REDACTED
Rocky Mountain Power
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Timothy J. Hemstreet

October 2017

REBUTTAL TESTIMONY OF TIMOTHY J. HEMSTREET

Q. Are you the same Timothy J. Hemstreet who previously provided direct testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. I provide an update on the technical and commercial aspects of the Company's wind repowering project, demonstrating the project's increasing value and decreasing risk. I also respond to the direct testimony of Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger and Daniel Peaco recommending that the Public Service Commission of Utah ("Commission") not approve the Company's energy resource decision for wind repowering.

Q. What are the key issues you address in your rebuttal testimony?

A. I address the following key issues:

- A description of the fully negotiated contracts with General Electric International, Inc. ("GE") and Vestas-American Wind Technology, Inc. ("Vestas") for the wind repowering project, and associated cost-savings.
- An update on the wind turbine generator equipment specified for the wind repowering project and the increased generation benefits now anticipated as a result of changes to that equipment.
- In response to the DPU's testimony, I summarize the Company's significant efforts to date and future plans to minimize risk associated with the wind

repowering project to ensure that the project will deliver the anticipated benefits.

- The timing and process leading up to the Company's decision to execute safe-harbor equipment-purchase contracts in late 2016, the evaluation of the repowering project in the Company's integrated resource planning process, and the appropriateness of the Commission's review of the wind repowering resource decision.

Q. Please summarize your testimony.

A. The Company has continued to work diligently on the wind repowering project to deliver benefits to its customers. The Company has finished negotiating a master retrofit contract with GE and a turbine supply contract with Vestas. The negotiated contract provisions reduce the initial estimated cost of the repowering project, increase the generation output, and reduce or eliminate various project risks. In addition, the Company has now completed most of its siting and permitting work, clearing this important project hurdle.

The DPU opposes Commission approval of the wind repowering resource decision for various reasons, mostly related to project risk and process issues. My testimony addresses each of the technical and commercial risks raised by the DPU. I show that the Company has aggressively managed these risks and none outweigh the customer benefits from repowering. I also demonstrate that the Company timely raised wind repowering in its 2017 Integrated Resource Plan ("IRP"), and has appropriately invoked the resource approval statute to obtain Commission review and approval of wind repowering.

UPDATE ON CONTRACT STATUS

Q. At the time you prepared your direct testimony, the Company was still negotiating a turn-key agreement with GE for the wind repowering project employing GE equipment. Has the Company now completed these negotiations?

A. Yes, the Company has completed negotiating a master retrofit contract that commits GE to perform turn-key supply, delivery, installation and commissioning of the repowering turbines at a fixed price.

Q. Does the fully negotiated GE retrofit contract reflect differences in pricing compared to the previous estimate used in the Company's economic analysis?

A. Yes, the negotiated contract reduces the pricing for those wind facilities that will be repowered using GE turbines. [redacted]

Q. Does this mean that the Company has committed to move forward with the wind repowering project regardless of the Commission's determination in this case?

A. No. The GE retrofit contract provides an off-ramp if the Company does not obtain regulatory approval for the repowering project or any approval that includes conditions that present a material concern to the Company in moving forward with the repowering project.

Q. Does the GE retrofit contract provide other off-ramps to address potential changes in circumstances that may affect the economics of the wind repowering project or the ability of the Company to execute the project as currently anticipated?

A. Yes. The GE retrofit contract allows the Company, before issuance of a retrofit work order directing GE to repower a facility, to not move forward with the retrofit work for a number of reasons. These include situations in which the Company was not able to timely obtain any required permit, or if the terms and conditions imposed by a permit are unacceptable to the Company; for technical reasons related to the suitability of the new turbines for the site or existing foundations; the Company's determination that changes in local, state, or federal law or corporate tax law create a material risk to the project; or if the federal production tax credit ("PTC") law or Internal Revenue Service ("IRS") guidance regarding PTCs (including the safe-harbor requirements or the 80/20 Rule) is adversely modified, amended, or changed.

Q. When does the Company anticipate issuing its first retrofit work order to repower a GE facility?

A. The first retrofit work order is expected to be issued in [redacted] to allow turbine delivery to begin in time to support repowering of facilities in 2019.

Q. If a retrofit work order is issued to GE for a facility and tax law changes, new permit requirements, or changes in PTC rules occur and those off-ramps are no longer automatically available to the Company, what recourse would the Company have?

A. Following the issuance of a retrofit work order, the GE retrofit contract has provisions that allow the Company to terminate the retrofit work order for convenience at known costs that escalate from the date the retrofit work order is executed up to the date of the first anticipated turbine delivery. Thus, the Company will still have the ability to respond to potential changes in the legal framework that may impact the value of the GE repowering facilities.

Q. Has the Company also completed negotiations on a turbine supply contract with Vestas?

A. Yes. The Company has completed negotiations with Vestas and has fixed pricing for turbines ordered [redacted].

Q. Do the two contracts with the turbine suppliers provide for the costs of the turbines (and installation in the case of GE) to be adjusted up or down for factors such as inflation, currency indexes, or steel price indexes?

A. No, the contracts provide that the prices are fixed and have no such adjustment mechanisms for those common price indexes. Generally, the turbine suppliers can only seek a change order for price relief as a result of changes in state and/or local law that impacts their costs.

UPDATE ON TURBINE SPECIFICATIONS AND ENERGY OUTPUT

Q. Please provide an update on the turbine equipment specified for use in the wind repowering project.

A. In my direct testimony, I noted that GE was developing a 91-meter rotor for repowering at wind facilities, like the Company's, that currently have GE 1.5-77 SLE turbines installed. GE finished developing this rotor and has completed the engineering and design review on a [redacted] turbine, which the Company can use to repower its [redacted]. The nameplate capacity of the generator of this turbine is [redacted] megawatts greater than the [redacted] turbine previously specified.

Q. Has GE evaluated this new turbine to ensure it can be used to repower the Company's [redacted]?

A. Yes, GE has completed a mechanical loads analysis for the new turbine type at each of the Company's [redacted] sites. The mechanical loads analysis is an engineering study to assess the site-specific climatic conditions and turbine loading to verify that the turbine is suitable for use at the facility site with the existing towers.

Q. Has the Company also verified that the existing foundations at these wind facilities are suitable for use with the new turbine, which may have different loading due to the larger rotors?

A. Yes, the Company's consultant Black & Veatch reviewed the new foundation loading at each facility site and determined that the existing foundations at the facilities can support the new turbines.

Q. Does the change in turbine specification for the wind facilities require modification to the nacelles purchased to meet safe-harbor requirements?

A. No, the existing nacelles the Company acquired from GE in December 2016 can be operated as a [redacted] turbine.

Q. What are the energy benefits of this new turbine type?

A. The increase in rotor diameter allows the wind turbine to capture additional wind energy, while the higher nameplate capacity allows the turbine to convert more of that available wind energy into electrical energy at higher wind speeds. Previously the

Company expected the generation output of the wind facilities to be fitted with GE [redacted] wind turbines to increase by 13.3 percent. The new GE [redacted] wind turbine results in an increase of 22.4 percent. Confidential Exhibit RMP__(TJH-1R) provides an update on the energy estimates for the repowering project.

Q. Does this new turbine selection for the wind facilities require additional modifications, like changes in the towers, substations, or the energy collector systems?

A. No. If operated within the limits of the existing large generator interconnection agreements, the Company does not anticipate that any such modifications are necessary.

Q. What is the net result of the changes in equipment specifications to the amount of additional energy expected to be produced as a result of repowering?

A. Assuming the generation interconnection agreements of the projects are not modified, the repowering project is estimated to result in an additional 743 gigawatt-hours ("GWh") of energy annually, or an overall increase of 25.9 percent. This compares to the 551 GWh and 19.2 percent increase in energy output estimated previously in the Company's Application. If the generation interconnection agreements are modified to allow all of the turbines to operate at their full nameplate capability during periods of higher winds, the generation benefits increase to 862 GWh, or 30.0 percent.

Q. Given the changes in turbine equipment that can generate additional energy, have the estimated costs of the repowering project increased?

A. No. The Company has fixed pricing for the turbines from GE and Vestas and for installation of the GE project turbines. Costs for turbine supply at each facility have either not changed from prior estimates or decreased. As a result, the total cost of the repowering project is now $1.083 billion—a reduction in cost of $45 million.

Q. If the generation interconnection agreements are modified, does the Company expect there will be additional costs to realize that additional generation?

A. Yes. Due to the higher nameplate capacity of the GE [redacted] turbines, enabling them to operate at full capacity would require replacing the turbine pad-mount transformers, upgrading some segments of the collector systems, and retrofitting or replacing certain generator step-up transformers. The Company expects the total cost of these upgrades to increase project costs by $36 million, for a total cost of approximately $1.119 billion. In addition, ongoing transmission studies will determine the costs of interconnecting the additional project capacity to the transmission system.

Q. Are there other updates to the project since the Company filed its request for resource approval?

A. Yes. The Company has also negotiated [redacted].

[redacted]

Q. Does the Company's updated economic analysis reflect the costs of this fully negotiated contract?

A. Yes. The Company's updated economic analysis reflects higher operations and maintenance costs [redacted] and reduced capital expenditures at the projects [redacted]. Capital expenditures are reduced for the [redacted].

Q. Are all of these changes reflected in the economic analysis in the rebuttal testimony of Company witness Mr. Rick T. Link?

A. All of the costs associated with these changes are reflected in the updated economic analysis described by Mr. Link. However, the Company did not receive verification from GE that the [redacted] turbine was technically suitable for its repowering project until October 6, 2017. As a result, Mr. Link's detailed analysis evaluates the energy output assuming a GE [redacted] turbine is used on sites that will be repowered with GE equipment instead of a GE [redacted] turbine—the difference being that the [redacted] turbine has the same cost as the GE [redacted] turbine but higher energy output as a result of a greater generator capacity.

REBUTTAL ON RISKS OF REPOWERING PROJECT

Q. DPU witnesses Dr. Joni Zenger and Mr. Daniel Peaco oppose Commission approval of the Company's repowering resource decision on the basis that the project risks outweigh the potential benefits. (Zenger Direct, lines 55 - 60; Peaco Direct, lines 72 - 75.) Please respond.

A. I strongly disagree with the DPU's conclusion and rationale. Wind repowering has clear and immediate benefits to customers, and the Company has identified and managed project risks and will continue to successfully manage those risks. The DPU's testimony does not properly account for the steps the Company has already taken to eliminate or mitigate the risks they identified. On each issue raised by the DPU, the Company can demonstrate that it has considered and prudently managed project risk, as set forth below.

Q. When discussing risks related to the repowering project qualifying for PTCs, Mr. Peaco states that the Company's 2016 safe harbor expenditures for four of the repowering facilities are less than 6.7 percent, and that these margins "do not leave a large room for error in compliance with the rule." (Peaco Direct, lines 658 - 662.) Do you believe that potential cost overruns pose a substantial risk to the ability of the project to qualify for the full value of PTCs?

A. No. The wind repowering project has a great deal of cost certainty because it involves equipment replacement rather than new construction. Cost and scope uncertainties that can increase costs are largely absent from this project. This is because the repowering project will not involve the construction of new roads, turbine foundations, substations or operations and maintenance buildings—where changed site conditions or uncertain geotechnical conditions can create cost uncertainty.

Q. Why is there little risk of not meeting the safe harbor requirement in this case?

A. The cost of the wind repowering project consists mainly of turbine supply costs which are fixed and set forth in fully negotiated turbine supply contracts with both GE and Vestas. In the case of the GE projects, the Company's fixed-price turn-key contract also includes turbine installation. To put the risks Mr. Peaco raises in perspective, Confidential Table 1 below shows the applicable project costs subject to the five percent safe-harbor requirement for each facility, as well as the current safe-harbor percentage for each facility given the Company's current cost estimates and allocation of 2016 safe-harbor equipment. Confidential Table 1 also shows the amount and percentage of each facility's costs that are now fixed under the Company's negotiated contracts.

Under these contracts, cost overrun exposure is largely limited to the aspects of the repowering scope that are not yet subject to negotiated, fixed-price contracts. As shown in the table, the non-fixed project costs could escalate between 100 percent and 5,300 percent and each facility would still be able to comply with the five percent safe-harbor requirement. In the worst case scenario, the Company's cost estimates, which have been informed by budgetary quotes from wind energy construction companies and reflect its experience constructing and maintaining these very same wind projects, can be exceeded by 100 percent and still qualify under the five percent safe-harbor rule.

Confidential Table 1
Cost Overrun Sensitivity of Repowering Facilities to Meet Five Percent Safe Harbor

Wind Project	Total Project Cost Applicable to Five Percent Safe Harbor ($000s)	Current Safe Harbor Percentage (%)	Cost that are Fixed with Turbine Suppliers ($000s)	Turbine Supplier Fixed Costs (%)	Costs Not Yet Contractually Fixed ($000s)	Amount that Non-Fixed Costs Can Increase and Meet 5% Safe Harbor (%)
McFadden Ridge	[redacted]					
Seven Mile Hill II						
High Plains						
Dunlap I						
Glenrock III						
Glenrock I						
Rolling Hills						
Seven Mile Hill I						
Marengo I						
Marengo II						
Leaning Juniper						
Goodnoe Hills						

Q. The Company produced detailed construction cost estimates in discovery in this case. Has any party questioned specific aspects of the Company's construction cost estimates or identified cost elements the Company has underestimated or overlooked?

A. No.

Q. Do you believe the contracting mechanisms the Company intends to use for the majority of the non-fixed costs shown in the table above create risk of potential cost overruns?

A. No. The majority of the non-fixed costs are turbine installation costs not already covered by a contract. The Company—as it has traditionally done for its wind energy development construction projects—will execute fixed-price contracts for all turbine installations so that the costs are known in advance and not subject to variability except for standard provisions that allow the installer to seek price relief (e.g., force majeure, change in law).

Q. Are there other actions the Company can take to mitigate the risk associated with the five percent safe harbor?

A. Yes. As discussed in the rebuttal testimony of Ms. Nikki L. Kobliha, the Company could reallocate safe-harbor turbine components among facilities if a specific facility is experiencing cost overruns. This would increase that facility's safe-harbor percentage, ensuring it equals or exceeds five percent.

Q. What if the Company determined, after the equipment was already installed, that the five percent safe-harbor requirement was not met. Would that result in the entire project losing its full PTC value?

A. No. As described in Ms. Kobliha's rebuttal testimony, in such a case, the Company would simply reduce the scope of its repowering project to exclude a specific turbine or turbines, thereby reducing the overall project cost such that the allocated PTC safe-harbor equipment is sufficient to satisfy the five percent requirement. This would allow those turbines that remain within the defined project to qualify for the full value of PTCs. As demonstrated by the fact that the Company will not be repowering 32 turbines at the Glenrock/Rolling Hills site because they would not meet the 80/20 test, the Company is free to define the number of turbines at a facility site that it is including within its wind repowering project.

Q. Wouldn't that affect the economics of the project since individual turbines would be left out of the project and not generate PTCs?

A. Yes, but it would preserve full PTC qualification for nearly all of the wind repowering project and thus does not materially affect the overall project economics.

Q. When implementing projects like the wind repowering project, does the Company have personnel and processes to track costs and ensure awareness of forecasted and actual project spending throughout the project?

A. Yes, for all capital projects of this scale, the Company has assigned project managers who work with the Company's construction management, finance and accounting staff to forecast and accrue project costs and track project invoices and contract payments such that any cost changes are identified as they occur. The Company can use this information to make any needed adjustments to manage the limited risk of potential cost overruns.

Q. For the wind facilities the Company has previously constructed, has the Company ever had an issue in meeting the applicable IRS requirements such that the projects did not qualify for PTCs?

A. No.

Q. Do you believe there are material risks that the 2016 safe-harbor purchases could be inadequate?

A. No. As shown in Confidential Table 1, the only realistic potential for cost overruns to impact the adequacy of the 2016 safe-harbor purchases [redacted]. Thus, before committing to the project, the Company will have certainty that cost overruns for those facilities pose no threat to the adequacy of the 2016 safe-harbor equipment. Should there be a potential for the 2016 safe-harbor equipment to be insufficient to cover anticipated project costs, the Company will have the ability to address those risks as described above.

Q. How do you respond to Mr. Peaco's testimony that the Company has not provided any analysis of the risk of potential cost overruns causing the 2016 safe-harbor expenditures to be insufficient? (Peaco Direct, line 667.)

A. The Company has assessed and addressed the safe-harbor risk since the inception of the project. For example, the Company acquired safe-harbor equipment sufficient to achieve a six percent safe-harbor to ensure adequate coverage. The Company has also taken the steps described above to ensure certainty around project costs and will continue to monitor these costs. Because it is highly unlikely that the Company's cost estimates will be off by 100 percent or more, an economic analysis or sensitivity around these risks, as Mr. Peaco suggests, is not productive or necessary.

Q. Has Mr. Peaco proposed a methodology the Company should use to assess these risks?

A. No.

Q. Mr. Peaco also alleges that there is risk that the repowered facilities may not be in service by the end of 2020 due to the possibility turbines, contractors or equipment may not be available. (Peaco Direct, lines 697 - 699.) Do you believe this is a significant risk to the project or its economics?

A. No. As noted above, for the [redacted] wind facilities, the Company already has a fully negotiated contract with GE to perform repowering on a turn-key basis and thus has secured the equipment and resources to complete those projects. The Company has also negotiated a turbine supply contract with Vestas and will be able to secure those turbines. GE will be contractually obligated to complete repowering by guaranteed completion dates that will be specified by the Company. The Company plans to complete seven of the [redacted] facilities before the end of 2019—a year ahead of the required December 31, 2020 deadline for the repowered facilities to achieve commercial operation. Thus, there is little risk of those facilities not meeting the 2020 deadline. The Dunlap facility is the only facility the Company is planning to repower in 2020 to avoid significantly truncating the existing PTCs from that facility.

Q. Does the Company have any remedies if GE does not meet a guaranteed turbine-completion date for a wind facility?

A. Yes. If the delay is not caused or otherwise agreed to by the Company or due to certain strictly limited "excusable delay" events, and the Company has met its contract requirements, GE will be required to pay liquidated damages to the Company of [redacted] per day for any turbine that is not completed by a guaranteed turbine-completion date, [redacted]. In addition, as discussed in more detail below, if there is any slip in the turbine-completion date beyond December 31, 2020, [redacted]. These mechanisms in the GE contract create a powerful incentive for GE to maintain the contractual schedule.

Q. Mr. Peaco alleges that the Company has not "provided any mechanism for damage recovery due to 'lost' PTC." (Peaco Direct, lines 709 - 712.) Does the GE contract provide any remedies to the Company if the repowered facilities (or individual turbines within those facilities) fail to qualify for PTCs as a result of not being placed in service by December 31, 2020?

A. Yes. Under the terms of the GE retrofit contract, [redacted]

[redacted]

[redacted]

[redacted]

Q. Mr. Peaco also cites permitting and financing risks as having the potential to cause a delay in repowering the facilities, threatening their ability to qualify for PTCs. (Peaco Direct, lines 694 - 699.) Do you agree?

A. No. The Company has now received notice from the Wyoming Industrial Siting Division that no amendments to its existing operating permits for the Wyoming wind facilities are necessary to complete the repowering project. Similarly, the Company has received notice from Columbia County, Washington, that its conditional use permit for

[redacted]

the Marengo facility need not be modified and that no additional permits are needed to repower the facility. The Company now has the major permit authorizations for 10 of the 12 facilities proposed for repowering. I do not expect any issues in obtaining required regulatory approvals for the remaining two facilities.

Q. Mr. Peaco alleges that the Company has not assessed the risks related to potential lost PTC revenue as a result of permitting delays. (Peaco Direct, lines 694 - 702.) Please respond.

A. The Company will not order further turbines (beyond those already procured to satisfy the safe-harbor requirements) or otherwise move forward with the repowering project until it has secured the necessary permits—a task that is near completion. For this reason, permitting issues are not a material risk to achieving the benefits of the repowering project.

Q. What about the risk Mr. Peaco raises that repowering costs could be less than anticipated such that the 80/20 rule is not met due to insufficient expenditures? (Peaco Direct, lines 734 - 735.)

A. Given the fixed-priced contracts that the Company has negotiated for turbine supply and installation, there is very minimal risk that the Company could underspend on repowering costs such that a turbine failed the 80/20 test. In Confidential Table 2 below, I show the preliminary Ernst & Young valuation for each turbine type that the Company proposes to repower, based on a December 31, 2018 valuation date. Also shown is the required spending necessary to meet the 80/20 Rule, the anticipated spending per turbine, and the amount by which the anticipated spending is over the 80 percent threshold. As shown in the table, the turbines with the highest estimated fair market value of the retained components still have spending [redacted]. I am confident that cost under-run risk does not pose a significant threat to the ability of the projects to meet the 80/20 test. In addition, the turbines with the lowest spending in excess of the 80/20 requirements are planned to be repowered in the third quarter of 2019, and their fair market value at that time will likely be less than at the end of 2018–creating additional margin above the 80/20 spending requirement.

Confidential Table 2
80/20 Rule Spending Requirements by Project

Location Name	Turbine Foundation Type	# of Turbines	Ernst & Young Preliminary FMV of Retained Components Per Turbine 12/31/2018 ($000s)	Minimum Threshold of New Turbine Costs Required ($000s)	Qualifying Machine Head Costs Per Turbine ($000s)	New Turbine Costs in Excess of Requirement ($000s)
Goodnoe Hills	Standard	47	[redacted]	[redacted]	[redacted]	[redacted]
Marengo I	Standard	78	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock I	Standard	58	[redacted]	[redacted]	[redacted]	[redacted]
McFadden Ridge	Standard	19	[redacted]	[redacted]	[redacted]	[redacted]
Rolling Hills	Standard	42	[redacted]	[redacted]	[redacted]	[redacted]
Marengo II	Standard	39	[redacted]	[redacted]	[redacted]	[redacted]
Leaning Juniper	Standard	67	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill I	Standard	57	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill I	Dynamic	9	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock III	Standard	13	[redacted]	[redacted]	[redacted]	[redacted]
High Plains	Standard	66	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill II	Standard	13	[redacted]	[redacted]	[redacted]	[redacted]
Dunlap	Standard	74	[redacted]	[redacted]	[redacted]	[redacted]
Rolling Hills	Dynamic	6	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock III	Dynamic	7	[redacted]	[redacted]	[redacted]	[redacted]

Q. Dr. Zenger states that the Company previously experienced issues with deploying safe-harbor wind-turbine generator ("WTG") equipment when technical analysis later determined that the equipment purchased was unsuitable for particular wind development sites, and suggests that the repowering project presents a similar risk. (Zenger Direct, lines 148 - 179.) Do you agree?

A. No. The Company did not execute contracts to purchase the safe-harbor equipment acquired in December 2016 until it had completed technical analysis to verify the equipment was suitable for repowering. GE prepared this technical analysis in November 2016, which provided assurances that the GE nacelles could be deployed at 237 turbine locations in Wyoming. Vestas completed similar technical analysis in late

December 2016, verifying that the Vestas nacelles were suitable for deployment at the Marengo facility, with 117 turbine locations. GE subsequently completed mechanical loads analyses for the Dunlap, High Plains, and McFadden Ridge wind facilities in February and March 2017, providing assurance that repowering the entire Wyoming wind fleet was technically feasible with the equipment acquired in December 2016. GE completed technical analysis of the GE [redacted] turbine for use at all Company sites in Wyoming on October 6, 2017. These technical evaluations—as well as the verification by the Company's consultant that the foundations are suitable to accommodate the repowering turbines—fully address the risks identified by Dr. Zenger.

Dr. Zenger's criticism of the Company's prior acquisition of wind turbines intended for an Idaho site, but ultimately used for the Rolling Hills wind facility, is also misplaced. The Company determined that Rolling Hills was the best project in which to cost-effectively use the turbines it had acquired. At the time, turbines were in short supply and it would have been difficult for the Company to cost-effectively obtain turbines for an alternative project or even obtain turbines at all had it not already acquired the turbines. Moreover, to take advantage of the value of PTCs, which were set to expire at the end of 2008,[2] the Company needed to act quickly so it could place the resource in service by the end of 2008. In the end, the Company acted reasonably and in customers' interests, as indicated by the fact that the Commission did not find the Company's development of the Rolling Hills facility imprudent.

[2] The Emergency Economic Stabilization Act of 2008 (P.L. 110-343) passed on October 3, 2008, subsequently extended PTC eligibility to wind projects constructed by December 31, 2010, effectively extending the earlier December 31, 2008 eligibility window.

Q. Dr. Zenger also cites the Company's past experience in obtaining or extending land leases for wind projects under development as a risk related to the repowering project. (Zenger Direct, lines 182 - 187.) Has the Company verified that it has the land rights to operate its wind turbines for the anticipated extended life of the repowered wind facilities?

A. Yes, the Company has reviewed the terms for all of the leases where its wind turbines are located and has determined that, with two exceptions, the current lease expiration dates either already cover the extended asset life of the repowered wind turbines or that the Company has the unilateral ability to extend the duration of the land leases to cover the extended asset life. The first exception is Leaning Juniper, where the Company has the unilateral right to extend the lease term to January 2046. The second exception is two turbines at Marengo I that are located on State of Washington lands, where the current lease term runs through 2041. The Company has been in contact with both landowners and will work with them to extend the lease terms to cover the remaining additional years of project operations following repowering.

Q. What if the Company is unable to extend the leases for those turbines?

A. The Company would then re-evaluate the economics to determine if moving forward with a shorter lease term—or alternatively, not repowering certain turbines in the case of Marengo I—adversely impacts project economics. Because repowering the turbines is priced on a per-turbine basis, reducing the number of turbines repowered while also reducing the commensurate investment cost does not adversely impact project economics. Alternatively, it may be more prudent to wait to renew the leases until the lease expiration is closer at hand given the long time before the leases would need to be extended.

Q. Mr. Peaco alleges that the economic benefits of the repowering project are highly sensitive to the amount of energy produced by the repowered facilities, as well as the existing assets, and that there is risk to customer benefits because the Company's revenue estimates are "based entirely on assumed capacity factors." (Peaco Direct, lines 834 - 836.) Please respond.

A. I strongly disagree, with respect to both the existing and the forecast post-repowering generation from the facilities. The Company's assessment of the existing generation from the facilities, listed as Current Long Term Generation (MWh), Column 4 in Confidential Exhibit RMP__(TJH-1R), is not based on assumed capacity factors. The existing generation reflects the actual generation output from each facility since its first full year of commercial operations. It is not based on expected generation increases predicted by wind modeling nor based upon a P50 forecast of generation that may not reflect a project's actual generation history.

Q. Do the generation estimates following repowering also consist simply of "assumed capacity factors?"

A. No. The post-repowering estimates of energy production upon which the Company's current economic analysis are based also reflect the actual operating history of the wind facilities. The Company worked with its consultant, Black & Veatch, to use the extensive data history from the Company's facilities to derive precise estimates of the energy production expected from repowering. This analysis used more than 160 million data points from the operational record of the wind facilities and incorporated additional modeled wake losses anticipated from the new equipment. The results reflect as accurately as possible the energy production that would have occurred from the repowered turbines under the same operational conditions and availability as the existing equipment. Thus, the energy estimates do not rely upon assumptions about either the wind conditions that are expected to exist at the projects or improved availability as compared to the Company's actual experience.

Q. Do you believe these repowering energy estimates to be conservative?

A. Yes. The estimates reflect the generation increase that is expected to occur solely based on the different equipment performance specifications of the newer equipment. As described above, the generation estimates do not reflect any improvements in the operational availability of the wind facilities from repowering. I expect that the availability of the wind turbines will improve after repowering given the additional sensors and condition monitoring systems in the repowered turbines that should allow for improved diagnostics and implementation of preventative maintenance measures that can reduce turbine down-time. Additionally, given the [redacted], I anticipate the [redacted] availability of the projects may increase—resulting in more generation under similar wind conditions as compared to the past.

Q. Mr. Peaco states that "[w]ind generation is highly variable, and there is definite potential that actual project generation could be less than assumed." (Peaco Direct, lines 836 - 837.) Please respond.

A. While I agree that wind generation is highly variable, I do not agree that there is a definite potential that actual project generation could be less than assumed. As described above, the Company's estimates of existing energy production reflect the actual average annual generation observed over the life of the facilities. As described above, the repowering energy estimates are also derived from the actual operating history of the projects and applied to that same average baseline generation history. Thus, even with variability on a year-by-year basis, the long-term generation should revert to the mean.

Q. Does Mr. Peaco point to any specific factors in the Company's estimates of energy production that would create a bias towards an overestimation of the generation benefits from repowering?

A. No. He suggests there is potential for generation benefits to be less than anticipated due to the variable nature of wind generation, but he does not appear to ascribe a commensurate likelihood that the generation benefits could be greater than anticipated as a result of that same variability. Mr. Peaco does not provide any other rationale supporting his claim that the Company's generation estimates could be less than assumed.

Q. Mr. Peaco states that assumptions on project life have significant impacts on the customer benefits of the repowering projects and that these risks are borne by customers. (Peaco Direct, lines 869 - 874.) Do you believe the project life assumptions are biased in any way?

A. No. The Company's assumptions regarding asset life reflect the current depreciation lives of the wind facilities, as approved by the Commission. The Company's project life assumption simply reflects the reasonable assumption that equipment that is new will last 10 years longer than equipment that is already at least 10 years old.

APPLICABILITY OF VOLUNTARY RESOURCE APPROVAL STATUTE

Q. Dr. Zenger opposes the Company's request for approval of wind repowering because Utah's resource approval statute (the "pre-approval statute") does not contemplate approval of resource decisions that have "already been committed to." (Zenger Direct, lines 103 - 105.) Is this a valid objection?

A. No. As Mr. Jeffrey K. Larsen also explains in his rebuttal testimony, my understanding is that the pre-approval statute is designed to determine whether a resource decision is in the public interest before a utility implements its decision–which is the purpose of this docket. Although the Company made expenditures of [redacted] in 2016 to qualify for the full value of the PTC and preserve the option to repower the entirety of the wind fleet, the Company's expenditures to date for the wind repowering project represent only seven percent of the currently anticipated total costs of repowering. The Company's actions to date should not be interpreted as an absolute, unqualified commitment to proceed with the repowering project regardless of the outcome of this case. The Company is also not obligated contractually to either GE or Vestas to proceed with repowering or to purchase any additional equipment or services in support of the repowering project if the Commission denies the Company's request. The Company has asked for the Commission's review and approval of the repowering project—an option made economically feasible by the Company's decision to purchase safe harbor equipment in 2016—on the basis that the project is beneficial to customers and in the public interest.

Q. Dr. Zenger faults the Company for not including stakeholders in the planning process, and specifically notes the lack of a Commission-approved IRP or Action Plan identifying wind repowering as a factor relevant to the Commission's public interest determination. (Zenger Direct, lines 105 - 108, 222 - 227.) Could the Company have raised the wind repowering project early in the Company's 2017 IRP process?

A. No. The technical analysis demonstrating that it was feasible to repower any of the Company's wind facilities was not completed until November 1, 2016. On that date, GE completed a mechanical loads analysis of the Rolling Hills project (66 turbines) and a portion of the Glenrock III project (13 turbines). Subsequent mechanical loads analysis was completed for Glenrock I (66 turbines) and the remainder of Glenrock III (13 turbines) on November 3, 2016, and for the Seven Mile Hill I and II projects on November 7, 2016. Before this time, the Company did not know that repowering was feasible and did not have the information (*i.e.*, turbine types suitable for use in repowering, and their associated energy production) necessary to develop meaningful scenarios in the IRP.

Q. If the Company knew that repowering was technically feasible for at least a subset of its Wyoming wind projects in early November 2016, why did it not develop a proxy repowering scenario to include in the IRP process or state that it was contemplating repowering its wind facilities during the Company's November 17, 2016 IRP public meeting?

A. Although the Company knew in November 2016 that it was technically feasible to repower at least a portion of its Wyoming wind fleet, the Company had not completed negotiations with GE regarding equipment pricing, and it remained uncertain whether safe-harbor equipment was available—and to what extent—for delivery before the end of 2016. The Company also did not yet know whether repowering wind facilities with Vestas equipment was feasible since that technical analysis was not completed until December 22, 2016.

Q. Are there other factors that impacted the Company's ability to publicize its discussions with turbine suppliers at the end of 2016 or integrate repowering scenarios earlier in the IRP process?

A. Yes. First, only the original equipment manufacturers of the Company's wind turbines could complete the technical analysis validating whether repowering was technically feasible in time to acquire safe-harbor equipment in 2016. Thus, analysis of repowering projects within the IRP—had it been possible—would not have resulted in modeling proxy resources but rather in identifying specific projects requiring equipment from individual equipment suppliers. Public modeling of the economics of repowering—and potentially individual projects—could have disadvantaged the Company's negotiations with suppliers.

Second, safe-harbor WTG equipment was in short supply in late 2016 because it was the last year for wind projects to purchase equipment to qualify as having begun construction in 2016 and thereby qualify for 100 percent of the PTC. Thus, the Company was competing with other market participants to purchase limited safe-harbor equipment. Public information that the Company was considering repowering its wind fleet of known turbine types at known locations may have induced other market participants to evaluate repowering their own projects and could have resulted in greater competition for the limited safe-harbor equipment, increased prices, or limited turbine availability. This could have limited the Company's options for wind repowering and reduced customers' benefits.

Q. OCS witnesses Messrs. Mangelson and Hayet argue that additional analysis of the repowering project should be conducted over the next four to six months, extending the current schedule for a Commission decision on the Company's request for resource approval. (Magelson Direct, lines 56 - 59; Hayet Direct, lines 594 - 597.) Is this proposal reasonable?

A. No. In Mr. Link's rebuttal testimony, the Company has provided additional analysis of the type OCS requests, further documenting that the wind repowering project—and each individual facility proposed to be repowered—is beneficial to customers. Additionally, scheduling another four to six months to conduct more analysis and delaying the Commission's decision on the Company's request would negatively affect the viability of the repowering project. The delay would impact the ability of the Company to execute contracts in early 2018, as required to maintain the construction schedule described in my direct testimony. Given the negotiated rate of turbine deliveries and project completion durations in the Company's negotiated contracts, this would likely push projects scheduled for 2019 completion into 2020, potentially increasing project costs as a result of the change in schedule and increasing risks related to meeting the December 31, 2020 deadline.

Q. Does this conclude your rebuttal testimony?

A. Yes.