Oregon
Kate Brown, Governor

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May 15, 2017

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97302-1088

RE: <u>Docket No. UM 1801</u>–In the Matter of
IDAHO POWER COMPANY, Application for Authority to Implement Revised Depreciation Rates for Electric Plant-in-Service.

Enclosed for filing is Staff Testimony in support of Stipulation along with a Certificate of Service and UM 1801 Service List.

Exhibit 102 and 103 are spreadsheet and are filed in electronic format.

Exhibit 302 is confidential and a CD is being placed in today's first class US mail.

/s/ Kay Barnes
(503) 378-5763
Email: kay.barnes@state.or.us

CASE: UM 1801
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Testimony In Support
Of Stipulation

May 15, 2017

Table of Contents

I. Introduction

Q. Please state your name and position with the Public Utility Commission of Oregon.

A. My name is Ming Peng. I am a Senior Economist and case manager for the Public Utility Commission of Oregon (OPUC or Commission). My business address is 201 High St SE Suite 100, Salem, OR 97301. My qualification statement is found in Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of Staff's Testimony in Support of Stipulation (Staff Testimony) is to describe my analysis and to support the Stipulation submitted by Idaho Power Company (IPC or Company), Commission Staff (Staff), and the Citizens' Utility Board of Oregon (CUB), in docket UM 1801 (Docket). With the exception of the Valmy generating plant, which is being addressed in Docket No. UE 316, the Stipulation resolves all issues surrounding depreciation rates on common and directly assigned plant, respectively. The adjustments discussed in the Stipulation are reasonable and, for its part, will yield fair and equitable rates if adopted by the Commission in its final order in this docket. I have attached Staff/102 which sets forth the settlement of detailed depreciation parameters.

Q. What precipitated this proceeding?

A. Pursuant to ORS 757.140, "Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission." In compliance with the ORS 757.140, IPC filed a depreciation study with the Commission on November 2, 2016. Again, except for the Company's Valmy

Coal-Fired Plant, all assets in the study are included as of December 31, 2015, in traditional FERC classification of transmission, distribution and general plant assets.

II. Summary of Proceeding

A. Depreciation Study Results

Q. Please summarize IPC's depreciation study proposal.

A. IPC's depreciation study recommended revisions in depreciation lives, survivor curves, and net salvage rates for all plant accounts, and a revision to the average remaining life methodology for plant assets.

On November 2, 2016, the Company filed its Application for Authorization to Implement Revised Depreciation Rates (Application). The Application requested Commission approval for the Company to revise its book depreciation rates consistent with the results of a study recently undertaken by the Gannett Fleming, Inc. (Gannett Study or Study). The objective of the Gannett Study was to determine and recommend depreciation rates to be utilized by IPC for accounting and ratemaking purposes.

The Study, according to the Company, shows that the system-wide annual depreciation expense as of December 31, 2015, on the Company's books should be increased by approximately $24 million, based on the average service life rates of electric plant in service as of December 31, 2012.

As set forth in more detail in the Stipulation, the parties reached final agreement on revisions to the Company's book depreciation rates at their April 20, 2017 settlement conference. If approved by the Commission, such rates would constitute the Oregon direct depreciation rates, which, per the parties' agreement, would be effective on June 1, 2017, in IPC's Oregon rates. For the remainder of this testimony, I will refer to the parties who have signed the Stipulation (i.e. IPC, CUB and Staff) as the "Stipulating Parties."

B. Support for Stipulation

Q. Did you independently review the depreciation study?

A. Yes, I performed an independent review of IPC's depreciation statistics and recommended depreciation parameters for numerous depreciation groups. Utility depreciation expense includes components for both the recovery of the original cost of the asset and an estimate of net salvage costs (gross salvage less cost of removal) at retirement. The depreciation rate utilized will ensure an appropriate level of total cost allocation to the customers who benefit from the asset's service, based upon the best estimate of useful service life. (*See* Introduction to Depreciation - for Public Utilities and Other Industries, page 111, April 2015.) I proposed two types of adjustments. The first type of adjustment concerns Iowa survivor curves and projected average service lives. The second type of adjustment concerns net salvage rates.

Q. Did your analysis suggest adjustments to IPC's proposal?

A. Yes. I proposed seven adjustments concerning Iowa survivor curves and projected average service lives, and 22 adjustments concerning net salvage rates.

Q. Were the Stipulating Parties able to resolve the study differences for the electric plant accounts?

A. Yes, the differences were resolved in a settlement meeting held on April 20, 2017. I accepted most of IPC's proposals for its FERC 300 level accounts. The positions that differed from IPC's filing were reasonably close to those requested by IPC. After considerable discussion and an understanding of the methods for all plant assets at existing facilities, the Stipulating Parties reached the final agreement as set forth in the Stipulation at Table 1 and I recommend that the Commission adopt it.

Q. What is the final impact on estimated depreciation expense due to Stipulation?

A. The result of the settlement is a depreciation expense of $124,598,097 or a depreciation rate of 2.55 percent, as shown in the Stipulation, Staff/103 - Depreciation Settlement Summary Report. The net annual difference in depreciation expense, when comparing the Stipulation to the depreciation study as filed in the Company's Application, is a reduction of approximately $6.62 million.

Q. Please describe the analyses that you performed regarding IPC's depreciation study.

A. I considered Iowa survivor curves and average service lives as well as net salvage rates. The review procedures included the selection of the capital recovery parameters of retirement dispersion (survivor curve), service life projections for the future, salvage, and cost of removal projections for the future. The settlement of detailed depreciation parameters is set forth in Staff/102.

Q. How did you analyze Iowa Curves and Average Service Lives?

A. I utilized the plant balances to analyze historical retirement data to help determine Iowa survivor curves and average service lives for each depreciation group. For survivor curve fitting purposes, I utilized the ordinary least-squares statistical method. Under this method, the Iowa survivor curve alternative resulting in a "fit" with the smallest sum of squared differences (fit to actual) is considered to be the best fit and to be indicative of average life and retirement dispersion of the account. Staff/102 shows the depreciation groups for which the analyses produced differing results from IPC, and the final position agreed to by the Stipulating Parties.

Q. Could you please summarize the settlement results?

A. Yes. The settled weighted depreciation rate for total depreciable plant is 2.55 percent from IPC's originally proposed rate of 2.69 percent. The Stipulation has resulted in annual depreciation expense on a system basis of $124.6 million, based on December 31, 2015 plant values, which is a reduction from Idaho Power's original proposed of $131.2 million. (See settlement results by plant function below) When the agreed upon depreciation rates are applied to approved test year plant balances, the resulting incremental Oregon jurisdictional depreciation expense is approximately $343,000, as compared to the Company's initial request of approximately $604,000.

Summary of Settlement Results - Depreciation Rate & Expense

UM 1801 ELECTRIC PLANT	Depreciation%		Depreciation%	Depreciation%
FUNCTION	**IPC Proposed**	**Staff Proposed**	**SETTLED**	**SETTLED Difference**
Steam Production Plant (2025JB)			**6.13**	
Steam Production Plant (2034JB)*	**3.60**	**3.53**	**3.46**	**(0.14)**
Hydraulic Production Plant	**2.03**	**1.91**	**1.98**	**(0.05)**
Other Production Plant	**2.93**	**2.44**	**2.91**	**(0.01)**
Transmission Plant	**2.00**	**1.85**	**1.86**	**(0.14)**
Distribution Plant	**2.42**	**2.16**	**2.23**	**(0.18)**
General Plant	**5.62**	**5.49**	**5.36**	**(0.26)**
TOTAL DEPRECIABLE PLANT	**2.69**	**2.49**	**2.55**	**(0.14)**
Annual depreciation expenses	**131,213,914**	**121,265,356**	**124,598,097**	**(6,615,817)**
***JB 2034 is for book purposes**				**-5.04%**

UM 1801 ELECTRIC PLANT	**IPC Annual Accrual**	**Staff Annual Accrual**	**SETTLED**	**SETTLED Difference**
Steam Production Plant (2025JB)			**37,801,636**	
Steam Production Plant (2034JB)	**22,184,440**	**21,755,324**	**21,338,297**	**-846,143**
Hydraulic Production Plant	**15,245,122**	**14,325,807**	**14,837,407**	**-407,715**
Other Production Plant	**15,684,211**	**13,098,836**	**15,613,598**	**-70,613**
Transmission Plant	**21,430,635**	**19,844,748**	**19,889,481**	**-1,541,154**
Distribution Plant	**37,957,919**	**33,958,361**	**35,087,549**	**-2,870,370**
General Plant	**18,711,587**	**18,282,279**	**17,831,765**	**-879,822**
TOTAL DEPRECIABLE PLANT	**131,213,914**	**121,265,356**	**124,598,097**	**-6,615,817**

Q. Is there any background information that is relevant for the Commission's consideration?

A. Yes, there are two important considerations concerning IPC's coal plants as follows.

1. <u>Jim Bridger (JB) Coal Plant End-Life at year 2025 in Oregon, and at year 2034 in Idaho</u>

IPC has a 33 percent ownership share of the JB plant, which is jointly owned with PacifiCorp. In its Order No. 08-427, the Commission affirmed 2025 as the end-life-date for the JB plant for PacifiCorp. To be consistent with Commission Order No. 08-427, I did not make an adjustment related to the JB plant's service life.

2. <u>Valmy Coal-fired Plant Shutdown by 2025, depreciation is not in this case</u>

IPC has a 50 percent ownership share of the Valmy Plant (Nevada Energy owns the other 50 percent). Valmy depreciation has been removed from and is not considered in Docket No. UM 1801. The requirements for (1) the accelerated depreciation and (2) the Valmy plant decommissioning cost recovery are being addressed in Docket No. UE 316.

Q. How did you determine curve-lives?

A. Iowa survivor curve-projection life selection was based on the Company's raw data, and I also compared data from other electric companies. The curve-life statistic is the minimum sum of the normalized squared deviations. Normalization is done by dividing each deviation by the corresponding observed balance. The selected survivor curve-projection lives were made in the average service life or dispersion curve (or both) for the FERC account categories in the Transmission Plant, Distribution Plant, and General Plant. For example, R2-55 means the Right-Modal IOWA Type Survivor Curve with 2 Degree of Dispersion that has 55 years of Projection Service Life.

Q. Could you provide examples of how you agreed upon the curve-life adjustment?

A. Yes. I modified curve life positions for seven accounts from 81 accounts for depreciable plants. My modifications are not only based on statistical analysis and tests on observational data set, but also take into consideration the factual comparisons of the actual curve-life historical data from other 101 electric companies nationwide to help identify asset survival behaviors and determine trends.

In the settlement proposal, I had an Account by Account Discussion of Service Life Adjustment. For example, my position for the Hydraulic Production Plant Account 334 Accessory Electric Equipment was a curve life combination of R1-60 (R1 curve type & dispersion and 60 year of average service life). The IPC Study recommendation was R1.5-54. I evaluated that curve life combination in a statistical model, finding that the curve fitting Residual (SSR) for R1-60 shows a significantly better fit for a set of observations and it has 51 percent less residual (see Table 2 above) than does the curve of R1.5-54. I also reviewed national data from 101 electric companies, and found out that Industry projection life for this account has a wide range from 35 to 80 years, but the majority projection life is 60 years and above. My recommended projection life is 60 years, which is within the range of majority industry statistics. I believe that assets such as these have life characteristics to justify an average 60-year depreciation life.

For settlement purposes, the Stipulating Parties agreed to a curve of R1.5-65 after coordinated with the curve-life from Idaho parties' proposal. This service life is longer than Oregon's R1-60, and IPC's R1.5-54.

Account Description	Account Number	IPC curve life	Staff Curve-life	Settled Curve-life
ACCESSORY ELECTRIC EQUIPMENT	**334**	**54-R1.5**	**R1-60**	**65-R1.5**

My position for Account 370.1 Meters – AMI (Advanced Metering Infrastructure) under the Distribution Plant is a curve life combination of R1-20. IPC discussed the statistical support underlying the S1.5-16 curve life in its filing. I evaluated that curve life combination in a statistical model, finding that the curve fitting Sum of Squares of Residuals (SSR) for R1-20 shows a significantly better fit for a set of observations, and it has 41 percent less residual than the curve of S1.5-16 does. I also reviewed national data from 101 electric companies. I found that Industry projection life for this account has a wide range from 15 to 21 years, but the majority projection lives are 15 and 20 years respectively. I then conducted a field trip investigation to an AMI workshop, and found out that the Battery life for an AMI meter is 20 years, and also, the retirement data shows that after 10 years of AMI usage, 90 percent of AMI has survived (not been replaced). I believe that assets such as these have life characteristics to justify an average 20-year depreciation life.

IPC believes that a service life of 16 years with a S1.5 curve for AMI account is preferred, because AMI is a new technology, and the Company might have to face future uncertainty and risks. Given the lack of retirement activity, and assuming the actual life is equal to the average life, the Stipulating Parties agreed to a curve of R1.5-18 for this depreciation study which the Stipulating Parties find supportable and fair.

Account Description	Account Number	IPC curve life	Staff Curve-life	Settled Curve-life
METERS - AMI	370.1	16-S1.5	R1-20	18-R1.5

Q. Why it is 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 percent). 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, the 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 did you determine net salvage rates?

A. To set the proper net salvage rates, IPC and Staff thoroughly studied the observed data for plant assets to help estimate net salvage characteristics and help determine future net salvage trends.

Net salvage is the difference between gross salvage and cost of removal. Net salvage is positive when gross salvage exceeds the "cost of removal" and reduces the revenue requirement. Conversely, net salvage is negative when cost of removal exceeds gross salvage and increases the revenue requirement. FERC defines cost of removal as "the cost of demolishing, dismantling, tearing down, or otherwise removing retirements of utility plant, including the cost of transportation, and handling incidental thereto." (*See* FERC 18 CFR 4-1-12 Edition, Pt 101, Definition 10, Pg. 365).

To determine net salvage rates for its facilities, the analysis relied primarily upon historical retirement data. The Stipulating Parties utilized the statistical methods of overall averages, and "Rolling Band" (i.e., moving average) analyses, to study historical data to help estimate net salvage characteristics. Banding is the compositing of a number of years of data in order to merge them into a single data set for further analysis. By making determinations of the net salvage indicated in successive bands, it is possible to determine a clear indication of whether there is a trend in the net salvage experience. The Rolling Band analyses have the selection of three and five years' bandwidth to detect trends. The "3-year and 5-year Bandwidth" (three and five years of data banded together over the period 1909 through 2015) are used in Rolling Band analyses to detect account trends.

Q. Please explain why you recommend the stipulated net salvage rates for plant assets.

A. I made 22 modifications to IPC's proposed Net Salvage Rates from 81 accounts for depreciable plants and determined there should be an adjustment for net salvage rates.

For example, for Account 312.1 – Boiler Plant Equipment - Scrubbers and 312.2 Boiler Plant Equipment - Other under the Jim Bridger Steam Production Plant I concluded that there should be a salvage level of negative 9 percent (-9 percent). In its Application, IPC proposed a salvage level of negative 10 percent (-10 percent).

From my net salvage analysis based on IPC's book salvage record, the year-by-year net salvage rate was negative 12 percent (-12 percent), the 3-year and 5-year rolling bands results were negative 6.7 percent (-6.7 percent) and negative 8.4 percent (-8.4 percent) respectively. The average of the three data trends is -9 percent.

I also reviewed national data from 101 electric companies. I found that Industry net salvage for this account has a wide range from -35 percent to 0 percent, but the majority net salvage rates are from -10 percent to 0 percent.

Based on IPC's actual asset retirement and cost removal level, I concluded that an average net salvage level at negative 9 percent (-9 percent) for Accounts

312.1 was appropriate. However, after discussions with IPC and CUB, I concluded, and recommend to the Commission, that a net salvage of negative 5 percent (-5 percent) is appropriate. This takes into consideration the net salvage from State of Idaho parties' proposal for this Account 312.1.

Account Description	Account Number	IPC net salvage	Staff net salvage	Settled net salvage
BOILER PLANT EQUIPMENT - SCRUBBERS	312.10	-10	-9	-5

For Account 312.3 - Boiler Plant Equipment - Railcars under the Jim Bridger Steam Production Plant, my initial determination was a salvage level of positive 20 percent (+20 percent). IPC proposed a salvage level of 0 percent (0 percent).

I reviewed national data from 101 electric companies and I found that the majority of Industry net salvage for this account are from +20 percent to +30 percent.

For settlement purposes, the Stipulating Parties agreed to a net salvage of positive 10 percent (+10 percent). For comparison, the net salvage from Idaho parties' proposal for this Account 312.3, which the net salvage is less positive than Oregon's +20 percent and more positive than IPC's 0 percent.

Account Description	Account Number	IPC net salvage	Staff net salvage	Settled net salvage
BOILER PLANT EQUIPMENT - RAILCARS	312.3	0	20	10

For Account 356 - Overhead Conductors And Devices under the Transmission Plant, my initial conclusion was that a Salvage level of negative

41 percent (-41 percent) was appropriate. IPC proposed a salvage level of negative 50 percent (-50 percent).

My analysis was based on IPC's actual asset retirement activities and cost removal level, and I recommended the net salvage level at negative 41 percent (-41 percent) for Account 356. The net salvage from year-by-year data result was -48 percent, the 3-year Rolling Band data result was -14 percent, and 5-year rolling bands result was -63 percent, the average of the three data trends is -41 percent. I also reviewed national data from 101 electric companies. I found that Industry net salvage for this account has a wide range from -100 percent to 0 percent, but the majority net salvage rate is -20 percent. Based on all information above, in this review I concluded that the net salvage level at negative 41 percent (-41 percent) for Account 356, which is within the range of industry statistics.

I then reviewed FERC definition on this account: 356 Overhead conductors and devices. This account includes the cost to install of overhead conductors and devices used for transmission purposes: 1. Circuit breakers. 2. Conductors, including insulated and bare wires and cables. 3. Ground wires and ground clamps. 4. Insulators, including pin, suspension, and other types. 5. Lightning arresters. 6. Switches. 7. Other line devices.

I considered that the net salvage experience is highly correlated to scrap material prices for salvage, labor costs related to removal and inflation rates over the life of the plant. Therefore, when analyzing such data, emphasis should be placed on more recent periods.

Given the consideration of the labor economics that the functioning and dynamics of the markets for wage labor is increasing, and net salvage economics that the factors which determine the production, distribution and consumption of goods and services is changing, I gave more weight to more recent net salvage activities to deal with the upward trend of labor cost. I concluded that a negative 50 percent (-50 percent) for Account 356 is supportive.

Account Description	Account Number	IPC net salvage	Staff net salvage	Settled net salvage
OVERHEAD CONDUCTORS AND DEVICES	356.00	-50	-41	-50

Q. Were the Stipulating Parties able to resolve the study differences for the plant accounts?

A. Yes, the differences were resolved in the settlement meeting held on April 20, 2017. The Stipulating Parties recommend that the Commission adopt the position outlined in the Stipulation. The Stipulation discusses the changes in depreciation parameters, and also provides a table which details the straight line, asset remaining life, average service life group depreciation rates derived for each depreciation group (see Staff/102 and Staff/103).

The Bridger 2025 rates are not reflected in Staff/103 (the Table reflects a Bridger 2034 end-of-life for book purposes), but they do reflect the final agreed upon Bridger 2025 end-of-life dates that were used to calculate the revenue requirement impact for Oregon customers.

Q. What is the final impact on estimated depreciation expense due to settlement discussions?

A. About 4 percent depreciation expense will be allocated to Oregon based on the share of IPC's service in Oregon. The net annual difference in total system depreciation expense comparing the final settlement position to the depreciation study as-filed is a reduction of approximately $6.6 million, from $131.2 million to $124.6 million.

Q. What is the depreciation effect on the revenue requirement?

A. In the traditional rate base rate-of-return environment, customer rates and utility costs are components of a utility's revenue requirement. NARUC, in its "Public Utility Depreciation Practices" manual on "Depreciation Expense and Its Effect on the Utility's Financial Performance – Revenue Requirement" states:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[1]

Q. What is the relationship between depreciation and revenue requirement?

A. Under cost of service regulation, revenue requirement refers to the revenues the utility must earn to recover the cost of providing service and to earn a reasonable return on its investment. To compute the revenue requirement (RR) (RR is measured by cost-of-service), a basic formula is followed[2]:

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[1] NARUC, Public Utility Depreciation Practices p.195 (1996).
[2] Federal Energy Regulatory Commission, Cost-of-Service Rates Manual p. 6-7 (1999), **www.ferc.gov**/industries/gas/gen-info/**cost-of-service-manual**.doc

RR = O&M Expense + "Depreciation" + Taxes + Return percent x Rate Base

Rate Base = Gross Plant – "Accumulated Depreciation" – Accumulated Deferred Income Taxes + Working Capital

In this formula, "Depreciation" is one of the largest line items in the cost of service; therefore, "Depreciation" is important as both an annual expense and as a reduction of rate base.

Q. How are depreciation parameters used in determining the utility's revenue requirement?

A. In a general rate case filing, the depreciation expense is calculated by using the Commission's authorized depreciation parameters, from which depreciation rates are derived, and in traditional FERC classification of generation, transmission, distribution, and general plant assets.

Accumulated Depreciation is the cost of the investment in gross plant that is recovered through the cost-of-service as Depreciation Expense. Accordingly, the depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the Net Book Plant. The net book plant represents the portion of gross plant that is not depreciated.

Q. Please describe Idaho Power's original revenue requirement increase request.

A. The Company's proposed rate adjustment related to the revised depreciation rates would have resulted in an increase to "annual depreciation expense" in

Oregon of approximately $604,000—which translates to an increase in the Company's Oregon "revenue requirement" of $721,548. The Stipulating parties agreed to an increase in the incremental Oregon jurisdictional revenue requirement of $300,000, which equates to an overall increase of 0.54 percent.

Q. Why do you support the revisions to the depreciation rates proposed?

A. The final adjustment decisions were made based on the combination of the considerations of IPC's plant retirement patterns and in-house engineering opinion, the industry average level, and my analytical skills and industry experience. The stipulated position on plant asset survivor curves-projection life, net salvage rates as reflected in the depreciation rates is consistent with the results of my thorough review and valuation of plant asset by depreciation groups. Accordingly, the stipulated adjustment represents a fair and reasonable level of depreciation expenses to be included in the depreciation rates.

Q. What do you recommend regarding the Stipulation?

A. I recommend that the Commission adopt the Stipulation in its entirety.

Q. What is the date for the next depreciation filing?

A. IPC agreed to file a new detailed depreciation study within five years of the date of the Company's most recent filing – i.e. within five years of November 2, 2016.

Q. Does that complete your testimony in this proceeding?

A. Yes, it does.

List of Staff Exhibits

Exhibit	Description
101	Witness Qualification Statement: Ming Peng
102	Settlement Adjustments – Parameter Comparison
103	Depreciation Settlement Summary Report

CASE: UM 1801
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

May 15, 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: Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst
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.

Principal Analyst & Case Manager, Settlement Leader/Negotiator for Depreciation and Ratemaking:
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: UM 1801
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Testimony

May 15, 2017

Exhibit 102

Settlement Adjustments-Parameter Comparison

Is provided in electronic format

CASE: UM 1801
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Testimony

May 15, 2017

Exhibit 103

Depreciation Settlement Summary Report

Is provided in electronic format

CASE: UM 1801
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Testimony in Support of the Stipulation

May 15, 2017

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

A. My name is Marianne Gardner. I am a Senior Revenue Requirement 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 Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Staff's review of Idaho Power's (IPC or Company) earnings and overall staff recommendations.

Q. What are Staff's overall recommendations?

A. We recommend the Commission adopt the stipulation supported by the parties to raise rates related to increases in depreciation rates applied to current plant balances for plant that was used and useful as of December 31, 2011.

Q. How is Staff's testimony organized?

A. Staff witness Matt Muldoon discusses cost of capital and Staff witness Ming Peng discusses depreciation rates.

Q. Did you include any other exhibits for this docket?

A. Yes. I included Exhibit Staff/202 and Exhibit Staff/203.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, SUMMARY OF COMPANY REQUEST

Q. What is the Company's request in this case?

A. The Company is requesting rate recovery due to changes in depreciation rates as applied to plant.

Q. Is the Company asking for recovery of a change in depreciation rates relating to all used and useful plant?

A. No. While the Company has made many plant additions since its last general rate case, the Company is only asking for recovery of its overall increase in depreciation costs due to changes in depreciation rates applied to the plant balances that are in rates, from the last general rate case. That is remaining plant balances for plant that was used and useful on December 31, 2011, as found by the Commission in Idaho Power's most recent general rate case order.

Q. What increase did the Company request and how does that differ from the level stipulated to among the parties?

A. The Company requested a rate adjustment related to the revised depreciation rates that would have resulted in an increase to annual depreciation expense in Oregon of approximately $604,000 based on a 4% of Oregon allocation factor, which translates to an increase in the Company's Oregon jurisdictional revenue requirement of $721,548, as measured against the revenue requirement identified in the Partial Stipulation in Docket UE 233, which was approved by the Commission on February 23, 2012. The Stipulating Parties in this case agreed to an increase in rates of $300,000, which translates to a 0.54 percent rate increase.

ISSUE 2, STANDARD OF STAFF'S REVIEW AND PAST COMMISSION PRACTICE

Q. Does Staff support ratemaking treatment of the difference in depreciation rates outside of a general rate proceeding?

A. Typically not. Although it is Staff's long-standing policy position that changes in depreciation rates should not be reflected in rates outside of a general rate review, Staff believes that the circumstances in this case warrant what might be viewed as a departure from that policy.

Q. Please describe the circumstances that led Staff to recommend the stipulated ratemaking treatment in this case.

A. Typically, the Commission implements changes in depreciation rates for ratemaking purposes in general rate proceedings.[1] In this case, Idaho Power is seeking to update retail rates outside of a general rate proceeding to include new book depreciation rates. The timing of the Company's request is driven by OAR 860-027-0350(2), which requires that each energy utility file a new depreciation study with the Commission no less frequently than once every five years. Therefore, there is a mismatch between the

[1] *See e.g. In re PacifiCorp*, OPUC Docket No. UM 1647, Order No. 13-347 (Sep. 25, 2013) (change in depreciation rates implemented via PacifiCorp's UE 263 general rate case); *In re Portland General Electric*, OPUC Docket UM 1679, Order No. 14-297 (Sep. 2, 2014) (change in depreciation rates implemented via PGE's UE 283 general rate case); *In re Avista Utilities*, OPUC Docket No. UM 1626, Order No. 13-168 (May 6, 2013) (Ratemaking treatment for changes in book depreciation rates reserved until Avista's next general rate case); *In re Cascade Natural Gas Co.*, OPUC Docket No. UM 1727, Order No. 15-315 (Oct. 14, 2015) (change in depreciation rates implemented via Cascade's UG 287 general rate case).

Company's requirement to file a depreciation study and the timing of a general rate case.

Idaho Power's most recent depreciation study was filed on February 2, 2012, and docketed as UM 1576. In that case, the Commission approved ratemaking treatment for the change in book depreciation rates outside of a general rate proceeding, for rates effective July 2012.[2] However, rates from the Company's most recent general rate proceeding, docket UE 233, became effective five months prior to the rate change in docket UM 1576.[3]

Similar to its last depreciation study, there is a mismatch between the timing of the Company's request for a change in depreciation rates for ratemaking purposes, and the timing of a general rate case. However, the timing between the Company's most recent general rate case and depreciation study is approximately five years, rather than five months.

Therefore, Staff believes that a review of the Company's earnings is necessary prior to recommending the Commission order new rates resulting from a depreciation rate change. As discussed later on in my testimony, Staff conducted a limited review of the Company's earnings rather than an in depth review that is typically the case for general rate filings.

As discussed more fully below, Staff began its earnings review by beginning with the Company's 2016 results of operations, after Type I and Type II adjustments. Staff believes that this provides a reasonable picture for the Company's future earnings levels.

[2] *In re Idaho Power Co.*, OPUC Docket No. UM 1576, Order No. 12-296 (Jul. 20, 2012).
[3] *In re Idaho Power Co.*, OPUC Docket No. UE 233, Order No. 12-055 (Feb. 23, 2012).

ISSUE 3, RESULTS OF OPERATIONS BACKGROUND

Q. Please provide general background regarding a results of operations (ROO) review as it relates to electric utilities regulated by the Commission.

A. Annually each electric utility is required to report to the Commission its ROO based on its most recent fiscal year's operating results.[4] The utility is required to restate its actual ROO using a two-stage adjustment process. This requirement is rooted in past Commission policy that is detailed in Staff's letter to utilities provided in Exhibit 202.

Q. Why is a two-stage adjustment process important?

A. The two-stage adjustment process is critical because it allows Staff to better evaluate each utility's earnings on a normalized basis. These adjustments are segregated into Type I and Type II.[5]

Q. Would you please describe the purpose of Type I adjustments?

A. Yes. Type I adjustments take into account certain normalizing and ratemaking adjustments, which adjust the utility's actuals so the operational results align with Commission policies and precedents established primarily in general rate case dockets.[6]

---

[4] OAR 860-027-0045(3) provides that "Each electric company having multistate operations must file annually its Oregon allocated results of operations using allocation methods acceptable to the Commission. The results of operations report must be filed with the Commission on or before May 1 of each year."

[5] Staff/202, Gardner/1-4.

[6] Ibid/1-2.

Q. What is the purpose of Type II adjustments?

A. Type II adjustments are adjustments made after Type I adjustments and provide pro forma operational statements that are forward-looking. These adjustments are primarily annualizing adjustments. For example, some changes like an overall wage increase may have occurred close to year end. Annualizing operational results for known and measureable changes like wages provides results that are representative of a forecasted test year.

ISSUE 4, RESULTS OF OPERATIONS IDAHO POWER COMPANY

Q. Did Staff review Idaho Power's ROO?

A. Yes. Staff requested the Company provide its 2016 ROO report before the May 1st report filing deadline so that Staff could review the Company's earnings level after Type I and Type II adjustments. In response, Idaho Power filed Witness Mr. Larkin's supplemental testimony in UE 316[7] that includes the 2016 ROO.[8]

Q. Did Staff find that Idaho Power presented its 2016 ROO consistent with Commission Staff instructions?

A. Yes. As Mr. Larkin explains in his testimony, Idaho Power's ROO Type I and Type II adjustments are consistent with a January 2011 agreement between the Commission Staff and Idaho Power.[9] For the purposes of the earnings test after Type I, it was agreed to move normalizing adjustments from Type I to Type II.

Q. Did Staff review the Company's Type I and Type II adjustments and the results at each stage?

A. Yes. Staff issued more than 15 data requests, reviewed the Company's ROO report and supporting work papers.[10]

[7] UE 316 - Idaho Power/300, Larkin/1 at 13-20.
[8] UE 316 - Idaho Power/302, Larkin.
[9] UE 316 - Idaho Power/301, Larkin/1-2.
[10] Staff203, Gardner.

Q. What Type I adjustments did the Company make to its unadjusted 2016 ROO?

A. The Company made adjustments that Staff would expect to be made in a general rate case consistent with Commission orders or precedents. The Company's Type I adjustments are as follows:[11]

- Removed revenue and expenses for the Demand-Side Management (DSM) rider fund since these transactions are tracked separately in a balancing account;
- Removed deferred expenses related to excess power costs from prior years,
- Restated CSPP contracts to non-levelized amounts and removed capacity payments;
- Removed 100 percent of general advertising expenses, lobbying, charitable donations, and either 33 percent of 100 percent of memberships and dues expenses;
- Removed 50 percent of employee target incentive payout and 100 percent of the incentive payout above target and 100 percent of officer incentives
- Synchronized interest expense; and,
- Removed accounting entries related to prior period activities.[12]

[11] Ibid/1-4.
[12] Ibid/9.

Q. What Type II adjustments did the Company make?

A. The Company made the following adjustments:

- Normalized net power supply expense (NPSE), and revenue sensitive items,
- Annualized payroll costs,
- Removed NPSE related amortization,
- Annualized depreciation and amortization expense; and,
- Synchronized interest expense. [13]

Q. How did Staff conduct its earnings review?

A. To review what may be the Company's earnings on the time period the requested rates will be in effect, Staff selected 2016 as a representative year of Idaho earnings as that is the last calendar year for which we have recorded results. To that end, Staff began with the Company's 2016 results of operations, including Type I and Type II adjustments.

Q. Did Staff make any changes to the Company's 2016 results of operations?

A. Yes. Staff analyzed Idaho Power's cost of capital. That is discussed in Staff Witness Matt Muldoon's testimony (Staff/300).

[13] Ibid.

Q. Why is Staff's methodology for an earnings review appropriate under the circumstances in this case?

A. Staff believes that the length of time between the Company's last general rate case and its current request warrants a review of the Company's earnings prior to reflecting the change in book depreciation rates in retail rates.

Q. Did Staff analyze the Company's 2016 ROE based on additional assumptions?

A. Yes. Staff reviewed the Company's ROE after Type I and Type II adjustments based on the following scenarios that are illustrated in Table 1, below. The analysis directly below uses the Company's estimate of the updated cost of debt of 5.214 percent. That value is slightly higher than the Staff estimate that I will more fully discuss later on in this testimony.

- Scenario 1 – The Company's Capital Structure (CS) and the actual cost of long-term debt (COD) of 5.214 percent as presented in the Company's testimony.[14]
- Scenario 2 -The Company's average CS with the 5.214 percent COD.[15]
- Scenario 3 – Scenario 2 with the additional assumption that the costs associated with the scrubbers have been removed.[16]

Additionally, Staff calculated the basis point impact of the difference of the stipulated incremental revenue requirement of $300,000 and the requested

[14] UE 316 -Idaho Power/302, Larkin.
[15] Staff/ 203, Gardner/23.
[16] Ibid/25.

change of $405,000;[17] a difference of $105,000. Using the Company's value of $130,000 for 10 basis points provided in the Company's May 5th e-mail,[18], Staff calculates the difference of $105,000 in revenue requirement translates to 8.1 basis points (105/130 x 10 = 8.1).

Table 1

(1)	(2)	(3)	(4)	(5)
Scenario	ROE percentage after TYPE I	ROE percentage after Type II	Basis points adjustment	ROE percentage after Type II and basis point adjustment
1	7.075	9.36	.081	9.279
2	7.129	9.447	.081	9.366
3	7.103	9.549	.081	9.468

Q. Please explain how the above ROE percentages are relevant to Staff's evaluation of whether ratemaking treatment for the change in Idaho Power's depreciation rates is appropriate?

A. Staff's calculated ROEs after Type II adjustments and the basis point adjustment are relevant to this case because the pro forma results after Type II adjustments are forward-looking and an indicator of whether a change in rates is merited.[19] Also Staff, in its review of the Company's structure, has added an additional layer. As stated above, Staff believes that a 9.5 notional ROE for the limited purposes of this case, in conjunction with the actual cost of long-term debt and the average capital structure, provides a reasonable approximation of whether the Company's forward-looking ROE justifies an increase in customer rates. This is further substantiated by Staff' calculated 9.468 ROE in Table 1.

[17] Ibid/22 at 5.
[18] Ibid/24.
[19] Staff/202/, Gardner/2.

(See Scenario 3, col (5).) This ROE is lower than Staff's notional rate because parties stipulated to an incremental revenue requirement that is $105,000 less than the actual $405,000 of revenue requirement associated with the change in depreciation rates. Staff's calculation supports its belief the incremental revenue requirement will not result in the Company earning above Staff's 9.5 percent notional ROE. Also, the $300,000 of incremental revenue requirement represents an overall change of 0.54 percent in customer rates. Therefore, Staff supports the stipulation as it results in a change in rates that is just and reasonable for customers.

Q. Did you ask the Company to do similar analysis but with Staff's estimate of the updated cost of debt?

A. Yes. Staff's updated cost of debt value is 4.981 percent. From Staff witness Matt Muldoon, I understand from Staff's perspective, the difference is that the Company retained in the calculation of the cost of debt a debt issuance that matures in 2016, while Staff removed it consistent with long-standing Commission practice. The Company supports its calculated cost of debt of 5.214 percent. Whether the Company or Staff is correct with regards to the cost of debt is not material to the conclusion as to whether recovery of increases in depreciation is warranted. Under either case, there is support for recovery of $300,000 in additional revenues as that level will not cause Idaho to exceed 9.5 percent ROE on a forward-looking basis.

In addition to the change in cost of debt for the Staff analysis, there was one additional item that Staff requested the Company provide in the analysis below.

Q. What was the additional issue?

A. Staff asked the Company to identify the level of increase in depreciation expense the Company will incur associated with plant additions post 2011. This is an additional cost that the Company will absorb having not requested recovery of that cost.

Q. What is the increase in depreciation expense?

A. The Company calculated the increase to the Oregon jurisdictional depreciation expense to be $595,000.[20]

Q. What is the impact to ROE using Staff's cost of debt value of 4.981 percent and including the revenue requirement effect of the depreciation expense related to post 2011 plant additions?[21]

A. The impact is shown as Scenario 4 in Table 2 below:

Table 2

(1)	(2)	(3)	(5)
Scenario	ROE percentage after TYPE I	ROE percentage after Type II	ROE percentage after Type II
4	6.245	6.751	9.233

Q. What do you conclude from Table 2?

A. Table 2 illustrates that with the Staff cost of debt and taking into account the increase in depreciation expense associated with post 2011 plant additions,

[20] Staff/203, Gardner/26.
[21] Ibid at 27.

the Company's earnings after Type II adjustments is well below 9.5 percent. These values exclude plant associated with Jim Bridger scrubbers that have not been recognized in rates in Oregon by this Commission. This table supports the stipulation terms for recovery of increased depreciation expense through an increase in revenues of $300,000.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 1801
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Staff Witness Qualifications Statement

May 15, 2017

ITNESS QUALIFICATION STATEMENT

NAME:	Marianne Gardner
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Master of Business Administration Oregon State University, Corvallis, Oregon Bachelor of Science in Accounting Montana State University, Bozeman, Montana CPA, Oregon

EXPERIENCE:

I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UE 294, UG 284, UG 287, UG 288, and UG 305.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UM 1801
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Testimony

May 15, 2017

Oregon

PUBLIC
UTILITY
COMMISSION

March 25, 1992

Anne Eakin
Pacific Power & Light Co
920 SW 6th Ave
Portland OR 97204

Kelley Marold
Portland General Electric Co
121 SW Salmon St
Portland OR 97204

Bruce Samson
Northwest Natural Gas Co
220 NW 2nd Ave
Portland OR 97209

John Buergel
Washington Water Power Co
PO Box 3727
Spokane WA 99220

Jon Stoltz
Cascade Natural Gas Corp
PO Box 24464
Seattle WA 98124

J Ric Gale
Idaho Power Co
PO Box 70
Boise ID 83707

RE: Semiannual Adjusted Results of Operations Reports

My letter of February 17, 1989, outlined several principles for making adjustments to your semiannual results of operations reports. Based on our review of recent filings, I believe it would be useful to restate those principles along with the rationale behind them.

As you know, we have asked each energy company to file its semiannual report using a two-stage adjustment process. Each stage provides operating results which can be evaluated for a specific purpose.

<u>Earnings Test Adjusted Results</u>

The first stage takes into account certain normalizing and rate-making adjustments and results in "Earnings Test Adjusted" results of operations. The purpose of this stage is to produce an earnings picture that can be used to perform earnings

Barbara Roberts
Governor

350 Winter St. NE
Salem, OR 97310-0335
(503) 378-5849

tests required by ORS 757.259. Such tests are necessary for evaluating potential amortization of deferred costs and revenues. Accordingly, the operating results at this stage of the report should reflect as closely as possible the company's actual earnings for the reporting period and its ability to absorb a deferred cost or its need to retain deferred revenues.

Under current policy, therefore, **the first stage of the report should include adjustments to actual recorded results as follows:**

1. Normalizing for weather, streamflows, and plant availability;

2. Incorporating significant rate-making adjustments adopted in your most recent Oregon rate order if not reflected on your books (for example, advertising, memberships, payroll escalation, bonuses, and nonoperating expenses); and

3. Removing entries relating to prior period activity, and including subsequent period transactions clearly related to the test period. Examples include corrections of estimates or errors, and removal of credits or charges associated with other periods.

To avoid confusion, refer to these as "Type I" adjustments, as shown in the attached tables.

No other adjustments should be made at this stage of the report. Common adjustments which have been misclassified here include annualizing revenues and expenses and removing entries related to nonrecurring events. Although such adjustments are reasonable when constructing a test year, for example, they distort the company's earnings position for deciding whether a deferred amount should be amortized.

<u>Total Pro Forma Results</u>

The second stage of adjustments is intended to provide results of operations on a more forward-looking basis, by reflecting known and measurable changes occurring before the end of the 12-month period. These results help us to assess each company's current earnings situation and whether a rate change may be needed. The following "Type II" adjustments should be included in this stage of the report:

1. Annualizing adjustments to reflect end-of-period customers, tariff rates, employee levels, wage rates, tax rates, supply contracts, rate base, etc.

2. Restating adjustments to remove recorded entries related to significant nonrecurring events.

The most common error in this second stage has been to make adjustments for plant or expense changes occurring <u>after</u> the end of the recorded period. All "future" events--even if known and measurable--should be excluded from this report. (Note the exception above, however, for Type I adjustments to incorporate subsequently recorded error or estimate corrections.)

<u>Workpapers</u>

Each company should provide the following supporting documentation for its semiannual report:

- A table consisting of a columnar summary for the adjustments; with a total for both Types I and II. (Tables 2 and 3 of the attached sample illustrate some typical adjustments.) Also include in the same form the calculation of income taxes associated with each adjustment. (Not shown here)

- A short narrative description of each adjustment. (See attachment for sample; provide additional detail as needed.)

- Backup workpapers supporting actual recorded results by revenue, expense, income tax and rate base categories, tying Oregon allocated data to system data, if applicable. Note that the report is to be prepared showing Oregon allocated adjustments as well as summary data.

- Summary workpapers supporting each adjustment.

- The information used to calculate the cost of capital and the implied rate of return on equity--that is, average actual capital structure (describe any other formulation) and average actual debt and preferred stock costs for the 12-month period. The appropriate data may be included with the summary table as shown or by reference to a separate workpaper.

- For companies with jurisdictional allocations, a summary of the allocation factors used and a description of any material changes in the method from the prior report.

Unless we hear from you otherwise, we will expect adjustments in subsequent semiannual reports to be classified according to the above criteria. Call me, Ed Busch (378-6625), or Ed Krantz (378-6117) if you have any questions regarding these reports.

T. Ray Lambeth

T. Ray Lambeth
Manager
Energy Revenue Requirements
(503) 378-6917

18/20/3718HH

Attachment

cc: Mike Kane
Bill Warren
Phil Nyegaard
Scott Girard
Ed Busch
Ed Krantz
Les Margosian

SAMPLE

NORTHWEST NATURAL GAS COMPANY
Oregon Allocated Results of Operations
Twelve Months Ending December 31, 199X
($000)

		12/31/9X ACTUAL	TOTAL TYPE I ADJUSTMENTS (f/Table 2, col.K)	EARNINGS TEST ADJUSTED RESULTS	TOTAL TYPE II ADJUSTMENTS (f/Table 3, col.K)	TOTAL PRO FORMA RESULTS
		(1)	(2)	(3)	(4)	(5)
	Operating Revenues					
1	Sale of Gas	$253,400	$8,100	$261,500	$7,750	$269,250
2	Oil & Incentive Gas Margin	500	0	500	0	500
3	Revenue & Technical Adj.	(1,500)	0	(1,500)	0	(1,500)
4	Transportation	30,400	0	30,400	(1,350)	29,050
5	Miscellaneous Revenues	1,000	0	1,000	0	1,000
6	Total Operating Revenues	283,800	8,100	291,900	6,400	298,300
	Operating Revenue Deductions					
7	Gas Purchased	111,300	3,300	114,600	6,070	120,670
8	Uncollectible Accrual	1,100	40	1,140	35	1,175
9	Other Oper. & Maint. Exp.	53,000	(3,520)	49,480	425	49,905
10	Total Oper. & Maint. Exp.	165,400	(180)	165,220	6,530	171,750
	Taxes					
11	Federal Income	14,500	2,744	17,244	(970)	16,274
12	State Excise	4,100	2,076	6,176	(180)	5,996
13	Taxes Other than Income	20,800	19	20,819	1,432	22,251
14	Depreciation & Amortization	24,700	16	24,716	760	25,476
15	Total Oper. Revenue Deductions	229,500	4,675	234,175	7,572	241,747
16	Net Operating Revenues	$54,300	$3,425	$57,725	($1,172)	$56,553
	Average Rate Base					
17	Utility Plant in Service	$636,600	($120)	$636,480	$18,500	$654,980
18	Accumulated Depreciation	(174,200)	8	(174,192)	(380)	(174,572)
19	Net Utility Plant	462,400	(112)	462,288	18,120	480,408
20	Customer Advances for Constr.	(100)	0	(100)	0	(100)
21	Average Materials & Supplies	18,600	0	18,600	0	18,600
22	Leasehold Improvements	2,500	0	2,500	0	2,500
23	Water Heater Program	900	0	900	0	900
24	Accum. Deferred Income Taxes	(22,300)	0	(22,300)	(296)	(22,596)
25	Total Rate Base	$462,000	($112)	$461,888	$17,824	$479,712
26	Rate of Return	11.75%		12.50%		11.79%
27	Implied Return on Equity	13.80%		15.32%		13.88%

COST OF CAPITAL (Average) for twelve months ending: 12/31/9X

	% OF CAPITAL	COST	WEIGHTED COST
Long Term Debt	45.00%	9.92%	4.46%
Preferred Stock	6.00%	8.76%	0.53%
Common Equity	49.00%	13.25%	6.49%
TOTAL	100.00%		11.48%

Type I: Normalizing adjustments for water, weather, plant availability; ratemaking adjustments; removing out–of–period.

Type II: In–period annualizing adjustments for significant revenue, expense and rate base elements; removing nonrecurring entries.

SAMPLE

NORTHWEST NATURAL GAS COMPANY
Twelve Months Ending December 31, 199X
Description of Adjustments

Type I Adjustments

(1a) Weather–Normalized Revenue & Gas Purchases

Adjusts revenues and purchased gas costs to the levels which would have been realized under normal system temperatures.

(1b) Income Taxes

Reflects the difference between the estimated income tax as booked and the actual tax liability calculated based on the actual results of operations for the period.

(1c) Interest Coordination Capital Structure

Adjusts income tax expense to reflect an appropriate regulatory interest deduction using Oregon allocated rate base multiplied by the company's current weighted cost of debt.

(1d) Payroll and Incentive Pay

Reduces non–union wages and salaries using the three–year wage formula model applied in the company's most recent rate case. Also reduces O&M expense to exclude, for ratemaking purposes: (a) bonuses paid to officers, and (b) one–half of actual payments under the company's general employee bonus program.

(1e) Advertising

Adjusts advertising expense to a level equal to .125% of authorized gross retail revenues, as specified in OAR 860–26–022 and adopted in the company's most recent general rate order, UG 81.

(1f) Corporate Communications

As adopted in UG 81, removes a portion of utility corporate communications department salary and overhead expense associated with nonutility operations.

(1g) Nonoperating

Removes expenses exceeding Commission ordered allowance of 75% of AGA and PCGA membership dues. For promotional activities, removes 50 percent of expenditures for trade shows and open houses as directed by the OPUC in UG 81.

(1h) Main & Service Extensions

As adopted in UG 81, adjusts rate base to reflect under recoveries of excess footage charges by the company.

(1i) Insurance Recovery

Removes the effect of insurance reimbursement for damage claim relating to a prior period. (i.e., removing an out–of–period entry)

(1j) Legal Fees

Adjustment to include refund of legal expense booked in subsequent period but related to activity in the current period.

TABLE 2

SAMPLE

NORTHWEST NATURAL GAS CO.
Oregon Allocated TYPE I Adjustments
Twelve Months Ending December 31, 199X
($000)

		Weather-Normalized Revenue & Gas Purchases	Income Taxes	Interest Coord. Cap. Str.	Payroll & Incentive Pay	Advertising	Corporate Commun.	Non-Operating	Main & Service Extensions Adjustments	Insurance Recovery	Legal Fees	TOTAL TYPE I ADJUSTMENTS
		(1a)	(1b)	(1c)	(1d)	(1e)	(1f)	(1g)	(1h)	(1i)	(1j)	(1k)
	Operating Revenues											
1	Sale of Gas	$8,100										$8,100
2	Oil & Incentive Gas Margin											0
3	Revenue & Technical Adj.											0
4	Transportation											0
5	Miscellaneous Revenues											0
6	Total Operating Revenues	8,100	0	0	0		0	0	0			8,100
	Operating Revenue Deductions											
7	Gas Purchased	3,300										3,300
8	Uncollectible Accrual	40										40
9	Other O & M Expenses				(1,300)	(950)	(520)	(790)		110	(70)	(3,520)
10	Total O & M Expenses	3,340	0	0	(1,300)	(950)	(520)	(790)	0	110	(70)	(180)
	Taxes											
11	Federal Income	1,510	(490)	610	410	300	170	250	(3)	(35)	22	2,744
12	State Excise	290	1,450	120	80	60	30	50	(1)	(7)	4	2,076
13	Taxes Other than Income	20							(1)			19
14	Depreciation & Amort.								16			16
15	Total Oper. Rev. Ded.	5,160	960	730	(810)	(590)	(320)	(490)	11	68	(44)	4,675
16	Net Operating Revenues	2,940	(960)	(730)	810	590	320	490	(11)	(68)	44	3,425
	Average Rate Base											
17	Utility Plant In Service								(120)			(120)
18	Accumulated Depreciation								8			8
19	Net Utility Plant	0	0	0	0	0	0	0	(112)	0	0	(112)
20	Customer Adv. for Constr.											0
21	Ave. Materials & Supplies											0
22	Leasehold Improvements											0
23	Water Heater Program											0
24	Accum. Def. Income Taxes											0
25	Total Rate Base	$0	$0	$0	$0	$0	$0	$0	($112)	$0	$0	($112)

SAMPLE

NORTHWEST NATURAL GAS COMPANY
Twelve Months Ending December 31, 199X
Description of Adjustments

Type II Adjustments

(2a) Annualized Revenue & Gas Purchases

Adjusts revenues and purchased gas costs to reflect levels which would have occurred had current (year–end) rates and costs been in effect for the entire period.

(2b) Payroll Adjustment

Normalizes actual salaries and wages to reflect end–of–period wage levels and employee counts. (Note: This adjustment should not reverse the effect of adjustment 1d.)

(2c) Payroll Overhead

Adjusts health and life insurance costs for year–end employee counts and carrier per person rates. Includes retiree costs and offsets for member contributions. Also adjusts payroll taxes for year–end employee counts and for changes in taxing rates.

(2d) Postage Increase

Normalizes utility–related mailing expense for the change in postage rates which occurred during the period.

(2e) Early Retirement Program

Removes nonrecurring expense associated with one–time bonuses paid to employees participating in the company's early retirement program.

(2f) Property Taxes

Normalizes property taxes from an accrual for two separate tax years to an actual cash basis.

(2g) Year–End Customers & Rate Base

Adjusts revenues and associated expenses not accounted for separately to reflect end–of–period customer counts. Includes annualized loss of two major transportation customers to bypass during the period. Also adjusts rate base, depreciation expense, depreciation reserve and property tax expense to reflect end–of–period plant balances.
(Note: Must include year–end customer adjustment if year–end rate base adjustment made.)

TABLE 3

SAMPLE

NORTHWEST NATURAL GAS CO.
Oregon Allocated TYPE II Adjustments
Twelve Months Ending December 31, 199X
($000)

		Annualized Revenue & Gas Purch.	Payroll	Payroll Overhead	Postage Increase	Early Retirement Program	Property Taxes	Year-End Customers/ Rate Base				TOTAL TYPE II ADJUSTMENTS
		(2a)	(2b)	(2c)	(2d)	(2e)	(2f)	(2g)	(2h)	(2i)	(2j)	(2k)
	Operating Revenues											
1	Sale of Gas	$5,200						$2,550				$7,750
2	Oil & Incentive Gas Margin											0
3	Revenue & Technical Adj.											0
4	Transportation							(1,350)				(1,350)
5	Miscellaneous Revenues											0
6	Total Operating Revenues	5,200	0	0	0	0	0	1,200				6,400
	Operating Revenue Deductions											
7	Gas Purchased	5,050						1,020				6,070
8	Uncollectible Accrual	25						10				35
9	Other O & M Expenses		720	175	230	(775)		75				425
10	Total O & M Expenses	5,075	720	175	230	(775)	0	1,105				6,530
	Taxes											
11	Federal Income	40	(230)	(60)	(70)	250	(270)	(630)				(970)
12	State Excise	10	(40)	(10)	(10)	50	(50)	(130)				(180)
13	Taxes Other than Income			2			850	580				1,432
14	Depreciation & Amort.							760				760
15	Total Oper. Rev. Ded.	5,125	450	107	150	(475)	530	1,685				7,572
16	Net Operating Revenues	75	(450)	(107)	(150)	475	(530)	(485)				(1,172)
	Average Rate Base											
17	Utility Plant In Service							18,500				18,500
18	Accumulated Depreciation							(380)				(380)
19	Net Utility Plant	0	0	0	0	0	0	18,120				18,120
20	Customer Adv. for Constr.											0
21	Ave. Materials & Supplies											0
22	Leasehold Improvements											0
23	Water Heater Program											0
24	Accum. Def. Income Taxes							(296)				(296)
25	Total Rate Base	$0	$0	$0	$0	$0	$0	$17,824				$17,824

CASE: UM 1801
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Testimony

May 15, 2017

IDAHO POWER®
An IDACORP Company

April 17, 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. 66-79

STAFF'S DATA REQUEST NO. 66:

Referring to the Company's workpaper, "2016 Oregon Results of Operations Report.xlsx", tab "STMTOPS1", please:

a. **Add a column and provide the Oregon allocated amount for each Type I and Type II adjustment;**

b. **Provide a narrative explanation for each Type I and II adjustment listed. In the narrative, please provide the rationale or basis for the adjustment and, where applicable, please cite the relevant OPUC order.**

c. **Explain why the total interest synchronization expense is the total of the Type I and Type II adjustments.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 66:

a. Please see the "Oregon1" tab in the "2016 Oregon Results of Operations Report.xlsx" file for the Oregon allocated Statement of Operations on an Actual, Type I and II basis.

b. Please see the attached Excel file for a narrative explanation for each Type I and II adjustment listed.

c. The total interest synchronization expense does not total the Type I and II adjustments. The total interest synchronization expense listed on the "STMTOPS1" is the sum of the Type I and II interest synchronization *adjustments*. The total interest synchronization expense can be found on page 96 of the 2016 Oregon Results of Operations ("ROO") workpapers.

ATTACHMENT - RESPONSE TO STAFF'S DR 66

IDAHO POWER COMPANY
STATEMENT OF OPERATIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

OREGON - Adjusted

	Adjustments		ADJUSTMENT NARRATIVE
OPERATING REVENUE			
Type I Adjustments			
Actual Adjustments:			
Other Revenue - Account #415	4,054,219	<--	Merchandising Revenue and Expense (Accounts 415 and 416, respectively) are below-the-line accounts for ratemaking purposes. As discussed on page 10 of Idaho Power Exhibit No. 802 in the Company's last general rate case, Docket No. UE 233, these accounts are related to Idaho Power Solutions, water management services, and joint pole use. These accounts are typically close to equal and offsetting, and are therefore excluded from earnings test calculations and rate case test year development.
DSM Rider Fund Removal	(33,754,061)	<--	Demand-Side Management ("DSM") Rider revenues and expenses are effectively recorded and tracked through a balancing account. Therefore, these revenues and expenses are removed from adjusted runs of the Oregon report. (see line 32 below for the exact offsetting expense entry. The sum of these adjustments nets to zero).
Type II Adjustments			
Revenue Normalization/Annualization			
Firm Energy - Retail	(98,482,867)	<--	Reflects an adjustment due to weather normalizing sales and applying rates in effect as of December 31 of the historical period to the entire year. These are standard rate case test year adjustments to remove the impact of a single year of weather on a rate case filing. All general rate case filings reflect normalized retail revenues and annualized retail rates, and have been relied upon by the Commission as the basis for test year development.
Firm Energy - Wholesale	0		
Opportunity Sales - System	14,483,715	<--	Net Power Supply Expense (NPSE) normalization. The Company's approved NPSE methodology is detailed in the stipulation approved by Order No. 08-238 in Docket No. UE 195, which esablished the Company's Annual Power Cost Update ("APCU"). To summarize this component of the stipulated methodology, the AURORA power supply model utilizes an average of all known historical water conditions to develop a normalized amount of NPSE. This methodology has been utilized and relied upon by the Commission in each of the Company's APCU Filings since UE 195.
Total Revenue Adjustments	(113,698,994)		
OPERATING EXPENSES			
OPERATION & MAINTENANCE			
Type I Adjustments			
Actual Adjustments:			
O&M - Account #416	3,886,708	<--	Please see row 12 above for an explanation regarding Accounts 415 and 416.
DSM Rider Funds	(33,754,061)	<--	Please see row 13 above for an explanation of DSM rider revenues and expenses.
Out of Period Adjustments			
Account #557 Deferred Expenses	43,840,810	<--	Reflects removal of out-of-period NPSE deferrals. This treatment is further detailed on page 2 of Staff's letter to Idaho Power dated March 2, 2011, provided as Exhibit No. 301 in this docket.
Commission-Ordered Adjustments:			

CSPP at Oregon Rates	23,743,797 <—	OPUC Order No. 85-010 requires CSPP contracts to be priced using a non-levelized methodology. The adjustment brings actuals to non-levelized amounts. The adjustment also includes the removal of capacity payments.
Account 930.1	(582,063) <—	Adjustment to remove 100% of general advertising expenses consistent with approved treatment in the Company's 2003 Idaho general rate case, IPC-E-03-13. Consistent with treatment in all subsequent Oregon general rate case filings.
Account 930.2	322,484 <—	Adjustment to remove 100 % of lobbying and charitable donations, and either 33% or 100% of memberships and dues expenses.
Employee Incentive Adjustment	(17,763,196) <—	Established in Order No. 12-055. Removes half of the employee target incentive payout, plus all payout amounts above target, plus all executive incentive payments.
<u>Type II Adjustments</u>		
Normalizing Adjustments:		
Account #501 - Fuel	(54,369,323) <—	Please see note in line 21 regarding NPSE normalization
Account #547 - Fuel	19,444,571 <—	Please see row above.
Account #555 - Purchased Power	(25,891,929) <—	Please see row above.
Account #555 - CSPP	7,629,266 <—	Net Power Supply Expense (NPSE) normalization. The Company's approved NPSE methodology is detailed in the stipulation approved by Order No. 08-238 in Docket No. UE 195, which esablished the Company's Annual Power Cost Update ("APCU"). To summarize this component of the stipulated methodology, the AURORA power supply model utilizes an average of all known historical water conditions to develop a normalized amount of NPSE. This methodology has been utilized and relied upon by the Commission in each of the Company's APCU Filings since UE 195.
Commission-Ordered Adjustments:		
Account 904 - Revenue Sensitive	(13,159) <—	Commission-ordered adjustment showing impact of the difference between normalized and actual revenues on Account 904 - Uncollectible Accounts.IN PROGRESS
Annualizing Adjustments:		
Operating Payroll	255,763 <—	Standard rate case adjustment reflecting annualization of payroll. Similar to the annualization of retail revenue, applies labor rates in effect as of December of the historical period to the entire historical year.
Payroll Related Items	9,290 <—	Similar annualization adjustment applied to Employee Savings Plan employer contributions.
Labor Taxes Transferred from Other Taxes	0	
Removal of #557 Amortization Expense	(38,510,643) <—	Reflects removal of out-of-period NPSE amortization. This treatment is further detailed on page 2 of Staff's letter to Idaho Power dated March 2, 2011, provided as Exhibit No. 301 in this docket.
Total O&M Adjustments	(71,751,584)	
DEPRECIATION		
<u>Type II Adjustments</u>	2,024,648 <—	Standard rate case adjustment reflecting annualization of depreciation expense.

ATTACHMENT - RESPONSE TO STAFF'S DR 66

AMORTIZATION		
Type I Adjustments		
Actual Adj: Acct#411.8	49,267	<— Standard rate case adjustment reflecting the removal of Idaho Power's share of the gain associated with the sale of Clean Air Credits.
Type II Adjustments		
Annualizing Adjustment	(332,073)	<— Standard rate case adjustment reflecting annualization of amortization expense.
Total Amortization Adjustments	(282,806)	
ACCRETION		
Type II Adjustments	0	
TAXES OTHER THAN I/T		
Type II Adjustments		
Normalized Irrigation KWH Taxes	465,242	<— Because this amount is based on kWh / revenues, when energy and revenues are normalized as detailed above, this item changes as well.
Normalized Irrigation Refund	127,318	<— Please see row above.
Franchise Fees - Revenue Sensitive	(46,058)	<— Please see row above.
OPUC Fees - Revenue Sensitive	(4,112)	<— Please see row above.
Total Taxes Other Than I/T Adjustments	542,390	<— Reflects an adjustment to normalize kWh taxes and irrigation rebates as of December 31 of the historical period to the entire year. These are standard rate case test year adjustments. Also includes the Commission ordered adjustment showing impact of the difference between normalized and actual revenues on Account 408 – Franchise Fees and State of Oregon Regulatory Commission Fees.
REGULATORY DEBITS/CREDITS		
Type I Adjustments	(1,075,354)	<— Removal of amortization associated with the Siemens Long-Term Program Contract deferrals approved with IPUC Order No. 33420.
INTEREST SYNHCRONIZATION EXPENSE		
Type I Adjustments	5,558,265	<— When rate base changes due to the adjustments listed above, the corresponding level of interest expense changes as well. This adjustment is made to synchronize interest expense with final as-adjusted rate base amounts.
Type II Adjustments	(109,495)	<— Please see row above.
Total Interest Synchronization Expense	5,448,770	

STAFF'S DATA REQUEST NO. 67:

Referring to the OREOM1, Removal of Advertising Expenses, please provide supporting details that demonstrate the Company has properly categorized advertising expenses as Category A, B, C, and D and removed the proper amounts consistent with Commission policy. Additionally, please explain why the adjustment to account 930.2 is an increase to expense rather than a decrease.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 67:

As can be seen on the JSS – PF tab, Idaho Power Company ("Idaho Power" or "Company") has removed 100 percent of the Account 930.1 – Advertising Expenses balance. The adjustment to Account 930.2 was entered incorrectly and should be a decrease to the Account 930.2 balance. If the above error is corrected in the ROO, the Type I Return on Equity ("ROE") would increase from 7.075 percent to 7.100 percent, still below the Company's current authorized ROE.

STAFF'S DATA REQUEST NO. 68:

Referring to Idaho Power/302, Larkin/1, has the Company removed the following costs as Type I adjustments:

a. 100 percent of costs related to lobbying or charitable donations. Please provide the amount and supporting details of the adjustment. If no adjustment was required, please explain; and,

b. 100 percent of memberships and dues expense excluding payments to industry research organizations and national and regional industry trade organization. Please provide the amount and supporting details of the adjustment. If no adjustment was required, please explain.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 68:

a. Yes. Idaho Power has identified $322,484 in expenses associated with lobbying, charitable donations, memberships, and dues expenses that should be excluded from Account 930.2 and removed as a Type I adjustment. Please see pages 71-72 of the workpapers filed as part of the Company's ROO for supporting details.

b. Yes. Please see the response to a. above.

STAFF'S DATA REQUEST NO. 69:

Please explain whether any Valmy-related costs requested to be included as set forth in the UE 316 filing are also included in the Company's 2016 Oregon ROO.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 69:

A portion of the Valmy-related costs requested in UE 316 are included in Idaho Power's ROO as the ROO includes Valmy-related costs through December 31, 2016.

STAFF'S DATA REQUEST NO. 70:

Please explain whether the Company made any major rate base adjustments for the 2016 Oregon ROO.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 70:

The only major rate base adjustment made was the Type I adjustment of $28,650,771 to Account 151, Fuel Inventory, to reduce the fuel inventory balance to allowed inventory levels. Please see Section C (pages 45-57) of the ROO for the development of the rate base components.

STAFF'S DATA REQUEST NO. 71:

Please explain whether in the Company's 2016 Oregon ROO the Company removed accounting entries related to prior period activities.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 71:

As detailed in Exhibit 301, Type I adjustments remove all out-of-period transactions, including the current reporting year's power cost deferral amounts, if any exist, to reflect expenses for the period in which they are recognized. Please see page 29 of the ROO for a summary of all Oregon-allocated Type I adjustments.

STAFF'S DATA REQUEST NO. 72:

Please explain if any subsequent period transactions that clearly relate to the 2016 year have been included in the 2016 Oregon ROO.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 72:

All known transactions related to 2016 have been included in the ROO.

STAFF'S DATA REQUEST NO. 73:

Please provide the calculation of the interest synchronization and the related income tax calculation and adjustment.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 73:

Please see the attached Excel spreadsheet for the calculation of the interest synchronization presented on page 96 of the ROO workpapers. Please note, the interest synchronization calculation can be a circular process depending on any tax adjustments. Because adjustments to accumulated deferred income taxes can affect rate base, final adjusted rate base amounts in the ROO may not tie to initial rate base levels contained in this spreadsheet.

ATTACHMENT - RESPONSE TO STAFF'S DR 73

IDAHO POWER COMPANY
Interest Synchronization
For the Historical Year Ended December 31, 2016

LINE NO.	DESCRIPTION	ADJUSTED - TYPE I	ADJUSTED - TYPE I & II
1	Total Company Rate Base	3,163,968,898	3,159,464,761
	Adjustments to Rate Base:		
2	Construction Work-in-Progress	435,978,988	435,978,988
3	Adjusted Rate Base	3,599,947,886	3,595,443,749
4	Company Weighted Cost of Debt	2.431%	2.431%
5	Synchronized Interest Expense	87,514,733	87,405,238

STAFF'S DATA REQUEST NO. 74:

Referring to Idaho Power/300, Larkin/2 at 11- 21 and Exhibit 301, does the inclusion of this exhibit imply that Idaho Power is requesting recovery of costs only up to 100 basis points of its currently authorized 9.9 percent return on equity?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 74:

No. Exhibit 301 was provided as a basis for the methodology behind Idaho Power's Type I and II adjustments. The letter was a result of Staff's review of the ROO in the Company's Power Cost Adjustment Mechanism ("PCAM") docket (UE 195) and was prepared to document the agreement made between Idaho Power and Commission Staff with respect to Type I and II adjustments made in the ROO. The reference to earnings within 100 basis points of Idaho Power's authorized ROE is pursuant to Order No. 08-238, the methodology for determining PCAM true-up amounts approved for subsequent recovery or refund.

STAFF'S DATA REQUEST NO. 75:

If Idaho Power Company used the UE 233 capital structure (50.1 LTD, 49.9 CE) what would be the 2016 effective ROE and ROR: 1) after the Type I adjustments; 2) after Type I and Type II adjustments.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 75:

Please see the attached Excel file for the 2016 effective ROE and Rate of Return using the UE 233 docket capital structure. Please note, the attached Excel file includes a correction for the error identified in the Company's Response to Staff's Data Request No. 67.

STAFF'S DATA REQUEST NO. 76:

If Idaho Power Company used the updated cost of long-term debt the Company prepared in response to Staff DR No. 23 and the UE 233 capital structure, what would be the 2016 effective ROE and ROR: 1) after the Type I adjustments; 2) after Type I and Type II adjustments.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 76:

Idaho Power objects to this request because the information it seeks is not relevant or designed to lead to relevant evidence. The requested analysis would yield an invalid result because it creates a mismatch between capital structure and cost of capital which are interrelated.

STAFF'S DATA REQUEST NO. 77:

What was the average equity capital over calendar year 2016? Please provide supporting workpapers in Excel.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 77:

The following summarizes the average equity capital over the calendar year 2016 based on Idaho Power's consolidated balance sheets published in its quarterly reports on Form 10-Q and Annual Report on Form 10-K:

	Q1 2016 (000s)	Q2 2016 (000s)	Q3 2016 (000s)	Q4 2016 (000s)	**AVG (000s)**
Common at par	97,877	97,877	97,877	97,877	
Premium less expense	710,161	710,161	710,161	710,161	
Accumulated other comprehensive income	(20,712)	(20,149)	(19,586)	(20,882)	
Retained earnings	1,127,095	1,156,138	1,210,430	1,211,547	
Total common equity	1,914,421	1,944,027	1,998,882	1,998,703	**1,964,008**

STAFF'S DATA REQUEST NO. 78:

Referring to Idaho Power/302, Larkin/1, is the actual capital structure reflecting that as of December 31, 2016?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 78:

Yes.

STAFF'S DATA REQUEST NO. 79:

For purposes in Idaho, below what equity return is Idaho Power allowed to track additional costs in rates? For example, is it 9.5 percent ROE? Please provide a copy the Idaho PUC order that establishes this threshold.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 79:

Idaho Power does not have an approved mechanism that allows the Company to track additional costs in rates should Idaho Power's ROE fall below a certain threshold. The Company does however have a regulatory mechanism in its Idaho jurisdiction that includes provisions for the accelerated amortization of certain tax credits to help achieve a minimum 9.5 percent Idaho jurisdictional ROE on year-end equity. This mechanism also includes a provision that requires the Company to share earnings above a 10 percent Idaho jurisdictional ROE. The Company retains earnings between a 9.5 percent Idaho jurisdictional ROE and a 10 percent Idaho jurisdictional ROE. Please see the attached IPUC Order No. 33149 for details regarding the mechanism.

IDAHO POWER®
An IDACORP Company

April 17, 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. 80-81

STAFF'S DATA REQUEST NO. 80:

If Idaho Power Company used the updated cost of long-term debt the Company prepared in response to Staff DR No. 23, 9.5 percent cost of equity, and the capital structure of 50.10 percent long term debt and 49.90 percent common equity, what would be the 2016 effective ROE and ROR: 1) after the Type I adjustments; and 2) after Type I and Type II adjustments respectively.

Note that this notional ROE is restricted to analysis herein.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 80:

Idaho Power objects to this request because the information it seeks is not relevant or designed to lead to relevant evidence. The requested analysis would yield an invalid result because it creates a mismatch between capital structure and cost of capital which are interrelated.

STAFF'S DATA REQUEST NO. 81:

Does the Company's Oregon 2016 Results of Operations include any one-time charges in excess of $500,000? If so, for each one-time charge, please identify the amounts and the reason/cause of the one-time charge.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 81:

As clarified in discussions with Public Utility of Oregon Staff on April 13, 2017, the request is to provide the one-time, out-of-period adjustments, made in excess of $500,000. Idaho Power made a single, one-time out-of-period adjustment of $43,840,810 in the 2016 Results of Operations ("ROO") associated with the 2016 Idaho jurisdictional power supply expense deferral. Please see a summary of the other Oregon allocated Type I adjustments on page 29 of the 2016 ROO. Please note this adjustment is Idaho-specific and has no impact on results in the Company's Oregon jurisdiction.

GARDNER Marianne

From:	White, Tami <TWhite@idahopower.com>
Sent:	Tuesday, April 25, 2017 4:55 PM
To:	HELLMAN Marc
Cc:	'Moser Sommer'; Weirich Michael; GIBBENS Scott; GARDNER Marianne; Tatum, Tim; Waites, Courtney
Subject:	FW: supplement to data request
Attachments:	Email DR 1_Cap Structure_Avg.xlsx; Email DR 6_Allocation of Expense and Reserve.xlsx; Email DR 7_IPC2015-ASLREMLIFE_OR Settlement_Bridger 2025.xlsx; Email DR 8_Rate spread.xlsx

Hello Marc,
Per our conversation this afternoon, below and attached please responses to your supplemental data request dated April 20, 2017 and received via email. As we discussed, we expect to follow-up with the answers to 3. and 4. by this Friday.
Thanks,
Tami

--
Tami White
MANAGER, REVENUE REQUIREMENT
Idaho Power | Regulatory Affairs

1221 W. Idaho St. | Boise, ID | 83702

Work 208-388-6938
Fax 208-388-6449

Email twhite@idahopower.com

From: HELLMAN Marc [mailto:marc.hellman@state.or.us]
Sent: Thursday, April 20, 2017 12:29 PM
To: Tatum, Tim
Cc: Bob Jenks (Bob@oregoncub.org); WEIRICH Michael; MOSER Sommer
Subject: [EXTERNAL] FW: supplement to data request

Here is the information I am requesting:

1. Type 1 and Type 2 results, including ROE, for 2016 assuming actual average capital structure and updated cost of debt.

Please see the attached Excel file titled Email DR 1_Cap Structure_Avg.

2. Increase in depreciation, so increase in 2016 depreciation expense, above 12/31/2011 plant balances. Expressed in both expense and revenue requirement.

The proposed depreciation rates, when applied to 12/31/2015, would result in depreciation expense of approximately $131.3 million on a total system basis, or approximately $15.7 million more than what's currently included in customer rates. The Oregon jurisdictional share of the increase in depreciation expense is approximately $568k. The proposed depreciation rates, when applied to 12/31/2011 plant balances, would result in an increase in the Oregon jurisdictional depreciation expense of $343,041 and an increase in the Oregon jurisdictional revenue requirement of $404,887.

3. Type 1 and Type 2 results, including ROE, for 2016 assuming actual average capital structure, updated cost of debt excluding revenue requirement effects of new Bridger SCRs that was included in request (1) above.

4. Increase in depreciation, so increase in 2016 depreciation expense, above 12/31/2011 plant balances, excluding depreciation expense associated with new Bridger SCRs that was included in request (2) above. Expressed in both expense and revenue requirement.

5. Change in revenue requirement associated with a change in 100 basis points ROE

A change in the Oregon jurisdictional revenue requirement of approximately $114k would result in a change in the ROE of 100 basis points.

Other things to consider including

6. Oregon composite allocation factor used to develop depreciation expense amounts

Please see the attached Excel file titled Email DR 6_Allocation of Expense and Reserve.

7. A third table that combines the change in depreciation rates as well as the different life of Bridger.

Please see the attached Excel file titled Email DR 7_IPC2015-ASLREMLIFE_OR Settlement_Bridger 2025

8. We will need rate spread table and estimate of change in monthly bill for a typical residential customer.

Please see the attached Excel file titled Email DR 8_Rate Spread for the rate spread table. The agreed upon settlement proposal of a change in the Oregon jurisdictional revenue requirement of $300,000 would increase the average Residential customer, using 1,175 kWh, approximately $0.60 or 0.52%.

Please give me a call if any request is unexpected from our call or unclear

---

IDAHO POWER COMPANY
STATEMENT OF OPERATIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

OPUC JURISDICTION

DESCRIPTION	ACTUAL ALLOCATION	TYPE I ADJUSTMENTS	ADJUSTED TOTAL - TYPE I	TYPE II ADJUSTMENTS	ADJUSTED TOTAL - TYPE I & II
OPERATING REVENUES					
Retail Sales Revenues	53,271,854	0	53,271,854	(3,289,846)	49,982,008
Sales for Resale	0	0	0	0	0
Opportunity Sales	1,176,057	0	1,176,057	661,656	1,837,713
Other Operating Revenues	4,613,177	(2,273,242)	2,339,934	(16,439)	2,323,495
Total Operating Revenue	59,061,088	(2,273,242)	56,787,845	(2,644,629)	54,143,216
OPERATING EXPENSES					
Operation & Maintenance Expense	42,151,872	(2,284,495)	39,867,377	(5,191,939)	34,675,438
Depreciation Expense	5,936,079	0	5,936,079	42,876	5,978,954
Amortization Expense	285,073	2,128	287,200	(16,698)	270,503
Accretion Expense	10,127	0	10,127	0	10,127
Taxes Other Than Income Taxes	2,317,483	0	2,317,483	(37,732)	2,279,751
Regulatory Debits/Credits	167,068	0	167,068	0	167,068
Provision for Deferred Income Taxes	1,299,323	154,248	1,453,571	51,395	1,504,966
Investment Tax Credit Adjustment	13,172	0	13,172	(100)	13,072
Federal Income Tax	(989,650)	(254,045)	(1,243,695)	783,130	(460,565)
State Income Taxes	12,686	(222,562)	(209,875)	136,115	(73,761)
Total Operating Expenses	51,203,233	(2,604,727)	48,598,507	(4,232,952)	44,365,554
OPERATING NET INCOME	7,857,855	331,484	8,189,339	1,588,323	9,777,661
Add: IERCO Operating Income	372,976	0	372,976	(2,850)	370,126
CONSOLIDATED OPERATING INCOME	8,230,830	331,484	8,562,314	1,585,473	10,147,787
RATE OF RETURN EARNED	5.917%		6.221%		7.440%
IMPLIED RETURN ON EQUITY	6.550%		7.129%		9.447%

COST OF CAPITAL - DEC 31, 2016	ACTUAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
Long Term Debt	47.409%	5.214%	2.472%
Preferred Stock	0.000%	0.000%	0.000%
Common Equity	52.591%	9.900%	5.207%
Total	100.000%		7.678%

GARDNER Marianne

From:	White, Tami <TWhite@idahopower.com>
Sent:	Friday, May 5, 2017 2:11 PM
To:	GARDNER Marianne
Cc:	HELLMAN Marc; Weirich Michael; 'Moser Sommer'; MULDOON Matt; GIBBENS Scott; Waites, Courtney; Tatum, Tim
Subject:	supplement to data request
Attachments:	Email DR 3_Earnings Test less SCRs.xlsx; Email DR 4_Earnings Test less SCRs_Plus New Depr Exp.xlsx
Importance:	High
Follow Up Flag:	Follow up
Flag Status:	Flagged

Hi Marianne,
Below and attached please find the answers to questions 3 and 4. Please note that we are also providing a corrected answer to question 5 because when we responded previously on 4/25/17 we had incorrectly answered this question in regards to a **10** basis point change in the ROE (which would be approximately $114K) instead of a **100** basis point change in the ROE (which would be approximately $1.3 million). I apologize for the error. Please let me know if you have any questions or need anything else from us.
Thanks,
Tami

--
Tami White
MANAGER, REVENUE REQUIREMENT
Idaho Power | Regulatory Affairs

1221 W. Idaho St. | Boise, ID | 83702

Work 208-388-6938
Fax 208-388-6449

Email twhite@idahopower.com

3. Type 1 and Type 2 results, including ROE, for 2016 assuming actual average capital structure, updated cost of debt excluding revenue requirement effects of new Bridger SCRs that was included in request (1).

   Please see the attached Excel file titled Email DR 3_Earnings Test less SCRs.

4. Increase in depreciation, so increase in 2016 depreciation expense, above 12/31/2011 plant balances, excluding depreciation expense associated with new Bridger SCRs that was included in request (2). Expressed in both expense and revenue requirement.

IDAHO POWER COMPANY
STATEMENT OF OPERATIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

OPUC JURISDICTION

DESCRIPTION	ACTUAL ALLOCATION	TYPE I ADJUSTMENTS	ADJUSTED TOTAL - TYPE I	TYPE II ADJUSTMENTS	ADJUSTED TOTAL - TYPE I & II
OPERATING REVENUES					
Retail Sales Revenues	53,271,854	0	53,271,854	(3,289,846)	49,982,008
Sales for Resale	0	0	0	0	0
Opportunity Sales	1,176,057	0	1,176,057	661,656	1,837,713
Other Operating Revenues	4,613,177	(2,273,242)	2,339,934	(16,439)	2,323,495
Total Operating Revenue	59,061,088	(2,273,242)	56,787,845	(2,644,629)	54,143,216
OPERATING EXPENSES					
Operation & Maintenance Expense	42,151,872	(2,254,951)	39,896,921	(5,192,073)	34,704,848
Depreciation Expense	5,936,079	0	5,936,079	9,295	5,945,374
Amortization Expense	285,073	2,128	287,200	(16,694)	270,506
Accretion Expense	10,127	0	10,127	0	10,127
Taxes Other Than Income Taxes	2,317,483	0	2,317,483	(37,730)	2,279,753
Regulatory Debits/Credits	167,068	0	167,068	0	167,068
Provision for Deferred Income Taxes	1,299,323	154,007	1,453,330	(431,895)	1,021,435
Investment Tax Credit Adjustment	13,172	0	13,172	(99)	13,072
Federal Income Tax	(989,650)	(263,445)	(1,253,095)	1,337,073	83,978
State Income Taxes	12,686	(224,022)	(211,335)	137,820	(73,516)
Total Operating Expenses	51,203,233	(2,586,284)	48,616,949	(4,194,303)	44,422,646
OPERATING NET INCOME	7,857,855	313,042	8,170,896	1,549,674	9,720,570
Add: IERCO Operating Income	372,976	0	372,976	(2,850)	370,126
CONSOLIDATED OPERATING INCOME	8,230,830	313,042	8,543,872	1,546,824	10,090,696
RATE OF RETURN EARNED	5.917%		6.207%		7.494%
IMPLIED RETURN ON EQUITY	6.550%		7.103%		9.549%

COST OF CAPITAL - DEC 31, 2016	ACTUAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
Long Term Debt	47.409%	5.214%	2.472%
Preferred Stock	0.000%	0.000%	0.000%
Common Equity	52.591%	9.900%	5.207%
Total	100.000%		7.678%

IDAHO POWER COMPANY
STATEMENT OF OPERATIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

OPUC JURISDICTION

DESCRIPTION	ACTUAL ALLOCATION	TYPE I ADJUSTMENTS	ADJUSTED TOTAL - TYPE I	TYPE II ADJUSTMENTS	ADJUSTED TOTAL - TYPE I & II
OPERATING REVENUES					
Retail Sales Revenues	53,271,854	0	53,271,854	(3,289,846)	49,982,008
Sales for Resale	0	0	0	0	0
Opportunity Sales	1,176,057	0	1,176,057	661,656	1,837,713
Other Operating Revenues	4,613,177	(2,273,242)	2,339,934	(16,439)	2,323,495
Total Operating Revenue	59,061,088	(2,273,242)	56,787,845	(2,644,629)	54,143,216
OPERATING EXPENSES					
Operation & Maintenance Expense	42,151,872	(2,254,951)	39,896,921	(5,192,073)	34,704,848
Depreciation Expense	6,530,979	0	6,530,979	9,283	6,540,262
Amortization Expense	285,073	2,128	287,200	(16,694)	270,506
Accretion Expense	10,127	0	10,127	0	10,127
Taxes Other Than Income Taxes	2,317,483	0	2,317,483	(37,730)	2,279,753
Regulatory Debits/Credits	167,068	0	167,068	0	167,068
Provision for Deferred Income Taxes	1,296,913	156,251	1,453,164	(425,415)	1,027,749
Investment Tax Credit Adjustment	13,172	0	13,172	(99)	13,072
Federal Income Tax	(1,177,900)	(270,500)	(1,448,400)	1,344,599	(103,801)
State Income Taxes	(14,889)	(188,849)	(203,738)	88,931	(114,808)
Total Operating Expenses	51,579,898	(2,555,923)	49,023,976	(4,229,198)	44,794,778
OPERATING NET INCOME	7,481,190	282,680	7,763,870	1,584,568	9,348,438
Add: IERCO Operating Income	372,976	0	372,976	(2,850)	370,126
CONSOLIDATED OPERATING INCOME	7,854,165	282,680	8,136,845	1,581,719	9,718,564
RATE OF RETURN EARNED	5.646%		5.912%		7.217%
IMPLIED RETURN ON EQUITY	6.035%		6.541%		9.023%

COST OF CAPITAL - DEC 31, 2016	ACTUAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
Long Term Debt	47.409%	5.214%	2.472%
Preferred Stock	0.000%	0.000%	0.000%
Common Equity	52.591%	9.900%	5.207%
Total	100.000%		7.678%

GARDNER Marianne

From:	White, Tami <TWhite@idahopower.com>
Sent:	Monday, May 15, 2017 10:37 AM
To:	MULDOON Matt; GARDNER Marianne
Subject:	FW: Additional UM 1801 Questions
Attachments:	REVISED Email DR 4_Earnings Test less SCRs_Plus New Depr Exp_Updated LT ....xlsx

Hi Matt,
I got your message. I had sent this to Marc earlier today. I believe this is the run you guys need, but please take a look and let me know if there is anything else you need from us in order to complete your testimony.
Thanks,
Tami

From: White, Tami
Sent: Monday, May 15, 2017 10:25 AM
To: 'HELLMAN Marc'
Cc: Waites, Courtney; Tatum, Tim
Subject: RE: Additional UM 1801 Questions

Hi Marc,
Attached please find an updated response to your follow up data request number 4 using Staff's updated cost of debt number of 4.981%.

In this run you had asked for the Type 1 and Type 2 results, including ROE, for 2016 assuming actual average capital structure, updated cost of debt excluding the revenue requirement effects of new Bridger SCRs and including the increase in 2016 depreciation expense above 12/31/2011 plant balance, excluding depreciation expense associated with the new Bridger SCRs. In this run we are using Staff's updated cost of debt number of 4.981%.

The proposed depreciation rates, when applied to 12/31/2016 plant, excluding depreciation expense associated with the new Bridger SCRs, would result in depreciation expense of approximately $132.0 million on a total system basis, or approximately $16.5 million more than what's currently included in customer rates. The Oregon jurisdictional share of the increase in depreciation expense is approximately $595k.

I would like to note that the Company believes the correct cost of long-term debt number to use is 5.214%. The debt issuance you are referring to was redeemed in April of 2016 and was not included in Idaho Power's 2016 cost of long-term debt calculation.

I am looking at our Response to Staff's DR 23 that had a note about the debt issuance that was redeemed in April of 2016 and Staff's calculated 4.981% end of test period cost of LT debt. The difference between our 5.214% and Staff's 4.981% is not due to the removal of the debt issuance that was redeemed in April of 2016 but rather is due to a difference in the calculation that Staff used.

IDAHO POWER COMPANY
STATEMENT OF OPERATIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

OPUC JURISDICTION

DESCRIPTION	ACTUAL ALLOCATION	TYPE I ADJUSTMENTS	ADJUSTED TOTAL - TYPE I	TYPE II ADJUSTMENTS	ADJUSTED TOTAL - TYPE I & II
OPERATING REVENUES					
Retail Sales Revenues	53,271,854	0	53,271,854	(3,289,846)	49,982,008
Sales for Resale	0	0	0	0	0
Opportunity Sales	1,176,057	0	1,176,057	661,656	1,837,713
Other Operating Revenues	4,613,177	(2,273,242)	2,339,934	(16,439)	2,323,495
Total Operating Revenue	59,061,088	(2,273,242)	56,787,845	(2,644,629)	54,143,216
OPERATING EXPENSES					
Operation & Maintenance Expense	42,151,872	(2,254,951)	39,896,921	(5,192,073)	34,704,848
Depreciation Expense	6,530,979	0	6,530,979	9,283	6,540,262
Amortization Expense	285,073	2,128	287,200	(16,694)	270,506
Accretion Expense	10,127	0	10,127	0	10,127
Taxes Other Than Income Taxes	2,317,483	0	2,317,483	(37,730)	2,279,753
Regulatory Debits/Credits	167,068	0	167,068	0	167,068
Provision for Deferred Income Taxes	1,296,913	156,251	1,453,164	(425,415)	1,027,749
Investment Tax Credit Adjustment	13,172	0	13,172	(99)	13,072
Federal Income Tax	(1,177,900)	(270,500)	(1,448,400)	1,344,599	(103,801)
State Income Taxes	(14,889)	(188,849)	(203,738)	88,931	(114,808)
Total Operating Expenses	51,579,898	(2,555,923)	49,023,976	(4,229,198)	44,794,778
OPERATING NET INCOME	7,481,190	282,680	7,763,870	1,584,568	9,348,438
Add: IERCO Operating Income	372,976	0	372,976	(2,850)	370,126
CONSOLIDATED OPERATING INCOME	7,854,165	282,680	8,136,845	1,581,719	9,718,564
RATE OF RETURN EARNED	5.646%		5.912%		7.217%
IMPLIED RETURN ON EQUITY	6.245%		6.751%		9.233%

COST OF CAPITAL - DEC 31, 2016	ACTUAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
Long Term Debt	47.409%	4.981%	2.361%
Preferred Stock	0.000%	0.000%	0.000%
Common Equity	52.591%	9.900%	5.207%
Total	100.000%		7.568%

CASE: UM 1801
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 300
Abbreviated Cost of Capital Update

Testimony in Support of Stipulation

May 15, 2017

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

A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, OR 97301.

Q. Please describe your educational background and work experience.

A. My educational and work experience are set forth in Staff Exhibit 301.

Q. What is the purpose of your testimony?

A. The general purpose of my testimony is to provide support for the settlement reached in this proceeding. More specifically, my testimony discusses three issues related to Staff's review of Idaho Power's earnings in docket UM 1801. The overall methodology for Staff's earnings review is described in Staff Witness Marianne Gardner's testimony (Staff/200). Specifically, my testimony addresses the following inputs for Staff's review of Idaho Power's earnings:

<u>Cost of Capital (CoC):</u>

1. Capital Structure;
2. Cost of Common Equity (CE), also known as Return on Equity (ROE); and
3. Cost of Long-Term (LT) Debt.

Q. Please describe how your issues fit within Staff's earnings review for the revenue requirement effect of the change in book depreciation rates settled in this case.

A. My recommendations herein in support of Staff's narrowly-focused settlement position in this case. CoC components and overall Rate of Return (ROR) were last set by Commission Order No. 12-055 in Idaho Power's most recent general rate case, Docket No. UE 233.

For purposes of settlement in this case, I examined Idaho Power's Capital Structure and Cost of Long Term (LT) Debt. I analyzed the Company's financial conditions in 2016, developed a lower bound for a reasonable ROE informed by the Idaho Commission's processes, and updated both cost of long-term debt and Company's capital structure to actual 2016 values.

Q. What were your summary findings for discrete components of CoC for the limited purposes of Staff's earnings review in this case?

A. I conclude that a Capital Structure of 52.1 percent Equity and 47.9 percent LT Debt represents the Company's actual 2016 experience with a lower ROE bound of 9.5 percent, and an actual 2016 Cost of LT Debt of 4.981 percent.

Q. What Rate of Return (ROR) do the above values represent?

A. They generate an overall required ROR of 7.335 percent.

Q. Did you prepare tables showing current Commission authorized Cost of Capital values and Staff's inputs in this case?

A. Yes, the following two tables provide that information.

Table 1

IPC Current OPUC Authorized (UE 233 Order No. 12-055)			Last
Component	Percent of Total	Stipulated or Implied Cost	Weighted Average
Long Term Debt	50.10%	5.623%	2.817%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	49.90%	9.90%	4.940%
	100.00%		7.757%

Table 2

Staff Proposed – UM 1801		Joint Testimony in Support		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	47.9%	4.981%	2.386%	-0.422%
Preferred Stock	0.00%		0.000%	
Common Stock	52.1%	9.5%	4.950%	
	100.00%		7.335%	

Q. Have you issued data requests (DRs) relevant to Cost of Capital issues in this case?

A. Yes, however please note that the most directly dispositive CoC DR response related to my issues is that of DR 23. The Company's response to DR 23 updates Staff's Cost of LT Debt table as of the last calendar day of 2016, and is included as Staff Exhibit 302 within Staff's framework. Again, this financial snapshot is supportive of the stipulated agreement and provides a check on reasonable Staff's settlement position.

ISSUE 1 – CAPITAL STRUCTURE

Q. What is the basis for your use of a capital structure of 52.1 percent equity and 47.9 percent LT Debt?

A. I have three primary reasons for my recommended Capital Structure:

1. The average annual Capital Structure for 2016 matches the timing for other CoC inputs;
2. Use of actual values is preferable when data inputs are certain; and
3. This approach somewhat smooths the effect of CE issuances which, due to cost and complexity, are less frequent than issuances of LT Debt.[1]

Q. What is the source data for the capital structure of 52.1 percent equity and 47.9 percent LT Debt?

A. The Company provided the average capital structure for 2016 within settlement for the limited purpose of facilitating Staff's calculations herein. As 2016 is Staff's representative "test-year" for the earnings review, Staff recommends using the actual average 2016 capital structure in place of the basis the Company provided in its testimony.

Q. What did the Company propose in its testimony?

A. The Company proposed an end of year 2016 snap-shot. I do not recommend an end of year value as capital structure changes within the year, if for no other reason than timing of cash flows.

<u>ISSUE 2 – COST OF COMMON EQUITY (ROE)</u>

Q. Why is an ROE of 9.5 percent reasonable for purposes of an earnings threshold above which Staff recommends the Company absorb the changes in depreciation expense?

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1 See Idaho Power Annual Report Form 10-K for the fiscal year ended December 31, 2016 at https://www.sec.gov/Archives/edgar/data/49648/000105787717000035/ida12311610k.htm

A. According to *MarketWatch*, rates in Idaho are intended to allow Idaho Power an opportunity to recover its expenses and earn a reasonable return on investments. *MarketWatch,* on February 18, 2016, discussed a stipulation in Idaho Power's Form 10-K annual report filed with the US Securities and Exchange Commission (SEC) that included provisions **remaining in effect in 2016** to help Idaho Power achieve a minimum 9.5 percent end of year ROE in the Idaho jurisdiction.[2]

I view, in the context of this settlement, that a 9.5 percent ROE is reasonable for the review performed herein. Even if this review may not capture all forward looking information, it is informed by Idaho proceedings and general market trends since the Commission's (now rather distant) last Cost of Capital decisions regarding Idaho Power in UE 233.

I also note that this Commission has adopted cost of equity values in recent general rate cases of roughly between 9.4 and 9.6 percent, with the lower values representing natural gas companies. My analysis has shown that natural gas companies tend to be lower risk than electric utilities providing service in Oregon. Therefore, having a lower range of ROE equal to 9.5 percent for purposes of this earnings review, in the context of this case, is reasonable.

Q. Are you recommending the Commission reset Idaho Power's ROE to 9.5 percent for general rate purposes?

---

2 See this report and the Edgar Online Comtex source material links at: http://www.marketwatch.com/story/10-k-idaho-power-co-2016-02-18

A. No. As noted by Staff witness Marianne Gardner, a long-standing Commission practice is that changes in depreciation rates should not be reflected in rates outside of a general rate review. There have been exceptions for those occasions where the depreciation docket concluded somewhat close to a Commission general rate decision. Given that the Company's most recent general rate case order was almost five years ago, Staff believes it reasonable to review Idaho Power's earnings in order to determine whether the change in depreciation rates should be absorbed by the Company. Staff's use of a 9.5 ROE lower bound is for purposes of its review of Idaho Power's earnings in this case ONLY.

Staff believes this approach is appropriate because the Company is not asking to reflect in rates changes costs that they may be experiencing other than depreciation costs, or to even recover ANY changes in depreciation costs for plant added after the year 2011. This testimony is therefore narrowly considering only whether it is reasonable to allow the Company to include in rates increases in depreciation costs for plant balances remaining for plant that was in service as of the end of 2011.

INFORMED STAFF ANALYSIS

Q. Do you monitor and analyze current and projected market conditions?

A. Yes. My analysis includes analysis of the current economic climate and its impact on my estimates of long-term growth. I also rely heavily on feeds from SNL Financial LC (SNL), Bloomberg, Moody's, S&P, WSJ and other sources to make sure that my financial understandings are reflective of investor expectations.

Q. Did you develop your inputs while informed by authorized ROEs in other parts of the country?

A. Yes. I examined 2016 authorized ROEs across the nation in comparison with 2015 ROE decisions published by SNL Financial LC. Staff's recommended ROE here is within 10 basis points of national average electric utility rate case ROEs decided in 2016 according to Regulatory Research Associates (RRA).

ISSUE 3 – COST OF LT DEBT

Q. Have you compiled a summary table illustrating your calculation of Idaho Power's Cost of LT Debt?

A. Yes. See the table in Exhibit 302 supporting my recommendation for a 4.981 percent Cost of LT Debt. Because LT Debt inputs shown are known and measurable point-in-time historical values, Staff believes that this update is appropriate. Again. Staff is not recommending these values replace the Commission authorized CoC and ROR values outside of this docket. Rather they act as a check of to ensure Staff's considerations are reasonably reflective of the Company's actual operating conditions now.

Q. Why is it appropriate to update the cost of debt?

A. The changes in Cost of LT Debt capture historical changes in the outstanding long-term debt since the last general rate order. LT debt expense is a known and measurable change from the Company's last general rate case and so seems appropriate to include in the Staff earnings review.

Q. Why is this table confidential?

A. This Table is confidential because it captures and organizes more issuance detail than is publicly available.

Q. Is this table accurate as December 31, 2016?

A. Yes, it captures Bloomberg, SNL, SEC filing and presentations information.

Q. Did Staff ask the Company to check this work and provide additional issuance detail allowing for very high certainty of accuracy?

A. Yes, the Company reviewed and updated Staff's Cost of LT Debt Table in response to Staff DR 23. The Commission can have high confidence in Staff's recommendation for updated Cost of LT Debt.

CONCLUSION

Q. Please recap Staff's position regarding Cost of Capital for purposes of its earnings review.

A. For purposes of an earnings review in this case, which Staff relied upon in order to reach settlement in this proceeding, I utilized a Capital Structure of 52.1 percent equity and 47.2 percent LT Debt, an ROE of 9.5 percent, and a Cost of LT Debt of 4.981 percent. Each component of CoC is well supported.

Q. What ROR is generated by the above inputs to CoC?

A. Staff's inputs generate a 7.335 percent ROR.

Q. Does that conclude your testimony?

A. Yes.

CASE: UM 1801
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

May 15, 2017

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Energy – Rates Finance and Audit Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION:	In 1981, I received a Bachelor of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on Cost of Capital. I have worked on Cost of Capital in the following general rate case dockets: AVA UG 186, UG 201, UG 246, UG 284, UG 288, and UG 325 current; NWN UG 221; PAC UE 246, and UE 263; PGE UE 262, UE 283, UE 294, and UE 319 current CNG UG 287 and UG 305. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc., where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There, I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

CASE: UM 1801
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Cost of Long-Term Debt

Exhibits in Support
of Testimony

May 15, 2017

Staff Exhibit 302 is confidential and

Is subject to Protective Order Nos.16-441 and 16-445