CASE: UE 301
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Testimony
(March Forecast)

April 15, 2016

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a Utility Analyst for the Public Utility Commission of Oregon (Commission). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Are you the same Scott Gibbens who previously submitted testimony in this docket?

A. Yes. I previously sponsored Staff's Opening Testimony in this proceeding regarding the October Update for the 2016 Annual Power Cost Update. *See* Staff/100-103.

Q. What is the purpose of Staff's March Forecast Testimony?

A. The purpose of Staff's current testimony is to present Staff's analysis regarding the March Update filed by Idaho Power Company (Idaho Power or Company) in UE 301 as part of its 2016 Annual Power Cost Update (APCU). I will also provide an update to Staff's position regarding the issues addressed in Staff's Opening Testimony.

Q. Did you prepare exhibits for this docket?

A. Yes. Staff prepared Staff/202 Staff/203, and Staff/204

Q. How is your testimony organized?

A. My testimony is organized as follows:

MARCH UPDATE FILING, COMPLIANCE AND UPDATES

Q. Did the March Update filing conform to applicable Commission rules and orders?

A. Yes, the filing follows all applicable rules and orders. Commission Order No. 08-238 (Order) sets forth the majority of the requirements regarding the APCU March Update. The Order requires the Company to use the AURORA model to perform a single water condition run of the power supply model for the April through March Test Period. The Order also delineates the manner in which forward price curves are to be updated, the process of calculating the March Forecast Rate Adjustment and the Combined Rate, as well as the following list of input variables to be updated.

Q. Please describe what inputs the Company updated.

A. Per the Order, the Company updated the following inputs:

a. Fueling prices and transportation costs;

b. Planned outages and forced outage rates;

c. Forecast of Normalized Load and Normalized Sales, updated only for known significant changes since the October APCU;

d. Forecast Hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center;

e. Contracts for wholesale power and power purchases and sales;

f. Forward price curve; and

g. PURPA contract expenses.

Idaho Power did not update wheeling expenses, heat rates, or the Oregon state allocation factor from the previous filing because there was no update to these variables since the October filing.

Q. Did Staff check the validity and reasonableness of the updated input parameters?

A. Yes, Staff reviewed every updated input used in the March Forecast. All values are reasonable and in line with Company's previous filings and provided actuals.

Q. Was Staff able to clarify "potential issues associated with input parameters" in the October filing of the APCU as mentioned in Staff/100?

A. Yes, in Staff's Opening Testimony, I stated that the Boardman Operation & Maintenance (O&M) costs seemed extraordinarily low, even when accounting for the relative size and ownership percentages of the plant. It was found that the value, as listed in Idaho Power/101, is an error. This was corrected in the March Update shown in Idaho Power/302, where the expense for Boardman O&M went from 0.4 to 356.4. This correction was also verified in Company witness Noe's reply testimony.[1]

Q. Did Idaho Power perform the prescribed calculations properly?

A. Yes, Staff has found no errors associated with the calculations used in the APCU. The Company adhered to all pertinent Commission orders in every calculation.

[1] Idaho Power/200, Noe/3, lines 23-24

ISSUE 1, O&M MODELING CHANGE

Q. Please summarize the changes to the AURORA model in the October and March filings.

A. Idaho Power changed the way it models the O&M expenses associated with coal plants in AURORA. The Company believes the O&M expenses are more fixed in nature, as opposed to varying with generation and should be modeled as such. In all previous filings, the O&M expenses were input as a per-unit cost for each coal plant. Now the expenses are forecast and added as a lump sum after AURORA has run its economic dispatch.

Q. What are the components that make up the O&M costs?

A. The O&M costs in this circumstance are also known as "Oil, Handling, Administrative and General" (OHAG) expenses. The expenses in question are set forth the Company's response to Staff Data Request (DR) 20 as follows:

> **"**The oil component is the diesel oil burned at the plant for startup and flame stabilization. The handling component is the cost to move the coal from the train trestle (or additionally, when the coal is on the plant site at Bridger from the mine) to the coal silos in the plant. Included in the handling costs are the operating expenses for conveyors, heavy equipment, heavy equipment fuel, and labor."

See Staff/201.

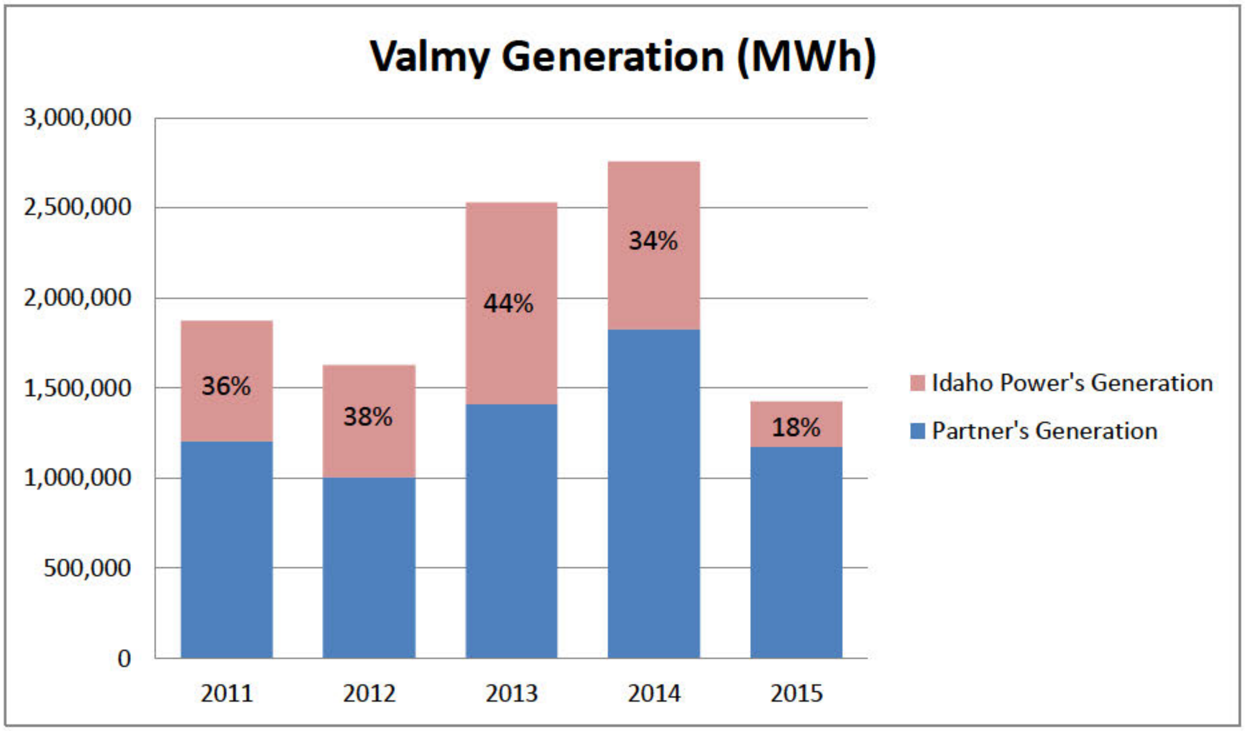
Q. How has Staff's understanding of the situation changed since the filing of its Opening Testimony?

A. It is Staff's understanding that the O&M expense contains both fixed and variable portions. This situation is further complicated by the fact that costs are not only incurred when the Company dispatches a plant, but also when its plant-ownership partners dispatch the plant. This is due to the fact that the O&M expense is based on ownership percentage in any given plant.

Q. Can you provide an example of this situation?

A. Yes, I can. For example, Idaho Power owns one-half of Valmy Power Plant, meaning the Company would pay 50 percent of the total O&M costs at Valmy, regardless of the amount that resulted directly from Idaho Power's dispatch of the plant. Currently, natural gas prices are low enough that the Company is not dispatching its coal fleet as often as it had been in previous years. However, some of Idaho Power's partners have found it economical to dispatch the plant more often. This has resulted in much larger OHAG costs when measured in per-MWh of IPC generation. Staff/202, reproduced below as Figure 1, illustrates the issue.

Figure 1



Idaho Power's share of total generation dropped from 34 percent to 18 percent from 2014 to 2015. If we assume O&M costs are completely variable (the assumption made in the old model), then the $/MWh charge for O&M would increase by 192 percent from the previous year..

Q. Please explain how O&M was modeled in the 2014 APCU filing.[2]

A. In the older model, the O&M costs were included in AURORA as an added $/MWh expense for each coal plant. AURORA would then add the O&M into each plant's cost when determining which plants could produce power below market prices.

Q. What is Staff's opinion of Idaho Power's former approach to O&M cost modeling?

[2] UE 293

A. This approach would work well for linearly-related variable costs.[3] This is clearly not the correct assumption given the $/MWh changed by 192 percent between years. It could be the case that the model is using a linear approximation of a higher-order variable cost relationship[4], however the large swings in the size of the variable cost lead Staff to conclude that this approach cannot capture the real world dynamics at play sufficiently. Staff/203 contains an example of how a linear approximation could break down as generation changes.

Q. Please explain how O&M is modeled in the 2015 APCU filing.

A. In the current filing, Idaho Power removed all per-unit costs for O&M. The Company then ran the model and estimated the O&M costs for the year. It then took the total estimation for each coal plant and divided by 12 to achieve a monthly estimate of O&M costs.

Q. What is Staff's opinion of the Company's new approach to O&M cost modeling?

A. This approach would work well if O&M costs were fixed. However, Staff does not believe that this is the case. If the O&M costs were completely fixed in nature, there would be no change from year-to-year in the total O&M costs unless capital investments were required to be made at the plant. Staff/204, reproduced as Figure 2 below for convenience, shows O&M costs by plant from 2012-2015. The amounts have been indexed in order to illustrate the changes over time.

[3] As generation increases by a single unit, variable costs always increase by a particular set amount.
[4] The change in variable cost is dependent on the level of generation (i.e. cost=MWh^{2}). *See* Staff/204.

Figure 2

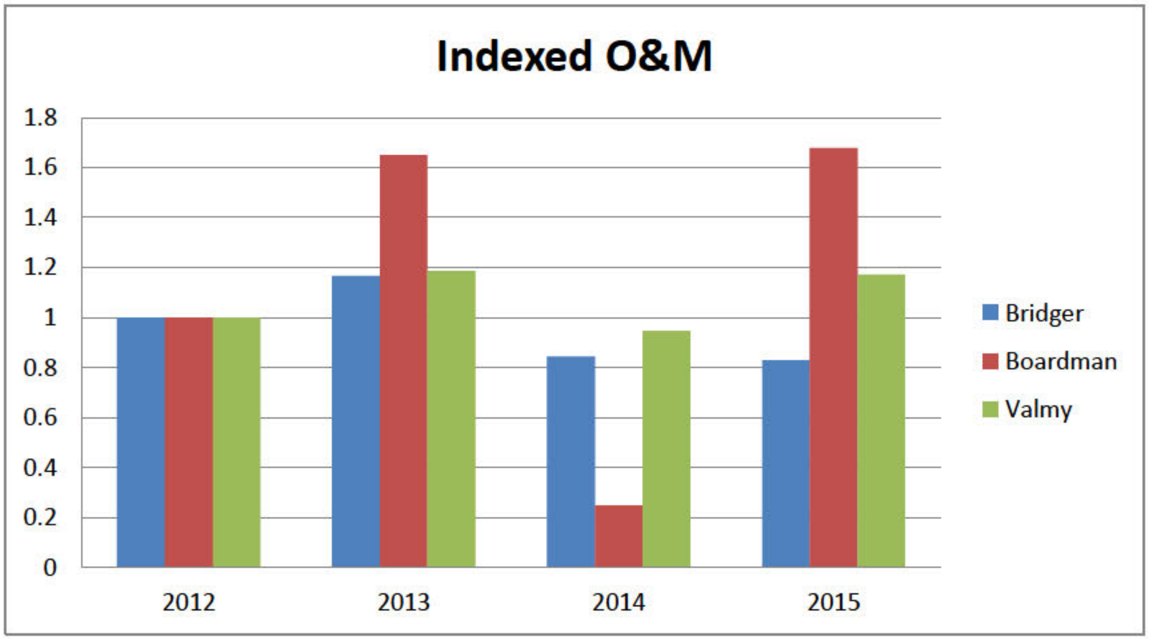


Figure 2 shows that O&M costs have changed every year, a sign that the cost in not in fact fixed. By not including a cost that is variable in the model, AURORA is performing its economic dispatch using incomplete information.

Q. Please describe the Staff's current position regarding the AURORA O&M Modeling Change.

A. Staff continues to support any modeling changes that better reflect the way costs are actually incurred and that lead to forecasts that better predict future costs. However, in this case, Staff continues to question the Company's new approach to O&M modeling, mainly regarding plant operation and dispatching decisions made by Idaho Power and its partners. It is imperative to understand precisely how the costs are incurred during the year in order to properly model them in AURORA.

Q Does Staff have any proposals related to the Company's O&M modeling changes?

A. Yes. The Company's proposed change results in an economic dispatch that does not account for all of the costs associated with coal based generation. Although the suggested change does allow AURORA to model Valmy's dispatch better given current conditions, it does not properly calculate costs. This change makes incremental improvements to the current filing, but may not out preform the old model in subsequent years. Staff recommends a change that would treat the expected portion of O&M that was the result of ownership partner dispatch as fixed, while treating the portion of O&M that resulted from Idaho Power's dispatch decision as variable. Staff's goal with this approach is two-fold:

1) To have AURORA include the added cost of generation in its economic dispatch, thus better capturing the true costs.

2) Ensuring Idaho Power recoups the costs that it has no control over by leaving partner-related O&M as fixed.

Staff believes that a well-designed hybrid modeling of the fixed and variable portions of the OHAG cost will achieve both dispatch fidelity and proper cost accounting.

Q What is Staff's recommendation regarding Issue 1?

A. Staff recommends working with the stakeholders to design and test a hybrid cost model which utilizes a reasonable estimate of fixed OHAG costs coupled with a reasonable variable portion of the costs for use in AURORA. In the event that the hybrid model cannot be incorporated into this year's APCU, Staff recommends that the Commission approve the Company's model as filed, with the stipulation that the change be revisited during the 2017 APCU filing.

ISSUE 2, PURPA CONTRACTS

Q. In Staff's Opening Testimony you stated that Staff was examining PURPA Contract expenses. Why did Staff want to look at PURPA contracts?

A. Staff felt that close examination of PURPA contracts was warranted given the large portion of Net Power Supple Expense (NPSE) that they make up (nearly 60 percent). Because the $/MWh for PURPA-related energy is over twice the cost of Idaho Power-owned generation, Staff wanted to ensure that forecasted energy production from PURPA contracts were close to actuals. If projections were to be inflated, the Company could over-collect from rate payers by purchasing cheaper energy from the market or by dispatching a thermal plant.

Q. What were the results of your findings?

A. Staff compared estimated energy outputs to actuals for the previous four years. Staff found no evidence of over-inflated projected energy outputs.

Q Does Staff have a recommendation regarding PURPA contracts?

A. No, not at this time.

ISSUE 3, LABOR EXPENSES

Q. Staff's Opening Testimony raised labor costs in FERC account 501 as a potential issue. What is your conclusion regarding this issue?

A. Staff's primary concern regarded the potential for labor to be double-collected in both base rates and energy charges. Staff reviewed workpapers from Idaho Power's last rate case (UE 233) and evaluated labor related data responses in this Docket. Based on this review, labor does not appear to be double-counted. Staff no longer considers this an issue in this case.

Q. Does this conclude your testimony?

A. Yes.