ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

December 19, 2018

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 18-035-01 - Application of Rocky Mountain Power to Decrease the Deferred EBA Rate through the Energy Balancing Account Mechanism**

Rocky Mountain Power hereby submits its response to the audit report and direct testimony of the Utah Division of Public Utilities filed on November 15, 2018. As requested by the Utah Public Service Commission, Rocky Mountain Power is also providing seven (7) printed copies of the filing via
overnight delivery.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Sincerely,

Joelle Steward
Vice President, Regulation

cc: Service List

Rocky Mountain Power
Docket No. 18-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Response Testimony of Michael G. Wilding

December 2018

Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("the Company").

A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Are you the same Michael G. Wilding who submitted direct testimony on behalf of the Company in this proceeding?

A. Yes.

Q. What is the purpose of your response testimony?

A. My testimony responds to certain issues raised by the Utah Division of Public Utilities ("DPU") in its energy balancing account ("EBA") Audit Report and by Daymark Energy Advisors ("Daymark"), on behalf of the DPU. Specifically, I address the replacement power costs calculated by Daymark for the proposed adjustment related to plant outages, the system overhead ("SO") allocation factor used to determine Utah's share of the Incremental Non-Fuel FAS 106 Savings, and the proposed changes to the Energy Risk Management ("ERM") Policy. I also provide a small update to an item addressed in my direct testimony.

Q. Do any other Company witnesses also provide testimony in response to issues raised by the DPU and Daymark?

A. Yes. Company witness Mr. Dana M. Ralston provides testimony responding to the proposed adjustments related to plant outages. Mr. Ralston explains that the Company was prudent in its operations and management of its thermal generation plants.

REPLACEMENT POWER COSTS

Q. Please describe the proposed adjustment for plant outages.

A. Daymark recommends removing replacement power costs from the EBA for seven plant outages, which it claims were imprudent.

Q. Does the Company agree the replacement power for plant outages should be disallowed?

A. No. Company witness Mr. Ralston provides detailed testimony explaining that the Company prudently operates it thermal generation plants and there should be no disallowance for the identified plant outages.

Q. Does the Company agree with Daymark's calculation of the replacement power costs?

A. Yes, the methodology used by Daymark to calculate the replacement power costs is reasonable.

INCREMENTAL NON-FUEL FAS 106 SAVINGS

Q. Please describe the adjustment to the Incremental Non-Fuel FAS 106 Savings proposed by the DPU.

A. The Incremental Non-Fuel FAS 106 Savings is related to the settlement of the Deer Creek Retiree Medical Obligation and the resulting reduced expense. This expense reduction is allocated to Utah using the SO allocation factor. In its initial filing the Company used the SO factor from the 2016 Results of Operations report. The DPU recommends updating the Utah allocation of the cost savings by using the 2017 SO allocation factor.

Q. Does the Company accept the DPU's adjustment to the Incremental Non-Fuel FAS 106 Savings to use the 2017 SO allocation factor?

A. Yes. Additionally, the Company will ensure that the current SO allocation factor is used in future filings where applicable.

ENERGY RISK MANAGEMENT POLICY CHANGES

Q. Please summarize the changes Daymark proposes to make to the ERM Policy.

A. As part of Daymark's review of a sample of PacifiCorp's front office transactions a trade was discovered where a clerical error resulted in the trade being entered under a trader who did not have the appropriate authority limits. Daymark agreed with the Company that this situation was a clerical error and not a breach of the ERM Policy. In response to this error, the Company implemented a new detective control to review a weekly exception report that identifies any trades that exceed a trader's authorized limits and to investigate any such trades. Daymark proposes the newly implemented control be formally adopted in the ERM Policy and that the results of any investigations including any resulting actions be reported to the Risk Oversight Committee.

Q. Does the Company agree with the proposed changes?

A. Yes. The Company will work with the DPU and Daymark to adopt in the ERM Policy language similar to what Daymark proposed in its audit report. Additionally, the Company will report to the Risk Oversight Committee, when necessary, the results of the investigations including any actions taken as a result of the investigations.

Q. Do you have any other items you would like to address in your response testimony?

A. Yes. My direct testimony described an adjustment to the EBA for a non-generation agreement with a special contract customer. Specifically, lines 180 – 182 of my direct testimony state, “Due to the time sensitive nature of the non-generation agreement, a formal agreement between parties has not yet been filed with the Commission, but parties are planning to file one soon.”

Q. Has a formal agreement been filed with the Commission?

A. Yes. The formal agreement was finalized and filed with the Commission in Docket No. 16-035-33 on August 7, 2018, which was approved September 26, 2018.

Q. Does this conclude your response testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 18-035-01
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Response Testimony of Dana M. Ralston

December 2018

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("the Company").

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Senior Vice President of Thermal Generation and Mining.

Q. Mr. Ralston, have you previously submitted direct testimony on behalf of Rocky Mountain Power in this proceeding?

A. No.

Q. What is the purpose of your response testimony in this proceeding?

A. I respond to the direct testimony of Mr. Philip DiDomenico and Mr. Dan F. Koehler of Daymark Energy Advisors, Inc. ("Daymark") and the Technical Report on the Energy Balancing Account Audit for Rocky Mountain Power for Calendar Year 2017 ("Audit Report"), filed on behalf of the Utah Division of Public Utilities. Specifically, I explain and support the actions taken by the Company that demonstrate its prudence with respect to the proposed generation plant outages identified in the Audit Report.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I am currently PacifiCorp's Senior Vice President of Thermal Generation and Mining. Prior to November 2017, I was the Vice President of Coal Generation and Mining since March 2015, and Vice President of Generation from January 2010 to March 2015. For 29 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's Generation organization, including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operating and maintaining PacifiCorp's coal- and gas-fired generation fleet, coal fuel supply, and mining.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the utility commissions in Utah, Oregon, Washington, California, and Wyoming.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony demonstrates that the Company was prudent in managing its plant resources, and that the adjustment for the outages identified in the Audit Report are unwarranted.

GENERATION PLANT OUTAGES

Craig Unit 2 Outage

Q. What did Daymark conclude based on its review of the May 23, 2017 outage at Craig Unit 2?

A. Daymark states that the outage occurred after a hydrogen leak was discovered near the #5 and #6 bearings, caused by a missing ¼ inch plug near the South side of the collector bell end. It claims that the fact that the plug was missing shows a procedural failure and general lack of concern by Tri-State Generation and Transmission ("Tri-State"), the plant operator, and is cause for a disallowance. The calculated replacement power cost associated with this outage is $21,384.

Q. Do you agree with the Daymark review and recommendation related to the Craig Unit 2 Outage that the missed plug in question indicates a procedural failure that could have been corrected?

A. No. Daymark's claims are unreasonable. There are approximately 50 plugs around the perimeter of the channel seal on the collector end of the generator. These plugs were used to put a Dow Corning Sealant Compound into the channel which essentially makes a flexible O-ring. Tri-State hired General Electric ("GE") as the contractor who in-turn hired sub-contractor APM (millwrights) to remove/install the plugs. The process starts by removing the first two plugs for installation of the applicator and applying Dow Corning Sealant Compound. The first plug is then re-installed and the next plug in sequence is pulled until all plugs around the seal have been removed, sealant compound applied, and re-installed. The plugs are then tightened (torque not required) and pressure-tested to verify the seal integrity. Following this maintenance, Craig Unit 2 generator was pressurized to 48 psi which maintained pressure for 24 hours with no indication of leaks. The generator was put into service where it ran for 24 hours before any indication of a hydrogen leak. During inspection to identify the cause of the hydrogen leak, it was discovered that one of the plugs was missing and is believed to have vibrated out after the unit was returned to service. GE admitted fault and paid for all the labor to tear apart the hydrogen seal/collector end brushes, identify the leak, fix the leak, and re-assembly to get Craig Unit 2 generator back online.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Craig Unit 2 outage was the direct result of GE's sub-contractor's (APM) failure to correctly tighten all of the plugs and not the lack of established procedures and practices as Daymark claims. GE has taken responsibility for the incident, corrected known deficiencies in a timely manner, and paid for costs associated with its sub-contractor's mistake. Therefore, I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Q. Do you have any other concerns with Daymark's characterizations of "Third Party Operators," in Section 3 of the Audit Report?

A. I agree that PacifiCorp's policy of using significant event reporting at its plants, and documenting root cause analysis soon after an event, is useful for learning from mistakes and avoiding repeat occurrences, as suggested in the Audit Report. This is why PacifiCorp uses these tools. I disagree, however, with the implied conclusion in Section 3, that PacifiCorp could require Tri-State to use the exact same documentation tools as used by PacifiCorp. Tri-State is not a "contractor" in the manner suggested by Daymark. Instead, PacifiCorp and Tri-State are co-owners of Craig Unit 1 and Unit 2 (with three other entities as co-owners also). Under the controlling Participation Agreement between all of the co-owners, Tri-State is the operating agent for Craig Units 1 and 2, making it responsible for daily operations. PacifiCorp diligently participates with all of the co-owners to coordinate Tri-State's actions as operating agent, especially through regular involvement in the committees established by the Participation Agreement. As a co-owner and a member of governing committees, PacifiCorp, as a minority owner (19.28 percent ownership in both Unit 1 & Unit 2, 12.86 percent ownership in the common facilities), does not have unilateral authority to force Tri-State to use any particular type of documentation for event reporting.

Tri-State has agreed to implement an outage reporting procedure by January 31, 2019. They also started creating reports for 2018 which includes events requested by PacifiCorp.

PacifiCorp has certain rights under the Participation Agreement to obtain information from Tri-State regarding operations at the Craig plant, and PacifiCorp exercises such rights as necessary and appropriate. PacifiCorp diligently manages its relationship with Tri-State with respect to the Craig plant and the actions by the Company were prudent with the best interests of customers in mind. Daymark's view that the Company can dictate to Tri-State how to perform the work is incorrect and shows a lack of understanding of joint owned contractual agreements of plants. As stated above, Tri-State has agreed to implement an outage reporting procedure by January 31, 2019.

Dave Johnston Unit 3 (April 25, 2017) Outage

Q. What did Daymark conclude based on their review of the April 25, 2017 outage at Dave Johnston Unit 3?

A. The April 25, 2017 outage at Dave Johnston Unit 3 occurred due to several failures along the leading edge of the reheat superheater. Daymark points to Metallurgical reports, which indicate that the failure was caused by use of incorrect tubing material, SE-213 T11 as opposed to SA-209 T1a. Daymark concluded that this was unacceptable and recommends a disallowance associated with this outage of $265,673 in replacement power costs.

Q. Do you agree with the Daymark review and recommendation related to the Dave Johnston (Dave Johnston) Unit 3 Outage on April 25, 2017?

A. I agree that the non-conforming material replacement in question could have been a contributor to the failure. However, the use of the specific non-conforming SA-209 T1a tubing in the U3 Reheat ("RH") outlet pendant was an anomaly that was installed over 20 years ago. The SA-209 T1a tubing material that was installed lasted for a minimum of 20 years which is well within acceptable operation expectations for the material. The Company recognizes that non-conforming material was installed due to significantly different standards and processes that were in place over 20 years ago. As these standards, codes, and records have improved, PacifiCorp plants have and will continue to adopt these best practices to ensure our plant equipment life is maximized.

To demonstrate that the performance of the Dave Johnston plant has improved, a review of repairs of the Unit 3 RH outlet pendants over the past 15 years showed that the standard of like/kind materials has and will continue to be used maximizing plant equipment life. Additionally, the 2019 scheduled overhaul has significant work planned so the potential for more tube failures will be minimized.

Daymark references a statement from the Intercontinental Exchange Corporation ("IEC") that recommends the Company limit the use of explosive deslagging, consider the use of a less aggressive (slower) detonation cord, or allow for a greater standoff between tubes and the detonation cord. Daymark implies that IEC's recommendation refers to the April 25, 2017 outage. However, the tube discussed by IEC in this recommendation relates to a different outage, but was evaluated in the same report. Furthermore, the primary reason the Company uses explosive deslagging is for the safety of our personnel who enter the boiler by using explosives to knock down potential falling slag deposits.

The Company has prudently implemented best practices in a timely manner as they have been developed. For example, prior to the utilization of contractors for deslagging, Dave Johnston utilized a Company blasting crew. At that time, explosives with higher power and velocity were used for deslagging the boilers. As information became available that these methods could have a detrimental effect on boiler tubing, the use of a less aggressive detonation cord was mandated. The Dave Johnston plant implemented best practices by hiring Rocky Mountain Specialty Services as a contractor in order to confirm that the Dyno Nobel detonation cord used at the Dave Johnston plant has the slowest pressure transient development in the industry. The Dave Johnston Plant has utilized the same blasting contractor and the scope of work since 2011 which requires the use of low velocity detonation cord and cast boosters.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The plant outage was the result of a Unit 3 RH outlet pendent leak likely caused by non-conforming material that was used over 20 years ago. Processes, standards, and codes have significantly changed and the Company has prudently implemented the changes. A 15-year review of the Dave Johnston Unit 3 demonstrates conformance for the RH outlet pendants. The Dave Johnston plant has also incorporated solutions based on IEC's feedback by implementing the use of low velocity detonation cord and cast boosters, all while ensuring the focus on safety is maintained. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Dave Johnston Unit 3 (September 19, 2017) Outage

Q. What did Daymark conclude based on their review of the September 19, 2017 outage at Dave Johnston Unit 3?

A. The outage at Dave Johnston Unit 3 occurred due to several failures in the reheat superheater. Daymark points to Metallurgical reports, which indicated a similar cause to the April 25, 2017 outage related to blasting. Daymark claims that this outage was a repetitive event caused by the Company's lack of attention to changing its deslagging practices, as recommended by IEC. The calculated replacement power cost associated with this outage is $705,475.

Q. Do you agree with the Daymark review and recommendation related to the Dave Johnston Unit 3 Outage on September 19, 2017? If not, why not?

A. No. Once again, the Company disagrees with Daymark's claims that the Dave Johnston plant event was essentially a repeat of the April 25, 2017 event due to the Company's lack of attention regarding its deslagging practices. Daymark's statements lack the understanding of explosive deslagging practices and impacts to the Units. The degree of damage from explosive deslagging will be dependent on the high strain rate loading to the tube material, as generated by the explosive, and the degree of temper embrittlement (occurs in the 700 F to 1000 F range) of the tube material. Since neither of these characteristics can be fully defined at the time the event occurs, the degree of damage cannot be quantified. Therefore it is not possible to attribute the failure that occurred on September 19, 2017, to any specific explosive deslagging event. The blasting procedures currently in place will have little to no impact on remaining tube life.

As discussed above, PacifiCorp prudently implemented new best practices in a timely manner. The Dave Johnston Plant has utilized the same blasting contractor and the scope of work since 2011, which utilizes low velocity detonation cord and cast boosters.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. Daymark's claims that the lost generation is due to the Company not considering the use of less aggressive (slower) detonation practices is unfounded. The Company has demonstrated prudence in modifying its practices to require the use of Dyno Nobel detonation cords for deslagging operations while maintaining safety. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Huntington Unit 1 Outage

Q. What did Daymark conclude based on its review of the May 3, 2017 outage at Huntington Unit 1?

A. Huntington Unit 1 was taken offline due to a boiler tube leak. Daymark states that the failure was the fourth failure since 2008, and that the Company's plan to address the issue in the major overhaul scheduled for 2022 is not acceptable. The calculated replacement power cost associated with this outage is $80,391.

Q. Do you agree with the Daymark review and recommendation relating to the Huntington Unit 1 outage?

A. No. The Company does not dispute Daymark's claims that this is a known potential issue. However, Daymark's claims that waiting fourteen years and multiple overhaul cycles to address a known industry problem warrants a disallowance is not reasonable.

There are over 600 of these welds in the outlet of the reheater and the costs to review each to check for this issue would largely outweigh the benefits. The four failures, noted by Daymark, represent a less than 1 percent failure rate. The Company strongly believes it is not prudent to make an expensive full replacement decision with less than 1 percent failure rate. Even though the dissimilar metal weld is a potential issue, the Company must balance the need to remedy the issue with its fiduciary responsibility to customers to optimize the utilization of its assets, which includes scheduling replacements appropriately. In scheduled overhauls, inspection data and tube samples are taken to conduct examination of the welds. The Company documents the condition of the dissimilar metal welds and conducts analysis for predicted remaining life. With this information, the Company can more confidently plan for the component replacements in the future. The decision by the Company to gather this data during planned unit overhauls is prudent and in the best interests of our customers.

Q. Do you believe that the duration of the outage was excessive?

A. No. The Company initiated a plan immediately with a contractor to cool the boiler for safe entry. The Company worked diligently to expedite the cooling by placing temporary fans in the area. Even with these extra measures it took 36 hours to cool down the penthouse for safe entry. This is a typical time allotment for that area of the boiler in order to complete the tube weld repair in a safe and timely manner.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The lost generation was a result of a boiler tube leak due to a component failure and not a procedural failure on the part of the Company or its contractors. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Jim Bridger Unit 2 Outage

Q. What did Daymark conclude based on its review of the January 17, 2017 outage at Jim Bridger Unit 2?

A. The Jim Bridger Unit 2 outage occurred due to water freezing in the water-cooled spacer tubing during a shutdown to repair the Submerged Drag Chain Conveyor. When the unit was restarted after the drag chain shutdown, the water-cooled spacer tubing failed in various places due to a flow blockage caused by ice. Additionally, the heat tracing on the supply line on the water-cooled spacer appeared to be inoperable. To fix the issue, two failed sections of the spacer at the front Reheater assemblies and one failed section at the Superheater platen assemblies were replaced. The spacer tubes were cut and the ice blockage was melted. To ensure no further blockage remained, the spacer tubes were flow-checked. Daymark points to the heat tracing equipment, claiming the Company should have known the equipment was inoperable. The calculated replacement power cost associated with this outage is $132,375.

Q. Do you agree with Daymark's review and recommendation relating to the Jim Bridger Unit 2 outage?

A. No. The Company had processes in place to inspect heat tracing to verify operation, but the process had a void in it that resulted in this failure to not be identified so repair work could be completed. Changes have been made to the process to avoid a reoccurrence. The changes are listed below.

- The heat trace preventative maintenance ("PM") now instructs the Control and Electrical Technician to write a work order to correct any deficiencies found during the PM. The completed PM is routed to the Electrical Supervisor or Planner for review before the work order is closed out.

- Capital projects have been established to replace the heat trace on all four Jim Bridger units. The heat trace on the spacer tube supply line was replaced as part of a capital project on Unit 1 in 2018.
- To mitigate the risk of line freezing, plant personnel have evaluated if there is positive slope in the horizontal sections of the spacer tube supply lines. Where the positive slope did not exist, modifications have/will be made to ensure water will not pool when the boiler is drained (eliminate freezing concerns). This work has been completed on Units 1 and 2. Work orders have been created to complete the work on Units 3 and 4 (requires Unit to be offline).
- Plant personnel have modified the boiler shut down procedure to drain the boiler when the water temperature reaches 180 degrees rather than waiting until blasting and deslagging efforts are complete.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Company was prudent in that processes were in place to verify heat tracing operation but a gap in the process was discovered. Gaps are an on-going risk within any organization and the Company's management was prudent by implementing adequate corrective actions when the gap was investigated. This event was not a lack of prudence but the discovery of a gap in a procedure. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Jim Bridger Unit 3 Outage

Q. What did Daymark conclude based on its review of the October 13, 2017 outage at Jim Bridger Unit 3?

A. The Jim Bridger Unit 3 outage occurred due to water from a broken flange at the Central Deluge House of the Unit 1 Cooling Tower, which flooded the underground wire vault. The cable faults were located in the conduit between manhole #7 at the Unit 1 Cooling Tower and manhole #8 at the Unit 2 Cooling Tower. The cables may have failed due to age and damage received during an initial pull in the 1970s. Daymark claims that the cable damage that might have occurred over 40 years ago is avoidable and therefore recommends a disallowance of $21,505 in replacement power cost associated with this outage.

Q. Do you agree with the Daymark review and recommendation relating to the Jim Bridger Unit 3 Outage?

A. No. Daymark claims that, irrespective of when the damage to the conductors occurred, it was avoidable. The cables in question have been in place for approximately 40 years and have functioned correctly over that period. To say that although a cable which functioned for 40 years until an aggravating event brought to light the damage that occurred during the initial construction of the unit 40 years ago warrants a disallowance is unreasonable and unrealistic. There was no indication during the course of normal operation of the plant that the cable had been damaged prompting the need for any corrective action. Only when the cable vault and conduit that housed the damaged cable became flooded was an electrical path to ground established.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. While subsequent removal of the original 40 year old cable revealed the damage to the cabling to be the root cause, there was nothing that previously warranted any investigative need to evaluate the condition of the cabling before the October 13, 2017 event and thus should not be considered avoidable and disallowed.

Dave Johnston Unit 4 Outage

Q. What did Daymark conclude based on their review of the March 17, 2017 outage at Dave Johnston Unit 4?

A. During a planned outage at Dave Johnston Unit 4 to replace a Control Rotor Main Oil Pump Impeller, it was discovered that the wrong impeller had been installed and the control rotor had to be sent back to be corrected, causing an extension of the planned outage. Daymark claims this procedural failure warrants a disallowance of replacement costs of $728,023.

Q. Do you agree with the Daymark review and recommendation relating to the Naughton Unit 2 outage on May 28, 2016? If not, why not?

A. No. The Root Cause Analysis ("RCA") performed by MD&A confirms this event was not a procedural failure. Along with the RCA, effective corrective actions have been implemented to ensure these type of events are eliminated.

The Dave Johnston Unit 4 turbine control rotor assembly was incorrectly installed by the MD&A shop before shipping back to the Dave Johnston Plant site. Once the equipment was on Dave Johnston plant site, this mistake was identified by MD&A's on-site manager who noticed the error and informed the Dave Johnston plant staff. MD&A immediately scheduled priority shipping to return the turbine control rotor assembly back to their shop to address the error (the turbine control rotor had to be returned to the repair shop because the impeller is press fitted onto a stub shaft and the Dave Johnston plant does not have this capability). When the control rotor impeller and shaft assembly was fixed, MD&A again used priority shipping to get the assembly back to Dave Johnston for installation.

Following the event, a RCA was done to determine what happened and what could be done to prevent future occurrences. MD&A explained that the error was due to their repair shop having an increased amount of work from several other utilities at the same time. MD&A determined the root cause was that MD&A had recently increased the repair shop's capacity for work, however, they had not yet caught up with fully staffing appropriately. Corrective actions implemented included MD&A increasing their repair shop staff and a process was implemented to review and improve their quality control program.

The Company diligently managed MD&A and the processes in place. This incident was the result of a human error and not due to imprudence. As stated above this error was discovered during a secondary check, a prudent control to avoid potentially greater loss, before the machine was assembled and was worked on an expedited basis by MD&A. The Company acted prudently when managing this work.

Q. What is your recommendation to the Commission with respect to the Dave Johnston plant proposed by Daymark?

A. This incident was the result of a human error and not due to imprudence. As stated above this error was discovered during a secondary check before the machine was assembled and was worked on an expedited basis by MD&A. The Company acted prudently when managing this work and avoided the potential of greater loss. MD&A has taken responsibility for the incident, corrected known deficiencies in a timely manner, and paid for costs associated with shipping and restoration of the incorrectly installed turbine control rotor assembly. I respectfully recommend that the Commission reject the Dave Johnston adjustment proposed by Daymark.

CONCLUSION

Q. Do you have any closing remarks with respect to Daymark's recommended changes?

A. PacifiCorp's generating fleet availability is significantly better than the industry average which has benefited our customers. In 2017 PacifiCorp's coal fleet had an equivalent availability of [redacted] percent compared to a North American Electric Reliability Corporation average for a similar sized fleet of [redacted] percent. This is value our customer receive. Daymark's recommendations are based on 20/20 hindsight and assumes an unrealistic standard of perfection and not a standard of prudence. PacifiCorp operates its fleet in a prudent manner and the fleet availability and cost history shows that this provides significant value for our customers. Daymark's recommendations should be rejected by the Commission.

Q. Does this conclude your response testimony?

A. Yes.

<u>**CERTIFICATE OF SERVICE**</u>

Docket No. 18-035-01

I hereby certify that on December 19, 2018, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

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