BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 301

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, IDAHO POWER 2016 ANNUAL POWER COST UPDATE	))))))))

TESTIMONY ON THE MARCH FORECAST OF THE
CITIZENS' UTILITY BOARD OF OREGON

April 15, 2016

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My name is Dr. Jaime McGovern, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

The purpose of this docket, as defined by Idaho Power Company's ("Idaho Power" or "the Company") Schedule 55 is to update the Company's annual power costs in accordance with the tariff, which states "to define procedures for annual rate revisions due to changes in the Company's projected Net Power Supply Expense".[1]

In March, the Company filed it last update in this docket. In the March forecast, the Company adjusted its forecast to reflect actual water conditions rather than normalized hydro. The March update failed to resolve CUB's concern with the Company's proposal to alter O&M modeling costs from variable to fixed. There are costs at the North Valmy coal plant that Idaho Power incurs, yet does not drive, as part of its

[1] *Idaho Power Company, Schedule 55 Annual Power Cost Update,* https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=287.

contract arrangement with the operating co-owner NV Energy. The Company, Staff and CUB have held multiple settlement conferences involving this issue. CUB recognizes the concern the Company has about the shared O&M costs (specifically, OHAG costs), but feels that the Company has not solved the problem. CUB believes the Company, in its filing has merely created a workaround that may have unintended consequences at North Valmy (the main target) and other plants.

II. The Company's Position

Idaho Power, in this case, takes costs that have been historically modeled as variable (and estimated on a $/MWh basis), and reclassifies them as fixed:

> The O&M expense that was historically included in the AURORA dispatch cost inputs includes Oil, Handling, and Administrative and General ("OHAG") expenses at each of the coal plants. These OHAG expenses are considered to be more fixed in nature and are not directly driven by the annual output of the plant. While the expenses are not directly correlated to the energy output of the plant, they are nonetheless properly booked to FERC Account 501, Fuel Expense, which is considered a variable power supply expense appropriately recovered through the APCU mechanism[2].

They state that this is done to "better align the AURORA dispatch of the coal-fired generation units with the actual operational decisions that result in the dispatch of those plants and to produce a more accurate forecast of NPSE to be included for recovery in the APCU[3]. This change has the impact of increasing the forecasted per-unit cost of North Valmy by almost $10/MWh and tripling generation at that coal plant.

[2] UE 301/Idaho Power/100/Noe/7
[3] UE 301/Idaho Power/100/Noe/7

Table 1

Valmy	Energy (MWh)	Total Cost (000's)	Per-Unit Cost ($/MWh)
2014 October Update[2]	470,994	$16,721	$35.50
2015 October Update[3]	393,636	$13,954	$35.45
2016 October Update - OHAG as Fixed	276,333	$13,037	$47.18
2016 October Update - OHAG as Variable[4]	89,378	$3,450	$38.60

The Company disputes Staff's concern that the increase in per unit cost is driven by decreased generation at North Valmy, and instead asserts that the aforementioned modeling change is the largest driver of the increased cost.[4,5]

At first blush, Table 1 seemed counter-intuitive to CUB. If the same costs were being distributed across more generation (even treated as fixed), then it would seem that the per-unit costs of generation would go down. However, CUB now understands that is not the extent of the change. When the costs went from variable to fixed, they also changed in overall magnitude in a manner that would enable the Company to recover their full forecasted share of the OHAG costs that they share with NV Energy. Increasing the magnitude of forecasted OHAG, on a variable basis, to a level which would approximate full recovery of OHAG costs, would have set OHAG in AURORA at an unreasonable level (unreasonable in the sense that they wouldn't reflect operating costs, and in the model, North Valmy would never get dispatched).

In its co-owner operating agreement with NV Energy, Idaho Power is in the position that, even if it produces no power from North Valmy, it is still responsible for a full 50% of the OHAG costs:

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[4] UE 301/Idaho Power/200/Noe/2
[5] UE 301/Idaho Power/100/Noe/8

> The Valmy Operating Agreeement, as amended, splits the plant operating costs per the ownership percentage. Idaho Power owns 50 percent of the plant and pays 50 percent of the total operating costs, regardless of Idaho Power's utilization of the plant. The operating costs include the fixed and variable costs associated with running the plant. The exception is the fuel costs which are allocated to each owner based on their individual usage of the plant.[6]

CUB now understands from discussions with the Company that, although Idaho Power exercises its dispatch opportunity economically[7,8], NV Energy, as the operator of the plant, operates more prominently in Southwest markets (Mead and Palo Verde) than Idaho Power (primarily Mid-C). The Southwest markets often maintain a higher price, and therefore, NV Energy has recently been dispatching the plant more than Idaho Power. Therefore, although both NV Energy and Idaho Power share OHAG costs down the middle, NV Energy is getting a larger share of the output. Another way to phrase this would be to say that half of Idaho Power's OHAG costs are socialized to NV Energy, and half of NV Energy's OHAG costs are being socialized to Idaho Power. Because Idaho Power gets less annual output from the plant than NV Energy, but the Operating Agreement requires them to still pay half the costs, Idaho Power's unit cost is higher.

III. CUB's Understanding

The Company states in testimony that OHAG costs are not really variable costs: In recognition that the O&M cost component does not vary with the amount of production at each plant, the Company this year has removed the O&M expense component from the AURORA dispatch cost inputs and instead included it outside of the

[6] UE 301/Idaho Power/100/Noe/8
[7] UE 301 CUB Exhibit 102, Idaho Power's response to CUB DR 4
[8] https://www.nvenergy.com/company/rates/filings/IRP/NPC_IRP/ERCR_NPC/Vol13-ESPNarrative-Testimonies.pdf pg 91

AURORA analysis[9]. CUB believes that this is a misrepresentation, and that a more accurate depiction lies in the Company's response to CUB's data request:

> Under the prior method (i.e., OHAG expenses modeled as variable), modeled costs and actual costs appropriately track when Idaho Power's share of total dispatch at each plant is close to its respective ownership share. However, when Idaho Power's share of total dispatch declines to less than its ownership share, the modeling of forecasted OHAG over lower expected dispatch volumes inflates the modeled dispatch cost. This is what occurred at the Valmy plant in 2015 and prompted the APCU modeling change.[10]

The OHAG costs are variable costs. They vary with plant production. This is why they are recorded in FERC account 501. It can be said that they do not vary directly with Idaho Power's share of plant production, since Idaho Power agreed to pay half of the costs regardless of their share of the output, but the OHAG costs are variable costs.

CUB agrees that the AURORA model is not appropriately handling these costs, but not because they are fixed – instead they are being mistreated. It is because they are variable socialized costs that are contingent on the co-owner's (NV Energy's) production. If the costs were fixed, then there wouldn't be a difficulty in establishing what the fixed amount was. However, the OHAG costs are contingent on total production (NV MWh + IPCO MWh), and therefore, difficult to forecast without knowing NV Energy's planned generation. Note, however, that this relationship goes both ways, and that the actual dispatch OHAG costs that Idaho Power incurs for its own generation is only half of the cost to the overall plant for that generation. This further complicates the implications for treatment in modeling.

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[9] UE 301/Idaho Power/100/Noe/7
[10] UE 301 CUB Exhibit 102, Idaho Power's response to CUB DR 3

CUB also understands that Idaho Power has similar arrangements with its co-owners at Bridger and Boardman, but since those plants provide output that largely reflects ownership shares, the disproportionate per MWh generation cost is not an issue.

The Company attempts to demonstrate that the proposed modeling is appropriate because the AURORA-modeled costs per MWh at North Valmy closely track actuals from 2015. However, this does not demonstrate that the costs are being treated appropriately or that these costs are being excluded in dispatch decisions, as fixed costs would be.

Idaho Power-Owned Thermal Generation $/Megawatt-Hour ("MWh") Cost			
Plant	2015 Actual[1]	October APCU Model OHAG Fixed	October APCU Model OHAG Variable[2]
Bridger	$29.54	$27.44	$28.64
Boardman	$25.37	$25.32	$27.26
Valmy	$26.65	$32.39	$54.71

Instead, it demonstrates that, at Bridger and Boardman, the socializing of costs currently has little impact because the two owner shares of generation are relatively similar to their ownership shares. Although, at $32.39/MWh, the proposed modeling seems seductively less than the $54.71 resulting from the current modeling, this savings pales in the light that the output of North Valmy is forecasted to be three times as large under the proposed modeling.

IV. CUB's Position

CUB opposes the modeling change that the Company has proposed for several reasons. We summarize them here and discuss them in detail below:

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A. **Model Change is not a Fix**

B. **Unintended Consequences**

C. **APCU is not the Best Venue**

D. **FERC Classification**

E. **Cost Benefit Mismatch**

A. Model Change is not a Fix

The Company has not demonstrated that this modeling change fixes the problem in the model. In fact, it is not a modeling change, but a change that artificially sets an input to zero, and moves it outside the model. This is a workaround that achieves full OHAG recovery. CUB understands the issue that the Company is facing. Between its two plants North Valmy has 522 MW of generating capacity[11], leaving each of the two owners 260 MW for their capacity shares. Recently, Idaho has been producing less than NV Energy, but paying the same amount in OHAG costs (aside from fuel). This has caused a mismatch of modeled costs and actual Company costs. CUB understands and agrees that AURORA is not handling the OHAG input in a way that seems intuitive or representative of actual dispatch. However, the OHAG costs are variable costs. Another way of saying that they are variable is to say that they are conditional on output. However, some of the output that is driving those costs is outside of the Company's control.

The Company is looking at options to better align the actual OHAG costs with those included in rates. In conversations with Staff and CUB, Idaho has presented their

[11] *NV Energy, North Valmy Generating* Station, https://www.nvenergy.com/company/energytopics/images/Valmy_Fact_Sheet.pdf.

concerns and another option, dubbed "the hybrid model" which attempted to ferret out the OHAG costs due to Idaho's production and those due to NV Energy's production. In doing this, they also attempt to model the actual costs that the dispatch operators consider when economically dispatching the plant. The other costs, the ones coming from NV Energy, are left outside the model, and then added back to power costs afterward.

However, this approach does not completely solve the fundamental issue. In the hybrid model, which CUB views as an improvement over the Company's initial proposal. Idaho Power attempts to identify the fixed portion, the portion attributable to NV Energy's generation at the plant, and separate that from the variable driver, Idaho Power's generation. The proposed approach in the original filing did not make this valuable distinction. However, CUB believes that the portion of costs attributable to NV Energy's generation is not fixed, and, in fact, is not completely identifiable. It is a variable cost, over which Idaho Power has no control. So possibly, it can be classified and forecasted as a variable cost, but not inside Aurora. However, this raises another concern for CUB, because the cost of production per MWh is a function of the operating state of the plant. That is, the per unit cost of Idaho Power's generation is going to be different depending on what level at which NV Energy is already operating the plant. CUB believes there is still more progress to be made on that end, in terms of accuracy, drivers, and range of error.

Therefore, although CUB believes that the "hybrid model" addresses one of the main issues of the OHAG reclassification, we believe it is worth identifying and considering the other consequences of the various options.

B. Unintended Consequences

The situation with NV Energy is temporal and currently unique to this jointly owned plant. The current owner-operating agreement between NV Energy and Idaho Power was established in the early 90's, long before the evolution of modern market optimization and hourly economic markets. Historically, coal plants were built and intended as baseload plants. Technological and economic changes are altering these relationships. Unprecedentedly low gas prices are making coal dispatch un-economical. Prudency requires us to consider what a proposed change in the standard handling of these contract costs would have on likely future scenarios. If the modeling change is equitably appropriated to all jointly owned plants, there could be unintended consequences.

Idaho Power is currently an equal co-owner in three coal plants (1) North Valmy, (2) Boardman, and (3) Bridger. They are currently experiencing minority generation at North Valmy. However, the movement of costs that are actually variable to be modeled as fixed, if they are actually variable, can have some negative impacts. There are two possibilities: (1) Actual dispatch logic does not consider OHAG costs in the economic dispatch of the plant; or (2) dispatch logic does consider OHAG costs as variable in consideration for economic dispatch, but AURORA does not. Let’s explore both.

In the Case that Actual dispatch logic does not consider OHAG costs as variable and neither does AURORA. What are these costs? The Company describes them in a data response to Staff:

> 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.[12]

But these costs do vary with production:

> Although OHAG expenses vary with total production, Idaho Power Company's ("Idaho Power' or "Company") **share of these expenses is fixed** based on the Company's ownership share of each plant. ln other words, OHAG expenses fluctuate with total generation at each plant, but ldaho Power's proportional share of these expenses does not. (emphasis added)[13]

It is true that their share is a fixed percentage, but 100% is a fixed percentage also. That is, being responsible for a fixed share of a variable cost does not make that cost fixed. Then we have a case where there are costs that do truly vary with production, but are being excluded from dispatch logic. This is a problem. It makes a coal plant run more often than it should be. Put otherwise, a coal plant, which has real costs potentially higher than the market, is running because some of the costs of dispatch are being ignored. The fact that coal is potentially displacing cleaner resources is just one problem. A more direct problem is that the Company is displacing cheaper resources and unjustly burdening customers with artificially high priced power.

Consider the second case, in which AURORA *excludes* OHAG costs as a variable cost, but power operators are *including* it in their economic dispatch decisions. This would mean that there is a mismatch between forecasted dispatch economics and actual dispatch economics. In particular, AURORA, with its artificially low marginal cost of production, would often calculate that the coal plant was in the money, even when it was not, and model it to generate more than it would in reality under the exact same conditions. Put another way, if the Company were exactly right about load, hydro,

[12] UE 301 CUB Exhibit 103, Idaho Power's Response to Staff DR 20
[13] UE 301 CUB Exhibit 102, Idaho Power's response to CUB DR 3

market and weather conditions, they would be overproducing in AURORA and, therefore, over-collecting power costs from customers. The fact that forecasts are never exact only confounds the issue. And, in fact, we see that a change in the modeling has resulted in modeled generation at North Valmy going from 89 thousand MWhs to 276 thousand MWh-a whopping three times as much. This consequence, which the Company identifies as driven mainly by the modeling change, is significant.

Either scenario is concerning to CUB. Without a convincing argument that these OHAG costs do not vary with generation, CUB is not comfortable modeling them as if they did not.

In conversations with CUB and Staff, Idaho Power's presentation of the "hybrid model" also attempts to resolve this issue. It is CUB's understanding that by pulling out the OHAG costs that Idaho views as fixed, but leaving a portion in the AURORA model, the portion which Idaho Power's production is driving, the hybrid model attempts to closer align the costs modeled inside AURORA with the ones that the actual dispatch operators consider. Set the internalized costs too high (by including all of NV Energy's costs in AURORA), and AURORA forecasts North Valmy never to run, and therefore OHAG costs to be zero. This is clearly a mismatch with reality. Set the internalized OHAG costs too low (pulling them out of the model completely as with the Company's proposal), and North Valmy runs more often than it will in reality. This, in turn, may cost customers more in forecasted rates. Finding the appropriate level that matches reality is an important step.

CUB believes that on this end, the hybrid model is a step in the right direction. Further work is needed here to verify what the real per MWh cost is based on total plant production, and to determine whether an overall average is more appropriate, or whether per MWh costs are contingent on co-owners production.

C. APCU is not the Best Venue

The APCU is not the best place for this type of modeling change. The Idaho Power Tariff 55 identifies the variables that are updated in the APCU[14]:

October:

- Fuel prices and transportation costs;
- Wheeling expenses;
- Planned outages and forced outage rates;
- Heat rates;
- Forecast of Normalized Sales and Normalized Load determined in accordance with the methodology employed in the most recently acknowledged Integrated Resource Plan ("IRP");
- Contracts for wholesale power and power purchases and sales;
- PURPA contract expenses;
- The Oregon state allocation factor; and
- The average forward electric price curve calculated from the previous October through September daily Mid-Columbia heavy load and light load forward price curves for the period April through March immediately following the April through March Test Period, adjusted for inflation back one year.

March:

- Fuel prices and transportation costs;
- Wheeling expenses;
- Planned outages and forced outage rates;
- Heat rates;
- Forecast of Normalized Sales and Normalized Loads, updated only for known significant changes since the October Annual Power Cost Update filing;
- Forecast hydro generation from stream flow conditions using the most recent water supply forecast from the Northwest River Forecast Center in Portland, Oregon, and current reservoir levels;
- Contracts for wholesale power and power purchases and sales;
- PURPA contract expenses;
- The Oregon state allocation factor; and
- The most recent monthly forward price curve, as of the date of the filing, for the April through March Test Period.

CUB does not find allowance for a change in the methodology for non-fuel variable costs in any section of the tariff. If these costs are so significant to the Company that a modeling change is required, then it should be done properly with considerations of all implications. It should not be done for a particular circumstance at one plant, but to

[14] *Idaho Power Company, Schedule 55 Annual Power Cost Update*, https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=287.

match operations with modeling. If the Company believes that an overhaul of the modeling is appropriate for AURORA, and that it is a significant issue, the Company can propose a comprehensive redesign, or a model update that addresses the problem, not do an outboard adjustment. CUB prefers a modeling change to ex-post adjustments, for reasons of accuracy, predictability, and consistency. To be clear, the Company has an opportunity to recover these costs. If the forecasted costs are so misaligned with actuals that they trip the deadband, and Idaho Power is under-earning, then the Company can recover costs in the true-up. For all these reasons, CUB does not think that this docket is the appropriate place for such a change in modeled costs practice. While it may improve the Company's cost recovery of OHAG, it may also make the forecast of North Valmy dispatch less accurate.

D. FERC Classification

FERC account 501 governs variable costs. The Company should not treat the cost as fixed for ratemaking purposes, but report to FERC that it is a variable cost. It is one or the other. CUB believes that it is a variable cost and should be treated as such for ratemaking purposes.

CUB believes that Idaho Power should not be booking OHAG costs related to NV Energy’s production in FERC Account 501.

FERC designates 501 in the following way:

<u>501 Fuel.</u>

> A. This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-house structure.

Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.

B. The cost of fuel shall be charged initially to account 151, Fuel Stock (for Nonmajor utilities, appropriate fuel accounts carried under account 154, Plant Materials and Operating Supplies) and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to account 152, Fuel Stock Expenses Undistributed (for Nonmajor utilities, an appropriate subaccount of account 154, Plant Materials and Operating Supplies). In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.

ITEMS

Labor:

1. Supervising purchasing and handling of fuel.

2. All routine fuel analyses.

3. Unloading from shipping facility and putting in storage.

4. Moving of fuel in storage and transferring fuel from one station to another.

5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler-house structure.

6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc.

Materials and Expenses:

7. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).

8. Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point (Major only).

9. Cost of fuel including freight, switching, demurrage and other transportation charges.

10. Excise taxes, insurance, purchasing commissions and similar items.

11. Stores expenses to extent applicable to fuel.

12. Transportation and other expenses in moving fuel in storage.

13. Tools, lubricants and other supplies.

14. Operating supplies for mechanical equipment.

15. Residual disposal expenses less any proceeds from sale of residuals.

NOTE: Abnormal fuel handling expenses occasioned by emergency conditions shall be charged to expense as incurred.[15]

The Company has not specified to which component of FERC account 501 it would charge a fixed amount of OHAG expenses. Importantly, CUB recognizes that, regardless of the modeling, the Company will continue to incur actual variable costs exactly equal to half of their own OHAG costs (excluding fuel). CUB does not believe that the FERC designation above was intended for the costs of unloading, taxes, handling, transportation, etc. for *another* company's generation. That is exactly how Idaho Power is describing the charges that they are incurring because of NV Energy's generation. The costs due to NV Energy's generation do not have a proper classification in Idaho Power's FERC 501 account.

Moreover, the Company was recently audited by FERC on a related issue. FERC's audit particularly identified an issue regarding overcollection of O&M costs by Idaho Power for a facility that was co-owned by Idaho and PacifiCorp, in which Idaho Power was the operator in the owner-operator agreement. In other words, an analogous situation in which the roles of owner-operator were flipped when compared to the NV Energy/Idaho Power agreement. According to FERC:

<u>O&M Costs Incurred under a Joint Ownership Operating Agreement</u>

Idaho Power included O&M costs related to PacifiCorp's share of their jointly owned substation, Hemingway, as part of its O&M expenses in its

[15] Order 218, 25 FR 5014, June 7, 1960, *available at* http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18.

> formula rate. This resulted in an estimated over-collection of $8,227 of cash working capital through Idaho Power's formula rate.[16]

FERC finds:

> Idaho Power should ensure that PacifiCorp's share of O&M expenses are not reported in Idaho Power's O&M accounts. Instead, Idaho Power should include these costs in Account 415, Revenue from Merchandising, Jobbing and Contract Work and Account 416, Costs and Expenses of Merchandising, Jobbing, and Contract Work. This will prevent the inclusion of these amounts through Idaho Power's formula rate and better represent the economic substance of the transaction.
>
> **It is imperative for companies that are part owners or operators of jointly owned facilities to know the correct treatment of costs incurred and recorded on their books that are borne by JOOAs. It is a company's obligation to hold its customers harmless of costs associated with its partner's share of facilities that are jointly owned.** By including PacifiCorp's responsible portion of transmission facilities O&M expenses, Idaho Power over-collected an estimated of $8,227 in cash working capital through its formula rate, before interest. This was calculated by taking one-eighth of $591,148 as cash working capital and multiplying it by Idaho Power's rate of return of .11134. Idaho Power should ensure that all costs incurred through any of its jointly owned facilities are being properly accounted for on its books and through all rate recovery mechanisms used.[17] (emphasis added)

FERC not only found that Idaho Power should file a customer refund with the Commission, but that it should appropriately record charges in the correct account that most closely matches the identity of the charge. Just as importantly, FERC deemed that "It is a company's obligation to hold its customers harmless of costs associated with its partner's share of facilities that are jointly owned". CUB believes that this principle applies here. Idaho power must hold its customers harmless of costs associated with NV Energy's share of North Valmy.

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[16] *FERC Audit of Formula Rates at Idaho Power Company*, Docket No. FA12-9-000, December 11, 2013 at 17, *available at* http://www.oasis.oati.com/IPCO/IPCOdocs/12-11-13_FERC_Letter_Order_Approving_Idaho_Power's_Audit_Report.pdf. pg 17

[17] *FERC Audit of Formula Rates at Idaho Power Company*, Docket No. FA12-9-000, December 11, 2013 at 18-19, *available at* http://www.oasis.oati.com/IPCO/IPCOdocs/12-11-13_FERC_Letter_Order_Approving_Idaho_Power's_Audit_Report.pdf. pg 18-19

E. Cost Benefit Mismatch

Finally, CUB believes that the costs and benefits of generation by customer owned facilities should be matched. The Company receives revenues from NV energy when NV generates beyond their 50% capacity share, and Idaho Power does not record these revenues in the APCU. There is a mismatch of costs and benefits.

Idaho Power and NV Energy jointly own North Valmy. However, NV Energy is the operator and, therefore, has dispatch authority. From a conference call with Idaho's power operations team, it is CUB's understanding that Idaho Power, based on load, market characteristics, the dispatch rate (or d-rate, the variable cost of generation) submits its desire to participate in generation for the period (usually a day ahead), or its desire to stay out. If the Idaho Power opts in, then it must opt in at a minimum of 90 MWs (its 50% share of North Valmy allows 260 max). If it opts out, then it is relieved of the fuel costs related to that output. In either case, NV Energy, armed with that information, makes its own choice about dispatch. It has the full capacity of North Valmy at its disposal less Idaho Power's opt-in amount. If for instance, Idaho Power opts in at 100 MWs, then NV can produce its own 260 MWs, but it also can use Idaho Power's unused capacity. (260-100=160), for a total of 360 MWs. (note: It can dispatch both units at North Valmy partway, or one unit full capacity or any combination). For every MW of unused capacity that it “exercises” from Idaho Power, NV Energy must pay Idaho Power a "usage charge." That usage charge is formulaic and known in advance, recorded to account FERC account 456 "other electric revenues," or revenues not includable in any other designated accounts. However, FERC account 456 is not included in the APCU. That is, Idaho Power is booking costs to customers’ power generation (NV Energy's generation), receiving revenue for this generation, and not crediting customers in the same mechanism. There is a clear mismatch of costs and value to customers. Although the Company is recording the revenues from the usage charge, rate spread and rate design affect how different customers are affected. Aligning the costs and benefits of this capacity transfer is equitable.

V. CUB's Recommendations

CUB recommends that the Commission disallow the proposed modeling change by the Company. CUB understands the issue that the Company is attempting to address, but does not believe that the approach is appropriate or well executed. There are consequences of the new approach that are problematic. Instead, CUB recommends that the Company continue to work with parties to solve the root of the problem, which consists of accurately forecasting, and classifying the different costs that the Company is incurring. To the extent that those costs are legitimate, and that the Company has authority to collect them, CUB recommends that the Company carefully analyze and allocate the costs and related revenues to the proper FERC accounts. CUB has several data requests outstanding on this issue and is continuing to work with parties to understand all related issues.

WITNESS QUALIFICATION STATEMENT

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EXPERIENCE: Provided testimony or comments in a number of OPUC dockets, including UE 262, UE 283, UM 1633, and UM 1654. Worked as Utility Analyst at the Oregon Public Utility Commission from 2006-2008, providing advice on rate cases, analysis in meetings with the Bonneville Power Administration and performing benchmarking studies regarding telecom and electric competition in the state of Oregon.

Economics professor at Mesa Community College and the State University of New York from 2004–2010.

IDAHO POWER®
An IDACORP Company

March 31, 2016

Subject: Docket No. UE 301 – 2016 Annual Power Cost Update
Idaho Power Company's **Redacted** Responses to the Citizens' Utility Board of Oregon's ("CUB") Data Requests 3-5

CUB'S DATA REQUEST NO. 3:

Re: UE 301/Idaho Power/100/Noe/7, please demonstrate that the actual dispatch at each of its plants reflects the current modeling. In particular:

(a) do the O&M (OHAG) costs vary with start up and shut down?

(b) do the O&M (OHAG) costs vary with unit production?

Please provide data to support both of the above responses.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 3:

Total oil, handling, administrative, and general ("OHAG") expenses vary over time based on several factors, including total plant production, plant operating characteristics, and market prices of each of the OHAG components. With regard to start-ups and shutdowns, a single start-up or shutdown is likely to have minimal impact on OHAG expenses, but the overall number of start-ups and shutdowns over time can impact these costs. For example, if a plant is experiencing multiple start-ups and shutdowns, it will require more oil than if the plant were operating continuously.

Although OHAG expenses vary with total production, Idaho Power Company's ("Idaho Power" or "Company") share of these expenses is fixed based on the Company's ownership share of each plant. In other words, OHAG expenses fluctuate with total generation at each plant, but Idaho Power's proportional share of these expenses does not.

The current modeling of expenses in the 2016 Annual Power Cost Update ("APCU") was intended to better reflect OHAG expenses actually incurred by the Company. Because Idaho Power is responsible for its ownership share of OHAG expenses regardless of the Company's dispatch of each plant, modeling OHAG expenses as a variable cost driven by Idaho Power dispatch volumes creates the potential for a disconnect between modeling assumptions and actual incurred costs.

Under the prior method (i.e., OHAG expenses modeled as variable), modeled costs and actual costs appropriately track when Idaho Power's share of total dispatch at each plant is close to its respective ownership share. However, when Idaho Power's share of total dispatch declines to less than its ownership share, the modeling of forecasted OHAG over lower expected dispatch volumes inflates the modeled dispatch cost. This is what occurred at the Valmy plant in 2015 and prompted the APCU modeling change.

As detailed in the table below, by modifying the AURORA® model to account for OHAG expenses as fixed rather than variable, the resulting modeled coal plant costs more closely align with actual costs incurred in the most recent historical calendar year. The first column contains actual historical cost data from 2015, while the second and third columns contain modeled costs from the 2016 October Update, with OHAG modeled as fixed and variable, respectively.

Idaho Power-Owned Thermal Generation $/Megawatt-Hour ("MWh") Cost			
Plant	**2015 Actual[1]**	**October APCU Model OHAG Fixed**	**October APCU Model OHAG Variable[2]**
Bridger	$29.54	$27.44	$28.64
Boardman	$25.37	$25.32	$27.26
Valmy	$26.65	$32.39	$54.71

[1] Reflects Idaho Power's actual 2015 coal costs divided by Idaho Power's actual generation at each plant, plus assumed plant handling and variable operations and maintenance ("O&M") expense on a $/MWh basis.

[2] Please see Scenario 1 (Valmy High) provided in the Company's response to Staff's Data Request No. 18.

CUB'S DATA REQUEST NO. 4:

When the operators of the plant dispatch, do they dispatch the plants economically? (That is, generally: does the Company dispatch Company owned resources when they are in the money, regardless of load/need, and not dispatch Company owned resources when the plant is out of the money, if other options are available?)

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 4:

Yes, Idaho Power dispatches its resources economically. The Company considers its overall resource stack, including buying from the market, and determines the best way to serve load in the most economic manner while taking into consideration operational limitations, reliability to Idaho Power's system, and the whole electrical grid. In the rare occurrence that grid stability becomes a concern (e.g., a plant unexpectedly trips off-line), Idaho Power will dispatch resources that may not be economical at that time. Grid stability will be provided at the least possible cost, but economics of a unit will not be the priority. Most Idaho Power-owned generation is dispatched manually. Two of the Company's hydro plants, Brownlee and Oxbow, can be put into CE (Control Economic) mode, which automatically dispatches those plants and their units in the most efficient manner based on controlling to ACE (Area Control Error) and the flows scheduled to run. CE mode is typically utilized to balance variations in load and wind production. Once load is reliably served, Idaho Power looks for market opportunities and will dispatch resources if they are in the money.

CUB'S DATA REQUEST NO. 5:

If the answer to the above question is yes, for Company owned resources, do the operators consider or exclude OHAG/O&M costs in their economic dispatch decisions in actual operations when deciding whether to dispatch the plant?

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 5:

A portion of OHAG expense related to coal handling is included in the actual dispatch rates used in the economic dispatch process. Amounts currently included in dispatch rates for each plant are as follows: $[redacted] at Boardman, $[redacted] at Jim Bridger, and $[redacted] at North Valmy. However, as discussed in the Company's response to CUB's Data Request No. 3, Idaho Power is responsible for its fixed ownership share of total OHAG expense at each plant regardless of how much Idaho Power actually dispatches each plant.

The response to this Request contains protected information and an unredacted version will be provided separately in accordance with General Protective Order No. 16-024.

STAFF'S DATA REQUEST NO. 20:

Please provide the following information regarding O&M:

a. Please give a detailed description of the purpose and makeup of the oil and handling component.

b. Please describe why these components and uses do not correlate with power generation at a plant.

c. Please provide a narrative description as to why Boardman has such a small O&M cost relative Idaho Power's other thermal plants.

d. Are there any fixed costs similar in nature to O&M for natural gas fired plants?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 20:

a. 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.

b. These components are based on total plant charges for the handling and storage of the coal, and are not specific to the generation Idaho Power receives from the plant.

c. Because total O&M costs are assigned based on capacity ownership percentage, and Idaho Power's ownership share at Boardman is smaller relative to the other jointly owned coal plants, the O&M costs related to Boardman are lower in comparison to the other plants.

d. Yes. As discussed on page 8 of Idaho Power/100, the Company has historically included the cost of natural gas pipeline capacity reservations as a fixed cost input to the APCU which is not included as a dispatch cost component within the AURORA model.