude or frequency is outside of the normal operation range, this relay will trip the 230 kV breaker at the tie line substation.

The lines to Windstar and Teckla substations will continue to use permission over reaching logic line distance relays so the existing relays at Windstar and Teckla substations will require setting adjustments to accommodate addition of the POI substation.

The new 230 kV line between Windstar and Shirley Basin substations will be protected with a line current differential relay system.

7.1.7 DATA (RTU) REQUIREMENTS

Data for the operation of the power system will be needed from the Generating Facility and the new POI substation. The Interconnection Customer will install a Transmission Provider approved data concentrator at the collector substation and will install OPGW between the collector substation and tie line substation. The data will then be tied into a Transmission Provider owned RTU at the new POI substation.

In addition to the control and indication of the new 230 kV breakers at the POI substation, the following data will be acquired through the POI substation RTU. Also listed is the data that will be acquired from the collector substation.

From POI substation:

Analogs:

- Net Generation MW
- Net Generator MVAr
- Energy Register

From the Q0713 collector substation:

Analogs:

- Transformer 1 Real power
- Transformer 1 Reactive power
- Transformer 2 Real power
- Transformer 2 Reactive power
- 34.5 kV Real power 52 A1 & N
- 34.5 kV Reactive power 52 A1 & N
- 34.5 kV Real power 52 A2 & C
- 34.5 kV Reactive power 52 A2 & C
- 34.5 kV Real power 52 D
- 34.5 kV Reactive power 52 D
- 34.5 kV Real power 52 E
- 34.5 kV Reactive power 52 E
- 34.5 kV Real power 52 F
- 34.5 kV Reactive power 52 F
- 34.5 kV Real power 52 G
- 34.5 kV Reactive power 52 G
- 34.5 kV Real power 52 H
- 34.5 kV Reactive power 52 H
- 34.5 kV Real power 52 I
- 34.5 kV Reactive power 52 I
- 34.5 kV Real power 52 J
- 34.5 kV Reactive power 52 J
- 34.5 kV Real power 52 K
- 34.5 kV Reactive power 52 K
- 34.5 kV Real power 52 L & B1
- 34.5 kV Reactive power 52 L & B1
- 34.5 kV Real power 52 M &B2
- 34.5 kV Reactive power 52 M & B2
- 34.5 kV Reactive power 52 CAP 1
- 34.5 kV Reactive power 52 CAP 2
- A phase 230 kV transmission voltage
- B phase 230 kV transmission voltage
- C phase 230 kV transmission voltage
- Average Wind speed
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

Status:

- 230 kV Transformer Breaker 1
- 230 kV Transformer Breaker 2
- 34.5 kV breaker 52 A1 & N
- 34.5 kV breaker 52 A2 & C
- 34.5 kV breaker 52 D
- 34.5 kV breaker 52 E
- 34.5 kV breaker 52 F
- 34.5 kV breaker 52 G
- 34.5 kV breaker 52 H
- 34.5 kV breaker 52 I
- 34.5 kV breaker 52 J
- 34.5 kV breaker 52 K
- 34.5 kV breaker 52 L & B1
- 34.5 kV breaker 52 M & B2
- 34.5 kV breaker 52 CAP 1
- 34.5 kV breaker 52 CAP 2
- 34.5 kV breaker Bus Tie
- Line Relay Alarm

From the Tie Line Substation
Status:
- 230 kV Breaker

7.1.8 SUBSTATION REQUIREMENTS

Q0713 POI Substation:
To support the requested interconnection, the Project will require a new 230kV, three breaker ring bus POI substation. The substation will be approximately 270’ x 470’ (fence dimensions) based on the Interconnection Customer provided facility requirements. The following is a list of the major equipment required for this Project:

- 3 – 230kV Power Circuit Breakers
- 6 – 230kV CCVTs
- 3 – 230kV CT/VT Metering units
- 13 – 230kV Switches
- 9 – 230kV Lightning Arresters
- 1 – 230kV SSVT
- 1 – Microwave Communication System

Q0713 Collector Station:
The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer’s Generating Facility for the Transmission Provider to install metering equipment. This area will share a fence and ground grid with the Generating Facility and have separate, unencumbered access for the Transmission Provider. AC station service for the

control house will be supplied by the Interconnection Customer. DC power for the control house will be supplied by the Transmission Provider.

Windstar Substation:

Install a new 230kV bay and line position to support a new 230kV line to Shirley Basin substation. The following major material will be required for this Project:

- 2 – 230kV Power Circuit Breakers
- 3 – 230kV CCVTs
- 5 – 230kV Switches
- 3 – 230kV Lightning Arresters

Shirley Basin Substation:

Install a new 230kV bay and line position to support a new 230kV line to Windstar substation. The following major material will be required for this Project:

- 1 – 230kV Power Circuit Breaker
- 3 – 230kV CCVTs
- 5 – 230kV Breaker Disconnect Switches
- 1 – Motor Operated Line Disconnect Switch
- 3 – 230kV Lightning Arresters
- 1 – Line Relay Panel
- 1 – Breaker Control Panel

7.1.9 Communication Requirements

The Interconnection Customer is required to install OPGW between the POI substation and the collector substation. ADSS fiber is required between the tie-line substation and the POI substation. The Interconnection Customer is to supply 2 - DNP3 circuits from the collector substation to the tie line substation and into the POI substation building with the SCADA points required.

Communications to the Transmission Provider's existing communications will be achieved through microwave. A new microwave communication system will be installed at the POI substation. The POI microwave will connect to the Transmission Provider's Flat Top communications site. The microwave tower at Flat Top will need to be replaced. The path will then connect to the Transmission Provider's Glenrock communications site and on through the existing system. The existing microwave between Glenrock and Flat Top will be upgraded to a 6 Ghz space diversity path.

Communication circuits are required between the POI, Windstar and Teckla substations over the new microwave. Multiplexes, routers and channel banks will be required at the POI, Teckla, and collector substations. At the POI substation a 48volt battery and charger is required for communication. At the collector substation the Interconnection Customer will supply AC voltage for the communication equipment.

7.1.10 METERING REQUIREMENTS

Interchange Metering

Point of Interconnection will be at the Transmission Provider Q0713 substation. Metering will be designed bidirectional and rated for the total net generation of the Project. The bidirectional metering will also include the retail load (per tariff) delivered to the Interconnection Customer. The Transmission Provider will specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination 1000:5 CT/VT extended range for high accuracy metering.

The metering design package will include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One meter will be designated a primary SCADA meter and a second meter will be used designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data.

An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.

Q0713 Transformer A metering:

Revenue metering is required on the high side of the step-up transformers. The primary metering transformers shall be combination 230kV, 500:5 CT/VT extended range for high accuracy metering.

The Transmission Provider will design and procure the collector revenue metering panels. The panels shall be located inside the collector control house. The collector substation metering panel shall include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block. An Ethernet phone line is required for retail sales and generation accounting via the MV-90 translation system.

Q0713 Transformer B metering:

Revenue metering is required on the high side of the step-up transformer. The primary metering transformers shall be combination 230kV, 500:5 current ratio, CT/VT extended range for high accuracy metering.

The Transmission Provider will design and procure the collector revenue metering panels. The panels shall be located inside the collector control house. The collector substation metering panel shall include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block. An Ethernet phone line is required for retail sales and generation accounting via the MV-90 translation system.

<u>Station Service/Construction Power</u>

The Project is within the Transmission Provider service territory. Please note, prior to back feed Interconnection Customer must arrange transmission retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-625-6078 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.2 COST ESTIMATE (ER)

The following estimate represents only scopes of work that will be performed by the Transmission Provider. Costs for any work being performed by the Interconnection Customer are not included.

<u>**Direct Assigned**</u>	
Q0713 Collector substation	$1,218,000
Add metering and control house	
Q0713 POI substation	$837,000
Add POI terminal and metering	
Total Direct Assigned	**$2,055,000**
<u>**Network Upgrade**</u>	
Q0713 POI substation	$9,702,000
Add 230kV ring bus substation	
Yellowcake – Antelope Mine transmission line	$399,000
Loop transmission line in/out of POI substation	
Windstar to Shirley Basin 230kV line	$28,726,000
Build 60 miles of new 230 kV line	
Windstar substation	$4,194,000
Add new line position, update relay settings	
Shirley Basin substation	$2,120,000
Add new line position	
Flat Top substation	$904,000
Upgrade communications equipment	
Teckla substation	$48,000
Upgrade communications equipment, update relay settings	
Glenrock substation	$174,000
Upgrade communications equipment	
Total Network Upgrade	**$46,267,000**
Grand Total	**$48,322,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Generating Facility to Transmission Provider's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

7.3 SCHEDULE

The Transmission Provider estimates it will require approximately 60-78 months to permit, design, procure and construct the facilities described in the Energy Resource sections of this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report as well as the current anticipated in-service date of the Transmission Provider's Gateway South transmission line (2024) does not support the Interconnection Customer's requested Commercial Operation date of December 31,2020.

7.3.1 MAXIMUM AMOUNT OF POWER THAT CAN BE DELIVERED INTO NETWORK LOAD, WITH NO TRANSMISSION MODIFICATIONS (FOR INFORMATIONAL PURPOSES ONLY)

Zero (0) MW can be delivered on a firm basis to the Transmission Provider's network loads with additional transmission modifications.

7.3.2 ADDITIONAL TRANSMISSION MODIFICATIONS REQUIRED TO DELIVER 100% OF THE POWER INTO NETWORK LOAD (FOR INFORMATIONAL PURPOSES ONLY)

In order to deliver 100% of the power into Network Load, in addition to the mitigation identified in section 5.1.1.2, the completion of additional Transmission Provider Energy Gateway projects and other system improvements would also be required.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

Transmission Provider has identified the following affected systems: WAPA, Black Hills, Tri-State, and Basin Electric

A copy of this report will be shared with each Affected System.

9.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

9.1.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0542 (240 MW) – QF/NR
Q0706 (250 MW) – ER
Q0707 (250 MW) – ER
Q0708 (250 MW) – ER
Q0712 (520 MW) – ER

9.1.2 Appendix 2: Property Requirements

Property Requirements for Point of Interconnection Substation

Requirements for rights of way easements
Rights of way easements will be acquired by the Interconnection Customer in the Transmission Provider's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Transmission Provider's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Transmission Provider's easement form.

Real Property Requirements for Point of Interconnection Substation
Real property for a Point of Interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's Project. The real property must be acceptable to Transmission Provider. Interconnection Customer will acquire fee ownership for interconnection substation unless Transmission Provider determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Transmission Provider's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Transmission Provider and are subject to the Transmission Provider's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the Project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Transmission Provider. The real property shall be a permitted or able to be permitted use in all zoning districts. The Interconnection Customer shall provide Transmission Provider with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Transmission Provider. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A

phase I environmental study is required for land being acquired in fee by the Transmission Provider unless waived by Transmission Provider.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Transmission Provider may require Interconnection Customer to procure various studies and surveys as determined necessary by Transmission Provider.

Operational: inadequate access for Transmission Provider's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Transmission Provider.

9.1.3 APPENDIX 3: STUDY RESULTS

Power Flow Study Results

A Western Electricity Coordinating Council (WECC) approved 2015 Heavy Summer case was used to perform the power flow studies using PSS/E version 33.7. The 2015 Heavy Summer case was modified for the study.

Power flow studies were performed on both peak and off-peak load cases. The study was performed assuming the Energy Gateway D.2 Projects are in-service. The local 500 kV, 345 kV, 230 kV and 115 kV transmission system outages were considered during the study.

N-0 Results:
Under N-0 conditions with the Q0713 project in service there is a 101% overload on the Difficulty – Amasa 230 kV line. A new approximately 60-mile 230 kV line from Windstar to Shirley Basin constructed with 2- 1272 ACSR will mitigate this issue as well as some N-1 issues discussed below.

The data provided by the Interconnection Customer indicated that the generator does not have adequate reactive capability to deliver 100% of its power output at +/- 0.95 power factor. Hence, external shunt compensation which is dynamic in nature will be required in order to control the voltage and provide adequate reactive capability to maintain the voltage at the POI with a +/- 0.95 power factor on the high side of the step-up transformer.

Figure 3 below, shows injection of approximately 17.2 MVAr into the transmission system was observed if the collector system was connected with no generation from the Project. The addition of 17.2 MVAr on the transmission system under light load conditions could cause high voltages. The Project must control the voltage at the POI within the required voltage range provided by the Transmission Operator.

N-1 Results: Assuming Energy Gateway D.2 segment and the system improvements associated with the prior queued projects are in service, the following issues were identified.

- Outage of the Amasa – Difficulty-Shirley Basin 230 kV line overloads the Dave Johnston South Tap – Refinery Tap to 101%. Low voltages in the Spence – Buffalo Head area also observed. The new Windstar – Shirley Basin 230 kV line identified as mitigation under the N-0 results will resolve these issues.

- Outage of the Aeolus – Anticline 500 kV line, the Aeolus 230/500 kV transformer or the Anticline 345/500 kV transformer, post generation dropping of 640 MW (Aeolus RAS), results in multiple 230 kV line overloads. Construction of the Transmission Provider’s planned Energy Gateway South 500 kV line from Aeolus to Clover, approximately 400 miles, will mitigate these issues.

N-2 Results: No N-2 thermal or voltage issues were observed in the studies.

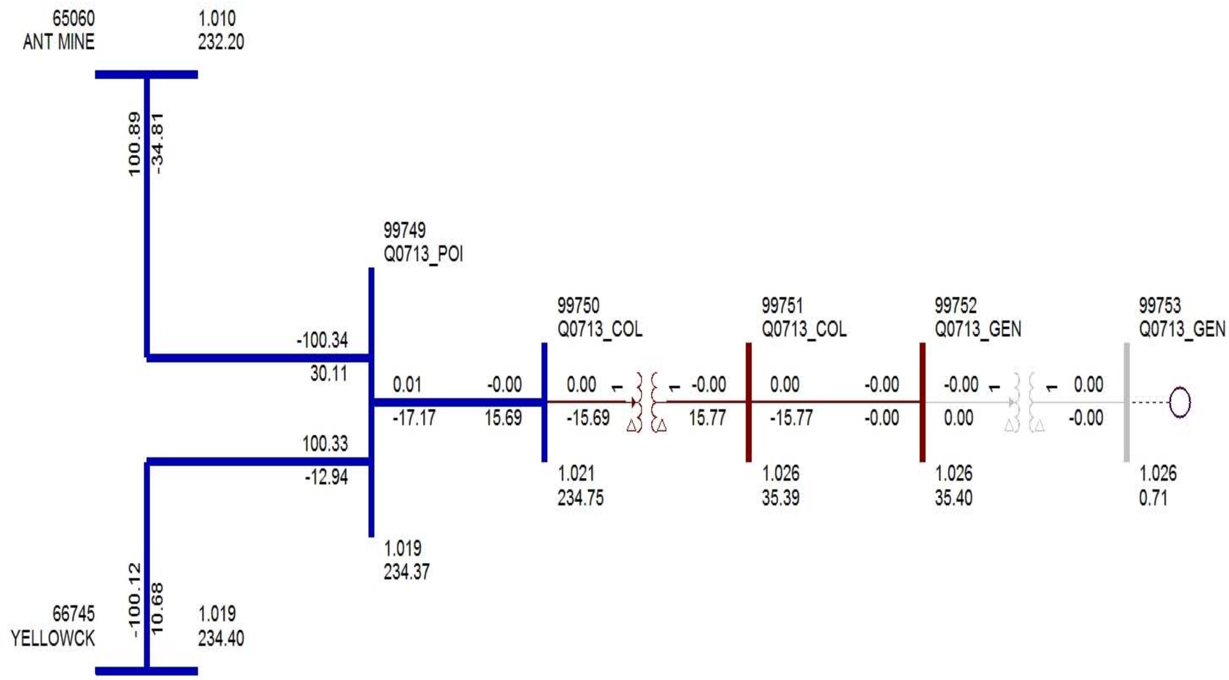

Figure 3: Charging from Q713 collector systems

Attachment Four

UPDATED FINAL SHORTLIST

Attachment Four contains confidential and commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request.

The confidential information is available to parties who have signed a confidential agreement in this docket.

The Company requests special handling of the commercially sensitive information. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Attachment Five

FINAL COSTS FOR SHORTLISTED BIDS

Attachment Five contain commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request.

The Company requests special handling. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Attachment Six

TRANSMISSION REVENUE REQUIREMENTS

Attachment Six contain commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request.

The Company requests special handling. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.

Appendix A

BENCHMARK BID ANALYSIS

Appendix A contains confidential and commercially sensitive information which is considered business confidential information subject to Utah Code 63G-2-305(2) and 63G-2-305(3) to protect it from a Government Records Access and Management Act (GRAMA) request.

The confidential information is available to parties who have signed a confidential agreement in this docket.

The Company requests special handling of the commercially sensitive information. Please contact Jana Saba at (801) 220-2823 to make arrangements to review.