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Xcel Energy
Docket No.: EL12-046
Response To: SD Public Utilities Commission Data Request No. 1-4
Requestor: Brittany Mehlhaff & Patrick Steffensen
Date Received: November 13, 2013

Question:

Refer to page 5 of the compliance filing regarding the Monticello EPU project.

a) Provide a more detailed description of each of the 4 bullet points on page 5 regarding the major reasons for the increase in expenditures. Provide a detailed breakdown of each cost overrun and the reason for the increase in cost.
b) Provide any documentation of management/board approval of the increased costs and additional scope.
c) Is the additional scope included in the parent work order 10245258?
d) Why was an extended outage necessary to complete the projects?
e) The filing states the in-service date moved to July 2013. However, according to the "Monti EPU" tab of "Infrastructure Rider Filing 2014 Rate.xls" provided on 10/08/2013, it appears there is an addition in January 2014. Please explain.

Response:

(a) The 4 bullet points referenced on page 5 of the compliance filing were as follows:

- Construction estimate increased for the 13.8kV project in January 2013 as the work package planning was completed.
- Actual construction cost increased, primarily for the Reactor Feed Pumps.
- Additional scope for design and construction of the condensate pump motor coolers.
- Outage extension costs for station support of Extended Power Uprate (e.g. engineering, maintenance, and operations testing).

The amount of cost increase (in the new September 2013 forecast from the earlier November 2012 estimate provided with respect to the Infrastructure Rider) for each of these items is as follows:

- 13.8kV project - $21.4 million
- Reactor feed pumps – $12.1 million; other construction cost increases included $5.3 million for feedwater heaters
- Condensate pump motors - $3.7 million
- Outage extension, station support and all other - $1.8 million

The cost increases described above total $44.3 million. The compliance filing references an increase in CWIP costs of $48.1 million, and when offset by the decrease in RWIP costs experienced of $3.8 million, the net increase in total project costs of $44.3 million from earlier estimates is accounted for.

The descriptions of these projects and reasons for these cost increases are as follows:

<u>13.8kV project</u>

The 13.8 kV modification added additional buses at 13.8 kV voltage level to supplement our existing lower voltage (4 kV) electrical distribution system in the plant. The installation of the 13.8 kV Project (Work Order No. 11257804) occurred during the 2011 and 2013 outages at a total cost of approximately $119.5 million. This was the most expensive modification we undertook, and it was one of the most difficult modifications to complete because we are required to maintain electric service to ensure cooling of the fuel at all times during the installation of the new system. As a result, we had to stage the installation to ensure that certain power sources were available at the appropriate times. A summary of the 13.8 kV modification and photos of installation can be found in Attachment A.

Primarily, the final cost of the modification exceeded the initial estimate because:

- The initial estimate was based on conceptual, rather than detailed engineering;
- We were implementing a first-of-its-kind system in a nuclear facility;
- As noted above, the new cable needed to travel through this area and because this is an electrically-sensitive area, the design work required careful analysis through an iterative process to ensure safe installation; and
- The Company and its external design organizations encountered design challenges to route the conduit and raceways and design the

switchgear room.

Among these reasons, the costs necessary to install the system was the largest driver, and we incurred more than $73 million in installation costs.

Specifically, we installed more than 14 miles of five-inch cable in raceways throughout the station. If cables are not carefully installed, they can be damaged by overstress or tensioning. To accommodate these considerations, we pulled the cables in a slow and methodical fashion using 20-foot intervals.

In addition, just as the condensate demineralizer system was installed in a highly radioactive space, the cable and conduit for the 13.8 kV electrical system was installed in a very precarious electrical area in the switchgear room. We took many steps to assure worker safety and nuclear safety by constructing shields, requiring tethers for tools, and requiring protective gear, all of which slowed the productivity of the work effort.

To understand the scope of this modification, for the 2013 outage we estimated that it would require over 183,000 hours (equivalent to 7,625 days) to install the system. The installation of this modification actually required 230,576 hours during the 2013 outage.

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Reactor feed pumps; Feedwater heaters

The reactor feed pumps and motors project occurred during the 2013 outage at a cost of approximately $92 million (Work Order No. 11286955). The reactor feed pumps and motors modification included the replacement of two reactor feed pumps and two motors, replacement and relocation of auxiliary piping, and replacement of regulating valves and controls. A summary of the reactor feed pumps and motors modification can be found in Attachment B.

The two reactor feed pumps are large pumps designed to move treated water (feedwater) into the reactor. The feedwater provides cooling for the reactor and is converted to steam to drive the high- and low-pressure turbines. Each pump is powered by an approximately 8,000 horsepower motor that is connected to the station's new 13.8 kV electric distribution system.

The primary cost increases for this modification resulted from the change in scope from a supplemental reactor feed pump and motor to the replacement of the two reactor feed pumps and motors. Not only did the cost increase due to the need to procure major equipment, but design and installation costs increased because of this decision. To minimize outage length, we constructed a two-level, load-bearing, structural, scaffold to provide two access points to the equipment, so work on the motors and pumps could occur concurrently instead of in sequence. We reduced the total modification time through our concurrent installation activities on the pumps and motors. The costs for the reactor feed pumps and motors modification would have either been incurred during the 2013 outage or at some time in the near future when the pumps and motors would have required replacement for operational issues.

We encountered delays in procurement because we had difficulty finding motors that would meet specifications. Also, our pump and motor fabricators encountered delays in providing the components because of difficulty fabricating equipment that met our specifications for startup and operations. This required greater on-site presence as well as additional testing efforts. Last, we incurred design costs for new pipe drawings, additional stress analysis, new pipe support calculations, as well as addition piping, as a result of the walk-downs.

Portions of the feedwater heater modification occurred during the 2009, 2011, and 2013 outages. The total cost for all work associated with this modification was approximately $115 million. A summary of the scope of the feedwater heater modification and photos of the arrival and initial line-up of the 15 A feedwater heaters are provided in Attachment C.

The scope of work for the feedwater heater modification changed substantially during the design of the LCM/EPU Program. Several changes were made to the feedwater heater modification scope for feedwater heaters, drain and dump piping, the turbine floor, main steam thermowell, and CARVs. The most notable scope additions are:

Replace 13 A/B, 14 A/B, and 15 A/B Feedwater Heaters:
We initially intended to rerate the feedwater heaters, but decided during the design phase that replacement was required. The 14 A/B and 15 A/B heaters were original equipment and we could no longer continue to modify and repair the shell and tube heat exchangers. The condition of the 13 A/B feedwater heaters during inspections in 2007 indicated that replacement was necessary. We determined that we could rerate the 11 and 12 feedwater

heaters for EPU conditions.

Turbine Floor 951:
The decision to replace the 14 A/B and 15 A/B Feedwater heaters with larger heaters required structural analysis and reinforcement of the turbine floor at a cost of approximately $6 million. This was a substantial undertaking from a design and installation perspective.

Replace Drain and Dump Piping:
We decided to replace approximately 400 feet of piping with larger piping and remove associated asbestos insulation, to accommodate the extended life of the station. This piping replacement likely could have been delayed to another outage, but because substantial feedwater heater work was underway, but it was most cost-effective to undertake the replacement concurrent with the other work.

Condensate pump motors

The condensate pumps and motors modification project occurred during the 2013 outage at a cost of approximately $21.9 million (Work Order Nos. 10943052 and 11845189). The project included the replacement of two condensate pumps and two motors, replacement of condensate pump and motor auxiliaries, modification of area cooling for the condensate pump motors, an increase in the condenser hotwell level, and completion of the required testing protocol. A summary of the scope of the condensate pumps and motors modification can be found in Attachment C.

The primary driver for the final cost relates to the decision to replace the condensate pumps and motors rather than add an impeller stage to the existing equipment. This replacement was not included in the original cost estimate and increased the equipment, design, and installation costs for this modification over the initial estimate. We also experienced vendor fabrication issues with the condensate pumps and motors. Our vendors experienced difficulties fabricating equipment that met our design specifications. To meet these specifications, we required the vendor to modify the motors, which increased the heat load of the motors. This required further analysis of the area cooling systems.

The additional analysis and resulting duct design and installation for area cooling added approximately $2 million to the modification. Additional fabrication issues delayed the shipment of necessary components from the estimated delivery dates. Many of the fabrication issues were addressed by our vendors at their cost. We incurred additional oversight costs and the delays affected our pre-outage planning protocol. However, these delays did not increase costs. This installation was not on the critical path and did not cause us to undertake material additional work.

Finally, the costs to install this modification were higher than anticipated. We attribute the higher installation costs to the in-outage designs required to address piping and wiring interferences encountered during the installation and the overall implementation productivity issues we encountered during the 2013 outage.

Outage extension, station support and other

The 2013 refueling outage, RFO 26, began on March 2, 2013, and was completed on July 18, 2013, for a total duration of 138 days, or 53 days longer than the targeted schedule and 38 days longer than the final budget schedule. We incurred $151 million for the installation of the 2013 Project modifications, which was $52 million over our initial budget, excluding contingency.

Xcel Energy faced several challenges during RFO 26. The most significant implementation challenges related to the 13.8 kV electrical system upgrade and the reactor feed pump replacement. The primary issue contributing to the extended outage duration for the feed pump replacement was the lack of space considerations. We expected the work space to be tight and built structural load bearing scaffolding to add work space so we could access two levels simultaneously. The construction and installation of the building pipes to the nozzles and the cable pulling to connect power to the pump motors were two activities associated with the feed pump replacement that were especially time-consuming and contributed to cost and schedule overruns during the outage.

The electric cable we had to pull was more than two inches in diameter and weighed in excess of 100 pounds per foot. Teams of ten electricians were required to pull the cable through the conduit. This task required care and precision to avoid over-tensioning and damaging the cables as they were being pulled.

We also experienced delay in completing the testing for the 13.8 kV and feed pumps after installation. The last three weeks of the outage were spent testing the feed pumps and the 13.8 kV system additions. In addition to the technical implementation challenges we faced during the 2013 outage, we also encountered lower productivity than we anticipated. There were several contributors to our lower than anticipated productivity. First, we had challenges hiring experienced craft labor due to the competitive nuclear labor market. Second, many of the tasks took longer than we had estimated due to the difficulty of workers being restricted due to radiological conditions or small work spaces. Third, we lost experienced workers as a result of the current market for craft labor and the NRC worker fatigue rule. Additionally, we had some concerns over the management of some of the tasks and are currently investigating those concerns and have begun a dialogue with our contractors to resolve them. These issues are discussed further below.

The demand for workers in the nuclear power industry, particularly those with major project experience, coupled with the declining supply of such workers made it acutely difficult to staff our project and maintain that staffing throughout the duration of the project. This combination of trends contributed to the difficulties we experienced on the Monticello LCM/EPU Program.

In addition, we experienced difficulties in hiring and retaining experienced craft labor for the outages and lost experienced workers to competing jobs in other industries that do not have the types of work place restrictions that exist at a nuclear power plant.

NRC's "fatigue rule" also impacted the 2013 outage. The NRC introduced new rules and guidance related to "fatigue management for nuclear power plant personnel," under 10 CFR Part 26. This guidance reduced the number of hours that can be worked by individual employees at our nuclear facilities. As a result, we were required to retain additional workers to comply with this rule change.

While we anticipated the reduction in hours, we did not anticipate the significant loss of contractors and associated productivity. In the construction trades, a large project will sometimes deploy its workforce on a 12 hour by 7 day schedule. Many workers prefer this schedule as it maximizes their earning potential during the job. The fatigue rule effectively limits workers to a six-day per week schedule. This created a competitive disadvantage to the extent that we had to compete for workers with other projects that do not have to comply with the fatigue rule.

As it relates to our refueling outages, our employees are permitted to work extended hours, subject to certain conditions, for the first 60 days of the outage. On the sixty-first day of the outage, we are required to meaningfully limit those hours to comply with NRC regulations. That requirement was implemented by the NRC to make certain our workers were able to diligently complete their duties following prolonged periods of extended hours. Nevertheless, the requirement does limit the hours that can be worked by an individual worker and forces the licensee to use additional workers to shorten the duration of the refueling outage.
Both the lack of skilled labor, the impacts of the NRC fatigue rule, and other vendor issues as described in this filing, all served to lower actual productivity compared to the levels we had budgeted.

(b) No additional management or Board approval was required for the increased costs, as the new forecast amount of $665 million was less than 15% different than the previously authorized amount of $587 million. Under the financial governance policies in place for the Board of Directors, an updated authorization was not required for the 13.3% increase over the authorized level of this project. However, regular updates of the cost increases were provided to management and the Board of Directors during 2012 and 2013 as project and outage planning proceeded and the final implementation occurred.

(c) Yes, the additional costs incurred were recorded in parent work order 10245258, as well as in the various child work orders that roll up into that parent work order.

(d) The reasons for the extended outage in 2013 for the Monticello LCM/EPU project are discussed above in response to part (a) of this data request.

(e) All of the equipment for the project was placed in service when the unit went back online in July 2013. However, we kept costs associated with the NRC EPU license in CWIP until such time that we receive the license from NRC and conduct the activities necessary to place it in service. Our assumptions at the time of the compliance filing were that the license would be obtained in the fourth quarter of 2013 but that the necessary activities to place it in service would not occur until January 2014. We still expect to be able to meet this schedule.

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