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

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah 84116. My present position is Vice President of Thermal Generation. I am responsible for the coal, gas, and geothermal resources owned by the Company.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering from South Dakota State University. I have been the Vice President of Thermal Generation for PacifiCorp Energy since January 2010. Before 2010, I held a number of positions of increasing responsibility with MidAmerican Energy Company for 28 years in the generation organization, including the plant manager position at the Neal Energy Center, a 1600 megawatt generating complex. In my current role, I am responsible for the operation and maintenance of the thermal generation fleet.

Purpose and Overview of Testimony

Q. What it the purpose of your testimony?

A. My rebuttal testimony is in response to issues raised by the Division of Public Utilities ("DPU") witness Mr. Richard S. Hahn regarding his request for an "Explanation of Outages" referenced in Figure 7 CONFIDENTIAL, line 314 of his Direct Testimony.

Q. Which outages from those listed in "Figure 7 CONFIDENTIAL" is Mr. Hahn seeking and explanation?

A. As requested in supplemental testimony Mr. Hahn is seeking additional information or justification for the following plant outages:

- Huntington – Unit 1 transformer fire
- Huntington – Unit 2 coal mill explosion
- Lake Side Combustion Turbine ("CT") 12 damage
- Wyodak ID fan repairs

Huntington – 1 Transformer Fire Outage

Q. What event occurred that caused the outage?

A. On November 16, 2011, one of the two generator step-up transformers connected to Unit 1 generator at Huntington plant failed catastrophically while in service. The failure resulted in a rupture of the main tank which started a fire that caused damage to the bus and the adjacent transformer.

Q. Was the age and condition of the transformer a concern prior to failure?

A. No. The failed transformer was purchased new from GE-Prolec as a spare for the Huntington plant in 2002 and subsequently moved into service in November 2010. The transformer had only been in service approximately 11 months prior to failure.

Q. Were proper precautions taken to ensure this transformer's reliability as it was placed into service?

A. Yes. Prior to being moved into position for initial service, insulating oil was removed from the transformer and a thorough and complete internal inspection conducted. Once the transformer was moved into position, the insulating oil was processed to ensure oil specifications were met in preparation for initial field energization.

Q. Was there any type of condition monitoring installed on this transformer?

A. Yes. In addition to regular monitoring of operating parameters, on-line oil analysis equipment was retrofitted to this transformer to continually monitor the condition of the transformer oil. Additionally, periodic oil samples were drawn for independent lab analysis while the transformer was operational.

Q. Was the transformer removed from service at any time prior to its failure as a result of oil analysis information?

A. No. Prior operating parameters or oil analysis results did not indicate a condition that would cause a definable reason to remove the transformer from service.

Q. Has the root cause of the transformer failure been determined?

A. No. Protective relay information and the physical evidence contained within the failed transformer have not produced conclusive evidence from which to determine the actual failure mechanism. The final report for this failure has been provided in response to DPU 19. The analysis did not find any negligence on the part of the Company or other actions that should have been taken.

Q. Given the review of this information and physical evidence, are there any definite conclusions that can be reached to explain the reason this transformer failed?

A. No. However, protective relay information indicates a “phase-to-phase” fault occurred between “B” and “C” phase low voltage bus work. Post failure inspection of the transformer internals did not reveal any evidence from which to determine a root cause for the phase-to-phase fault.

Q. Were PacifiCorp's actions and processes in dealing with the installation and operation of the transformer prudent and consistent with industry standards?

A. Yes. PacifiCorp installed the transformer following good industry practices and had in place on line oil monitoring to ensure continuous condition assessment was in place and being monitored. The analysis of the failure did not find fault with any of the Company's practices or actions with respect to the installation and operation of the transformer.

Huntington – 2 Coal Mill Explosion Outage

Q. What event occurred that caused the outage?

A. On November 30, 2011, a generator runback occurred that caused the boiler to trip offline. The resultant upset caused the hot boiler gases to flow backwards into the mills and caused them to explode. A generator runback is an automatic protection system that reduces the load on the generator to protect it when the generator cooling system cannot adequately cool the generator.

Q. Was a system installed that would prevent this from occurring?

A. Yes, a system had just been installed but had not been commissioned at the time of the explosion. The system is called a steam inerting system. A steam inerting system uses steam to displace the air in a coal mill to lower the oxygen content of the coal mill to a point that combustion is not sustainable and thereby preventing an explosion.

Q. What is the Company's knowledge and understanding regarding commercially available steam inerting systems?

A. The Company is familiar with steam inerting systems for coal mills. In fact, some coal mill suppliers, "Original Equipment Manufacturers" (OEMs), have historically provided steam inerting systems supplied from a low pressure steam source as part of the original coal mill equipment. Such a provision was not originally provided by the Huntington OEMs. A significant issue with installation of these systems is the ability to adequately regulate high pressure, high temperature steam for a low pressure, low volume application to consistently satisfy steam inerting system design requirements. Attempts by the Company, since as early as 1992, to find a functional and reliable system proved unsuccessful until recently, making installation of a National Fire Protection Association (NFPA) compliant inerting system prior to this time impractical and would not have functioned as required to prevent explosions.

Q. Has the issue of high pressure, high temperature steam regulation for currently available steam inerting systems been resolved?

A. Yes. Improvements in the regulation of high pressure, high temperature steam sources have rendered these systems viable. Commensurate with these technology improvements in steam supply regulation, and more recent experience with coal mill explosion outages that have occurred at the Huntington plant, the decision was made in 2009 to move forward with project development and installation of steam inerting systems during unit outages scheduled for both Huntington Unit 1 and Unit 2 in 2010 and 2011 respectively. The Huntington Unit 2 inerting system high energy steam supply connection was made and the balance of the system was installed during the scheduled outage in November 2011. The commissioning activities for the steam inerting system were planned to begin the week after the unit had returned to service following the scheduled outage to permit any start up issues to be resolved before commissioning.

Q. Is there a current NFPA code requirement that a steam inerting system be installed on coal mills?

A. Yes. In the current 2007 version of the NFPA 85 code it is specified that steam inerting systems be installed on milling systems constructed under the provisions of this version of the code. However, code requirements in place at the time of original equipment commissioning of the Huntington facility didn't require such systems. The more stringent requirements of more recent versions of the code only apply in the event there is a major alteration in design affecting unit operation, e.g., replacement of the milling system in its entirety which did not occur at the plant. To confirm this view the State of Utah Director of "Division of Boiler, Elevator and Coal Mine Safety" as the "Authority having Jurisdiction" (AHJ), was asked about the requirement to apply the 2007 code for the Huntington plant and has agreed that the modifications to the plant did not require the plant to update to the 2007 code.

Q. Were the Company's actions related to the application and installation of an inerting system within industry practices and prudent?

A. Yes. The Company prudently reviewed options for inerting systems and did not purchase and apply a system until it was convinced the system would provide a functional system that achieves the desired project objectives. Installing a system prior to this time would not have achieved the requirements of an inerting system to prevent explosions.

Lake Side Combustion Turbine 12 (CT 12) Turbine Damage

Q. What was the primary reason for the Lake Side unscheduled outage taken on October 29th, 2011?

A. The original scope of the unscheduled outage was to repair an exhaust expansion joint on CT 12 with an estimated return to service date of November 3, 2011. Failure of the expansion joint likely occurred due to detachment of an internal flow shield, which directs hot exhaust gases away from the expansion joint, and normal wear and tear associated with four years of operation.

Q. Did the scope of the outage include a borescope inspection of the CT 12 Row 2 turbine blades?

A. Yes. Based on communications from Siemens regarding a forthcoming Product Bulletin ("PB") associated with a requirement to inspect Row 1 Blade static seals before the next planned combustion inspection, a borescope inspection was scheduled to occur concurrent with the unplanned exhaust expansion joint repair to minimize overall unit unavailability. Siemens subsequently issued the Row 1 Blade static seal PB in November 2011.

In light of the existing Siemens Row 2 Blade "Technical Advisory" (TA) specifically recommending an inspection of the turbine section, Row 2 Blades before reaching 16,000 Equivalent Based Hours ("EBH") or 400 Equivalent Starts ("ES") and follow-up inspections every 200 to 400 ES to inspect for cracks in the trailing edge of the blades and due to four catastrophic failures in 2010 of Row 2 Blades in the Siemens W501F fleet, an inspection of the Row 2 Blades was scheduled at the same time. CT 12 Row 2 Blades had approximately 160 ES at the time of the unplanned outage.

Q. Did the bore scope inspection reveal substantive indication of issues raised in Siemens TA?

A. Yes. Impact damage was observed on the trailing edge of two blades that had breached and collapsed the blades' structural support. Additionally, all Row 2 Blades showed indication of rubbing and heavy seal segment material transfer. Subsequently, Siemens recommended replacing the two damaged Row 2 Blades and repairing remaining Row 2 blades based on the inspection findings. This required an extension of the unplanned outage beyond the planned return to service date of November 3, 2011.

Q. Was there a determinable root cause for the observed damage to the combustion turbine?

A. No. Neither Siemens nor an independent fact finder, J. Wilson with BWD Turbines Limited, Ancaster, Ontario, Canada conclusively arrived at a root cause of the failure; offering only possible causes that may have contributed to the observed damage.

Q. Was it necessary to adhere to Siemens recommendation for Row 2 blade failure replacement?

A. Yes. PacifiCorp was prudent in following Siemens' recommendation to replace damaged Row 2 Blades given four reported cases in October 2010 of Row 2

Blade liberation in the Siemens fleet of W501F units that had resulted in catastrophic failure of the combustion turbines. Failure to perform the inspection and replace the damaged components found could have resulted in a catastrophic failure that would have force the unit off for an extended period which would have increased costs for the Company and our customers.

Q. Was the Row 2 blade replacement and associated repairs to CT 12 made per the OEM recommendations?

A. Yes. The OEM recommended repairs were made to CT 12 and the unit was returned to service November 15, 2011, without incident.

Wyodak Inducted Draft (ID) Fan Repairs

Q. What event occurred that caused the outage?

A. On October 20, 2012, one of the ID fans motors failed and forced the unit off line.

Q. When were the motors placed in service?

A. New ID fan motors were installed during the planned major unit outage and placed in service April 27, 2011, as part of a comprehensive clean air initiative project.

Q. Following the catastrophic failure of the "A" ID fan motor during unit start-up, was the OEM involved in determining the failure mechanism?

A. Yes. Following the failure incident, an on-site inspection of the "A" ID fan motor was conducted by the motor OEM, Hyundai Heavy Industries (HHI), on October 19, 2011. HHI's inspection found cracks in the motor's rotor retaining rings and other signs of damage to the motor stator which necessitated shipping the complete motor to HHI's repair facility in Ohio for additional detailed inspections and ultimately repairs.

Q. Was there concern about the "B" ID fan motor condition as a result of the inspection results on the "A" motor?

A. Yes. Given the observed damage to the "A" ID fan motor, PacifiCorp opted to remove the unit from service two days later to facilitate a field inspection of the "B" ID fan motor to determine whether that motor may have the same or similar manufacturing deficiencies.

Q. Did the inspection of the "B" ID fan motor reveal similar damage and failure mechanism?

A. Yes. Cracks were also found in the rotor retaining rings of "B" ID fan motor, which also required detailed factory inspections and repair. This proactive approach likely prevented the same catastrophic failure experienced with the "A" ID fan motor and significantly decrease the repair time and return to service by comparison.

Q. Was the root cause for the ID fan motor failures determined?

A. Yes. PacifiCorp and HHI commissioned independent failure analysis studies. The conclusions of both failure analysis studies indicated that the rotor retaining ring welds failed due to improper welding procedures applied during manufacturing. HHI implemented their corrected welding procedure during the repair/rebuild process of each of PacifiCorp's motors to mitigate the potential for repeat failures.

Q. How was the repair costs allocated?

A. The repair costs were paid for by the supplier of the equipment.

Q. Did the Company act prudently in connection with its handling of the repairs of the Wyodak ID fan motors?

A. Yes. The motors were both under warrantee during this time and after the first motor failed with no advanced warning the second motor was removed from service to determine if the same possible failure conditions existed. It was determined that the same failure mode conditions existed on the second motor and it was repaired prior to experiencing a catastrophic failure.

Summary

Q. Were any of these outages caused by imprudent actions of the Company?

A. No, the Company prudently managed the equipment involved with these outages. PacifiCorp diligently and effectively manages its fleet to provide the best value for its customers. This can be seen in the availability numbers for the fleet during 2011. In 2011 the NERC average equivalent availability for the comparable fleet as PacifiCorp's was 84.41 percent and the PacifiCorp equivalent availability for the same period was 85.89 percent even with the outages discussed above.

Q. What is your recommendation to the Commission related to cost recovery related to these outages?

A. I recommend that the Commission reject Mr. Hahn's proposed outage adjustments because the evidence does not support a finding that the outages were caused by the Company's imprudence. Forced outages are to be expected during the course of a utility company's normal operating business and, as I discussed in my testimony, the Company prudently managed the equipment involved with each of these outages. And as I have shown above, PacifiCorp diligently and effectively managed its fleet to provide the best value for its customers which resulted in an equivalent availability for the PacifiCorp fleet better that the NERC average.

Q. Does this conclude your testimony?

A. Yes.