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May 4, 2017

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 316 – In the Matter of
IDAHO POWER COMPANY, Request to Increase Rates for Electric Service to Recover Costs Associated with Valmy Power Plant

Enclosed for electronic filing is the following Staff Reply Testimony:

- Exhibit 100 to 106 Gibbens
- Exhibit 200 to 205 Peng and
- Exhibit 300 to 304 St. Brown

Work papers will be sent to parties separately.

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
(503) 378-5763
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CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

May 4, 2017

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

A. My name is Scott Gibbens. I am a Senior Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Staff Exhibit/101.

Q. What is the purpose of your testimony?

A. In my testimony I present Staff's analysis of Idaho Power's (IPC or Company) request to accelerate depreciation for the North Valmy Power Plant (Valmy). My testimony also presents the Commission precedent set forth in similar filings, as well as Staff's analysis of the economics of potentially shutting down the plant ahead of the current schedule. I also address the recovery of Valmy capital investments made since 2011 and the mechanism which IPC proposes to use in order to recover the decommissioning and other costs.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared six staff exhibits, consisting of six pages.

- Staff Exhibit 101: Witness Qualification Statement
- Staff Exhibit 102: Company Response to Staff DR No. 11
- Staff Exhibit 103: Company Response to Staff DR No. 64
- Staff Exhibit 104: Staff's NPV Calculation
- Staff Exhibit 105: Company Response to Staff DR No. 59
- Staff Exhibit 106: Company Response to Staff DR No. 63

Q. How is your testimony organized?

A. My testimony is organized as follows:

I begin with a short introduction to the filing and background on the issues. I then discuss Staff's review of the decision to accelerate depreciation at Valmy. This is followed by Staff's analysis of the capital investments made at Valmy since Idaho Power's last general rate case. Finally, I discuss Staff's proposals for the mechanism design. Staff witness Max St. Brown's testimony discusses the rate spread and rate design of the cost recovery and Staff witness Ming Peng provides analysis of the depreciation calculations.

ISSUE 1, APPROPRIATENESS OF ACCELERATED DEPRECIATION

Q. Please summarize the Company's request in this docket.

A. In its filing, the Company requests that the Commission approve an accelerated depreciation schedule for Valmy, establish a balancing account to track the incremental costs and benefits associated with the accelerated Valmy end-of-life date of December 31, 2025, and adjust customer rates accordingly to recover the associated incremental annual levelized revenue requirement of $1,056,800 with an effective date of November 1, 2017.[1] The Company's requested $1,056,800 revenue requirement request includes capital additions for Valmy for the period of time since the Company's most recent general rate case and May 31, 2017.[2]

Q. Please describe the circumstances that led to the Company's proposal in this case.

A. Idaho Power owns 50 percent, or 284 MW, of both Valmy units 1 and 2. NV Energy owns the other 50 percent of each unit, and serves as the operator of the Valmy facility. Currently approved depreciation rates in Oregon reflect a retirement year of 2031 for Unit 1 and 2035 for Unit 2.[3]

Due to the changing economics of plant operations,[4] the general and regulatory trend towards cleaner and more sustainable power sources,[5] and the Public Utility Commission of Nevada's (PUCN) approval of a 2025 end-of-

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[1] This is the effective date on the Company's Advice 16-17. Note that in the Company's testimony, they request a rate change effective June 1, 2017.
[2] Idaho Power/100, Larkin/9.
[3] Idaho Power/100, Larkin/4.
[4] Idaho Power/100, Larkin/4; Idaho Power/200, Harvey/7-13.
[5] Idaho Power/200, Harvey/8.

life date for both Valmy units in Nevada,[6] IPC has requested that the Oregon Public Utility Commission (Commission) approve a request to effectively take steps to recognize in rates a 2025 end-of-life for both Valmy units.[7]

Q. Is there a date by which NV Energy and Idaho Power plan to shutdown plant operations for Valmy?

A. No, not at this time. IPC has been in discussions with NV Energy about an early closure of the plant since 2013, but has not settled on a date.[8] The Company also states that it may not be feasible to discontinue operations prior to 2025 absent the completion of its Boardman to Hemingway (B2H) transmission facility.[9]

Q. Why does a decision by the PUCN affect Idaho Power's decision to accelerate depreciation?

A. In 2013, the PUCN approved a 2025 end-of-life date for both Valmy units in Docket No. 13-06004. Like IPC, NV Energy also analyzed the worsening economics of the plant in a low priced natural gas market with increasing amounts of renewables coming online every year. Idaho Power states that "synchronized depreciation dates for ratemaking purposes will help in establishing a date to cease coal-fired operations."[10]

Q. Has the Commission previously approved accelerated depreciation for other coal-fired generating resources?

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[6] Idaho Power/100, Larkin/4-5.
[7] See the Company's application, page 2 line 13.
[8] See Staff Exhibit 102.
[9] Idaho Power/200, Harvey/10 and Staff Exhibit 103.
[10] Idaho Power/200, Harvey/11.

A. Yes. The Commission has approved stand-alone recovery mechanisms for both PGE's[11] and Idaho Power's[12] recovery of depreciation expense, return on undepreciated investment and decommissioning costs for the Boardman plant, and for PGE's recovery for its share in the Colstrip plant.[13]

Q. Is Staff recommending that the Commission wait until a closure date has been set before approving accelerated depreciation for Valmy?

A. No. Staff recommends that the Commission grant Idaho Power's request to implement accelerated depreciation rates for Valmy in this case, which is prior to a final determination of the closure date. Staff believes this is consistent with the Commission's general policy to allow for accelerated depreciation of coal-fired generating resources when the early closure of those resources is determined to be in the public interest.

In OPUC Docket No. UE 215, the Commission approved PGE's Schedule 145, which established a mechanism to collect decommissioning and accelerated depreciation costs for the Boardman power plant. Like in this circumstance, PGE's IRP had indicated an early closure date would be economically prudent, and setting up the mechanism provided flexibility in changing the closure date. Valmy and Boardman are not completely identical however, in PGE's case, the mechanism did not collect any amount from customers until the closure date was set.[14]

[11] *In re Portland General Electric*, OPUC Docket No. UE 215, Order No. 10-478 at 4 (Dec. 17, 2010)..
[12] *In re Idaho Power Company*, OPUC Docket No. UE 239, Order No. 12-235 (Jun. 26, 2012)..
[13] *In re Portland General Electric*, OPUC Docket No. UE 317, Order No. 16-468 (Dec. 7, 2016)..
[14] *In re Portland General Electric*, OPUC Docket No. UE 230, Order No. 11-242 (Jul. 5, 2011).

With PGE's Advice 16-15, the Commission approved an automatic adjustment clause to recover costs associated with PGE's share of Colstrip units 3 and 4, as specified by 2016 Oregon Laws, Chapter 28 (SB 1547), Section 1, without knowing the precise date that the plant will be either shuttered or PGE's interest sold to another party.[15] However, Staff notes that the basis for the Company's request was due to SB 1547, which is distinct from Idaho Power's request in this case.

In this filing, IPC is requesting immediate recovery of costs, ahead of a date-certain for shut-down. Given the interest by Oregon to promote the end of coal costs being in rates, as evidenced by the recent passage of SB 1547, the relatively short time-frame to recover costs from Oregon customers, and the Company's analysis in its 2015 IRP, Staff recommends that the Commission approve Idaho Power's request to accelerate depreciation for Valmy ahead of a date-certain for closure, based on a 2025 end-of-life for both units.

Q. Is Staff recommending that the mechanism be set up but no rate changes made until a closure date is set?

A. No. That is one course of action the Commission could take; however, it is not Staff's recommended approach. As I will show in my following testimony, the information available at this time indicates that early shutdown of Valmy is the least cost-, least risk-option. The Commission should therefore allow Idaho Power to begin collecting costs for the expected early closure of Valmy.

[15] Order No. 16-468.

Accelerating depreciation now will spread the costs over a longer period of time and have a smaller impact on rates.

Q. What is the impact if Valmy does not close down in 2025?

A. If market conditions change in favor of coal generation, the partners could determine that operating Valmy past 2025 is in the economic interest of customers. This would have the unfortunate effect of causing intergenerational inequity: current ratepayers would bear a greater burden of depreciation expense and closure costs than they otherwise should. Staff however believes that the risk of intergenerational inequity is outweighed by the risk of rate shock to customers if the recovery period for Valmy is required over a shorter period of time. Further, Staff's proposed mechanism is reviewed annually which will allow flexibility in handling new circumstances. Staff also finds it compelling that NV Energy operates the plant for IPC, and has already set a shorter end-of-life date in Nevada.[16]

Q. Please describe Staff's analysis of a 2025 end-of-life for Valmy.

A. Staff began its analysis by utilizing the assumptions, data, and cost/benefit models provided in the Company's 2015 IRP. Staff updated the benefit/cost model with current data, timeline, and discount rate using information provided by IPC in this filing and subsequent data requests. The discount rate was set to the Company's current weighted average cost of capital (WACC), changing it from 6.74% to 7.24%[17]. The analysis looked at both the fixed cost savings of an early closure date of Valmy and the subsequent loss of generation resulting

[16] Idaho Power/100, Larkin/4-5.
[17] Staff calculated an updated WACC based on information provided by the Company for this filing.

from the plant's closure. It utilizes Idaho Power's AURORA model to estimate the power cost impacts of serving its load in 2025 and beyond with and without the capacity at Valmy. Figures 1 and 2 below show the results of Staff's analysis in nominal and net present value (NPV) terms of the revenue requirement with a shutdown minus the revenue requirement without a shutdown. Figure 1 shows each year's cost (benefit) of closing Valmy in 2025, while Figure 2 shows the cumulative impact over time.

Figure 1

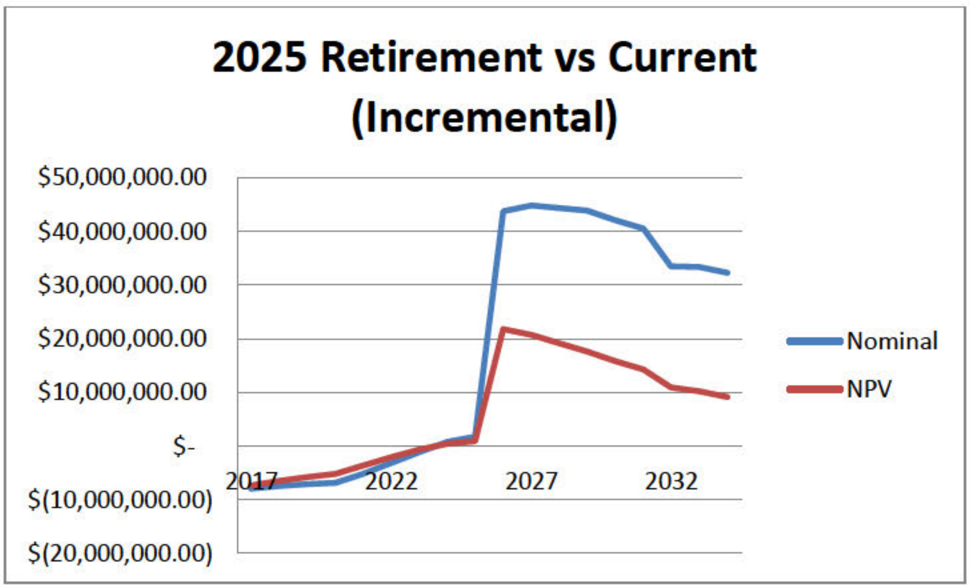
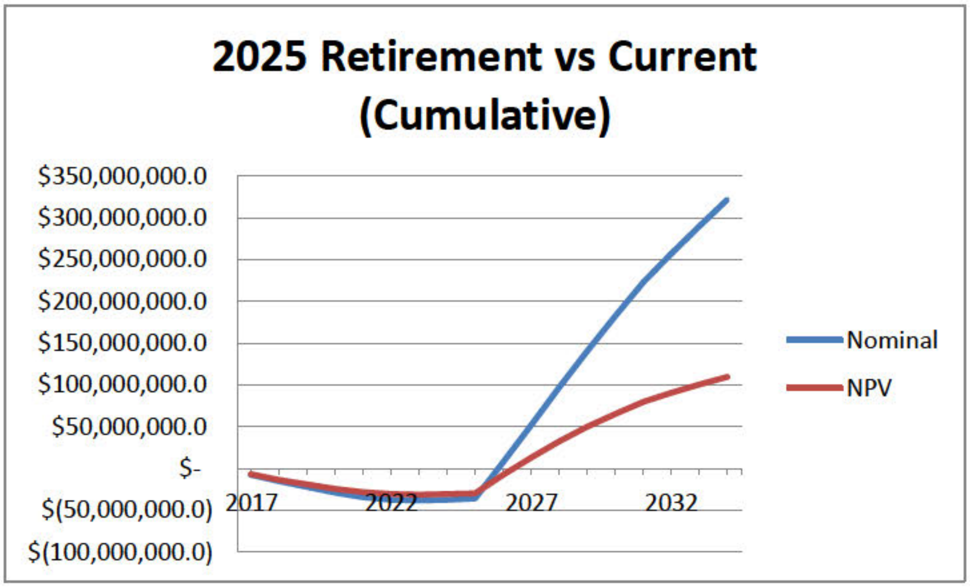


Figure 2



As evidenced by Figures 1 and 2, the decision to close Valmy in 2025 results in benefits to customers in 2025 and becomes a cumulative benefit to customers by 2027.[18]

Q. Did Staff perform any further analysis?

A. Yes, Staff performed additional sensitivity analysis around the estimates to identify the robustness of the results. Staff looked at what difference in net power supply expense would result in a negative NPV. Staff found that the difference in power costs between closing Valmy in 2025 and keeping it open would need to be roughly six times larger than the current estimates. Put another way, on average the cost under-estimation would need to be $31.5 million per year or roughly 9% of total net power supply expense.[19]

Q. How would you summarize the results of Staff's analysis?

[18] See Staff Exhibit 104 for further detail.
[19] *Ibid.*

A. Figure 2 shows the cumulative NPV impact of closing Valmy in 2025, given that the number is clearly in the positive a decision today to allow Idaho Power to close Valmy in 2025 is in the customer’s best interest. The results were robust and circumstances would have to dramatically change in order for the prudent decision to be different.

ISSUE 2, RECOVERY OF VALMY CAPITAL INVESTMENTS

Q. Please provide background on this issue.

A. Since IPC's last general rate case, the Company has made approximately $70 million in capital investments at Valmy.[20] IPC is requesting recovery of and on these investments as part of its request in this case. None of these investments have been previously reviewed by Staff for prudence, and therefore need to be examined before these costs are included in rates. Staff reviewed these investments as part of this docket and finds them to be prudent.

Q. What investments are included in the $70 million?

A. The investments are different plant part replacements, upgrades, rebuilds, and new installations. All of the investments can be seen in Idaho Power/201, Harvey/1-5. Of the four main categories, 10% of the total cost was due to safety related upgrades, 17% for Economic reasons, and 40% and 33% for environmental and reliability purposes, respectively.

Q. What are the criteria for including these investments in rates?

A. For capital investments, utilities must make two showings: (1) that the investment is presently used for providing utility service, and (2) the investments were prudently made, based on the information that the utility knew or should have known at the time.[21]

[20] Idaho Power/200, Harvey/5.
[21] *In re PacifiCorp*, OPUC Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).

Q. Please describe Staff's analysis.

A. Staff reviewed the process by which IPC analyzed the decisions, the information they obtained to evaluate the investments, and the reasoning behind each capital project.

Q. How did Staff analyze IPC's process for making these investment decisions?

A. Staff examined each investment's, "Generation Business Case" which was provided to Idaho Power from NV Energy for the evaluation of the investment decision. In response to Staff DR No. 59, IPC states:

> For all capital investments for the North Valmy Station, the Company receives a description of the factors driving the need for the projects, the expected cost, and a recommendation for the work to be performed from the plant operator, NV Energy. The Company reviews this information for each project, as well as the corresponding business case (at a minimum, for all projects over $1,000,000), at its annual budget meeting with NV Energy prior to any expenditures being made. Through these discussions, Idaho Power and NV Energy work together to establish and approve the capital investments to be made at the plant.[22]

Staff is satisfied that the process was sufficient to determine prudence in investments.

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[22] Staff Exhibit 105.

Q. Was Staff satisfied with the analysis and decision-making performed by IPC?

A. Yes. In addition to reviewing each Generation Business Case, Staff reviewed each investment based on the project justification. The four categories of justification were economic, reliability, safety, and/or environmental. Staff used the information present in IPC Exhibit No. 201 as well as the Generation Business Case to analyze the reasoning. Staff found the analysis thorough and sound.

Q. Does Staff recommend any adjustments to the recovery of these investments?

A. No. At this time, Staff believes that all of the investments were made in a prudent manner.

Q. Does the Company anticipate any additional capital expenditures to Valmy between 2017 and 2025?

A. Yes, IPC indicated that the evaporators for the evaporation ponds may need to be moved or replaced.[23] The project is currently being evaluated. The Company is not seeking pre-approval for future capital investments related to Valmy in this proceeding, and has stated that it will seek rate recovery of future capital investments for Valmy in future ratemaking proceedings.[24]

Q. Does Staff find Idaho Power's proposal to consider future capital expenditures in future rate proceedings reasonable?

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[23] Staff Exhibit 106.
[24] Idaho Power/100, Larkin/9.

A. Yes. Staff recommends that the Commission require IPC continue to seek approval of capital investments through general rate cases as they are filed. This would maintain the used and useful mandate and assure ratepayers of a thorough review of investments using a holistic approach.

ISSUE 3, MECHANISM DESIGN

Q. Please describe Idaho Power's proposed mechanism design to recover its requested annual incremental revenue requirement of $1,056,800.

A. The Company is seeking to amend its Schedule 92, Boardman Operating Life Adjustment, to incorporate the revenue requirement impacts associated with a 2025 end-of-life for Valmy.[25] The Company's proposal for rate recovery in this case mirrors the cost recovery for Boardman approved in Docket UE 239.[26] Specifically, the Company is proposing to use a balancing account to record: (1) accelerated depreciation associated with existing Valmy plant investments through May 31, 2017, (2) the return on the undepreciated capital investments until Valmy end-of-life, and (3) decommissioning costs related to Valmy shut-down.[27] The balancing account would be trued-up each year.[28]

Q. Does Staff have concerns with this approach?

A. Yes. First, Staff is concerned that a balancing account that seeks to track the monthly deviations between forecasted revenue collection and actual revenue collection and adjust rates annually could constitute retroactive ratemaking absent a deferral. The Company has not requested a deferral in this case. Second, even if the Company were to request a deferral to track the deviations between forecast revenue collection and actual revenue collection, Staff has a secondary concern regarding the Commission's authority to defer changes in revenue requirement for later ratemaking treatment. Because both of these

[25] Idaho Power/100, Larkin/8.
[26] Idaho Power/100, Larkin/8.
[27] Idaho Power/100, Larkin/8.
[28] Idaho Power/100, Larkin/12.

issues require legal analysis, Staff will address these issues in legal briefs. Staff also has the concerns related to the Company's Schedule 92 as it relates to Boardman, but will address those issues in the Company's currently pending Advice 17-04.

Q. Does Staff have a proposed alternative?

A. Yes. In order to address the concerns discussed above, Staff recommends that the Company collect accelerated depreciation associated with existing Valmy plant investments through May 31, 2017, and the return on the undepreciated capital investments at Valmy until its end-of-life pursuant to an automatic adjustment clause (AAC), similar to the cost-recovery mechanism that PGE employs for its Colstrip and Boardman plants. An AAC would set rates that are adjusted annually on a forward-looking basis based on the projected depreciation and revenue requirement amortization.

For recovery of decommissioning costs, Staff recommends that the Commission approve a deferral for decommissioning costs, to be tracked in a separate balancing account for transparency. This is similar to PGE's cost recovery mechanism for Boardman.[29] The balancing account would assure Idaho Power full recovery of decommissioning costs and ratepayers that the Company does not over-collect. Decommissioning costs studies traditionally include a contingency estimate (15% for currently utilized study[30]) which can result in over-estimation of actual costs. By deferring these costs, only actual

[29] See PGE's Schedule 145, accessed at https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_145.pdf
[30] See Idaho Power/100, Larkin/10 line 6.

expenses would be recovered by ratepayers. Further, separately tracking the decommissioning costs would allow interested parties to review the expenses more easily.

Staff also recommends that the Company be required to make annual filings to update amounts collected pursuant to the AAC, as it currently does with its Schedule 92 (Boardman Operating Life Adjustment), and as PGE does with its Schedule 145 (Boardman Power Plant Decommissioning Adjustment) and Schedule 146 (Colstrip Power Plant Operating Life Adjustment).

Q. Has the Commission authorized a similar mechanism before?

A. Yes. Commission Order No. 10-478 created PGE's Schedule 145. This schedule allows for the recovery of the remaining undepreciated investment in Boardman via a stand-alone automatic adjustment clause. The AAC implements the revenue requirement changes resulting from Commission authorized change in Boardman's operating life (i.e. the delta between 2040 end of life included in base rates and what the Commission ultimately approves for end of life). Like Staff's recommendation in this docket, Schedule 145 also incorporates a separate balancing account to track decommissioning costs. Commission Order No. 16-468 established a Colstrip Operating Life Adjustment Tariff similar to the Boardman AAC.

Q. Please describe the accounting and regulatory treatment for Staff's proposal.

A. Staff recommends that all costs and revenues associated with the Valmy end-of-life be removed from the Company's Results of Operations (ROO). This approach will ensure that the approval of this filing will not impact ratepayers in other unintended ways. It keeps the costs and revenues associated with Valmy end-of-life self-contained within the AAC and balancing account.

Q. How should Valmy be treated if it continues to operate past 2025?

A. Staff recommends that Valmy be treated the same in Idaho Power's Annual Power Cost Update (APCU) and Power Cost Adjustment Mechanism (PCAM) as it currently is. Although all capital and decommissioning costs may be recovered, variable power costs will continue to accrue. Should Idaho Power continue to operate past 2025 due to another Commission or operating partner's decision which results in sub-optimal power costs, Staff and parties can address those issues in the APCU and PCAM as they arise. When the actual closure date is set or changed, Staff recommends that the Company notify the Commission so it can take any appropriate action.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

May 4, 2017

WITNESS QUALIFICATION STATEMENT

NAME: Scott Gibbens

EMPLOYER: Public Utility Commission Of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Oregon
Masters of Science, Economics, University of Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 102

Exhibits in Support
Of Reply Testimony

May 4, 2017

STAFF'S DATA REQUEST NO. 11:

Idaho Power/200, Harvey/11, lines 8-10 state that Idaho Power has not yet set a closure date for Valmy. When do you believe Nevada Power and Idaho Power might reach agreement on a closure date? What are the key considerations driving the need to establish a date to cease operations? How long have Idaho Power and Nevada Power been discussing setting a closure date?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 11:

Idaho Power and NV Energy continue to have discussions on a closure date. At this time, it is uncertain when agreement will be reached on an actual shutdown date.

Key considerations driving the need to establish a date to cease operations would include each company's system reliability, resource adequacy, and customer impact.

Although discussions about a closure date likely began in 2013, more focused discussions between the utilities have occurred from 2014 to the present.

CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 103

Exhibits in Support
Of Reply Testimony

May 4, 2017

<u>STAFF'S DATA REQUEST NO. 64</u>:

Idaho Power/200, Harvey/10 states that it is not feasible to discontinue operations for Valmy prior to 2025 absent the completion of B2H. If B2H is not completed by 2025, is it feasible for the Company to discontinue operations at Valmy?

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 64</u>:

Please see the supplemental analysis and workpapers attached to the Company's response to Staff's Data Request No. 33 for the current approach to the Valmy Unit shutdown and the changes in assumptions from the 2015 IRP. This analysis has led the Company to utilize a Valmy Unit 1 shutdown assumption of 2019 for the upcoming 2017 IRP. While it may be feasible to cease operations at Unit 2 in 2025 absent the completion of B2H, this analysis is not yet complete.

CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 104

Exhibits in Support
Of Reply Testimony

May 4, 2017

Exhibit 104

(Provided in electronic format)

CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Reply Testimony

May 4, 2017

STAFF'S DATA REQUEST NO. 59:

For each capital investment listed in Idaho Power/201 whose purpose includes "environmental," please provide:

a. **The federal and state regulations and/or permits that the Company believes required the investment; and**
b. **The Company's analysis supporting the investment.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 59:

Please see Attachment 1 where three columns have been added to the original Exhibit 201:

Column A includes the NV Energy Budget ID.
Column L includes the environmental regulations for the appropriate projects.
Column M includes the safety standards for the appropriate projects.

Attachments 3 through 30 are the corresponding NV Energy Generation Business Cases which provide project justification for economic, reliability, safety, and/or environmental reasons. For all capital investments for the North Valmy Station, the Company receives a description of the factors driving the need for the projects, the expected cost, and a recommendation for the work to be performed from the plant operator, NV Energy. The Company reviews this information for each project, as well as the corresponding business case (at a minimum, for all projects over $1,000,000), at its annual budget meeting with NV Energy prior to any expenditures being made. Through these discussions, Idaho Power and NV Energy work together to establish and approve the capital investments to be made at the plant. Attachments 3 through 30 to this Request contain the business case documents reviewed by Idaho Power for the capital projects listed in Exhibit No. 201 of Mr. Harvey's direct testimony. In addition to these documents, NV Energy as the owner/operator has a Corporate Procurement Policy, which outlines the procedures to be followed for the procurement of goods and services in excess of $25,000. Please see Protected Information Attachment 2 for the NV Energy Corporate Procurement Policy.

Attachment 2 provided in response to this Request contains protected information and will be provided in accordance with General Protective Order No. 16-445, via U.S. Mail.

Exhibit 105

(Provided in electronic format)

CASE: UE 316
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 106

Exhibits in Support
Of Reply Testimony

May 4, 2017

<u>STAFF'S DATA REQUEST NO. 63</u>:

Does the Company anticipate additional capital expenditures for environmental compliance between 2017 and 2025?

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 63</u>:

There is one proposed project that has been identified to either move the existing, or purchase new, evaporators for the evaporation ponds. This project is currently being evaluated. It is budgeted at $200,000 for 2017 and $770,000 for 2018 (total plant costs).

CASE: UE 316
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Reply Testimony

May 4, 2017

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

A. My name is Ming Peng. I am a senior economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Staff Exhibit 201.

Q. What is the purpose of your testimony?

A. My testimony responds to Idaho Power Company's (IPC or Company) witness Mr. Larkin regarding (1) Accelerated Depreciation Expense and (2) Plant Decommissioning Cost recovery for Idaho Power's share of the North Valmy Generating Station (Valmy).

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following Staff Exhibits:

201. Witness Qualification Statement: Ming Peng
202. IPC Response to Staff Data Request No. 1
203. Staff Net Salvage Adjustment
204. Staff Decommissioning Adjustment
205. IPC Response to Staff Data Request No. 22

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, ACCELERATED PLANT RECOVERY-DEPRECIATION EXPENSES

Q. What is depreciation?

A. From a valuation perspective, depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant.

From an accounting perspective, depreciation is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept.

From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. What is the impact on customers when a plant's depreciable life is shortened for ratemaking purposes?

A. Both IPC and I use the straight-line depreciation method to spread cost evenly over the new life of an asset. In this way, when Valmy's depreciable life is shortened due to early shutdown, customers would pay their share of the Company's investment over the shorter period of time. This leads to an increase in revenue requirement, which has the effect of increasing retail rates.

Q. How are depreciation rates and depreciation accrual determined?

A. To develop depreciation rates, it is necessary to estimate (1) asset survivor curve-service life (Curve-Life), and (2) net salvage (Gross Salvage – Cost of Removal) rate. Depreciation rates are derived based on these two fundamental depreciation parameters.

Q. What is negative net salvage?

A. Net Salvage = Gross Salvage – Cost of Removal. In other words, it is the scrap value of the assets minus the costs of retirement. When the cost of retiring an asset has surpassed retirement salvage values, it is often referred to as "negative net salvage." Negative net salvage increases depreciation expense and proportionally decreases accumulated depreciation from rate base.

Q. What is the depreciation expense IPC is requesting for accelerated recovery of Valmy-related Costs?

A. IPC is requesting a $24 million increase in depreciation expense (total-Company) for Valmy, the estimated Valmy plant balances at May 31, 2017, based on Valmy actual plant balances as of July 31, 2016.[1] IPC's depreciation expense calculations do not include net salvage value (see Exhibit Staff/203). I find that IPC will incur negative net salvage of $1.25 million per year (see Exhibit Staff/203).

Q. Do you have any proposed changes to Idaho Power's proposed depreciation expense?

A. Yes. As discussed more fully below, I made an adjustment to the future annual depreciation expense by adding the net salvage value of $1.25 million back to the future depreciation expense. My adjustment will increase Idaho Power's annual depreciation expense by $1.25 million (total-Company) from $24.1 million to $25.3 million (see Table 2), and will decrease accumulated depreciation reserve from IPC's rate base by the same amount accordingly.

[1] Staff/202 - Idaho Power's Response to Staff DR 1, Attachment 1 (tab: Tax Calcs).

Q. Why is it important to include a net salvage component in depreciation rates?

A. The annual depreciation rate is the ratio of plant costs, adjusted for net salvage value, that are allocated to a one-year period in accordance with a rational and consistent plan of allocation over the average service life of the property.

It is important to include a net salvage component in depreciation rates for proper cost allocation. For example, assume an account with assets costing $100. Further, assume a net salvage cost of $80 is required to retire the $100 of assets at the end of their lives. That equates to a net salvage percentage of negative 80 percent (-80%). Instead of only allocating the installed cost of $100, to ensure equitable cost allocation to customers receiving the service value, $180 of cost allocation is required over the lives of the assets. Without the inclusion of the $80 in net cost to retire the assets, the Company will not be made whole, equitable cost allocation will not occur, and customers who have benefitted from the use of the assets will not pay the full cost of the assets. (See Introduction to Depreciation - for Public Utilities and Other Industries, page 112, April 2015.)

Q. How do you calculate net salvage value and add it to depreciation expense?

A. The net salvage rates of 18 FERC accounts for Valmy were approved by the Oregon Commission in OPUC Order No. 12-296, Docket No. UM 1576. To comply with the Order, I used the net salvage rates by account to calculate net salvage values that IPC needs for its future operation, and derived new depreciation rates.

The aggregated weighted net salvage rate is about (-5.4%), which means IPC needs to have an additional 5.4 percent more money on top of its plant balances to be recovered without shortening the plant service life.

Since -5.4 percent is the net salvage for the full decommissioning cost, which includes final decommissioning cost and interim cost of removal, I assume that half of net salvage is for interim retirements and interim cost of removal for Valmy's ongoing operation cost. The other half is in an external fund for decommissioning.

The calculation for interim net salvage value will be $11.25 million ($22,503,940 / 2 =$11,251,970, or the net salvage ratio is -2.7%). The total future depreciation accrual is $228,019,377 and the annual depreciation expense is $25,335,486 (See Table 1).

In contrast, IPC has a total future net salvage value for Valmy that is $0.[2] The future depreciation accrual is $216,767,407; the annual depreciation expense is $24,085,267.

[2] Staff Exhibit 203.

Table 1. Calculation for Interim Net Salvage Adjustment

	Plant Balance as of 5/31/2017	Net Salvage Value	Future Accruals	Annual Depreciation Expense	Current Depreciation Expense	Annualized Net Increase due to Change in Depreciable Life
IPC	413,693,168	0	216,767,407	**24,085,267**	8,573,000	**15,512,268**
Staff	413,693,168	(11,251,970)	228,019,377	**25,335,486**	8,573,000	**16,762,487**
Changes Between Staff and IPC's Calculation	0	11,251,970	11,251,970	**1,250,219**	0	1,250,219

As a result, from its regular depreciation expense of $8,573,000, Idaho Power's annualized net increase due to change in plant service life will go up from $15.5 million ($24,085,267 - $8,573,000) to $16.76 million ($25,335,486 - $8,573,000). (See Exhibit Staff/203).

Table 2. <u>Summary Adjustment for Valmy Accelerated Depreciation:</u>

End-of-Life 2025 Annual $ Depreciation Expense

IPC filed accelerated depreciation	24,085,267
Staff adjusted accelerated depreciation	25,335,486
Increase IPC's annual depreciation expense	<u>+1,250,219</u>

Q. What are the reasons do you propose adjustment to Idaho Power's depreciation expense?

A. Rate recovery for Valmy's depreciation related costs has two parts:

(1) Regular depreciation expense of Valmy's future capital to be recovered for its remaining service life, which is currently recovered in base rates; and

(2) Additional depreciation expense due to the shortened service life.

For Valmy's regular depreciation, IPC has complied with OPUC's Order No. 12-296 by using the depreciation parameters from the order.

I made my adjustment for the following reasons:

1. It is clear that before decommissioning Valmy in 2025, Idaho Power will still need to recover interim retirements and interim cost of removal from net salvage to maintain its operations, such as cost for repair and maintenance. Therefore, it is necessary to have net salvage value for plant operation.
2. Net Salvage is used for the future net cost of retiring an asset in service, and is determined based on previous year ratios between historical plant investment and historical net salvage on those assets, which has been established in the depreciation study, and approved in the Commission Order No. 12-296. Therefore, the net salvage value is a historical "known cost," and should be added back to Valmy's depreciation expense so as to ensure that

net salvage funds are available at the time they are needed in power plant operation.

ISSUE 2, DECOMMISSIONING COSTS CALCULATION

Q. What are decommissioning costs for Valmy?

A. "Decommissioning" means removing a power plant from service. The Company will incur decommissioning costs related to closure of Valmy in 2025.

Q. Have you reviewed the decommissioning cost study for Valmy?

A. Yes. I did. The study was done in 2012 by URS Corporation, prepared for Nevada Energy (NV energy north fleet demolition and pond decommissioning study). The study displays the costs to decommission and remove plant components, including the power plant and associated ponds and material handling facilities. It also includes a 15 percent contingency estimate and is partially offset by expected salvage proceeds associated with decommissioning the plant.[3]

Q. Did you have any questions during the decommissioning costs study review?

A. Yes. I had a question regarding the reasonableness of URS Corporation estimated a 15 percent contingency factor.

A contingency factor is a reserve that the cost estimator makes to cover unforeseeable expenses the project may incur. These expenses may result from unpredictable conditions, uncertainties within the project of demolition of Valmy.

I sent Staff Data Request No. 22 to IPC regarding the reasonableness of a contingency of 15 percent in the total capital cost. The Company's response

[3] DIRECT TESTIMONY OF MATTHEW T. LARKIN, Idaho Power/100, Larkin/10

identified the U.S. Department of Energy's (DOE) Estimating Guide[4] referenced in this request. DOE Guide in 6.4.5.5 Estimate Uncertainty, Table 6-2, Class 4 - Study or Feasibility shows that Study or Feasibility cost estimates can justify using a low range contingency of (-)15 percent to (-)30 percent and a high range contingency of 20 percent to 50 percent. (See also in Exhibit Staff/205).

Q. Have you made any adjustments on a 15 percent contingency factor?

A. No. After the review, I did not make an adjustment. Per the DOE Guidelines, 6.4.5.5 Estimate Uncertainty, "Estimate uncertainty is part of the risk analysis process for the development of contingency estimates as was illustrated in Figure 6-8. Estimate uncertainties are fundamental contributors to cost growth and are expected to decrease over time as the project definition improves and the project matures. Estimate uncertainty is a function of, but not limited to, the quality of the project scope definition, the current project life-cycle status, and the degree to which the project team uses new or unique technologies. Estimate uncertainties occur throughout the DOE baseline. Estimate uncertainty contributes to both cost and schedule contingency. Table 6-2 could be used for both cost and schedule estimate uncertainty and should be done separately for evaluating quantitative impacts on project contingency."[5]

[4] U.S. Department of Energy Estimating Guide (DOE G 413.3.21), 6.4.5.5, p.56 of 177.
[5] U.S. Department of Energy Estimating Guide (DOE G 413.3.21), 6.4.5.5, p.56 of 177

Table 6-2. Estimate Uncertainty Range as a Function of Estimate Class[6]

Class of Cost Estimate	Estimate Uncertainty (Low Range)	Estimate Uncertainty (High Range)
Class 5 – Concept Screening	-20% to -50%	+30% to +100%
Class 4 – Study or Feasibility	-15% to -30%	+20% to +50%
Class 3 – Budget Authorization	-10% to -20%	+10% to +30%
Class 2 – Control or Bid	-5% to -15%	+5% to +20%
Class 1 – Check Estimate	-3% to -10%	+3% to +15%

Based on DOE's classification of the estimate accuracy, I recommend no adjustment on Valmy's 15 percent contingency factor at this time is due to the fact that the contingency factor used is within the reasonable range of DOE Guidelines.

Q. Did you have any concerns regarding the inflation rate impact on decommissioning costs calculation?

A. Yes. In economics, inflation is a general increase in prices and fall in the purchasing value of money. IPC has 50 percent share of Valmy Plant of decommissioning costs, which is $14.7 million in 2012 dollars. An inflation adjustment is needed to calculate the future value. IPC assumed the inflation rate to be constant at 3 percent, and used 3 percent inflation/escalation rate to calculate the future value of the decommissioning cost through 2025. This cost in the year 2025 will be $21.6 million. I have concerns about using a constant 3 percent inflation rate to calculate the future value of decommissioning. Calculating the inflation rate based on the Consumer Price Index (CPI) is more appropriate because the CPI is a factor in determining inflation. Since the CPI

[6] U.S. Department of Energy Estimating Guide (DOE G 413.3.21), 6.4.5.5, p.56 of 177

can be viewed as a number used to measure the real changes, and CPI adjusted Inflation will track the prices of goods and services over time.

Q. Have you made any adjustments on IPC's 3 percent inflation rate?

A. Yes. Based on the CPI data, I converted CPI to various annual inflation rates to adjust the future values of decommissioning costs.

Inflation Rate = (Current CPI - Historic CPI)/(Current CPI) * 100

Table 3. Summary Adjustment for Valmy Decommissioning and Demolition:

End-of-Life 2025 Decommissioning Cost

IPC filed Valmy Decommissioning Cost	21,583,188
Staff adjusted Valmy Decommissioning Cost	19,201,336
Reduce IPC's Valmy Decom. Cost	-2,381,852

Table 3 illustrates how much value is reduced when more detailed inflation forecasts are used. The inflation rate analysis yields sufficient improvements for the Valmy decommissioning cost calculation. It will reduce the Valmy decommissioning cost by $2.38 million (see Exhibit Staff/204).

Q. Does this conclude your Reply testimony?

A. Yes.

List of Staff Exhibits

<u>Exhibit</u>	<u>Description</u>
201.	Witness Qualification Statement: Ming Peng
202.	IPC Response to Staff Data Request No. 1
203.	Staff Net Salvage Adjustment
204.	Staff Decommissioning Adjustment
205.	IPC Response to Staff Data Response No. 22

CASE: UE 316
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

May 4, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION & TRAINING:
M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

C.R.R.A. Certified Rate of Return Analyst
Society of Utility and Regulatory Financial Analysts

Depreciation studies - the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

300+ credit hours on 30+ topics trainings in public utility industry

EXPERIENCE: 1/11/1999-Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 18 years since January 1999. My roles include: <u>Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst</u>
I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

<u>Principal Analyst & Case Manager, Settlement Leader/Negotiator for Depreciation and Ratemaking:</u>
For the "Depreciation Rate Determination" (fixed cost allocation, capital recovery), I have served as a Principal Analyst and Case Manager for the

determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for past 10 years.

In this position, I investigate, analyze and calculate "Energy Asset Retirement Cost & Impact" and "Power Plant Decommissioning Cost & Impact" on Customer Rates. I review, calculate, analyze fixed asset depreciation and propose depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on are Steam/Coal, Hydraulic, Natural Gas, Wind, Solar and Geothermal.

My analyses of "Power-Plant-Shutdown" activities include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215),
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246)
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 - Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316)
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809)

I conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my present position, I was a lead analyst and case manager for cost of capital, mainly debt capital analysis for nine years. My responsibilities included: review and analyze regulatory policy on Cost of Capital and Market Risks from utility's financial applications for their Derivative Instruments & Hedging Activities and Capital Raising Activities.

I advised the Commission on over 60 Financial Dockets and obtained the Commission Orders.

I passed the certification test offered by "Society of Utility and Regulatory Financial Analysts", become a "Certified Rate of Return Analyst" in 2002.

Public Utility & Policy Analyst:

Energy Merger & Acquisition: I have testified in formal state hearings involving Energy Merger & Acquisition, I conducted Acquisition Premiums & Credit Risk Analysis and testified for the Merger case of "PacifiCorp vs. MidAmerican Energy Company" (a subsidiary of Berkshire Hathaway

Energy) in UM 1209. My reviews on Energy Merger & Acquisition also include “PacifiCorp vs. Scottish Power”, “PGE vs. Enron".

Clean Energy – Dollar Impact on Customer Rates: I performed analyses of “Rate Impact Calculation of Oregon Clean Energy Capital Investment, Comparative Advantage of Oregon Clean Energy – Dollar Impact in Rates”.

General Rate Case Ratemaking (Revenue requirement) and Other Cases: I testified and conducted analyses on some subjects in the revenue requirement models for General Rate Cases. I testified on Fuel Price Forecasting regarding Property Sales; I reviewed Load Forecasting, Weather Normalization in “Integrated Resource Planning” (IRP) and Rate Case filing.

My work functions have also included the Statistical Sampling Design & Procedure Design, and I testified on Revenue Issues (UM 1288) by presenting the sampling results.

I conducted Energy Utility Auditing for cost of capital component on energy companies and also preformed utility operational auditing. I have conducted “Interest Rate and Late Payment Charge” Survey and Analysis annually for state of Oregon (UM 779).

I conducted Telecommunications “Market Competition and Economic Policy Survey Analysis” and write report for House Bill 2577, the report has been published on OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators

I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My “Mentoring Topics” were focus on Incentive Regulation; Rate and Economic Impacts of “Cost-of-Service” regulation in US and “Price-Cap” in Europe; Cost of Capital, Energy Demand and Price Forecasting Models; Least Cost Planning; and Regulatory Policy & Renewable Energy issues affecting Utility Rates.

CASE: UE 316
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Reply Testimony

May 4, 2017

November 22, 2016

Subject: Docket No. UE 316 – Recovery of Costs Associated with North Valmy Power Plant Idaho Power Company's Response to the Public Utility Commission of Oregon Staff's Data Request No. 1

STAFF'S DATA REQUEST NO. 1:

(1) Please provide the Method that Idaho Power used to conduct the annual recovery amount for decommissioning costs; and (2) provide data and calculations that the company used to develop the accelerated depreciation and decommissioning costs recovery, by FERC Account, for Valmy plant, in Excel format with calculation formulas and links intact, including but not limited to:

- **Plant composite remaining life as of 12/31/2016, assuming end-life date is 12/31/2025**
- **Current Annual Depreciation expense for 2016 and 2017 assuming existing depreciation rates,**
- **New Annual Depreciation expense in the filing, assuming new depreciation rates are in effect 1/1/2017**
- **Actual plant balance expected as of 12/31/2016**
- **Plant balance as of May 31, 2017**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 1:

Please see the attached workpapers in Excel format with calculations and formulas intact. The first tab, Oregon Rev Req, includes the revenue requirement amounts associated with both the existing investments, as well as the decommissioning costs. The Existing Investments tab includes the detailed computation of the revenue requirement amounts on existing investments, including new, accelerated depreciation on existing Valmy plant balances. The next two tabs, Tax Calcs and Def Tax Proration, are supporting workpapers for the tax computations performed on the Existing Investments tab. The Valmy Existing Balance 5-31-17 tab computes the estimated Valmy plant balances at May 31, 2017, based on Valmy actual plant balances as of July 31, 2016. The estimated Valmy plant balances as of December 31, 2016, and estimated depreciation expense based on current depreciation rates can also be found on this tab. Finally, the Jurisdictionalizing tab provides the allocation factors approved in Idaho Power Company's last general rate case for jurisdictionalizing purposes.

ATTACHMENT - RESPONSE TO STAFF'S DR 1

(Provided in electronic format)

CASE: UE 316
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Reply Testimony

May 4, 2017

Staff Exhibit 203

(Provided in electronic format)

CASE: UE 316
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Reply Testimony

May 4, 2017

Staff Exhibit 204

(Provided in electronic format)

CASE: UE 316
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Exhibits in Support
Of Reply Testimony

May 4, 2017

January 26, 2017

Subject: Docket No. UE 316 – Recovery of Costs Associated with North Valmy Power Plant
Idaho Power Company's Response to the Public Utility Commission of Oregon Staff's Data Request No. 22

STAFF'S DATA REQUEST NO. 22:

Please refer to Tables 1 & 27 in the URS-conducted "NV ENERGY NORTH FLEET DEMOLITION AND POND DECOMMISSIONING STUDY" (Study). The Study includes a "contingency" of 15% in the total capital cost. URS said: "Per the U.S. Department of Energy Estimating Guide (DOE G413.3.21), §6.4.5.5, Table 6-2, page 56, this study is classified as a "CLASS 4 - Study or Feasibility" cost estimate, and therefore can justify using a low range contingency of (-)15% to (-)30% and a high range contingency of 20% to 50%."

If industry average data was considered when producing the Study, please provide the national electric industry average of contingency rates for the past 15 years, not including the 15% rate URS used from the "NV ENERGY NORTH FLEET DEMOLITION AND POND DECOMMISSIONING STUDY," in the Excel sheet below:

Contingency Rate%

Facility Name/year	Facility & Infrastructure Demolition	Civilworks & Pond Demolition	Project Management Consultancy Services	NYE-Operations, Management, & Contractor Services	Engineering and Design Services	Asbestos Abatement & Hazardous Material Allowance	Average Contingency rate
Valmy/2015							15%
Staff used/2011							10%
Name/year							
Name/year							
Name/year							
Name/year							
Name/year							
Name/year							
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<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 22</u>:

While Idaho Power Company ("Company") did not prepare the decommissioning study referenced in this request, it is the Company's understanding that the 15% contingency was not based on a consideration of average industry data. Rather, a reasonable range of contingency percentages was identified according to the U.S. Department of Energy's Estimating Guide referenced in this request, which states that "Study or Feasibility cost estimates can justify using a low range contingency of (-)15% to (-)30% and a high range contingency of 20% to 50%." URS ultimately utilized a contingency rate of 15% in the 2012 decommissioning study at the direction of NV Energy to reflect the findings of the Nevada Public Utilities Commission in Docket Nos. 11-06006 and 11-06007 that a 15% contingency was appropriate for application to the majority of decommissioning costs associated with the Valmy plant.

(Neither the request or the response contain confidential information.)

CASE: UE 316
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Reply Testimony

May 4, 2017

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

A. My name is Max St. Brown. I am a Senior Utility Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I review Idaho Power's rate spread and rate design proposal for recovering the requested annual incremental revenue requirement associated with its request in docket No. UE 316.

Q. Please summarize your rate spread finding.

A. I make two adjustments to the Company's proposed rate spread in order to spread rates based on the benefit received from Valmy. Staff's summary results are provided in Table 1 on page 6 below.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the red text on Exhibits Staff/302 and 303, consisting of 3 pages. Exhibit Staff/304 contains Idaho Power's response to Staff DR 53.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, RATE SPREAD

Q. How does Idaho Power propose to spread its requested annual incremental revenue requirement of $1,056,800 related to Valmy?

A. Idaho Power's proposed Schedule 92 (submitted as attachment 3 to its application) proposes to recover the requested annual incremental revenue requirement on an equal cents per kWh basis. Thus the rate spread is solely based on energy consumption.

Q. Staff witness Ming Peng has proposed adjustments to Idaho Power's requested annual incremental revenue requirement related to Valmy, so why do you spread rates based on the incremental revenue requirement as filed?

A. AS IS CUSTOMARY, "TO ACHIEVE A DIRECT COMPARISON WITH [COMPANY WITNESS LARKIN'S] APPROACH AND RESULTS, I WILL WORK WITH THE SAME REVENUE REQUIREMENT THAT HE USES."[1]

Q. What justification does the Company provide for its rate spread?

A. Generally, none. Per the Company's response to Staff DR 53, the Company's application incorrectly described the rate spread as not solely based on energy consumption.[2] Past filings have used an equal cents per kWh basis, including docket No. UE 239 related to an operating life adjustment for Boardman. In contrast to this application, in general rate cases, rate spreads are justified on the basis of a marginal cost of service study, which is Staff's preferred

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[1] *See* lines 12-14 of Staff/900, Compton/10 in Cascade Natural Gas Company's UG 287 general rate case.
[2] Attached as Staff Exhibit 304.

approach. Accordingly, at a future date Staff might address spreading rates associated with the operating life adjustment for Boardman on the basis of a marginal cost of service study.

Q. Has the Company performed an updated marginal cost of service study in conjunction with this application?

A. No, so instead Staff relies on the marginal cost of service study in Idaho Power's most recent general rate case, docket No. UE 233.

Q. How did the Company compute the per kWh rate?

A. The rate of $0.001535 per kWh is computed as $1,056,800 ÷ 688,652,995 kWh. Where 688,652,995 kWh is the Company's normalized energy sales.

Q. Who pays the rate?

A. Schedule 92 is applicable to all retail customers.

Q. Please provide a narrative description of the percent change billed to billed revenue column of attachment 1 of the Company's application.

A. Although the per-kWh rate is equivalent for all Schedules, the proposed bill percentage increases differ by Schedule. This is attributable to the fact that some Schedule's bills are more energy intensive in the sense that, at current average consumptions, those Schedule's total bills vary more as energy consumption varies. Consider the simplifying illustration below:

Column A	B	C	D	E	F	G
Schedule	Customers	Normalized kWh	Monthly kWh per customer	Monthly energy charge at current rates	Monthly service charge	E ÷ (E+F)
1 (residential)	13,818	191,786,131	1,157	$98.33	$8.00	92%
9 (large general service)	923	140,119,303	12,651	$726.16*	$10.25**	99%
			*assumes secondary service during the summer			
				**assumes single phase service		

In the illustration, compared to a large general service customer, a residential customer's service charge would mute any percentage increase in the total bill from an increase in the per-kWh charge.

Q. What is the average bill increase due to Idaho Power's requested annual incremental revenue requirement?

A. Per row 11 on page 2 of Staff Exhibit 302, bills will increase 1.91 percent on average if Idaho Power's full requested annual incremental revenue requirement is awarded.

Q. What criteria does Staff use to evaluate whether the Company's rate spread is equitable?

A. Staff uses two main criteria. First, whether the rates are spread on the basis of benefit from Valmy. By this methodology, customers that benefit most from Valmy would see the biggest rate increase. Second, whether the rate spread results in cost based rates. By this methodology, the rate increase is an opportunity to bring rates closer in line with relative costs of service.

Q. What other criteria does Staff consider?

A. Staff confirmed that no rate class received an unusually burdensome rate increase. Staff also considered this in Idaho Power's last GRC (*See* lines 11-13 of Staff/900, Compton/8 in UE 233).[3]

Q. Per Staff's first criteria, what is an equitable way to spread rates based on the benefit from Valmy?

A. Valmy is a baseload plant that was originally designed for the purpose of providing baseload energy and capacity. Thus, it is equitable for customers to pay in proportion to the energy and capacity values they would have received from Valmy between 2026 and 2031.

Q. Per Staff's first criteria, does the Company's proposal perform well in terms of spreading rates based on the benefit from Valmy?

A. No, because the Company's proposal does not spread rates based on the energy and capacity services customers receive from Valmy. This is because the "energy charge" in Idaho Power's tariffs does not represent the cost of "generation." For example, the "energy charge" line item on Idaho Power's Schedule 1 tariff recovers some non-generation costs.

Q. How does Staff propose to spread rates based on the energy and capacity services (the benefit) customers receive from Valmy?

A. Staff proposes two adjustments to the Company's rate spread proposal.

First, Staff spreads energy costs among Schedules using the generation energy component from the marginal cost study in the Company's most recent

[3] http://edocs.puc.state.or.us/efdocs/HTB/ue233htb163240.pdf

rate case rather than on an equal per-kWh basis for all Schedules as proposed by the Company.

Second, Staff spreads 27.91 percent of the incremental revenue requirement based on demand rather than 100 percent based on energy as proposed by the Company. Where 27.91 percent is computed as the generation demand marginal costs ($11,049,450) divided by the total generation marginal costs ($39,596,454) in the Company's most recent rate case (*See* 2. on page 1 of Staff Exhibit 302).[4] Staff then spreads those demand costs among Schedules based on the generation demand component from the marginal cost study in the Company's most recent rate case.

Q. Please describe further how Staff implemented Staff's two adjustments?

A. Staff Exhibit 302 provides the workpaper for Staff's adjustments; Staff's computations are in red text.

Q. Per Staff's second criteria, does the Company's proposal move rates closer to their relative cost of service?

A. Yes, per line 32 of Exhibit B of Order No. 12-055 in Idaho Power's last GRC (attached as page 1 of Staff Exhibit 302), Staff recommended rate decreases for Schedules 7, 9, 15, 19, and 41 and the Company's proposal allocates a rate increase below the average to each of these Schedules. But this is coincidental because the Company's rate spread is not based on a marginal cost of service study.

[4] The black text on page 1 of Staff Exhibit 302 is Exhibit B of Order No. 12-055, which is available at: http://apps.puc.state.or.us/orders/2012ords/12-055.pdf

Q. Does Staff's proposed rate spread move rates closer to their relative cost of service?

A. Yes, similar to the Company's proposal, Staff's recommended rate spread moves Schedules 7, 9, 15, 19, and 41 closer to their relative cost of service.

Q. Please provide and describe Staff's recommend rate spread.

A. Staff's rate spread is presented in the third column of Table 1 below:

Table 1			
		Percent Change Billed to Billed Revenue	
Schedule Description,	No.	**Company**	**Staff**
Residential Service,	1	1.54%	1.82%
Small General Service,	7	1.44%	1.46%
Large General Service,	9	1.98%	1.92%
Dusk to Dawn Lighting,	15	0.62%	0.54%
Large Power Service,	19	2.49%	2.25%
Agricultural Irrigation Service,	24	1.57%	1.47%
Unmetered General Service,	40	1.56%	3.56%
Street Lighting,	41	0.97%	0.65%
Traffic Control Lighting,	42	1.61%	1.23%

Table 1 above includes the Company's proposed rate spread in the second column.[5]

In summary, Staff spreads the incremental revenue requirement based on the marginal cost of generation. Because the Company's rate spread does not consider generation demand marginal costs, energy-intensive schedules (such as large general service and large power service) see a slight rate decease versus the Company's proposal.

[5] The percent changes billed to billed revenue are computed on page 2 of Staff Exhibit 302. The black text on page 2 of Staff Exhibit 302 is Attachment 1 of Idaho Power's UE 316 Initial Application.

Q. Is a rate spread partially based on demand reflective of how the Company currently uses Valmy?

A. Yes, lines 14-15 of Idaho Power/200, Harvey/9 state, “Idaho Power has been relying on Valmy to meet the Company’s peak energy needs.” By this basis, Valmy costs should be partially spread based on demand.

Q. Does Staff have a recommended rate design?

A. Yes, for schedules with per-kW rates, Staff recommends collecting generation demand charges through per-kW rates and generation energy charges through per-kWh rates. Staff’s rate design options versus the Company’s rate design are found in Staff Exhibit 303. Staff Option 1 spreads incremental generation demand costs to per-kW charges. If parties desire to reduce the percentage increase in the demand charges, then rates can be designed to increase demand and energy revenue by an equal percentage, which is Staff Option 2.

Q. How was Staff’s recommended rate design prepared?

A. Staff’s digital workpaper submitted with this testimony computes the rates necessary to provide the target incremental revenue requirement by Schedule using the equation: rate = incremental revenue requirement ÷ billing determinant.

Q. Does this conclude your reply testimony?

A. Yes.

CASE: UE 316
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

May 4, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Max St. Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Economist Energy Rates, Finance & Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2013) Washington State University B.S., Economics (2009) Central Washington University
EXPERIENCE:	I have been employed by the Public Utility Commission since July 2015, with my current position being a Senior Utility Economist, in the Utility Program's Energy – Rates, Finance and Audit Division. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies. Prior to working for the OPUC I served as an Assistant Professor of Economics at Eckerd College in St. Petersburg, FL from 2013 to 2015. I have taught courses including Econometrics, Labor Economics, and Intermediate Microeconomics. As a graduate student at Washington State University I taught six course sections, including Econ of Renewable Energy. My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies. I served as a summer fellow at the American Institute for Economic Research during summers 2011 and 2012.

CASE: UE 316
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Reply Testimony

May 4, 2017

Idaho Power Company
Before the Oregon Public Utility Commission
12 Months Ending December 31, 2011
Final Revenue Requirement Allocation
Proposed Settlement Stipulation

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL [1]	(C) GENSRV [7]	(D) GEN SRV SECONDARY [9-S]	(E) GEN SRV PRIMARY [9-P]	(F) GEN SRV TRANS [9-T]	(G) AREA LIGHTING [15]	(H) LG POWER PRIMARY [19-P]	(I) LG POWER TRANS [19-T]	(J) IRRIGATION SECONDARY [24-S]	(K) UNMETERED GEN SERVICE [40]	(L) MUNICIPAL ST LIGHT [41]	(M) TRAFFIC CONTROL [42]
1	Normalized Sales (kWh)	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328
2	Current Revenue	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231
3														
4	Demand Related Marginal Cost													
5	Generation - Staff Adj.	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200
6	Transmission - Staff Adj.	$12,432,118	$4,593,297	$301,584	$1,880,300	$233,817	$39,858	$703	$2,014,458	$1,669,382	$1,697,153	$177	$1,165	$225
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89
8														
9	Energy Related Marginal Cost													
10	Generation	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722
11	Transmission - Staff Adj.	$4,144,040	$1,297,863	$116,488	$746,184	$94,345	$17,092	$3,104	$1,112,259	$449,639	$301,881	$83	$4,996	$105
12														
13	Simple-Summed Energy-Related and Demand-Related Marginal Costs													
14	Generation Marginal Costs - Staff Adj.	$39,596,454	$13,023,020	$1,070,493	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922
15	Transmission Marginal Costs - Staff Adj.	$16,576,157	$5,891,160	$418,072	$2,626,484	$328,162	$56,950	$3,807	$3,126,717	$2,119,021	$1,999,034	$260	$6,160	$330
16														
17	Customer Related Marginal Cost	$2,805,903	$1,967,110	$385,570	$177,410	$6,759	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873
18														
19	Total Functionalized Revenue Requirement													
20	Generation - Staff Adj.	$25,202,690	$8,289,003	$681,357	$4,335,384	$545,931	$97,490	$14,008	$6,016,360	$2,915,844	$2,283,701	$463	$22,563	$587
21														
22	Transmission	$4,272,366	$1,518,397	$107,755	$676,954	$84,581	$14,678	$981	$805,885	$546,160	$515,234	$67	$1,588	$85
23														
24	Distribution													
25	Demand-Related	$8,930,530	$4,133,917	$233,025	$1,697,158	$129,585	$0	$7,378	$1,027,267	$0	$1,689,855	$207	$12,022	$114
26	Customer-Related													
27	Allocated	$2,859,472	$2,004,665	$392,931	$180,797	$6,847	$1,417	$0	$15,498	$2,583	$251,682	$232	$1,928	$990
28	Direct Assignment	$419,424	$188,447	$34,356	$12,375	$69	$14	$78,778	$83	$14	$21,953	$42	$83,209	$83
29														
30	Total: Staff-Adjusted Allocation	$41,634,482	$16,134,429	$1,449,425	$6,902,699	$767,013	$113,599	$101,145	$7,865,094	$3,464,601	$4,762,425	$1,011	$121,310	$1,759
31	Revenue Deficiency - Staff Adj. Allocation	$1,810,890	$778,497	($109,975)	($73,246)	($31,089)	($41,398)	($11,317)	($347,971)	$341,208	$1,308,154	$39	($2,541)	$528
32	% Increase Required by Staff Adj. Alloc. Approach	4.54%	5.07%	-7.05%	-1.05%	-3.90%	-26.71%	-10.06%	-4.24%	10.92%	37.87%	4.02%	-2.05%	42.91%
33	$ Increase Recommended per Stipulation	$1,810,890	$862,348	$44,153	$197,517	$22,598	$0	$0	$232,545	$212,777	$235,318	$44	$3,507	$84
34	% Increase Recommended per Stipulation	4.54%	5.62%	2.83%	2.83%	2.83%	0.00%	0.00%	2.83%	6.81%	6.81%	4.56%	2.83%	6.81%
35	Average Rate Given Stipulation ($/kWh)	0.0641	0.0816	0.0899	0.0628	0.0544	0.0547	0.2324	0.0471	0.0450	0.0791	0.0788	0.1637	0.0805
36	Final Revenue Allocation	$41,684,481	$16,218,280	$1,603,553	$7,173,432	$820,700	$154,997	$112,462	$8,445,610	$3,336,170	$3,689,589	$1,016	$127,358	$1,315
37														
38	Spread Floors and Ceilings:													
39	No increase forthose warranting a decrasegreater than 8%													
40	2.83% increase for those warranting a decrease less than 8%													
41	No increase greater than one-and-one-half times the average increase													
	6. Row 5: Schedule ÷ Total System	100%	36.95%	2.43%			17.33%	0.01%		29.63%	13.65%	0.00%	0.01%	0.00%
	7. Row 10: Schedule ÷ Total System	100%	31.32%	2.81%			20.70%	0.08%		37.69%	7.28%	0.00%	0.12%	0.00%
	Schedule's Inc. Rev. Req, generation demand (4 * 6)	$294,902	$108,957	$7,154			$51,094	$17		$87,384	$40,258	$4	$28	$5
	Schedule's Inc. Rev. Req, generation energy (5 * 7)	$761,898	$238,617	$21,417			$157,677	$583		$287,161	$55,502	$15	$918	$19

1. Inc. Rev. Req (See UE 316 line 9 of Idaho Power/100, Larkin/2) $1,056,800
2. Demand related proportion of generation marginal cost (Row 5, column A ÷ row 14, column A) 27.91%
3. Demand related proportion of generation marginal cost (Row 10, column A ÷ row 14, column A) 72.09%
4. Inc. Rev. Req, generation demand (1 * 2) $294,902
5. Inc. Rev. Req, generation energy (1 * 3) $761,898

ORDER NO. 13 073

Exhibit B
Partial Stipulation

APPENDIX A
PAGE 14 OF 16

Attachment 1 Page

Idaho Power Company
Calculation of Revenue Impact
State of Oregon
Coal Plant Operating Life Adjustment Filing
Effective June 1, 2017

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Current Billed Revenue	Mills Per kWh	Company Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Mills Per kWh	Company Percent Change Billed to Billed Revenue	Inc. Rev. Req Generation Demand	Inc. Rev. Req Generation Energy	Staff Total Adjustments to Billed Revenue	Staff Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:													
1	Residential Service	1	13.818	191.786.131	$19.141.539	99.81	$294.313	$19.435.852	101.34	1.54%	$108,957	$238,617	$347,575	1.82%
2	Small General Service	7	2.563	18.411.930	$1.960.259	106.47	$28.255	$1.988.514	108.00	1.44%	$7,154	$21,417	$28,571	1.46%
3	Large General Service	9	923	140.119.303	$10.851.334	77.44	$215.026	$11.066.360	78.98	1.98%	$51,094	$157,677	$208,771	1.92%
4	Dusk to Dawn Lighting	15	0	443.024	$110.520	249.47	$680	$111.200	251.00	0.62%	$17	$583	$599	0.54%
5	Large Power Service	19	7	270.322.296	$16.635.693	61.54	$414.834	$17.050.527	63.07	2.49%	$87,384	$287,161	$374,545	2.25%
6	Agricultural Irrigation Service	24	1.915	66.621.250	$6.509.533	97.71	$102.236	$6.611.769	99.24	1.57%	$40,258	$55,502	$95,760	1.47%
7	Unmetered General Service	40	2	5.568	$546	98.07	$9	$555	99.61	1.56%	$4	$15	$19	3.56%
8	Street Lighting	41	25	922.474	$145.432	157.65	$1.416	$146.848	159.19	0.97%	$28	$918	$946	0.65%
9	Traffic Control Lighting	42	8	21.019	$2.000	95.17	$32	$2.033	96.70	1.61%	$5	$19	$25	1.23%
10	Total Uniform Tariffs		19.261	688.652.995	$55.356.857	80.38	$1.056.800	$56.413.657	81.92	1.91%				
11	Total Oregon Retail Sales		19.261	688.652.995	$55.356.857	80.38	$1.056.800	$56.413.657	81.92	1.91%			$1,056,812	1.91%

CASE: UE 316
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Reply Testimony

May 4, 2017

			OPTION 1: demand charge for demand revenue		OPTION 2: equal percentage increase in energy and demand revenue	
		Company Rate Design	Staff Rate Design		Staff Rate Design	
Schedule	Description	Adjustment Rate	Adjustment Rate		Adjustment Rate	
1	Residential Service	$0.001535 per kWh	$0.001812 per kWh		$0.001812 per kWh	
7	Small General Service	$0.001535 per kWh	$0.001552 per kWh		$0.001552 per kWh	
9-S	Large General Service (Secondary)	$0.001535 per kWh	$0.001125 per kWh	$0.12 per kW*	$0.001166 per kWh	$0.11 per kW*
9-P	Large General Service (Primary)	$0.001535 per kWh	$0.001125 per kWh	$0.12 per kW*	$0.001166 per kWh	$0.11 per kW*
9-T	Large General Service (Transmission)	$0.001535 per kWh	$0.001125 per kWh	$0.12 per kW*	$0.001166 per kWh	$0.11 per kW*
15	Dusk to Dawn Lighting	$0.001535 per kWh	$0.001353 per kWh		$0.001353 per kWh	
19-S	Large Power Service (Secondary)	$0.001535 per kWh	$0.001062 per kWh	$0.18 per kW*	$0.001152 per kWh	$0.13 per kW*
19-P	Large Power Service (Primary)	$0.001535 per kWh	$0.001062 per kWh	$0.18 per kW*	$0.001152 per kWh	$0.13 per kW*
19-T	Large Power Service (Transmission)	$0.001535 per kWh	$0.001062 per kWh	$0.18 per kW*	$0.001152 per kWh	$0.13 per kW*
24-S	Irrigation Service (Secondary)	$0.001535 per kWh	$0.000833 per kWh	$0.24 per kW*	$0.001126 per kWh	$0.13 per kW*
24-T	Irrigation Service (Transmission)	$0.001535 per kWh	$0.000833 per kWh	$0.24 per kW*	$0.001126 per kWh	$0.13 per kW*
40	Unmetered General Service	$0.001535 per kWh	$0.003490 per kWh		$0.003490 per kWh	
41	Municipal Street Lighting	$0.001535 per kWh	$0.001026 per kWh		$0.001026 per kWh	
42	Traffic Control Lighting	$0.001535 per kWh	$0.001171 per kWh		$0.001171 per kWh	

*per kW of Billing Demand Summer and Non-summer

CASE: UE 316
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 304

Exhibits in Support Of Reply Testimony

May 4, 2017

April 12, 2017

Subject: Docket No. UE 316 – Recovery of Costs Associated with North Valmy Power Plant
Idaho Power Company's Response to the Public Utility Commission of Oregon Staff's Data Request Nos. 32-55

STAFF'S DATA REQUEST NO. 53:

See line 5 of page 6 of the partial stipulation in UE 233. Please provide each Schedule's rate elements used in the computation of the rate spread in the rightmost column of Attachment 1 of UE 316.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 53:

Please see the attached Excel file for each schedule's rate elements used in the computation of the rate spread. Please note, as described in Idaho Power/100, lines 24-26 of page 12, Idaho Power is proposing to recover the incremental revenue requirement through the Company's Schedule 92, Coal Plant Operating Life Adjustment, on a cents per kilowatt basis. The Company's Application filed in UE 316 (page 9, lines 2-3) incorrectly states the incremental revenue requirement will be recovered from all customer classes through a uniform percentage increase to all base rate components except the service charge; the Company will file the corrected information this week.