CASE: UE 233
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Brian Bahr. I am a Financial Analyst for the Corporate Analysis and Water Regulation Section of the Oregon Public Utility Commission. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am responsible for reviewing Idaho Power Company's (Idaho Power or Company) Customer Accounts Expense (FERC accounts 901-905) and Customer Services and Information Expense (FERC accounts 907-910) found in Exhibit IPC/905, Noe/14.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/302, consisting of three pages, and Exhibit Staff/303, consisting of four pages. Exhibit Staff/302 contains my adjustments that are supported by my testimony, and Exhibit Staff/303 contains the Company's responses to Staff Data Requests referenced in my testimony.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. I updated the Customer Accounts Expense (FERC accounts 901-905) and Customer Services and Information Expense (FERC accounts 907-910) using annualized actual expenditures for the first half of 2011.

The updated 2011 non-labor customer accounts and customer service and information expenditures were derived using the Company's reported actual expenditures in FERC accounts 901 through 905 and 907 through 910 from January through June of the 2011 test period and imputing a 46 percent to 54 percent split of the first and second halves expenditures, respectively. The back-weighted proportional split, based on monthly data provided in the Company's response to Staff Data Request 309a[1], was used to adjust for any "expense chunkiness" that may occur in the second half of the 2011 test year.

The second adjustment I made was to remove from FERC account 910 the expense of a residential customer satisfaction survey. The survey should not be included in rates as it is redundant to another service performed for the Company. Additionally, the survey appears to promote corporate image rather than improve customer service and should therefore be classified as institutional advertising and not included in retail rates.

These two adjustments are based on Idaho Power's initial filing and the Company's responses to 27 Staff Data Requests. The following table summarizes my adjustments to the Company's Customer Accounts Expense (FERC accounts 901-905) and Customer Services and Information Expense (FERC accounts 907-910).[2]

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[1] The Company's response to Staff Data Request No. 309a is included in Confidential Exhibit Staff/403, Cimmiyotti/1-2.

[2] Details of the adjustment amounts are shown in Confidential Exhibit Staff/302.

STAFF NON-LABOR ADJUSTMENT – OREGON ALLOCATED

Idaho Power (901-905)	$844,974	Exhibit IPC/905, Noe/14
Idaho Power (907-910)	$289,088	Exhibit IPC/905, Noe/14
Total Idaho Power (901-910)	$1,134,062	
Staff Proposal (901-910)	$1,104,404	Exhibit Staff/302, Bahr/1
Total Oregon Adjustment	**$29,658**	
Revenue Requirement Effect	$30,000	Exhibit Staff/100

Q. PLEASE DESCRIBE YOUR FIRST ADJUSTMENT.

A. In its July 19, 2011, general rate case filing, Idaho Power forecasted that it will incur during the test year, on a system basis, non-labor expenses of $20,985,183 for activities related to customer accounts and $7,886,256 for activities related to customer service, including dissemination of information.[3] Idaho Power asserts that the portions of these amounts allocated to Oregon are $844,974 for customer accounts and $289,088 for customer service and information.[4] The Company's 2011 forecast for these amounts included in its initial filing are based on actual expenditures for 2010 adjusted for the 2011 test year.[5]

On September 29, 2011, Idaho Power provided updated forecasts of these expenditures in response to a Staff Data Request.[6] The response included actual expenditures for January 1 – June 30, 2011, and an updated forecast of expenditures for July 1 – December 31, 2011. Idaho Power's revised forecast

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[3] *See* Idaho Power/905, Noe/14.
[4] *Ibid.*
[5] *See* Idaho Power/900, Noe/2-3.
[6] *See* Confidential Staff Exhibit/302, Bahr/2 and Confidential Staff Exhibit/403, Cimmiyotti/5-6.

for 2011 varied significantly from the Company's forecast in its original filing (some revised forecasts for individual accounts were greater than the original forecast, but overall, the sum of the revised forecasts for FERC accounts 901-903, 905, and 907-910 was less than the original forecast). Also, the average monthly expenses in the second half of 2011 forecast were significantly higher than the average monthly actual expenses reported for the first half of 2011.

Because a forecast based on the Company's actual expenditures for Idaho Power's Customer Accounts Expense (FERC account 901-905) and Customer Services and Information Expense (FERC account 907-910) for the first half of the 2011 test year appears to be more reliable than a forecast based on 2010 data, I adjusted Idaho Power's non-labor expenses for these accounts so that the 2011 test year forecast more accurately reflects likely 2011 actual expenditures.

Q. PLEASE EXPLAIN HOW YOU ADJUSTED IDAHO POWER'S EXPENSE.

A. As noted above, both labor and non-labor costs and expenses related to customer accounts are recorded in FERC accounts 901-905, and labor and non-labor costs and expenses related to customer service and information are recorded in FERC accounts 907-910. My adjustment does not address labor costs because they are addressed by another Staff witness.

Accordingly, as the first step in my adjustment, I separated Idaho Power's forecasted non-labor costs from the forecasted expense for the aforementioned FERC accounts (using information provided by Idaho Power in its original filing). To do this, I determined the percentage of non-labor expense compared to total expense for each of the aforementioned accounts for 2010 (except accounts 904 and 908). I found this percentage by dividing the 2010 system non-labor expense by the 2010 total system expenses. The 2010 system non-labor expense information was provided by the Company in response to Staff Data Request No. 57.[7] I then multiplied the calculated non-labor percent for each account by the 2011 total system expense for each account, the product of which approximates the 2011 system non-labor expenses.[8]

As I note above, the Company used the 2010 actual amounts to calculate the 2011 test year amounts.[9] Therefore, the proportion of non-labor to labor expense in the 2011 test year should not differ significantly from the 2010 non-labor to labor expense proportion.

For account 908, I calculated the 2011 system non-labor expense using specific 2011 Oregon-allocated total expense and Oregon-allocated non-labor expense data provided by the Company in response to Staff Data Request No. 284.[10] I did not include FERC account 904 in my analysis because the analysis of uncollectible accounts was assigned to other Staff.

Once I had separated the non-labor expense portion of the total system expense amounts in each FERC account in Idaho Power's original 2011 test year forecast, I created a new forecast for 2011 based on actual non-labor expense for the first half of 2011. As already noted, the Company provided

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[7] The Company's response to Staff Data Request No. 57 is included in Exhibit Staff/403, Cimmiyotti/3-4.

[8] The 2011 total system expenses for each account are provided in Idaho Power/905, Noe/14.

[9] *See* Idaho Power/601, Jones/6.

[10] The Company's response to Staff Data Request No. 284 is included in Exhibit Staff/303, Bahr/1.

actual 2011 non-labor expenses for the first half of the year and a revised forecast of non-labor expenses for the second half of the year.[11] Because the average monthly expenses of the second half 2011 forecast varied significantly from the average monthly expenses for the first half of 2011, I determined a proportion of total 2011 expenses for the second half (July -December) 2011 test period using 2010 monthly costs as a basis for the proportional split.

I developed the proportion by using month-to-month data provided by Idaho Power in its Response to Staff Data Request No. 309a.[12] In response to the data request, Idaho Power spent 45.51 percent of total 2010 costs in the first six months of 2010 and 54.49 percent in the second six months of 2010 in Account 565. Although these percentages were for one account, Account 565, I used the rounded percentages (46 / 54) as a proxy to determine the proportion of expenses for the accounts I reviewed. I performed the adjustment by dividing the January – June actual expenses by 46 percent (which is 0.46) to determine the annual expenditure amount. The use of these proportions resulted in a greater level of expense in the second half of the year as compared to the first half.

I believe this method addresses any potential “chunkiness” of costs, as actual 2010 data is used to determine the split. I then compared this annualized 2011 non-labor expense amount to the calculated 2011 system non-labor expense

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[11] The Company’s response to Staff Data Request No. 318a is included in Confidential Exhibit Staff/403, Cimmiyotti/5-6.

[12] The Company’s response to Staff Data Request No. 309a is included in Exhibit Staff/403, Cimmiyotti/1-2.

amount described above. The difference between the two amounts is my system adjustment. Details of all calculations are found in Exhibit Staff/302.

I then multiplied the system adjustment for each account by the Oregon non-labor allocation percentage for each account provided by the Company in response to Staff Data Request No. 318d,[13] the product of which is my proposed adjustment to the Company's 2011 Oregon-allocated Customer Accounts and Customer Services and Information Accounts. Details of Staff's analysis are shown in Exhibit Staff/302.

Q. IS THE 2010 NON-LABOR PERCENTAGE OF TOTAL EXPENSES FOR THESE ACCOUNTS AN ACCURATE ESTIMATE OF THE 2011 PERCENTAGE OF NON-LABOR?

A. Yes. For these accounts, the 2010 non-labor percentage was used because it is the most accurate information I had at the time of my analysis. However, several Staff Data Requests are pending requesting non-labor amounts included in the 2011 test year, actual 2011 non-labor expenses through October 31, 2011, and the percentage of expenses spent prior to and following October 31 for the past three years. In future rounds of testimony, I expect my adjustment to be updated using more accurate information provided by the Company.

Q. PLEASE DESCRIBE YOUR SECOND ADJUSTMENT.

A. Idaho Power currently subscribes to two customer satisfaction surveys, one performed by Burke, Inc., and one performed by J.D. Power and Associates.

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[13] The Company's response to Staff Data Request No. 318d is included in Confidential Exhibit Staff/403, Cimmiyotti/7-8.

According to the Company, *“The Burke surveys represent Idaho Power’s primary customer satisfaction research.*”[14] The Company also states in its application, *“the J.D. Power Study is used primarily as a benchmark to other electric utilities.”*[15] My adjustment removes from rates the cost of the J.D. Power and Associates study, which I believe is redundant with the Burke study and should be classified as a promotional/advertising expense rather than customer service and information. Both studies are described in Idaho Power’s initial filing, Idaho Power/300, Kline/15-18.

In its response to Staff Data Request No. 314[16], Idaho Power included the most recent customer satisfaction study results reports provided to it by both Burke and J.D. Power. The Burke Analytical Report, 78 pages long, comprehensively details the results of quarterly telephone interview surveys conducted with customers of the Company. The study identifies problem incidence, customer perceptions, relative performance, opportunities for improvement, and suggestions. I reviewed this study and am satisfied that the information provided therein should be informative to the Company in improving customer service and is appropriately included in rates in FERC account 910 (Miscellaneous customer service and informational expenses).

Whereas the Burke survey includes all customer classes, “the J.D. Power and Associates study is for residential customers only, as the number of Idaho Power commercial customers is not large enough at this point in time to qualify

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[14] Idaho Power/300, Kline/15

[15] *Ibid*

[16] The J.D. Power and Associates results report provided by the Company as part of Staff Data Request No. 314 is included in Confidential Exhibit Staff/303, Bahr/3-4.

for a subscription to the J.D. Power study."[17] The annual results report provided to the Company by J.D. Power and Associates, two pages long, focuses primarily on the Company's ranking against similar companies in the industry segment and also tracks the Company's ranking over time.

In its response to Staff Data Request No. 315, the Company states, *"The Company uses best practices identified in the Study as learning opportunities to facilitate maintaining and improving Idaho Power's customer satisfaction."*[18] However, based on my review of the report provided by J.D. Power, I believe it is apparent that specific feedback is not provided in the report that would support the Company's statement. Additionally, given the comprehensive detail of the Burke study, any information provided in the J.D. Power and Associates study that might help the Company identify and improve areas of customer service would already be provided in the Burke study and redundant. The cost of this unnecessary study should not be included in rates.

The Company did rank exceptionally well according to the J.D. Power study, and according to both studies has performed consistently well in the area of customer service. However, based on the results report of the J.D. Power survey, which focuses on ranking rather than specific data that the Company can use to improve customer service, and according to the definition of Advertising Expense in Oregon Administrative Rules, the cost of the J.D. Power study should not be included in rates.

The definition of an Institutional Advertising Expense according to

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[17] Idaho Power/300, Kline/16

[18] The Company's response to Staff Data Request No. 315 is included in Exhibit Staff/303, Bahr/2.

OAR 860-026-0022(1)(c) is, “advertising expenses, the primary purpose of which is not to convey information, but to enhance the credibility, reputation, character, or image of an entity or institution.” Institutional advertising expenses are categorized as Category “C” under OAR 860-026-0022(2)(c). Category “C” expenses are disallowed in rates unless the Company shows that they are just and reasonable, according to OAR 860-026-0022(3)(c), which states:

> The energy or large telecommunications utility shall carry the burden of showing that any advertising expenses in Category “C” are just and reasonable for rate-making purposes. In any filing under ORS 757.210 and ORS 759.180, the utility shall separately state the amount of advertising expenses in Category “C”.

I suggest that the J.D. Power and Associates study is incorrectly categorized by the Company in its application as a customer services and informational expense. The Company should categorize this cost as a Category “C” Institutional Advertising Expense under Oregon Administrative Rules. Further, I contend that Idaho Power, which is responsible for the burden of proof, has not sufficiently established in its application and subsequent responses to Staff Data Requests that the J.D. Power and Associates expense is just and reasonable for rate-making purposes and should be passed on to customers. Details of my analysis are shown in Exhibit Staff/302.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME: BRIAN BAHR

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: UTILITY ANALYST, CORPORATE ANALYSIS AND WATER REGULATION

ADDRESS: 550 CAPITOL ST. NE, SALEM, OR 97308-2148

EDUCATION: Bachelor of Science, Accountancy, Brigham Young University, Provo UT

EXPERIENCE: Employed with the Oregon Public Utility Commission from March 2011 to present, currently serving as Financial Analyst, Corporate Analysis and Water Regulation.

Employed by Modern Seouf Plastics in Alexandria, Egypt as a Managerial Intern from January 2010 to June 2010. Assisted in variety of duties including supervision of production facilities and staff, market analysis, budget forecasting, sales, and office administration.

Employed by PricewaterhouseCoopers LLP in New York City as a Financial Assurance Associate from October 2007 to November 2009. Performed audits of various financial institutions, including investment banks, hedge funds, and insurance companies.

Employed by TESRA, SA in Antofagasta, Chile as a Project Management Assistant from September 2005 to April 2006. Assisted in design process and implementation of rail road crossing and other civil engineering projects.

CASE: UE 233
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

December 7, 2011

STAFF EXHIBIT 302

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 11-288. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 233 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 233
WITNESS: Brian Bahr

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

December 7, 2011

STAFF'S DATA REQUEST NO. 284:

Per the response to Staff Data Request No. 141, please provide a reconciliation between the Oregon Retail amount shown on Idaho Power/905 Noe/14 line 565 and the 2010 Oregon Allocated amounts found in the response to Staff Data Request No. 141.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 284:

In the Company's response to Staff's Data Request No. 141, the Company provided the Oregon allocation for non-labor operations and maintenance ("O&M") expenses in Account 908 excluding demand-side management expenditures for 2009 and 2010. The resulting Oregon allocation for Account 908 was $153,902.25 and $29,197.79 for 2010 and 2009, respectively. The methodology used to remove labor expense in the Company's response to Staff's Data Request No. 141 was to exclude the following: straight-time labor, overtime labor, and indirect payroll loadings (labor entry expenses).

The Oregon allocation for Account 908 in Exhibit 905 (line 565) is $240,577. This amount includes both labor and non-labor. The non-labor portion is $79,961. The methodology used in the rate case to allocate specific test year adjustments over total non-labor O&M expenses was to start with 2010 actuals as the base and remove all labor-related components, which include the labor entry expenses listed above plus employee benefit expense and employment taxes. By removing all labor related components, any test year adjustment that was allocated over 2010 non-labor O&M was isolated to only non-labor related expenses and not any of the employee benefit or employment tax expense.

The variance of the two methodologies resulted in a $431,651.38 difference and represents the removal of 2010 labor. Please see the attached Excel spreadsheet detailing the amounts included in the Company's response to Staff's Data Request No. 141 and the reconciliation of the Oregon allocation of the 2011 Test Year to the 2010 non-labor base for Account 908.

STAFF'S DATA REQUEST NO. 315:

As a follow-up to Company testimony 300 Kline 15 and Staff Data Request No. 137, please explain how the results of the JD Power residential customer satisfaction study are used by the Company. On line 25 of the testimony mentioned it states, "The J.D. Power Study is used primarily as a benchmark to other utilities." Please expound specifically on this statement.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 315:

Idaho Power uses the results of the annual J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study ("Study") to compare its level of customer satisfaction on various attributes to the customer satisfaction levels of other like utilities in the United States. Attributes included in the Study include power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service. The Company uses best practices identified in the Study as learning opportunities to facilitate maintaining and improving Idaho Power's customer satisfaction.

Staff/303
Bahr/3-4

Pages 3 and 4 are confidential.

You must have signed the Protective Order in this docket in order to view these pages.

CASE: UE 233
WITNESS: Nick Cimmiyotti

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Nicholas (Nick) Cimmiyotti. I am employed by the Public Utility Commission of Oregon as Senior Financial Analyst, Corporate Analysis and Water Regulation Section, in the Economic Research and Financial Analysis Division of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I recommend the following adjustment to Idaho Power Company's (Idaho Power or Company) non-labor Transmission Operation and Maintenance (O&M) expense (FERC accounts 560-573) and the Company's Distribution O&M expense (FERC accounts 580-598) found in Exhibit IPC/905, Noe/13-14:

Transmission and Distribution O&M Expense	($249,741)

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/402 (one page of supporting calculations), and Exhibit Staff/403 (eight pages of Idaho Power data request responses / attachments and documentation in support of footnotes).

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENT.

A. I adjusted Idaho Power's Transmission O&M expense (FERC accounts 560-573) and its Distribution O&M expense (FERC accounts 580-598) using actual expenditures for the first half of 2011.[1] I based my recommendation for Idaho Power's 2011 non-labor operations and maintenance expenditures using the Company's reported actual expenditures in FERC accounts 560 through 598 from January through June of the 2011 test period, and imputing a 46 percent to 54 percent split for the first six months and second six months of 2011 expenditures, respectively. I used the back-weighted proportional split, based on monthly data provided in the Company's response to Staff data request 309a, in order to adjust for any "expense chunkiness" that may occur in the second half of the 2011 test period.[2]

The following table is a summary of my adjustment.

Table 1 – Non-labor O&M Adjustment – Oregon Allocated

Idaho Power (560-573)	$18.369,994	Exhibit IPC/905, Noe/13
Idaho Power (580-598)	$20,728,192	Exhibit IPC/905, Noe/14
Total Idaho Power (560-598)	$39,098,186	
Staff Proposal (560-598)	$33,055,671	Exhibit Staff/402, Cimmiyotti/1
Total System Adjustment	($6,042,515)	
Oregon Allocation Percent	4.13%	
Oregon Adjustment	($249,741)	

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[1] These adjustments are shown in Staff/402, Cimmiyotti/1.
[2] Included in Staff/403, Cimmiyotti/1-2.

Q. HOW DID IDAHO POWER COMPANY DETERMINE ITS TEST YEAR ESTIMATE FOR TRANSMISSION AND DISTRIBUTION O & M EXPENSE?

A. Idaho Power's test year in this case is the twelve months ending December 31, 2011. To derive its test year expense, Idaho Power started with expenditures in a "historical base year," 2010, and adjusted them to reflect the forecast 2011 test year.[3]

In its July 19, 2011, filing, Idaho Power forecasted that it will incur labor costs and expenses, on a system basis of $29,580,295 for activities related to Transmission O&M and $48,283,376 for activities related to Distribution O&M expense. Idaho Power asserts that the portion of these amounts appropriately allocated to Oregon is $1,307,314 for Transmission O&M and $2,551,393 for Distribution O&M.

Q. HOW DOES IDAHO POWER'S 2011 TEST YEAR EXPENSE COMPARE TO ITS 2010 ACTUAL EXPENSE?

A. In response to standard data request No. 57, the Company provided information that they had spent $33,766,720 in the 2010, base-year on non-electric transmission and distribution expenditures that were recorded in FERC accounts 560 through 598.[4] Comparing the Company's base-year expenditures in FERC accounts 560 through 598, the Company's initially filed expenditure request of $39,098,188, in the above FERC accounts, is 15.8 percent higher than the 2010 base period.

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[3] Idaho Power/100, Said/3.

[4] Included in Staff/403, Cimmiyotti/3-4.

Q. HOW DOES YOUR RECOMMENDED EXPENSE LEVEL COMPARE TO THAT PROPOSED BY IDAHO POWER?

A. My estimate is 15.5 percent lower than the Company's initial estimate for the 2011 test period, but is only 2.1 percent lower than the Company spent in 2010.

Q. PLEASE DESCRIBE YOUR ADJUSTMENT.

A. On September 29, 2011, Idaho Power provided updated forecasts of these expenditures in a confidential response to a Staff Data Request.[5] The confidential response included actual expenditures for January 1 – June 30, 2011, and an updated forecast of expenditures for July 1 – December 31, 2011. Idaho Power's revised forecast for 2011 varied significantly from its original forecast and the average monthly expenses in the second half of 2011 forecast varied significantly from the average monthly expenses reported for the first half of 2011.

Because it appears that Idaho Power has overestimated its 2011 expense (both in its initial filing and in its updated forecast for the second half of 2011), Idaho Power's actual expenditures for the first half of 2011 appear to be the most reliable measure of Idaho Power's expenditures for transmission and distribution operation and maintenance expenses for 2011. Accordingly, I adjusted Idaho Power's non-labor expense for these activities so that it more closely matches a forecast based on actual expenditures.

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[5] Included in Confidential Staff/403, Cimmiyotti/5-8.

Q. PLEASE EXPLAIN HOW YOU ADJUSTED IDAHO POWER'S EXPENSE.

A. As noted above, labor costs and expense related to transmission operations and maintenance expenses are recorded in FERC accounts 560-583 and labor costs and expense related to distribution operations and maintenance expenses are recorded in FERC accounts 580-598. My adjustment does not address labor costs because they are addressed by another Staff witness. Accordingly, as the first step in my adjustment, I separated Idaho Power's forecasted labor costs from the forecasted expense for the aforementioned FERC accounts (using information provided by Idaho Power with its original filing). To do this, I determined the percentage of non-labor expense compared to total expense for each of the aforementioned accounts for 2010. I made this determination by dividing the 2010 system non-labor expense by the 2010 total system expenses. The 2010 system non-labor expense information was provided by the Company in response to Staff Data Request No. 57.[6] I then multiplied the calculated non-labor percent for each account by the 2011 total system expense for each account, the product of which approximates the 2011 system non-labor expenses. [7]

As I note above, the Company used 2010 actual amounts to calculate the 2011 test year amounts.[8] As a result, the proportion of non-labor to labor expense in 2011 should not differ significantly from the 2010 non-labor to labor expense proportion.

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[6] Included in Staff/403, Cimmiyotti/3-4.
[7] The total system expenses for each account are provided in Idaho Power/905, Noe/13-14.
[8] *See* Idaho Power/601, Jones/5.

Once I separated the non-labor expense portion of the amounts in each FERC account in Idaho Power's original 2011 test year forecast, I created a new forecast for 2011 based on actual non-labor expense for the first half of 2011. As already noted, the Company provided a revised forecast of non-labor expenses for the second half of 2011 when it provided information regarding its actual expenditures for the first part of 2011. Because the average monthly expenses of the second half 2011 forecast varied significantly from the average monthly expenses for the first half of 2011, I determined a proportion of total 2011 expenses for the second half (July -December) of the 2011 test period using 2010 monthly costs as a basis for the proportional split.

I developed the proportion by using month-to-month data provided by Idaho Power in its Response to Staff Data Request No. 309a.[9] In responses to the data request, Idaho Power spent 45.51 percent of total 2010 in the first six months and 54.49 percent in the second six months of 2010 in Account 565 (Transmission of Electricity by Others). Although, these percentages were for one account, Account 565, I used the rounded percentages (46 / 54) as a proxy to determine the proportion of expenses for the accounts I reviewed. I performed the adjustment by dividing the January through June actual expenses by 0.46 percent to determine the annual expenditure amount. The use of these proportions resulted in a greater level of expenses in the second half of the year as compared to the first half. I believe this method addresses any potential "chunkiness" of expenditures as actual 2010 data is used to

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[9] Included in Staff/403, Cimmiyotti/1-2.

determine the split. I then compared this annualized 2011 non-labor expense amount to the calculated 2011 system non-labor expense amount described above. The difference between the two amounts is my system adjustment. Details of all calculations are found in Exhibit Staff/402.

I then multiplied the system adjustment for each account by the Oregon non-labor allocation percentage provided by the Company in response to Staff Data Request No. 318d, the product of which is my proposed adjustment to the Company's 2011 Oregon-allocated Transmission O&M and Distribution O&M Accounts. Details of my analysis are shown in Exhibit Staff/402.

Q. IN COMPARING THE COMPANY'S INITIAL TEST PERIOD ESTIMATES OF OPERATING AND MAINTENANCE EXPENSES FOR FERC ACCOUNTS 535 THROUGH 598 AGAINST THE COMPANY'S REVISED ESTIMATES PROVIDED IN RESPONSE TO DATA REQUEST 318, DID YOU OBSERVE A TENDENCY OF THE COMPANY TO OVERSTATE THE 2011 ESTIMATES FOR THESE EXPENDITURES?

A. Yes. Of the 64 accounts, (500-598), with revised estimates for the 2011 test period, 56 or 87.5 percent of these accounts had been initially overstated by the Company.[10] As shown below in Table 2, the Company over estimated their initial test period forecast of the selected $39,098,186 by over ([redacted]) percent or ($[redacted]). The adjustment to ratepayers in Oregon, as a result of the Company's own updated test-period forecast, would result in an adjustment of approximately ($295,465) for Oregon ratepayers.

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[10] Included in Confidential Staff/403, Cimmiyotti/5-8.

Table 2 – Non-labor O&M Variance Analysis (Filed Compared To Update)

Descriptions:	FERC Accounts	2011 Initial File UE-233	2011 Revised DR-318	Forecasted Variance	Percent Change
Transmission Expenses:					
Operations	(560-567)	$ 14,201,972	[redacted]	[redacted]	[redacted]
Maintenance	(568-573)	$ 4,168,022	[redacted]	[redacted]	[redacted]
Total Transmission Expenses		$ 18,369,994	[redacted]	[redacted]	[redacted]
Distribution Expenses:			[redacted]	[redacted]	[redacted]
Operations	(580-589)	$ 8,068,588	[redacted]	[redacted]	[redacted]
Maintenance	(590-598)	$ 12,659,603	[redacted]	[redacted]	[redacted]
Total Distribution Expenses		$ 20,728,192	[redacted]	[redacted]	[redacted]
Total Accounts 560-598		$ 39,098,186	[redacted]	[redacted]	[redacted]
Oregon Allocated at 4.47%				$ (295,465)	

Although, the Company's own updated forecast would result in an Oregon adjustment of ($295,465), I believe my proposed adjustment of ($249,741) is more reflective of actual and historical expenditures.

Q. DID YOU HAVE AN OPPORTUNITY TO REVIEW MONTH-TO-MONTH DIFFERENCES ON A SPECIFIC O&M ACCOUNT TO DETERMINE IF THE COMPANY'S FORECAST IS OVERSTATED?

A. Yes. The Company in its response to Staff Data Request No. 309a[11] provided a month-to-month analysis of Account 565. When comparing the first six months of 2010 to the first six months 2011, the Company spent slightly less (95.23 percent) in 2011 compared to 2010. This indicates that expenditures in 2011 generally tracked that of 2010 for the first six months. However, the six month expenditure forecast for the second half of 2011 is 131.47 percent of the actual 2010 expenditures for the July to December. This appears to indicate

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[11] Included in Staff/403, Cimmiyotti/1-2.

that the Company's forecast is overstated. The following table highlights the month-to-month expenditures for Account 565.[12]

Table 3 – Month-to-Month Analysis for Account 565

FERC Account Number 565

	Col. 1	Col. 2	Col. 3	Col. 4	Col.5	Col. 6
Row 1	**Month**	**2009**	**2010**	**2011**		
Row 2	Jan	116,008	274,338	286,977		4.6%
Row 3	Feb	159,220	364,046	251,821		6.2%
Row 4	Mar	631,123	331,387	324,477		5.6%
Row 5	Apr	482,242	371,978	337,992		6.3%
Row 6	May	178,933	322,545	309,423		5.4%
Row 7	June	1,114,419	1,029,307	1,054,471		17.4%
Row 8		2,681,945	2,693,601	2,565,161	95.23%	45.5%
Row 9						
Row 10	July	1,283,666	1,122,875	898,300		19.0%
Row 11	Aug	1,108,210	978,682	1,182,149		16.5%
Row 12	Sept	399,525	325,744	596,638		5.5%
Row 13	Oct	656,302	347,501	702,372		5.9%
Row 14	Nov	419,383	206,220	474,192		3.5%
Row 15	Dec	79,664	243,884	386,091		4.1%
Row 16		3,946,750	3,224,906	4,239,742	131.47%	54.5%
Row 17						
Row 18	Total	$6,628,695	$5,918,507	$6,804,903		
Row 19		Rows 8/18	Rows 8/18	Rows 8/18		Avgs.
Row 20	Jan-Jun	40.46%	45.51%	37.70%		41.2%
Row 21						
Row 22	Jul-Aug	59.54%	54.49%	62.30%		58.8%

Source: Idaho Power Company Response to Staff Data Request 309a.

As a result, Staff contends that the annualized update (especially with the opportunity to update in later rounds of testimony) is a more accurate method of determining 2011 expenses than using actual plus the Company's revised forecast.

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[12] Included in Staff/403, Cimmiyotti/1-2.

Q. IS THE 2010 NON-LABOR PERCENTAGE OF TOTAL EXPENSES FOR THESE ACCOUNTS AN ACCURATE ESTIMATE OF THE 2011 PERCENTAGE OF NON-LABOR?

A. Yes. For these accounts, the 2010 non-labor percentage was used because it is the most accurate information I had at the time of my analysis. However, two data requests are pending requesting non-labor amounts included in the 2011 test year, actual 2011 non-labor expenses through October 31, 2011, and the percentage of expenses spent prior to and following October 31 for the past three years. In future rounds of testimony, I expect my adjustment to be updated using more actual expenditures as that data becomes available and is provided by the Company.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT.

A. In UE 233, Idaho Power submitted a forecast of their total non-labor Operations and Maintenance in accounts 560 through 598 of $39,098,186. In response to Staff Data Request No. 318a through 318d (Confidential Exhibit Staff 403, Cimmiyotti/5-8), the Company provided an update of actual expenditures through June 30, 2011.

The response to Staff Data Request No. 318a through 318d demonstrated a proportional level of expenditures that were lower than the levels included in the Company’s initial testimony. Based on the first half actual spending levels for 2011, offset partially by the use of a back-weighted proportional split, I recommend a total of non-labor expenses in FERC accounts 560 through 598 of $33,055,671. As shown in Staff/402, Cimmiyotti/1 the difference of

($6,042,515) is allocated to Oregon at the weighted average retail non-labor factor of 4.13 percent to arrive at the Oregon allocated reduction of $249,741 in O&M for FERC accounts 560 through 598.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: Nick Cimmiyotti

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME: Nicholas (Nick) Cimmiyotti

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR FINANCIAL ANALYST, CORPORATE ANALYSIS AND WATER REGULATION

ADDRESS: 550 CAPITOL ST. NE, SALEM, OR 97308-2148

EDUCATION: Bachelor of Science in Finance, University of Oregon, Eugene, OR.

Masters of Business Administration in Management, Regis University, Denver, CO.

EXPERIENCE: Employed with the Public Utility Commission of Oregon from June 2011 to present, currently serving as Senior Financial Analyst, Corporate Analysis and Water Regulation.

Employed with PacifiCorp from October 1978 to March 2009, As the Lead Senior Business Consultant, in the Corporate Finance, my responsibilities included the following:

- Produced regulatory construction budget reports and the responses related to data request for information on financial performance, budgeting, and planning related questions from the Utah, Oregon, California, Washington, and Wyoming state utility regulatory entities;
- Reviewed, all major construction proposals for their conformance with the regulatory rulings, corporate governance, and financial guidelines. Deliver a recommendation regarding approval to the CFO;
- As the liaison to the Power Supply, Pacific and Rocky Mountain Power business units, I consulted them in the production of their input to the 10-Year plan forecast.
- Facilitated the developed the annual corporate goals and performance tracking metrics;
- Produced the monthly PacifiCorp President's report delivered to the MidAmerican Energy Holding Company; and
- Prepared the monthly financial and operational performance report of the corporate goals.

CASE: UE 233
WITNESS: Nick Cimmiyotti

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

December 7, 2011

STAFF EXHIBIT 402

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 11-288. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 233 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

CASE: UE 233
WITNESS: Nick Cimmiyotti

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

December 7, 2011

IDAHO POWER®
An IDACORP Company

September 21, 2011

Subject: Docket No. UE 233
Idaho Power Company's Response to Staff's Data Request 309

STAFF'S DATA REQUEST NO. 309:

In response to Staff's DR-195, the Company provided the "corrected" methodology used by the Company to forecast the 2011 Test Year. The methodology uses only one month of actual expenditures in the Test Year. The Company's account 565 expenses are forecasted to increase from $5,918,507 in the 2010 base period by $2,060,093 or approximately 34.8 percent.

a. **Please provide the non-labor actual expenditures for 2009, 2110, year-to-date 2011 and monthly estimates for the remainder of 2011. Please indicate in your response, which months are estimated for the remainder of 2011.**

Account 565 – Transmission of Electricity by Others (Non-Labor)			
Month	**2009**	**2010**	**2011**
Jan			
Feb			
Mar			
Apr			
May			
June			
July			
Aug			
Sept			
Oct			
Nov			
Dec			
Total	$	$	$

b. **Please provide the total account 565 expenses, including labor, by month, using the table format provided in DR-309 a.**

c. Using an Excel spreadsheet, with cells and formulae intact, please provide detailed 2011 monthly transaction summaries for all actual account 565 expenditures contained in DR-309 b.

d. Please provide invoices and other documentation that demonstrates the 2011 monthly actual expense amounts recorded in account 565 and the Company's response to DR-309 b.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 309:

a. Please see table below.

Account 565 – Transmission of Electricity by Others (Non-Labor)			
Month	**2009**	**2010**	**2011**
Jan	116,008	274,338	286,977
Feb	159,220	364,046	251,821
Mar	631,123	331,387	324,477
Apr	482,242	371,978	337,992
May	178,933	322,545	309,423
June	1,114,419	1,029,307	1,054,471
July	1,283,666	1,122,875	898,300
Aug	1,108,210	978,682	1,182,149
Sept	399,525	325,744	596,638
Oct	656,302	347,501	702,372
Nov	419,383	206,220	474,192
Dec	79,664	243,884	386,091
Total	$6,628,695	$5,918,507	$6,804,903

August though December 2011 amounts are estimates.

b. The response to this Request is the same as the Company's response to Staff's Data Request No. 309.a. There was no labor charged to Account 565; therefore, the amounts are the same for both Requests.

c. Please see the attached Excel file.

d. Please see the confidential invoices.

The invoices provided in response to Staff's Data Request 309.d are confidential and will be provided separately in accordance with Protective Order No. 11-288.

Attachment - Response to Master Data Request NO. 57

Account	2010 Base Year Total System	2010 Base Year OR Allocated	2009 Total System	2009 OR Allocated	2008 Total System	2008 OR Allocated
500	1,637,450.28	69,868.19	1,546,535.48	66,790.87	1,413,056.51	61,410.34
501	146,926,801.05	6,763,190.07	130,234,531.43	6,214,801.18	132,015,164.36	6,033,700.39
502	7,337,560.57	337,755.38	7,434,710.31	354,784.91	7,376,688.77	337,148.62
505	2,140,192.85	98,515.25	2,568,381.84	122,563.37	1,817,959.71	83,089.12
506	9,771,939.71	416,957.83	8,090,305.32	349,399.36	7,727,193.93	335,817.86
507	229,315.40	9,784.63	514,731.82	22,229.94	469,699.09	20,412.76
510	2,292,766.86	97,829.82	2,072,391.45	89,501.23	2,567,721.96	111,591.21
511	309,373.80	13,200.64	487,528.32	21,055.09	398,714.27	17,327.81
512	16,067,831.90	739,618.64	13,675,892.18	652,614.56	14,205,042.68	649,235.81
513	3,915,290.61	180,224.81	3,595,301.12	171,568.03	4,301,150.05	196,582.35
514	3,753,015.18	160,136.99	4,639,080.60	200,349.89	4,322,931.26	187,871.24
535	1,223,720.76	52,493.26	1,184,041.11	51,370.71	1,625,903.42	70,849.94
539	6,765,167.61	288,662.20	6,847,653.13	295,732.43	6,985,321.27	303,576.65
537	6,002,758.70	256,131.05	5,707,110.58	246,475.34	6,023,695.68	261,785.15
538	431,925.70	18,830.37	404,047.05	17,952.89	378,887.92	16,711.75
539	1,017,624.17	43,420.89	1,001,870.72	43,268.20	1,211,927.44	52,669.43
540	406,431.64	17,341.99	376,848.96	16,275.13	431,892.81	18,769.73
541	335,481.36	14,314.62	354,328.76	15,302.54	337,335.64	14,660.35
542	440,154.23	18,780.89	664,272.42	28,688.21	700,698.96	30,451.83
543	735,950.70	31,402.20	599,105.09	25,873.80	447,973.80	19,468.59
544	1,188,661.75	52,213.75	1,107,056.29	49,685.82	1,150,627.72	51,196.63
545	1,095,358.50	46,737.73	1,084,479.17	46,835.85	1,370,485.82	59,560.25
546	41,606.40	1,775.30	55,073.17	2,378.47	64,081.61	2,784.94
547	12,745,952.24	586,709.14	19,331,688.56	922,509.56	17,387,509.92	794,689.20
548	121,031.41	5,274.03	114,777.77	5,117.69	124,573.39	5,500.02
549	127,075.11	5,422.15	142,587.43	6,157.98	367,740.12	15,981.70
550	-	#DIV/0!	-	#DIV/0!	-	#DIV/0!
551	42.74	1.82	-	#DIV/0!	213.32	9.27
552	54,168.24	2,311.30	65,197.38	2,815.71	56,917.87	2,473.61
553	29,842.64	1,298.61	475,549.11	22,491.77	89,447.91	3,977.95
554	722,068.22	30,809.85	1,195,568.64	51,633.52	307,268.66	13,353.66
555	82,834,711.79	3,812,966.02	101,508,694.80	4,844,002.20	185,230,834.96	8,465,901.38
555.1	55,015,623.73	2,522,952.82	59,060,370.63	2,805,594.57	45,906,462.04	2,091,812.63
556	159.50	6.98	13,141.86	567.56	77,979.09	3,388.91
557	51,825,890.32	1,832,036.34	67,371,538.38	(3,665,676.97)	(46,820,009.20)	(2,034,761.33)
560	1,116,946.15	42,843.95	738,931.48	28,444.42	845,683.87	32,750.01
561	346,689.98	14,792.88	286,046.92	11,067.93	380,098.94	14,839.15
562	581,196.13	22,378.87	516,891.37	20,012.26	553,079.15	21,482.29
563	334,351.41	12,797.02	578,313.71	22,142.94	348,581.69	13,461.28
565	5,918,506.69	272,434.88	6,628,694.80	316,321.79	7,250,299.23	331,372.03
566	307,037.81	11,777.39	304,005.99	11,702.40	305,217.19	11,819.86
567	1,569,167.98	60,190.33	1,564,349.32	60,218.04	1,085,305.74	42,029.62
568	412,323.49	15,815.95	476,242.88	18,332.49	361,838.26	14,012.57
569	100,657.56	3,845.19	105,449.55	4,087.46	98,195.55	3,813.82
570	1,509,226.48	58,112.54	1,328,411.10	51,431.52	1,211,879.73	47,070.94
571	1,946,155.27	74,487.49	1,976,596.68	75,681.53	2,389,136.04	92,261.95
573	(40.43)	(1.55)	38.48	1.48	272.17	10.54
580	886,566.79	52,362.30	914,459.97	53,843.61	1,053,041.74	63,195.36
581	479,956.70	19,518.28	484,530.08	20,216.97	478,954.53	20,330.08
582	436,655.52	17,537.83	340,804.34	14,091.52	401,816.00	16,887.35
583	575,236.84	40,036.32	760,230.66	52,240.93	562,390.91	39,328.14
584	1,151,714.28	18,985.98	1,118,335.20	17,666.33	1,170,954.45	19,109.36

Attachment - Response to Master Data Request NO. 57

585	16,464.65	804.90	59,225.85	2,959.44	72,901.48	3,669.22
586	1,182,023.38	43,101.29	1,167,946.95	42,588.02	1,269,689.00	53,753.29
587	473,622.35	40,119.22	349,551.54	29,926.93	400,301.01	34,228.38
588	1,911,436.39	112,893.02	1,985,225.23	116,890.51	2,124,971.44	127,524.22
589	440,680.36	26,027.41	308,416.35	18,159.62	454,886.59	27,298.75
590	68,278.66	4,032.67	58,258.60	3,430.28	49,321.45	2,959.89
591	(11,385.43)	(461.95)	20,868.24	861.52	2,323.40	97.53
592	1,584,471.38	63,638.72	1,259,501.37	52,077.67	1,681,844.28	70,683.85
593	9,168,041.87	638,093.13	9,555,407.21	656,620.97	9,864,586.43	689,833.01
594	358,090.63	5,903.11	371,367.44	5,866.49	457,052.06	7,458.85
595	423,337.02	38,504.60	386,387.83	34,949.47	418,858.19	37,936.69
596	260,785.22	12,748.93	211,986.03	10,592.67	345,927.48	17,410.93
597	188,147.60	6,860.61	191,041.34	6,966.13	287,983.26	12,192.00
598	30,446.95	2,579.08	115,788.57	9,913.26	169,477.34	14,491.43
901	51,094.20	2,284.78	48,657.49	2,131.04	58,272.60	2,612.45
902	1,757,109.25	117,552.32	1,954,149.98	109,652.46	2,158,900.46	121,280.81
903	6,081,987.09	227,628.10	6,254,650.67	235,144.03	5,964,810.68	225,542.45
904	4,638,855.07	158,891.28	5,268,902.21	176,232.52	3,681,954.42	157,525.37
905	342.24	14.45	556.35	22.75	468.02	20.43
907	73,443.34	2,728.10	38,476.81	200.77	49,472.91	385.62
908	48,327,272.12	1,795,145.78	37,417,077.58	195,241.42	24,566,406.47	191,483.88
909	31,517.44	1,178.75	16,115.85	605.43	-	#DIV/0!
910	355,573.09	13,208.03	335,141.65	1,753.05	380,375.20	2,964.85
912	-	#DIV/0!	-	#DIV/0!	-	#DIV/0!
920	22,767,394.20	1,048,463.51	24,477,718.70	1,078,293.04	22,656,701.56	1,016,863.07
921	13,419,862.54	617,999.41	12,270,447.18	540,538.03	14,580,073.71	654,373.21
922	(27,799,634.13)	(1,280,203.69)	(27,866,621.19)	(1,227,581.05)	(22,736,029.25)	(1,020,423.40)
923	7,210,629.74	332,057.42	7,562,948.08	333,163.17	13,597,222.84	610,261.55
924	3,098,132.84	130,793.42	3,052,524.68	130,702.13	2,944,177.00	127,062.91
925	5,505,629.10	253,540.27	6,661,763.94	293,464.18	7,438,183.17	333,835.61
926	30,031,099.44	1,382,965.12	31,049,313.63	1,367,785.09	22,840,421.36	1,025,108.66
927	2,549.00	-	3,196.00	-	1,549.00	-
928	3,797,835.75	383,201.71	5,298,807.60	618,956.56	4,832,196.62	379,322.57
929	-	#DIV/0!	-	#DIV/0!	-	#DIV/0!
930.1	417,949.88	19,247.05	158,199.44	6,969.01	236,827.97	10,629.16
930.2	3,693,350.24	170,082.84	3,434,371.21	151,291.00	3,368,898.15	151,200.65
931	12,599.93	596.79	1,090.02	51.96	6,826.85	328.25
935	3,110,220.89	147,315.21	2,872,861.19	136,950.34	3,175,911.05	152,704.12

Pages 5 through 8 are confidential.

You must have signed the Protective Order in this docket in order to view these pages.

CASE: UE 233
WITNESS: PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ming Peng. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I am employed by the Public Utility Commission of Oregon as a senior economist in the Economic Research and Financial Analysis division.

My Witness Qualification Statement is found in Exhibit Staff/501.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am responsible for reviewing the depreciation/amortization expense and reserve, and plant additions method submitted by Idaho Power's (Company or IPC) witness Kelley Noe in Exhibit Idaho Power/901, 902. Based on that review, I recommend adjustments to Idaho Power's 2011 test year depreciation expense and reserves, amortization expense and reserve, and plant additions submitted in IPC's UE 233 filing.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I include my Witness Qualification Statement as Staff/501 and I prepared Exhibit Staff/502, consisting of 4 pages which contains the workpaper of this Testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

1. ADJUSTMENT IDENTIFICATION

Q. PLEASE DESCRIBE THE PROCESS YOU USED IN PREPARING THIS TESTIMONY.

A. I asked the Company to provide me the data it used to calculate depreciation/amortization expense and reserve and plant additions. I also issued several follow-up data requests.

Q. WHAT TEST PERIOD DID THE COMPANY USE TO DETERMINE THE REVENUE REQUIREMENT IN THIS CASE?

A. The test period used in this proceeding is the twelve month period ending December 31, 2011.

Q. PLEASE SUMMARIZE THE PROCESS USED TO ADJUST DEPRECIATION EXPENSE AND RESERVES, AND AMORTIZATION EXPENSE AND RESERVES.

A. I did the following:

1. Reviewed the depreciation (tangible assets) and amortization (intangible assets) expenses.
2. Reviewed depreciation and amortization reserves (accumulated depreciation and amortization).

3. Reviewed “in-service-date” of plant additions (capital additions, new investment).
4. Adjusted both depreciation/amortization expense and reserve.
5. Adjusted plant additions.

2. IMPACTS OF ADJUSTMENTS

Q. WHAT ADJUSTMENTS TO EXPENSES OF AND RESERVES FOR DEPRECIATION AND AMORTIZATION DO YOU RECOMMEND?

A. My recommended adjustments are set forth in the tables below.

Table 1

Adjustments related to Depreciation and Amortization Expense based on projected Plant as of 12/31/2011 ($)

Description	IPC Proposed System	Staff Proposed System	Staff Adjustment
EXPENSE			
Depreciation Expense	**116,113,901**	**113,888,740**	**(2,225,161)**
1/2 of 1st month Expense		**(140,000)**	**(140,000)**
Amortization Expense	**7,208,808**	**7,019,353**	**(189,455)**
Expense Total	**123,322,709**	**120,768,093**	**(2,554,616)**

Table 2

Adjustments related to Depreciation and Amortization Reserve

based on projected Plant as of 12/31/201 ($)

RATE BASE	IPC Proposed System	Staff Proposed System	Staff Adjustment
Reserve for Depreciation & Amortization			
Depreciation Reserve	1,789,401,601	1,788,289,020	(1,112,581)
1/2 of 1st month Expense		(70,000)	(70,000)
Amortization Reserve	21,305,872	21,211,144	(94,728)
Reserves Total	1,810,707,473	1,809,430,164	(1,277,309)

Table 3

Adjustments related to Plant Additions as of 12/31/2011

RATE BASE	IPC Proposed System	Staff Proposed System	Staff Adjustment
Plant in Service	4,428,841,043	4,401,416,442	(27,424,601)
TOTAL RATE BASE REDUCTION			(27,424,601)

3. REASONS TO MAKE SUCH ADJUSTMENTS

Q. PLEASE EXPLAIN THE REASONS TO MAKE SUCH ADJUSTMENTS.

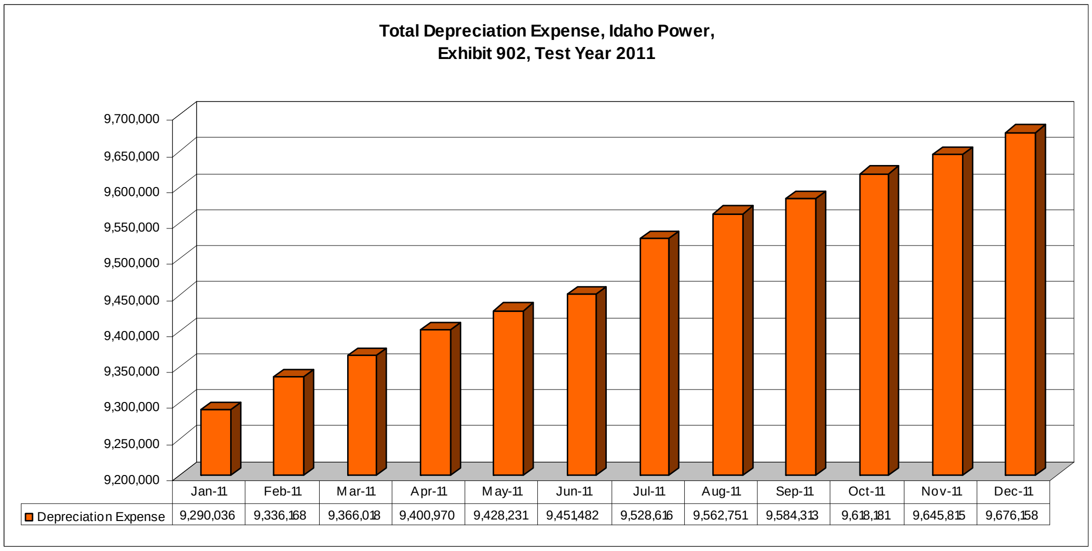
A. 1. Idaho Power witness Noe explains that the Company derived its test year expense for depreciation and amortization by forecasting depreciation expense on a month-by-month basis for the 2011 test year ("Forecasted Depreciation Expense"), and then making an "annualizing adjustment" to those forecasted amounts. To do the annualizing adjustment, Idaho Power multiplies the forecast expense for December 2011 by twelve to arrive at the “Annualized Depreciation Expense.” The difference between the Forecasted Depreciation Expense and the Annualized Depreciation Expense is Idaho Power’s “annualizing adjustment.” This adjustment added $2,225,161 to its depreciation expense for the 2011 test year and $189,455 to its amortization expense (a total of $2,414,616).

Idaho Power’s annualizing adjustment using the ending balance for the test year results in overstated expenses: (adjustment: -$2.4 million on depreciation/amortization expense). (IPC Exhibit 902)

The company has forecasted twelvemonths of data for the 2011 test year (IPC Exhibit 902-Monthly 11 Expense) and does not need to create another forecast based solely on year-end data to simulate the annual expense for the test year. Using the year end balance to calculate depreciation and amortization expenses will overstate the expenses because depreciation/amortization balances generally are increasing over the test period due to the increase of the plant additions (see Figure 1 below, data source: IPC Exhibit 902).

Figure 1

Using Year-End Balance will Overstate Expenses



IPC's "annualizing" adjustment adding $2.4 million depreciation/amortization expenses is unnecessary because the $2.4 million expense for 2011 is already included in the basic depreciation methodologies (survivor curve analysis, life analysis, and salvage analysis) used to calculate depreciation and amortization rates.

After a careful review of IPC's ending-balance methodology, Staff believes that Idaho Power's "annualizing adjustment", resulting in an additional $2.4 million for depreciation/amortization expenses, has no justifiable basis and therefore should be eliminated.[1]

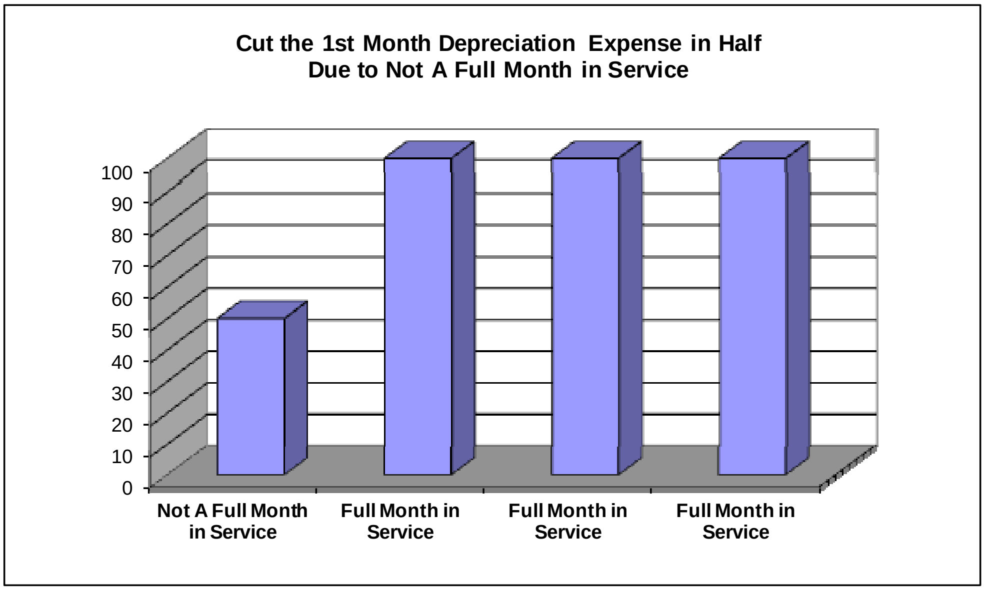
---

[1] *See* Idaho Power/902, 904.

2. Mid-Month Convention for Depreciation: (Adjustment: -$140,000 on depreciation expense) For depreciation, the mid-month convention means that an asset placed into service during a given month is assumed to have been placed into service in the middle of that month, and depreciation for that asset will be recorded for half of the month. This is because of varied “plant-in-service” dates within a month (in the beginning-month, or mid-month, or end-month). Given that the actual in-service dates of plant additions will vary, it is not appropriate for purposes of ratemaking to assume each asset addition occurred on the first of the month. This means that only one-half month of depreciation is allowed for the month the property is placed in service (see Figure 2).

Figure 2

Mid-Month Convention for Depreciation: A One-Half Month of Depreciation Is Allowed for the Month the Property is Placed in Service



It does not appear that IPC employed the mid-month convention when calculating depreciation expense for new plant additions. If it is assumed that plant added during the 2011 test year was added in the middle of the month (as opposed to the first of the month, as IPC has done), IPC's depreciation expense decreases by $140,000 system-wide.

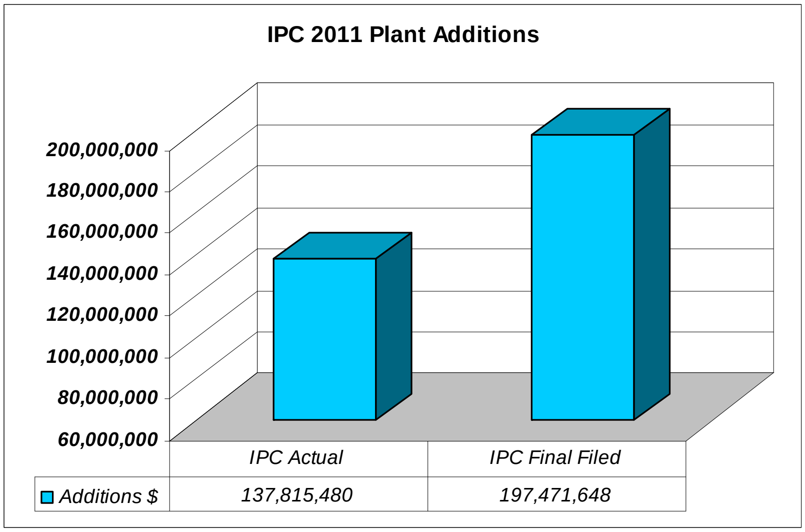
3. Change of reserve due to the change of Depreciation: (Adjustment: -$1.277 million on an average Depreciation/Amortization Reserve) This adjustment is made to be consistent with the adjustment to depreciation. The reserve is accumulated depreciation/amortization expenses in rate base.

4. Double Counted Plant Additions in IPC's Plant in Service: (Adjustment: -$27.4 million on plant additions) Idaho Power's 2011 Plant in Service includes double counted plant additions.

According to IPC's Data Response DR No 132, the net plant additions that should be used to develop the 2011 year-end balance to calculate the average plant balance in rate base equal $137.8 million (total plant additions of $180.5 million ("Capital WO Closings", DR 132) subtract total retirement of $42.7 million ("Estimated Retirements", DR 132). Idaho Power's calculations of how plant additions in 2011 affect their total electric plant in service balance for 2011 are not as straight forward. According to the Company's Exhibit 904, to calculate the amount for new plant additions that are included in its total electric plant in service, IPC determined plant additions for 2011, which includes large and small projects, total of $165.9 million. Then, Idaho Power added an adjusted $31.6 million for plant additions for large projects (IPC Exhibit 901-“2011 AnnPlnt”, IPC Exhibit 904). However, the costs of Idaho Power’s new plant additions for 2011 are already included in its calculation of the total plant additions for 2011. By adding these plant addition amounts together IPC double counts new large plant additions. Accordingly, IPC‘s total of $4.429 billion for its 2011 electric plant in service includes double counted capital additions (Figure 3).

Figure 3

IPC Actual Net Plant Additions Compared to
IPC Final Filed Plant Additions



Staff’s calculation is easy and clear; first, using IPC actual beginning plant balance of $4.3 billion (IPC DR 132), Staff adds IPC actual net plant additions of $137.8 million to obtain the actual ending plant balance of $4.47 billion, and then, using “actual beginning balance of $4.3 billion” plus “actual ending balance of $4.47 billion" divided by 2, obtains an average balance of $4.401 billion (see Table 5). The difference between IPC's $4.429 billion and Staff's $4.401 billion is $27.4 million, and this $27.4 million results from double counting on plant additions. The double counted portion of $27.4 million plant additions system-wide in rate base should be eliminated.

Table 5

Calculation of Plant Addition Adjustment ($)

(1) Actual BEGINNING Balance (IPC DR 132)	**4,332,508,702**
(2) Net Additions: Total $180M- Retired $43M	**137,815,480**
(3)=(1)+(2) Actual ENDING Balance	**4,470,324,182**
(4) =[(1)+(3)]/2 Average Ending Balance	**4,401,416,442**
(5) IPC Filed in Exhibit 902, 904	**4,428,841,043**
(6) = (4) – (5) Difference, Adjustment	**(27,424,601)**

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME: MING PENG (Ms.)

EMPLOYER: PUBLIC UTILITY COMMISSION OF OREGON

TITLE: SENIOR ECONOMIST

ADDRESS: 550 CAPITOL ST. N.E. SUITE 215, SALEM, OR 97301-2551

EDUCATION & TRAINING:

Depreciation studies - the Society of Depreciation Professionals	2008, 2009
Certified Rate of Return Analyst (CRRA) Society of Utility and Regulatory Financial Analysts	2002
NARUC Annual Regulatory Studies Program Michigan State University, East Lansing	1999
Master of Science, Agricultural Economics University of Idaho, Moscow	1990
Bachelor of Science, Statistics People’s University of China, Beijing	1983

EXPERIENCE:

SENIOR ECONOMIST 1999 - present
Public Utility Commission of Oregon. Review utility filings; testify as an expert witness in numerous proceedings on issues related to depreciation, cost of debt capital, financial and risk analysis on merger and acquisition dockets, electricity load and price forecasting, sampling design for revenue issues. Work functions have also included weather normalization, public utility auditing, interest rate reporting, and market competition survey and analysis for telecom industry.

INDUSTRY ANALYST 1996-1998
Weyerhaeuser Company. Forecasted product demand, price trends, and price elasticity. Established the process (specific methods and techniques) for market, investment and economic analyses. Activities included using a wide variety of analytical techniques.

ECONOMIST (Natural Resources) 1992-1996
Idaho Department of Water Resources. Conducted economic research. Developed analysis in evaluating policy and planning alternatives; determined the financial and economic feasibility of proposed natural resource projects using economic modeling and investment analysis.

CASE: UE 233
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

December 7, 2011

IDAHO POWER COMPANY
UE 233
Test Period Ending December 31, 2011
(000)

Staff
Adjustment
S-7

1. Remove "Annualized Depreciation Expense" by $2.225 million from Exhibit 902
2. Remove "Annualized Amortization Expense" by $189,455 from Exhibit 902
3. Cut in half on the 1st month of depreciation expense by $140,000

Reasons: (1) IPC using ending balance (December data) multiplied by 12 month to represent an annual expense is biased, The company already had monthly data for 2011 test year, the adjusted amount of $2.4 million is already covered through the basic Depre/Amort methodologies; (2) Cut in half on the 1st month of depreciation expense that associated with new plant additions due to the varies "plant-in-service" dates within a month.

EXPENSES	**Depreciation+Amortization**	**Total System**	**Oregon**
IDAHO POWER	Depreciation expense	116,113,901	5,098,532
	Amortization expense	7,208,808	331,470
	Total IPC	123,322,709	5,430,003
Staff Proposal	Depreciation expense	**113,748,615**	4,994,673
	Amortization expense	**7,019,352**	322,759
	Total Staff	**120,767,968**	5,317,515
Total Adjustment		**(2,554,741)**	**(112,571)**
INPUT Amount in $1,000		**(2,555)**	**(113)**

1. Remove Depreciation Reserve (Accumulated) Adjustment $1.113 million.
2. Remove Amortization Reserve Adjustment $94,728
3. Remove Reserve from Mid-Month Convention for Depreciation $70,000

Reason: Change of reserve due to the change of Depreciation, Amortization adjustments

RATE BASE	**Depreciation+Amortization Reserves**	**Total System**	**Oregon**
IDAHO POWER	Accumulated Depreciation Reserves	1,789,401,601	85,382,820
	Accumulated Amortization Reserves	21,305,872	939,189
	Total IPC	1,810,707,473	86,322,010
Staff Proposal	Accumulated Depreciation Reserves	1,788,219,020	85,326,393
	Accumulated Amortization Reserves	21,211,144	935,014
	Total Staff	1,809,430,165	86,261,406
	Depreciation Reserves Remove Annualized Adj	**(1,112,581)**	**(48,853)**
	Reserve from Mid-Month Convention for Deprecia	**(70,000)**	**(3,074)**
	Amortization Reserves Remove Annualized Adj	**(94,728)**	**(4,356)**
Total Adjustment	ADJ TOTAL	**(1,277,308)**	**(56,283)**
INPUT Amount in $1,000		**(1,277)**	**(56)**

Staff Initiator:
Ming Peng

IDAHO POWER COMPANY
UE 233
Test Period Ending December 31, 2011
(000)

Staff
Adjustment
S-7

1. Remove "Annualized Depreciation Expense" by $2.225 million from Exhibit 902
2. Remove "Annualized Amortization Expense" by $189,455 from Exhibit 902
3. Cut in half on the 1st month of depreciation expense by $140,000

Reasons: (1) IPC using ending balance (December data) multiplied by 12 month to represent an annual expense is biased, The company already had monthly data for 2011 test year, the adjusted amount of $2.4 million is already covered through the basic Depre/Amort methodologies; (2) Cut in half on the 1st month of depreciation expense that associated with new plant additions due to the varies "plant-in-service" dates within a month.

EXPENSES	**Depreciation & Amortization Expenses**	**Total System**	**Oregon**
IDAHO POWER	Depreciation expense	116,113,901	5,098,532
	Amortization expense	7,208,808	331,470
	Total IPC	123,322,709	5,430,003
		Total System	**Oregon**
Staff Proposal	Depreciation expense	113,748,615	4,994,673
	Amortization expense	7,019,352	322,759
	Total Staff	120,767,968	5,317,515
REMOVAL DETAILS:			
1	Remove Annualizing Adj on AMORTIZATION	**(189,455)**	**(8,711)**
2	Remove Annualizing Adj on DEPRECIATION	**(2,225,161)**	**(97,706)**
3	Mid-Month Convention for Depreciation	**(140,000)**	**(6,147)**
Depreciation remove		(2,365,286)	**(103,854)**
Total Depre & Amort Remove		**(2,554,617)**	**(112,565)**
INPUT Amount in $1,000		**(2,555)**	**(113)**

IDAHO POWER COMPANY
UE 233
Test Period Ending December 31, 2011
(000)

Staff
Adjustment
S-7

1. Remove Depreciation Reserve (Accumulated) Adjustment $1.113 million.
2. Remove Amortization Reserve Adjustment $94,728
3. Remove Reserve from Mid-Month Convention for Depreciation $70,000

Reason: Change of reserve due to the change of Depreciation, Amortization adjustments

RATE BASE	**Depreciation & Amortization Reserves**	**Total System**	**Oregon**
IDAHO POWER	Accumulated Depreciation Reserves	1,789,401,601	85,382,820
	Accumulated Amortization Reserves	21,305,872	939,189
	Total IPC	1,810,707,473	86,322,010
		Total System	**Oregon**
Staff Proposal	Depreciation Reserves	1,788,219,020	85,326,393
	Amortization Reserves	21,211,144	935,014
	Total Staff	1,809,430,165	86,261,406
Remove from Annualizing			
Adjustment	Depreciation Reserves Remove Annualized Adj	**(1,112,581)**	**(48,853)**
	Reserve from Mid-Month Convention for Depreciation	**(70,000)**	**(3,074)**
	Amortization Reserves Remove Annualized Adj	**(94,728)**	**(4,356)**
ADJ TOTAL		**(1,277,308)**	**(56,283)**
INPUT Amount in $1,000		**(1,277)**	**(56)**

Estimated First 1/2 month Depreciation Expense	
137,815,480	Net additions: Total Adds $180M- Retired $43M
12	Months
11,484,623	Each month
287,116	x Depr 2.5% = Monthly Depr Expense
(140,000)	Estimated 1st 1/2 Month Depr Expense
(70,000)	Reserve

IDAHO POWER COMPANY
UE 233
Test Period Ending December 31, 2011
(000)

Staff
Adjustment
S-8

Remove "Plant in Service" by $27.4 million. Reasons:
The net plant additions of $137.8 million (Total plant additions of $180.5 million subtract total retirement of 42.8 million) should be used to develop 2011 year-end balance in order to calculate the average plant balance.
However, IPC used mixed plant additions of $165.9 million adds an additional $31.6 million to calculate test-year plant in service, resulting in double counting.

RATE BASE	**Plant in Service**	
	System	**Oregon**
Idaho Power	4,428,841,043	212,347,364
Staff	4,401,416,442	211,032,451
TOTAL ELECTRIC PLANT IN SERVICE	**(27,424,601)**	**(1,314,913)**
INPUT Amount in $1,000	**(27,425)**	**(1,315)**

Staff Initiator:
Ming Peng

IPC Ex 904	IPC CALCULATION Description	2010 Actual	2010 Actual Adjustments	2010 Base	Forecast Adjustment	2011 Unadjusted Test Year	Annualizing Adjustment	2011 Test Year
		[1]	[2]	[3]	[4]	[5]=[3]+[4]	[6]	[7]=[5]+[6]
line #204	TOTAL ELECTRIC PLANT	4,231,369,395		4,231,369,395	**165,872,190**	4,397,241,585	**31,599,458**	**4,428,841,043**

IPC DR 132 **Elec Plant In Se**	**ACTUAL December-10 BALANCE**	**ADDITIONS**	**RETIREMENTS**
DR 132	**4,332,508,702**	**180,502,085**	**(42,686,605)**

Staff Calculation

Actual Beginni Balance	**NET ADDITIONS: Total Adds $180M subtract Retired $43M**	**Actual ENDING Balance**	**2011 Average Plant in Servive**
[1] = DR 132	**[2] = DR 132**	**[3]=[1]+[2]**	**[4]=([1]+[3]) / 2**
	180,502,085		
	(42,686,605)		
4,332,508,702	**137,815,480**	**4,470,324,182**	**4,401,416,442**

Staff Adjustment

STAFF	**4,401,416,442**
IPC	**4,428,841,043**
Difference	**(27,424,601)**

CASE: UE 233
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Direct Testimony

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Irina Phillips. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I reviewed the jurisdictional separation study submitted by Idaho Power Company's (Company, IPC) witness Kelley Noe in Exhibit Idaho Power/905. I recommend adjustments to test year 2011 Oregon share of the FERC account 368 Line Transformers.

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibits Staff/601-604. Exhibit Staff/601 contains my Witness Qualifications. Exhibit Staff/602 contains the Company response to Staff's data request no. 356, with my addition of a column "Cost per Mile". Exhibit Staff/603 contains the Company response to Staff's data request no. 379, with my addition of two lines to calculate percentages. These lines are below "Oregon Total" and "Idaho Total." Exhibit Staff/604 contains first tab "Total Company by State" of the electronic version of Noe Workpaper 18 (page 84) - Cost of Metering- 2009 Final- Oregon DA370 Allocator (00064034). I added six lines below Idaho and Oregon Totals to calculate Oregon and Idaho shares using sums of "Current Transformers Number" and "Voltage Transformer Number."

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

1. ADJUSTMENT IDENTIFICATION

Q. PLEASE DESCRIBE THE PROCESS YOU USED IN PREPARING THIS TESTIMONY.

A. I reviewed the Company's Exhibit 905 and corresponding work papers. I sent several rounds of data requests and reviewed the IPC's responses.

Q. DID YOU FIND THE COMPANY IN ITS RESPONSES TO THE DATA REQUESTS TO BE CONSISTENT WITH ITS TESTIMONY?

A. No. The Company in its testimony states that there is direct assignment for investments applicable to FERC account 368 line transformers. However, in the response to Staff's data request no. 356, the Company indicated that in actual practice investments related to this FERC account are not directly assigned to each jurisdiction, but instead are allocated across the state jurisdictions based upon distribution line miles. See Staff Exhibit/602.

Q. WHAT WAS COMPANY'S JUSTIFICATION FOR THE USE OF THIS ALLOCATOR?

A. The Company gave the following explanation in response to Staff's data request nos. 393 and 401:

> *“The initial use of an allocator based upon distribution line miles occurred many years ago. The original justification of this allocation methodology was not retained. However, a rationale for this proxy is that the equipment found in the warehouse does not have a specified location where it will be used. Therefore, the equipment could be installed at any point along any of the Company’s distribution feeders. To determine the probable location, the Company assigned each point along the distribution line the same probability of being the installation location for the equipment. As a result, the Company can then predict the probability of the equipment being installed in a region by the ratio of the line miles in that specific region compared to the total system line miles.”*
>
> *“Account 368 cannot be directly assigned to the jurisdictions in the same manner as the other distribution plant accounts (excluding Account 370) due to the fact that inplant accounting was used until 2004. Under that methodology, assets were capitalized at the time of purchase rather than installation, and property units in Account 368 (Distribution Line Transformers) were all closed to plant in service at the corporate headquarters location (Idaho). Therefore, when the Company queries the data by location, the amount in Account 368 for Oregon only represents the current accounting method from 2004 to present.”*

Q. DO YOU AGREE WITH IDAHO POWER'S APPROACH TO JURISDICTIONALLY ASSIGNING INVESTMENTS IN THIS FERC ACCOUNT?

A. No.

Q. WHY DO YOU DISAGREE WITH IPC'S ALLOCATION APPROACH?

A. Idaho and Oregon have different distribution system characteristics. In the response to Staff's data request no. 379 the Company identified that Oregon has 1.6% of its miles as underground, while Idaho has 12.6%. See Staff Exhibit/603.

In the responses to Staff's data request nos. 398 and 399, Idaho Power identified that the average installed cost of an underground distribution line transformer for the period January through October 31, 2011 was $2,081.24 and the average installed cost of an overhead distribution line transformer for the same period was $579.52. An underground transformer is almost 3.6 times more expensive.

Q. ARE THERE ANY OTHER DISTRIBUTION SYSTEM DIFFERENCES BETWEEN IDAHO AND OREGON JURISDICTIONS?

A. Yes. The population density is different. According to the Company's response to Staff's data request no. 397, the average number of Idaho Power customers served per distribution line transformer is 1.9 in Oregon and 3.2 in Idaho service territories.

Q. WHAT IS YOUR PREFERRED JURISDICTIONAL SEPARATION APPROACH TO FERC ACCOUNT 368?

A. The costs recorded in the account 368 ideally should be directly assigned to Oregon and Idaho jurisdictions. This will likely take some time and effort as the Company will need to identify the location of its plant equipment. It may be possible that a suitable random sample of plant investments could be a reasonable substitute for sampling the entire population. However, the Company would need to go and research its historical investments and tie them to location. Until such a study is completed, I recommend a revision to the Company's allocation and present it below.

2. IMPACT OF PROPOSED ADJUSTMENT

Q. WHAT ADJUSTMENT TO JURISDICTIONAL SEPARATION DO YOU RECOMMEND?

A. My recommended adjustment is set forth below in Table 1.

Table 1

Adjustment related to Rate Base Adjustment, $'000

Description	IPC System	Oregon Jurisdiction	Allocation Percent
RATE BASE ACCOUNT Electric Plant in Service 368 Distribution Line Transformers			
Proposed by the IPC	420,987	38,184	9.07
Proposed by Staff	420,987	17,471	4.15
Staff Adjustment	0	(20,713)	

This rate base adjustment will cause reduction in revenue requirement of $2.106M. For more detail see Exhibit Staff/100.

3. CALCULATION OF ALLOCATION PERCENT

Q. PLEASE EXPLAIN THE CALCULATION OF YOUR ADJUSTMENT.

A. As I stated earlier, the best approach for separation of costs of transformers is direct assignment, but for the purpose of this rate case I developed an allocation percent for Oregon jurisdiction after reviewing Idaho Power's work papers. I think that the number of transformers is a better allocator in comparison to distribution miles. Distribution transformers serve to transform electricity from one voltage or current level to another in order to make electric rate more manageable for home and business use. An ideal transformer imposes no load on the supply (feeding the primary) unless there is a load across the secondary. So the main reason for the transformer is to serve the final load and not to deal with the distribution system length. That is why I think that the number of customers in combination with the density of customers per transformer is a better allocator. The Company submitted Workpapers containing Cost of Metering Report by State by Rate Class (page 18 of 84 of Noe Workpaper) with current and voltage transformers added to the IPCO system in 2009. See Staff Exhibit/604. I recommend allocation of 4.15%.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

WITNESS QUALIFICATION STATEMENT

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME: Irina Phillips

EMPLOYER: Public Utility Commission of Oregon

TITLE: Economist

ADDRESS: 550 Capitol St. NE, Suite 215
Salem, OR 97308

EDUCATION: Master of Science, Economics
Oregon State University, Corvallis, OR

Bachelor of Science, Economics and Management
St. Petersburg State University of Economics and Finance, St. Petersburg, Russia

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UM 1431, UE 213, UE 215, UE 217, UG 186 and UG 201. Assisted in Staff review of Integrated Resource Plans (LC 48, LC 50, LC 51, LC 52, and LC 53). Participated in Staff audits of NW Natural and Cascade Natural Gas.

Between 2005 and 2009, worked as an Adjunct Instructor for Linn-Benton Community College, Albany, OR and Western Oregon University, Monmouth, OR

Between 1996 and 1999, worked as a Financial Analyst for Gillette International LLC, Russian Office, St. Petersburg, Russia

Between 1991 and 1994, worked as a Senior and Chief Accountant for Korex, Fiton and Tandem companies, St. Petersburg, Russia

CASE: UE 233
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

December 7, 2011

ATTACHMENT - RESPONSE TO STAFF'S DR 356

Idaho Power Company
Distribution Line Account 368
By State and County
December 31, 2010

		Overhead & UGD Miles	368 Account	Cost per Mile
Oregon				
	Baker	1,051.42	6,884,983.87	6,548.27
	Grant	1.34	8,774.68	6,548.27
	Harney	263.54	1,725,731.53	6,548.27
	Malheur	4,444.36	29,102,876.94	6,548.27
	Wallowa	0.63	4,125.41	6,548.27
		5,761.29	37,726,492.43	6,548.27
Idaho				
	Ada	8,098.78	53,033,012.12	6,548.27
	Adams	932.96	6,109,275.59	6,548.27
	Bannock	1,941.36	12,712,552.80	6,548.27
	Bingham	4,787.25	31,348,213.84	6,548.27
	Blaine	1,781.35	11,664,763.85	6,548.27
	Boise	1,238.05	8,107,087.81	6,548.27
	Camas	731.71	4,791,435.91	6,548.27
	Canyon	7,138.39	46,744,117.43	6,548.27
	Cassia	1,610.10	10,543,372.31	6,548.27
	Elmore	3,089.86	20,233,242.89	6,548.27
	Gem	1,410.35	9,235,355.03	6,548.27
	Gooding	2,382.85	15,603,549.29	6,548.27
	Idaho	188.48	1,234,218.26	6,548.27
	Jerome	2,809.11	18,394,815.60	6,548.27
	Lemhi	1,384.97	9,069,159.90	6,548.27
	Lincoln	1,245.43	8,155,414.06	6,548.27
	Minidoka	1,532.27	10,033,720.32	6,548.27
	Oneida	105.12	688,354.32	6,548.27
	Owyhee	2,737.25	17,924,256.79	6,548.27
	Payette	1,742.81	11,412,393.45	6,548.27
	Power	2,209.83	14,470,567.32	6,548.27
	Twin Falls	5,161.79	33,800,803.53	6,548.27
	Valley	1,763.89	11,550,431.02	6,548.27
	Washington	1,556.98	10,195,528.12	6,548.27
		57,580.94	377,055,641.56	6,548.27
Total		63,342.23	414,782,133.99	6,548.27

Check Figures		368 Account
	Oregon	37,726,492.44
	Idaho	377,055,641.56
	Total	414,782,134.00
		(0.01)
	Idaho %	**90.90%**

CASE: UE 233
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support
Of Opening Testimony

December 7, 2011

ATTACHMENT - RESPONSE TO STAFF'S DR 379

IDAHO POWER COMPANY
DISTRIBUTION WIRE MILES
BY STATE AND COUNTY
AS OF DECEMBER 31, 2010

		Overhead Miles	UGD Miles	OH & UGD Miles
State	**County**	**Total**	**Total**	**Total**
Oregon	Baker	1,040.14	11.28	1,051.42
Oregon	Grant	1.34		1.34
Oregon	Harney	263.31	0.23	263.54
Oregon	Malheur	4,364.35	80.01	4,444.36
Oregon	Wallowa	0.02	0.61	0.63
Oregon Total		**5,669.16**	**92.13**	**5,761.29**
		98.4%	**1.6%**	**100.0%**
Idaho	Ada	4,884.67	3,214.11	8,098.78
Idaho	Adams	760.06	172.90	932.96
Idaho	Bannock	1,605.83	335.53	1,941.36
Idaho	Bingham	4,675.29	111.96	4,787.25
Idaho	Blaine	1,312.79	468.56	1,781.35
Idaho	Boise	1,107.28	130.77	1,238.05
Idaho	Camas	695.57	36.14	731.71
Idaho	Canyon	5,897.05	1,241.34	7,138.39
Idaho	Cassia	1,603.15	6.95	1,610.10
Idaho	Elmore	2,937.29	152.57	3,089.86
Idaho	Gem	1,328.19	82.16	1,410.35
Idaho	Gooding	2,344.95	37.90	2,382.85
Idaho	Idaho	156.58	31.90	188.48
Idaho	Jerome	2,725.56	83.55	2,809.11
Idaho	Lemhi	1,325.15	59.82	1,384.97
Idaho	Lincoln	1,233.06	12.37	1,245.43
Idaho	Minidoka	1,519.33	12.94	1,532.27
Idaho	Oneida	104.80	0.32	105.12
Idaho	Owyhee	2,664.41	72.84	2,737.25
Idaho	Payette	1,665.36	77.45	1,742.81
Idaho	Power	2,161.96	47.87	2,209.83
Idaho	Twin Falls	4,732.11	429.68	5,161.79
Idaho	Valley	1,358.53	405.36	1,763.89
Idaho	Washington	1,526.37	30.61	1,556.98
Idaho Total		**50,325.34**	**7,255.60**	**57,580.94**
		87.4%	**12.6%**	**100.0%**
Grand Total		**55,995.48**	**7,347.75**	**63,343.23**

CASE: UE 233
WITNESS: Irina Phillips

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Exhibits in Support
Of Opening Testimony

December 7, 2011

Staff/604
Phillips/1

COST OF METERING REPORT BY STATE BY RATE CLASS
TWELVE MONTHS ENDING DECEMBER 31, 2009

1/2 AMI	Non-AMI	Total Non-AMI
$139,586	$1,892,817	$2,032,402

IPCO METER INFORMATION SYSTEM COST OF METERING REPORT FOR TOTAL COMPANY

		METERS		CURRENT TRANSFORMERS		VOLTAGE TRANSFORMER		TOTAL
	RATE DESCRIPTION	NUMBER	*DOLLARS	NUMBER	*DOLLARS	NUMBER	*DOLLARS	*DOLLARS
00	COMPANY USE	125	$50,962	116	$13,684	15	$1,434	$66,080
01	RESIDENTIAL SERVICE	407,894	$48,074,108	4,817	$919,236	4	$887	$48,994,231
03	MASTER METERED RESIDENTIAL SERVICE	22	3,603	28	3,982	3	706	8,290
04	RESIDENTIAL SERVICE - ENERGY WATCH	47	$9,959	3	$364	0	$0	$10,323
05	RESIDENTIAL SERVICE - TOU	80	$16,452	1	$149	0	$0	$16,601
07	SMALL GENERAL SERVICE	31,233	$5,576,034	1,936	$341,659	16	$4,292	$5,921,985
07B	SMALL GENERAL SERVICE - BPA	477	$64,054	3	$297	0	$0	$64,352
09P	LARGE GENERAL SERVICE	184	$240,972	555	$280,465	343	$376,865	$898,303
09S	LARGE GENERAL SERVICE	29,987	$11,303,357	27,055	$4,767,994	145	$97,247	$16,168,597
09SB	LARGE GENERAL SERVICE - BPA	273	89,046	280	$54,095	3	$706	$143,847
09T	LARGE GENERAL SERVICE	4	4,727	11	28,298	11	22,359	$55,383
19P	UNIFORM RATE-INDUSTRIAL	133	$174,023	396	$221,587	353	$369,553	$765,163
19S	UNIFORM RATE-INDUSTRIAL	1	$1,293	3	$393	0	$0	$1,687
19T	UNIFORM RATE-INDUSTRIAL	5	$5,705	15	$18,797	15	$23,731	$48,233
24C	IRRIGATION SERVICE - CONNECTED LOAD	5	$1,156	0	0	0	0	$1,156
24CB	IRRIGATION SERV - CONNECTED LOAD - BPA	679	$83,572	0	0	0	0	$83,572
24S	IRRIGATION SERVICE - SECONDARY	4	$2,346	6	$676	0	$0	$3,021
24SB	IRRIGATION SERVICE -SECONDARY - BPA	16,819	$5,867,433	8,550	$1,359,013	65	$20,988	$7,247,434
25SB	IRRIGATION SERV - SECONDARY - TOU BPA	3	$1,866	2	$298	0	$0	$2,164
41BM	METERED STREET LIGHT - CUST OWNED	8	$1,304	0	$0	0	$0	$1,304
41M	METERED STREET LIGHT	133	$35,060	3	$1,005	0	$0	$36,065
42M	METERED TRAFFIC LIGHT - SM COMM	264	$42,914	0	$0	0	$0	$42,914
84C	SMALL GENERAL SERVICE - NET METERING	10	$1,407	3	$258	0	$0	$1,664
84CS	LARGE GENERAL SERVICE - NET METERING	21	$6,617	24	$2,759	0	$0	$9,376
84R	RESIDENTIAL SERVICE - NET METERING	112	$8,560	5	$780	0	$0	$9,340
87	CSPP CONTRACTS	87	59,292	168	73,088	113	146,791	$279,172
ISBNA	STAND BY NAMPA AMALGAMATED SUGAR	1	$2,445	3	$0	3	$0	$2,445
ISBPL	STAND BY PAUL AMALGAMATED SUGAR	2	$1,248	6	$8,539	6	$27,453	$37,240
ISBT1	STAND BY TF AMALGAMATED SUGAR	1	$1,918	3	$2,154	3	$2,194	$6,267
OADHR	OREGON ALT DIST HOLY ROSARY	1	$294	3	$282	0	$0	$576
	********** SUB-TOTAL	488,615	$71,731,726	43,995	$8,099,852	1,098	$1,095,208	$80,926,786
	SPECIAL CONTRACTS	18	$20,226	51	$23,946	39	$33,348	$77,520
	SALE FOR RESALE	38	$74,139	115	$369,977	88	$428,478	$872,594
	********** TOTALS	488,671	$71,826,091	44,161	$8,493,775	1,225	$1,557,034	$81,876,899
	Total without Sale for Resale	488,633	$71,751,952	44,046	$8,123,798	1,137	$1,128,556	$81,004,306

1/2 AMI	Non-AMI	Total Non-AMI
$128,805	$1,760,052	$1,888,857

IPCO METER INFORMATION SYSTEM COST OF METERING REPORT FOR THE STATE OF IDAHO

		METERS		CURRENT TRANSFORMERS		VOLTAGE TRANSFORMER		TOTAL
	RATE DESCRIPTION	NUMBER	*DOLLARS	NUMBER	*DOLLARS	NUMBER	*DOLLARS	*DOLLARS
00	COMPANY USE	103	$40,713.01	101	$13,373.39	3	$0.00	$54,086
01	RESIDENTIAL SERVICE	394,409	$46,713,435.98	4,550	$855,747.46	3	$807.51	$47,569,991
03	MASTER METERED RESIDENTIAL SERVICE	22	$3,602.65	28	$3,982.16	3	$705.66	$8,290
04	RESIDENTIAL SERVICE - ENERGY WATCH	47	$9,958.65	3	$363.89	0	$0.00	$10,323
05	RESIDENTIAL SERVICE - TOU	80	$16,452.22	1	$149.06	0	$0.00	$16,601
07	SMALL GENERAL SERVICE	28,808	$5,180,116.15	1,707	$301,550.33	10	$3,035.12	$5,484,702
07B	SMALL GENERAL SERVICE - BPA	477	$64,054.23	3	$297.39	0	$0.00	$64,352
09P	LARGE GENERAL SERVICE	179	$236,329.12	540	$276,475.99	331	$374,042.80	$886,848
09S	LARGE GENERAL SERVICE	29,042	$10,990,339.70	26,045	$4,609,546.85	139	$96,405.78	$15,696,292
09SB	LARGE GENERAL SERVICE - BPA	264	$86,679.46	262	$51,080.23	3	$705.66	$138,465
09T	LARGE GENERAL SERVICE	3	$3,433.34	8	$10,297.58	8	$4,359.10	$18,090
19P	UNIFORM RATE-INDUSTRIAL	126	$163,667.00	375	$201,182.27	332	$348,165.52	$713,015
19S	UNIFORM RATE-INDUSTRIAL	1	$1,293.17	3	$393.45	0	$0.00	$1,687
19T	UNIFORM RATE-INDUSTRIAL	4	$4,411.81	12	$6,796.53	12	$5,731.26	$16,940
24C	IRRIGATION SERVICE - CONNECTED LOAD	5	$1,155.96	0	$0.00	0	$0.00	$1,156
24CB	IRRIGATION SERV - CONNECTED LOAD - BPA	537	$71,130.44	0	$0.00	0	$0.00	$71,130
24S	IRRIGATION SERVICE - SECONDARY	3	$1,834.80	3	$347.79	0	$0.00	$2,183
24SB	IRRIGATION SERVICE -SECONDARY - BPA	15,445	$5,452,717.59	8,423	$1,336,413.01	63	$20,802.86	$6,809,933
25SB	IRRIGATION SERV SECONDAY - TOU BPA	3	$1,865.50	2	$298.12	0	$0.00	$2,164
41BM	METERED STREET LIGHT - CUST OWNED	8	$1,304.25	0	$0.00	0	$0.00	$1,304
41M	METERED STREET LIGHT	133	$35,059.58	3	$1,004.94	0	$0.00	$36,065
42M	METERED TRAFFIC LIGHT - SM COMM	263	$42,896.09	0	$0.00	0	$0.00	$42,896
84C	SMALL GENERAL SERVICE - NET METERING	9	$1,293.94	0	$0.00	0	$0.00	$1,294
84CS	LARGE GENERAL SERVICE - NET METERING	19	$6,310.82	21	$2,501.75	0	$0.00	$8,813
84R	RESIDENTIAL SERVICE - NET METERING	109	$8,458.39	5	$779.65	0	$0.00	$9,238
87	CSPP CONTRACTS	83	$55,440.88	160	$62,737.24	105	$139,432.20	$257,610
ISBNA	STAND BY NAMPA AMALGAMATED SUGAR	1	$2,445.36	3	$0.00	3	$0.00	$2,445
ISBPL	STAND BY PAUL AMALGAMATED SUGAR	2	$1,248.08	6	$8,539.10	6	$27,453.27	$37,240
ISBT1	STAND BY TF AMALGAMATED SUGAR	1	$1,918.29	3	$2,154.27	3	$2,194.23	$6,267
	********** SUB-TOTAL	470,186	$69,199,566	42,267	$7,746,012	1,024	$1,023,841	$77,969,420
	SPECIAL CONTRACTS	18	$20,226	51	$23,946	39	$33,348	$77,520
	********** TOTALS	470,204	$69,219,792	42,318	$7,769,958	1,063	$1,057,189	$78,046,940

Idaho Transformers Allocation (including special contract and sales for resale)	95.58%
Idaho Transformers Allocation (excluding special contract and sales for resale)	96.00%
Idaho Transformers Allocation (excluding sales for resale)	96.01%

1/2 AMI	Non-AMI	Total Non-AMI
10,781	$132,189	$142,969

IPCO METER INFORMATION SYSTEM COST OF METERING REPORT FOR THE STATE OF OREGON

		METERS		CURRENT TRANSFORMERS		VOLTAGE TRANSFORMER		TOTAL
	RATE DESCRIPTION	NUMBER	*DOLLARS	NUMBER	*DOLLARS	NUMBER	*DOLLARS	*DOLLARS
00	COMPANY USE	22	$10,248.98	15	$310.95	12	$1,434.06	$11,994
01	RESIDENTIAL SERVICE	13,485	$1,360,671.93	267	$63,488.72	1	$79.52	$1,424,240
07	SMALL GENERAL SERVICE-OREGON	2,425	$395,917.87	229	$40,108.76	6	$1,256.97	$437,284
07B	SMALL GENERAL SERVICE - BPA							$0
09P	LARGE GENERAL SERVICE-OREGON	5	$4,643.16	15	$3,988.83	12	$2,822.64	$11,455
09S	LARGE GENERAL SERVICE-OREGON	945	$313,017.19	1,010	$158,446.73	6	$841.04	$472,305
09SB	LARGE GENERAL SERVICE - BPA	9	$2,366.86	18	$3,015.18	0	$0.00	$5,382
09T	LARGE GENERAL SERVICE	1	$1,293.17	3	$18,000.00	3	$18,000.00	$37,293
19P	UNIFORM RATE-INDUSTRIAL	7	$10,355.59	21	$20,404.50	21	$21,387.72	$52,148
19T	UNIFORM RATE-INDUSTRIAL	1	$1,293.17	3	$12,000.00	3	$18,000.00	$31,293
24CB	IRRIGATION SERV - CONNECTED LOAD - BPA	142	$12,441.75	0	$0.00	0	$0.00	$12,442
24S	IRRIGATION SERVICE -SECONDARY	1	$510.97	3	$327.90	0	$0.00	$839
24SB	IRRIGATION SERVICE -SECONDARY - BPA	1,374	$414,715.04	127	$22,600.12	2	$185.30	$437,500
41M	METERED STREET LIGHT	1	$1,733.31	0	$0.00	0	$0.00	
42M	METERED TRAFFIC LIGHT - SM COMM	1	$17.74	0	$0.00	0	$0.00	$18
84C	SMALL GENERAL SERVICE-NET METERING	1	$112.61	3	$257.73	0	$0.00	$370
84CS	LARGE GENERL SERVICE - NET METERING	2	$306.05	3	$257.73	0	$0.00	$564
84R	RESIDENTIAL SERVICE - NET METERING	3	$101.59	0	$0.00	0	$0.00	$102
87	CSPP CONTRACTS	4	$3,851.52	8	$10,350.41	8	$7,359.28	$21,561
OADHR	OREGON ALT DIST HOLY ROSARY	1	$294.02	3	$282.39	0	$0.00	$576
	********** TOTALS	18,430	$2,533,893	1,728	$353,840	74	$71,367	$2,957,366

Oregon Transformers Allocation	4.00%
Oregon Transformers Allocation (including sales for resale and special contract)	3.97%
Oregon Transformers Allocation (including special contract)	3.99%
Oregon Allocation taking into account Idaho share	4.42%
Staff Recommendation	4.15%

CASE: UE 233
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Direct Testimony

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC or Commission) as the Senior Financial Economist in the Economic and Policy Analysis Section. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualifications Statement is found in Exhibit Staff/701, Ordonez /1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is threefold: first, to review Idaho Power Company's (Idaho Power or Company) Cost of Long-Term Debt (Cost of LT Debt); secondly, to review the Company's Transmission Plant Additions for 2011 (2011 Transmission Additions); and finally, to review the Company's proposal to reduce revenues from facilities charges.

In conducting the three aforementioned reviews, Staff referred to the Company's initial filing and approximately 61 data requests pertaining to Cost of LT Debt, 2011 Transmission Additions and revenues from facilities charges.

Q. HAVE YOU PREPARED EXHIBITS FOR THIS DOCKET?

A. Yes, I have prepared the following exhibits:

1. Staff Exhibit/701 consisting of one page,
2. Staff Exhibit/702 consisting of four pages,
3. Staff Exhibit/703 consisting of six pages, and

4. Confidential Staff Exhibit/704 consisting of six confidential pages.

SUMMARY RECOMMENDATION

Q. WHAT IS YOUR SUMMARY RECOMMENDATION?

A. I recommend that the Commission adopt a Cost of LT Debt for Idaho Power of 5.623 percent[1] rather than the Company-proposed 5.728 percent.[2] The Oregon jurisdictional revenue requirement impact of this adjustment is combined with the Rate of Return adjustment in Item S-0 of Exhibit Staff/102 Bird/1.

I also recommend that the Commission exclude the $7.09 million of capital costs for the three transmission projects[3] that constitute the Company's 2011 Transmission Additions. The Oregon jurisdictional revenue requirement impact of this adjustment is a $23,000 reduction in Item S-6, of Exhibit Staff/102 Bird/1.

Finally, I recommend that the Commission not accept the Company-wide reduction of approximately $1.21 million[4] in Other Operating Revenues[5] from facilities charges unless and until the methodology used to assess facilities charges is addressed in Case No. IPC-E-11-08[6] at the Idaho Public Utilities

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[1] See OPUC's Docket No. UE 233, Exhibit Staff/702, Ordonez/1, line 25, column 11.
[2] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, line 25, column 11.
[3] The three transmission projects and the breakdown of the $7.09 million are described in greater detail later in this testimony.
[4] See OPUC's Docket No. UE 233, Exhibit Idaho Power/904 Noe/9, line 381, column 6.
[5] See OPUC's Docket No. UE 233, Exhibit Idaho Power/904 Noe/9, line 398.
[6] See IPUC's Case No. IPC-E-11-08 in www.puc.idaho.gov/internet/cases/summary/IPCE1108.html.

Commission (IPUC). The Oregon jurisdictional revenue requirement impact of this adjustment is a $69,000[7] reduction in Item S-10 of Exhibit Staff/102 Bird/2.

Q. HAVE YOU PREPARED TABLES THAT SUMMARIZE STAFF'S RECOMMENDATION?

A. Yes, Table 1 summarizes the Company-proposed and Staff-recommended Cost of LT Debt for Idaho Power.

Table 1

Cost of Long-Term Debt		
Company Proposed	**Staff Recommended**	**Adjustment**
5.728%	5.623%	(0.105%)

Table 2 summarizes the Company-proposed 2011 Transmission Additions which Staff is recommending adjustments.

Table 2

Company-wide 2011 Transmission Additions ($ Millions)			
Project	**Company Proposed**	**Staff Recommended**	**Adjustment**
Increase T342 to 700 MVA	$4.18	$0	($4.18)
Victory Line[8]	$1.76	$0	($1.76)
Kimberly Line[9]	$1.15	$0	($1.15)
Total	**$7.09**	**$0**	**($7.09)**

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[7] Per OPUC's Docket No. UE 233, Exhibit Idaho Power/1200 Sparks/24, lines 5-6, the Company estimates an impact of approximately $76,000 per year.

[8] Also referred to as the "Victory Lines and Stations" project in OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 5.

[9] Also referred to as the "Kimberly Lines and Stations" project in OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 6.

Table 3 summarizes the Company-proposed and Staff-recommended company-wide reduction of Other Operating Revenues corresponding to facilities charges.

Table 3

Other Operating Revenues from Facilities Charges for 2011 ($ Thousands)			
	Company Proposed	**Staff Recommended**	**Adjustment**
Company-Wide	$6,313	$7,527	$1,214
Oregon-Allocated	$359	$428	$69

1. COST OF LT DEBT

Q. WHAT IS LONG-TERM DEBT?

A. Per Docket UE-116, *"The Commission has defined long-term debt as any debt with a maturity of more than one year. Concomitantly, the definition of short-term debt is a debt with a maturity of one year or less."*[10]

Q. WHAT IS IDAHO POWER'S PROPOSED COST OF LT DEBT?

A. In Exhibit Idaho Power/503 Keen/1, Idaho Power proposes a Cost of LT Debt of 5.728 percent as of December 31, 2011.[11, 12]

Q. HOW DID IDAHO POWER ARRIVE AT THE 5.728 PERCENT FIGURE?

A. Idaho Power calculated the Cost of LT Debt primarily based on each debt series' Coupon Rate[13] and Issuance Costs[14] to produce a Yield to Maturity.[15]

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[10] See OPUC's Docket No. UE-116, Order No. 01-787, page 14.
[11] See OPUC's Docket No. UE 233, Exhibit Idaho Power/502 Keen/1, line 1, column 4.
[12] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, line 25, column 11.
[13] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, column 2.

The Yield to Maturity for each debt series was then multiplied by the Principal Amount Outstanding[16] of each debt issue to yield the Effective Cost.[17] The sum of the Effective Cost for all debt issuances represents the Cost of LT Debt on a dollar-value basis,[18] which, when divided by the sum of the Net Proceeds for all issuances,[19] yields the Cost of LT Debt on a percentage basis.[20]

Q. DOES STAFF DISAGREE WITH THE METHODOLOGY IDAHO POWER USED TO ESTIMATE ITS COST OF LT DEBT?

A. Staff does not disagree with the methodology, but disagrees with the inclusion of a series of bonds that is in fact short-term debt.

Q. PLEASE EXPLAIN.

A. In the estimation of its Cost of LT Debt, the Company included a series of bonds maturing in November 2012[21] (4.75 Percent Series). This series of bonds constitutes short-term debt as of the end of the test year of 2011, and therefore should not be included in the Company's Cost of LT Debt.[22]

Q. WHAT IS STAFF'S ADJUSTMENT REGARDING THE 4.75 PERCENT SERIES OF BONDS?

A. Staff has assumed replacement of the 4.75 Percent Series due November 15, 2012 with a *pro forma* 3.378 percent series of bonds[23] (3.378 Percent *pro*

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[14] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, column 10.
[15] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, column 11.
[16] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, column 6.
[17] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, column 12.
[18] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, line 25, column 12.
[19] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, line 25, column 10.
[20] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, line 25, column 11.
[21] See OPUC's Docket No. UE 233, Exhibit Idaho Power/503 Keen/1, line 1.
[22] See OPUC's Docket No. UE-116, Order No. 01-787, page 14.
[23] See OPUC's Docket No. UE 233, Exhibit Staff/701, Ordonez/1, line 1.

forma Series) maturing in ten years. The 3.378 percent coupon is the yield of Single A Utility Bonds, USD US Utility (A) as of November 15, 2011, as retrieved from Bloomberg Finance L.P.[24] The issuance costs[25] value used to derive the Yield to Maturity of 3.572[26] percent for the 3.378 Percent *pro forma* Series was estimated by averaging the issuance costs of two series of bonds issued in 2010.[27]

Q. HOW DID STAFF CHOOSE A TEN-YEAR MATURITY FOR THE 3.378 PERCENT PRO FORMA SERIES?

A. Idaho Power's Debt Distribution[28] as provided by Bloomberg Finance L.P. does not identify any series of bonds maturing in 2021.

Q. WHAT IS IDAHO POWER'S COST OF LT DEBT AFTER STAFF'S ADJUSTMENT?

A. After Staff's adjustment, Idaho Power's Cost of LT Debt is 5.623 percent.[29]

2. 2011 TRANSMISSION ADDITIONS

Q. WHAT ARE IDAHO POWER'S PROPOSED 2011 TRANSMISSION ADDITIONS?

A. The Company's initial filing included three transmission projects as Major Plant Additions for 2011:[30, 31]

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[24] See OPUC's Docket No. UE 233, Exhibit Staff/702, Ordonez/2-3.

[25] See OPUC's Docket No. UE 233,Exhibit Staff/701, Ordonez/1, line 10, column 9.

[26] See OPUC's Docket No. UE 233, Exhibit Staff/701, Ordonez/1, line 1, column 11.

[27] See Exhibit Staff/701, Ordonez/1, line 22, column 9; and Exhibit Staff/701, Ordonez/1, line 23, column 9.

[28] See OPUC's Docket No. UE 233, Exhibit Staff/702, Ordonez/4.

[29] See OPUC's Docket No. UE 233, Exhibit Staff/702, Ordonez/1, line 25, column 11.

[30] See OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1.

1. Increase T342 to 700 MVA project,[32]
2. Victory Line project,[33] and
3. Kimberly Line project.[34]

Q. HAS THE COMPANY PROVIDED A DESCRIPTION OF THE THREE PROJECTS ENUMERATED ABOVE?

A. Yes. In confidential response to Staff Data Request 165, part "a,"[35] the Company provided a description of each project. Additionally, in confidential response to Staff Data Request 165, part "b," the Company provided diagrams representing the configuration of each project. The Victory Line and the Kimberly Line are short[36] transmission lines. The Company also provided the projects' capital costs[37] as shown below in Table 4:

Table 4

Capital Costs ($ Millions)					
Project	**Labor**	**Materials**	**Vehicles**	**Other**	**Project Total**
Increase T342 to 700 MVA	$0.06	$4.11	$0.01	$0.01	$4.18
Victory Line	$0.59	$1.02	$0.09	$0.06	$1.76
Kimberly Line	$0.38	$0.67	$0.06	$0.04	$1.15
Total	**$1.03**	**$5.80**	**$0.16**	**$0.10**	**$7.09**

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[31] In OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, "Major Plant Additions for 2011," the Company included several capital additions such as transmission, distribution, meters, power supply, and corporate administration support. For the purpose of this testimony, Staff focused on the transmission capital additions.

[32] See OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 3.

[33] See OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 5.

[34] See OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 6.

[35] See OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/1-2 (Idaho Power's confidential part of response to Staff Data Request 165, part "a").

[36] See OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/2 (Idaho Power's confidential part of response to Staff Data Request 165, part "a").

[37] See OPUC's Docket No. UE 233, Exhibit Staff/703, Ordonez/1-2 (Idaho Power's non-confidential part of response to Staff Data Request 165).

Q. DID STAFF MAKE ADJUSTMENTS TO THE COMPANY-PROPOSED 2011 TRANSMISSION ADDITIONS?

A. Yes. Staff made three adjustments to the Company-proposed 2011 Transmission Additions.

Q. WHAT IS STAFF'S FIRST ADJUSTMENT?

A. Staff's first adjustment is to the approximately $4.18 million of capital costs for the "Increase T342 to 700 MVA" project. In the Company's response to Staff Data Request 312,[38] the Company updated the in-service date of this project from June 2011 to June 2012. The tariffs filed with the Company's request for a rate increase have an effective date of June 1, 2012, which is prior to the Company's projected in-service date for this project. Therefore, Staff excluded this project from the Company's 2011 Transmission Additions, because it will not be used to serve customers before the new rates go into effect.

Q. WHAT ARE STAFF'S SECOND AND THIRD ADJUSTMENTS?

A. Staff's second adjustment is to the approximately $1.76 million of capital costs for the Victory Line.[39] Staff's third adjustment is to the approximately $1.15 million of capital costs for the Kimberly Line.[40] Both facilities are short lines[41] located entirely within the State of Idaho,[42,43] and should not be allocated to the Company's customers in Oregon.

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[38] See OPUC's Docket No. UE 233, Exhibit Staff/703, Ordonez/3-4 (Idaho Power's response to Staff Data Request 312).

[39] See OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 5.

[40] See OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 6.

[41] See "comments" included in OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/2.

[42] For the Victory Line, see OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 5, column (4). Also see OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/3.

Q. WHAT IS THE STANDARD PRACTICE FOR ALLOCATING TRANSMISSION FACILITIES?

A. The standard practice is that transmission facilities, typically defined with reference to voltage threshold, are assigned system-wide.

Q. ARE THERE INSTANCES IN WHICH IT MIGHT BE APPROPRIATE TO ASSIGN "TRANSMISSION" FACILITIES ON A SITUS BASIS?

A. Yes, but such instances are rare. Transmission facilities should be treated as situs when such facilities clearly serve as distribution facilities in providing power solely to a specific location within a state and the lines are such that there are no economic and reliability benefits captured by other states through the existence of the line.

Q. DO THE VICTORY AND KIMBERLY LINES PROVIDE ANY ECONOMIC OR RELIABILITY BENEFITS TO THE COMPANY'S OREGON CUSTOMERS?

A. No. Both lines are short, [44] have the characteristics of distribution facilities that exclusively serve distribution substations located in Idaho,[45,46] and supply electricity and improve reliability only for the Company's Idaho customers.[47]

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[43] For the Kimberly Line, see OPUC's Docket No. UE 233, Exhibit Idaho Power/901 Noe/1, line 6, column (4). Also see OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/5.

[44] See "comments" included in OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/2.

[45] For the Victory Line, see the diagram included in OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/4 (Idaho Power's confidential part of response to Staff Data Request 165, Attachment 2).

[46] For the Kimberly Line, see the diagram included in OPUC's Docket No. UE 233, Confidential Exhibit Staff/704, Ordonez/6 (Idaho Power's confidential part of response to Staff Data Request 165, Attachment 1).

[47] See OPUC's Docket No. UE 233, Exhibit Staff/703, Ordonez/5 (Idaho Power's response to Staff Data Request 372, parts "a-d").

Therefore, costs associated with those transmission lines should not be recovered from Oregon ratepayers.

3. FACILITIES CHARGES

Q. WHAT ARE FACILITIES CHARGES?

A. "*The facilities charge[s] [service] is a service that allows primary and transmission service level customers the option, when agreed to by Idaho Power, of having electrical facilities necessary to supply service beyond the Company's point of delivery owned, operated, and maintained by Idaho Power in consideration of the customer paying a monthly charge. Idaho Power provides this service at its option to the approximately 240 Idaho jurisdictional customers that have requested it.*"[48]

The Company provides this service to approximately 12 Oregon jurisdictional customers, who represent approximately 4.8 percent of the total number of customers using this service.

Q. HOW WERE THE CURRENT RATES FOR FACILITIES CHARGES ESTABLISHED IN OREGON?

A. The rates for facilities charges in the Company's Oregon jurisdiction are equal to those in the Company's Idaho jurisdiction.[49] The rates for facilities charges were reviewed by the IPUC in 1987 in Case No. U-1006-298; under the same case in 1988, Order No. 21836 reaffirmed that the rates for facilities charges

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[48] See IPUC's Case No. IPC-E-11-08; Exhibit Kline, Reb/2; lines 6-15; www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1108/company/20111116KLINE%20REBUTTAL.PDF.

[49] See OPUC's Docket No. UE 233, Exhibit Idaho Power/1200 Sparks/20, lines 1-2.

were reasonable and should remain unchanged.[50] Since then, the Company has not reviewed the rates for facilities charges.

Q. DOES THE COMPANY INTEND TO UPDATE THE CURRENT RATES FOR FACILITIES CHARGES IN IDAHO?

A. Yes. The Company has filed with the IPUC an update to the rates for facilities charges in Case No. IPC-E-11-08, currently pending.[51] That update is identical to the update in Docket UE-233[52] that the Company has filed with the OPUC.

Q. WHAT IS THE STATUS OF THE FACILITIES CHARGES ON IPUC'S CASE NO. IPC-E-11-08?

A. Per Order No. 32380 of Case No. IPC-E-11-08 entered on October 13, 2011,[53] parties have agreed to resolve all but three of the issues in Case No. IPC–E–11–08; the unresolved issues include the methodology used to assess facilities charges.[54] The IPUC has scheduled a technical hearing to address the unresolved issues December 5-6, 2011.[55]

Q. WHAT IS THE IMPACT OF CHANGING THE RATES FOR FACILITIES CHARGES IN THE COMPANY'S REVENUE REQUIREMENT?

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[50] See IPUC's Case No. IPC-E-11-08; Exhibit Sparks, DI 34, lines 24-25; and Exhibit Sparks, DI 35, lines 1-4; www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1108/company/20110602SPARKS%20DI,%20EXHIBITS.PDF.

[51] See IPUC's Case No. IPC-E-11-08; Direct Testimony of Idaho Power's Scott Sparks; SPARKS, DI 34-41; www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1108/company/20110602SPARKS%20DI,%20EXHIBITS.PDF.

[52] See OPUC's Docket No. UE 233, Exhibit Idaho Power/1200 Sparks/19-24.

[53] See www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1108/ordnotc/20111013NOTICE_OF_PARTIAL_SETTLEMENT_ORDER_NO_32380.PDF.

[54] See IPUC's Case No. IPC-E-11-08, Order No. 32380, page 3, "7. Unresolved Issues."

[55] See IPUC's Case No. IPC-E-11-08, Order No. 32380, page 3, "Amended Notice of Technical Hearing."

A. Changing the rates for facilities charges will increase the Oregon-allocated revenue requirement by approximately $69,000.

Q. WHAT IS YOUR RECOMMENDATION IN THIS CASE?

A. I recommend that Idaho Power's proposed changes to facilities charges not be included in this case until the IPUC has ruled on the issue in Case No. IPC-E-11-08.

Q. DOES THE OREGON COMMISSION TYPICALLY FOLLOW THE IPUC DECISIONS WHEN SETTING OREGON RATES?

A. No. However, since this has been vetted in the IPUC in the past and adopted in Oregon, the IPUC ruling on this issue will result in a more consistent basis for the rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Financial Economist, Economic and Policy Analysis Section
ADDRESS	550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2115
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008 Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007 Fulbright Scholar, MBA, concentration in finance Willamette University, Oregon, 2005 Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002 BS, Mechanical Engineering, thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist in the Economic Research and Financial Analysis Division, evaluating utilities' issuance of securities, cost of capital, marginal cost studies, mergers and acquisitions, and integrated resource plans.

CASE: UE 233
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

December 7, 2011

Exhibit Staff 702 Ordonez-1 (from Attachment - Response MDR No 38)

IDAHO POWER COMPANY

STAFF ADJUSTMENT OF PRO FORMA COST OF LONG-TERM DEBT

As of 12/31/2011

(000's)

3.378% is the yield of Single A Utility Bonds, USD US Utility (A), as of November 15, 2011, as retrieved from Bloomberg Finance L.P.

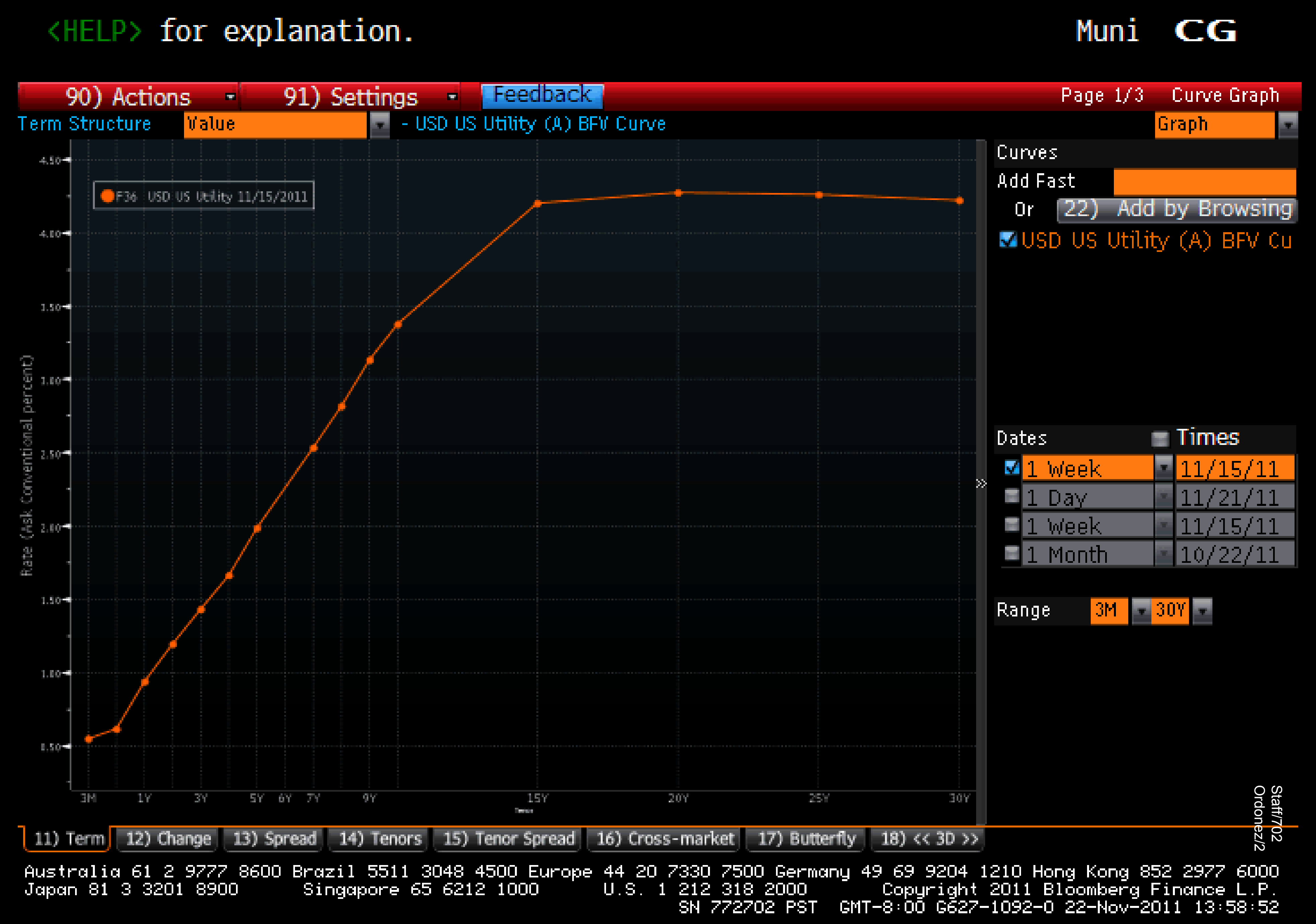
Issuance Cost average of the 3.4% and 4.85% Series issued in 2010.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line		Coupon	Settlement	Maturity	Principal Amount				Issuance	Net	Yield To	Effective
No.	Class and Series	Rate	Date	Date	Issued	Outstanding	Price	Discount	Costs	Proceeds	Maturity	Cost
	First Mortgage Bonds:											
1	3.378 % *pro forma* Series, due 2018	3.378 %	11/15/2011	11/15/2018	100,000	100,000	100.000	0.0	1,191.9	98,808.1	3.572%	3,572.0
2	6.00% Series, due 2032	6.00%	11/15/2002	11/15/2032	100,000	100,000	99.456	544.0	1,191.2	98,264.8	6.127%	6,127.1
3	4.25% Series, due 2013	4.25%	5/13/2003	10/1/2013	70,000	70,000	99.465	374.5	641.2	68,984.3	4.425%	3,097.7
4	5.5% Series, due 2033	5.5%	5/13/2003	4/1/2033	70,000	70,000	99.948	36.4	4,335.2	65,628.4	5.949%	4,164.3
5	5.5% Series, due 2034	5.5%	3/26/2004	3/15/2034	50,000	50,000	99.233	383.5	524.4	49,092.1	5.626%	2,813.0
6	5.875% Series, due 2034	5.875%	8/16/2004	8/15/2034	55,000	55,000	98.640	748.0	585.8	53,666.2	6.051%	3,328.2
7	5.30% Series, due 2035	5.30%	8/26/2005	8/15/2035	60,000	60,000	99.319	408.6	3,849.7	55,741.7	5.802%	3,481.3
8	6.30% Series, due 2037	6.30%	6/22/2007	6/15/2037	140,000	140,000	99.801	278.6	1,500.0	138,221.4	6.396%	8,953.9
9	6.25% Series, due 2037	6.25%	10/18/2007	10/15/2037	100,000	100,000	99.732	268.0	1,227.5	98,504.5	6.362%	6,362.3
10	6.025% Series, due 2018	6.025%	7/10/2008	7/15/2018	120,000	120,000	100.000	0.0	1,664.6	118,335.4	6.213%	7,455.6
11	6.15% Series, due 2019	6.15%	3/30/2009	4/1/2019	100,000	100,000	99.815	185.0	1,034.9	98,780.1	6.316%	6,316.3
12	4.50% Series, due 2020	4.50%	11/20/2009	3/1/2020	130,000	130,000	99.819	235.3	1,199.4	128,565.3	4.635%	6,026.0
13	3.40% Series, due 2020	3.40%	8/30/2010	11/1/2020	100,000	100,000	99.501	499.0	1,129.4	98,371.6	3.592%	3,592.2
14	4.85% Series, due 2040	4.85%	8/30/2010	8/15/2040	100,000	100,000	99.830	170.0	1,254.4	98,575.6	4.941%	4,941.5
15												
16	Total First Mortgage Bonds				1,295,000	1,295,000		4,130.9	21,329.9	1,269,539.2	5.532%	70,231.1
17												
18	Pollution Control Revenue Bonds:											
19	Sweetwater 5.25% Series, due 2026	5.25%	8/20/2009	7/15/2026	116,300	116,300	100.000	0.0	8,634.3	107,665.7	5.952%	6,922.2
20	Humboldt 5.15% Series 2003, due 2024	5.15%	8/20/2009	12/1/2024	49,800	49,800	100.000	0.0	4,355.0	45,445.0	6.033%	3,004.5
21	Port of Morrow Series 2000, due 2027	1.55% [1]	5/17/2000	2/1/2027	4,360	4,360	100.000	0.0	170.3	4,189.7	1.731%	75.5
22												
23	Total Pollution Control Revenue Bonds				170,460	170,460		0.0	13,159.7	157,300.3	6.359%	10,002.2
24												
25	TOTAL DEBT CAPITAL				1,465,460	1,465,460		4,130.9	34,489.6	1,426,839.5	5.623%	80,233.3

Staff proposed cost of long-term debt

[1] Forecasted 2011 rate.

NOTE: American Falls Dam Bond and Milner Dam Note are guarantees. These instruments are excluded from rate making calculations and therefore are omitted from this schedule.



Term Structure Value - USD US Utility (A) BFV Curve Graph

☑ USD US Utility (A) BFV Cu

Dates	Times
☑ 1 Week	11/15/11
☐ 1 Day	11/21/11
☐ 1 Week	11/15/11
☐ 1 Month	10/22/11

Range 3M 30Y

Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2011 Bloomberg Finance L.P.
SN 772702 PST GMT-8:00 G627-1092-0 22-Nov-2011 13:58:52

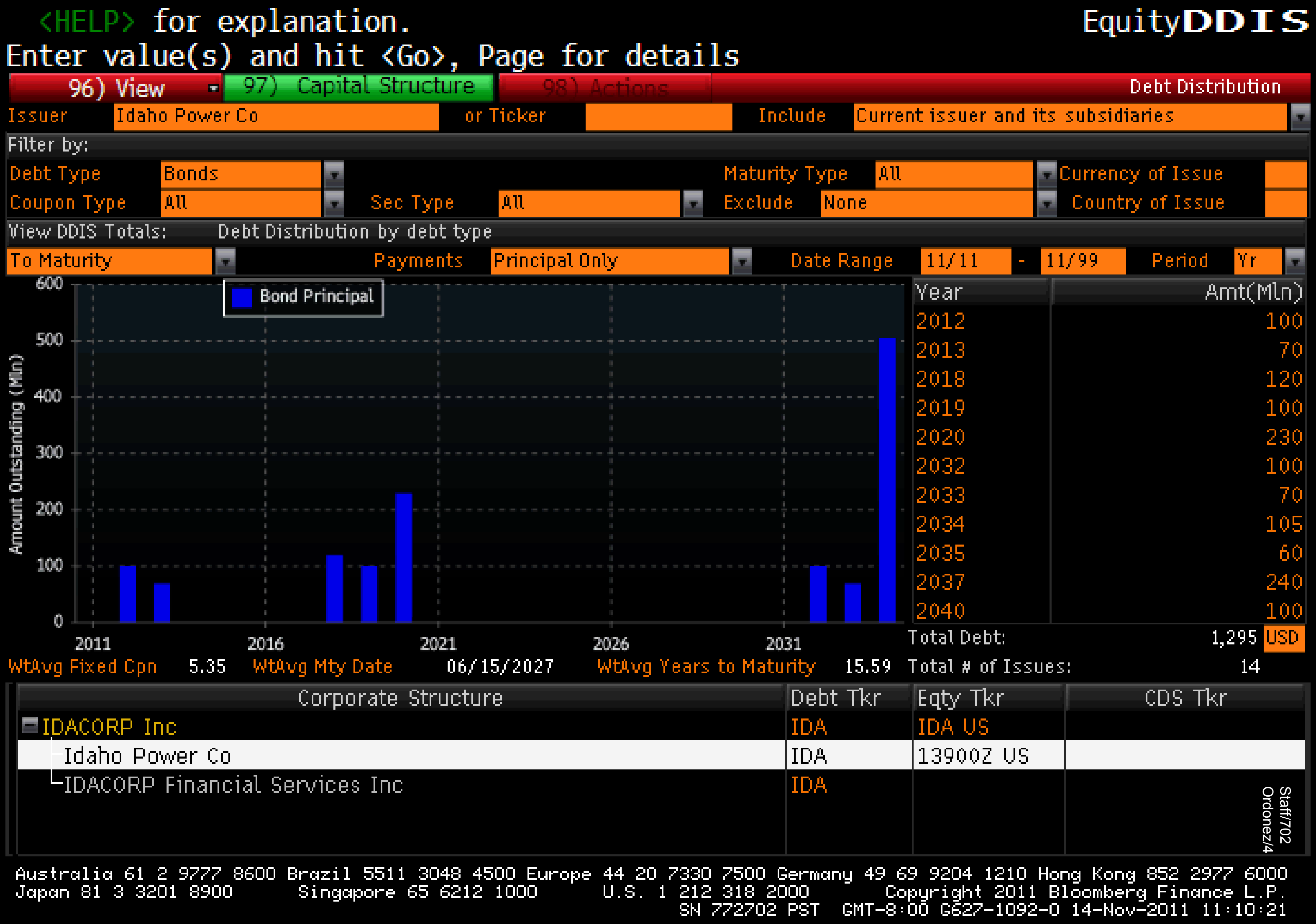
Staff/702
Ordonez/2

Date	F36 USD US Utility 11/15/2011
3M	0.553
6M	0.613
1Y	0.939
2Y	1.193
3Y	1.433
4Y	1.664
5Y	1.99
7Y	2.535
8Y	2.819
9Y	3.137
10Y	3.378
15Y	4.199
20Y	4.278
25Y	4.259
30Y	4.223

☑	1 Week	11/15/11
☐	1 Day	11/21/11
☐	1 Week	11/15/11
☐	1 Month	10/22/11

Staff/702
Ordonez/3

Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2011 Bloomberg Finance L.P.
SN 772702 PST GMT-8:00 G627-1092-0 22-Nov-2011 14:00:27



<HELP> for explanation.
Enter value(s) and hit <Go>, Page for details

Equity DDIS

Debt Distribution

Issuer: Idaho Power Co
or Ticker:
Include: Current issuer and its subsidiaries

Filter by:

Debt Type: Bonds
Maturity Type: All
Currency of Issue:
Coupon Type: All
Sec Type: All
Exclude: None
Country of Issue:

View DDIS Totals: Debt Distribution by debt type

To Maturity
Payments: Principal Only
Date Range: 11/11 - 11/99
Period: Yr

Year	Amt(Mln)
2012	100
2013	70
2018	120
2019	100
2020	230
2032	100
2033	70
2034	105
2035	60
2037	240
2040	100

Total Debt: 1,295 USD

Total # of Issues: 14

WtAvg Fixed Cpn 5.35
WtAvg Mty Date 06/15/2027
WtAvg Years to Maturity 15.59

Corporate Structure	Debt Tkr	Eqty Tkr	CDS Tkr
IDACORP Inc	IDA	IDA US	
Idaho Power Co	IDA	13900Z US	
IDACORP Financial Services Inc	IDA		

Staff/702
Ordonez/4

Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2011 Bloomberg Finance L.P.
SN 772702 PST GMT-8:00 G627-1092-0 14-Nov-2011 11:10:21

CASE: UE 233
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

December 7, 2011

<u>STAFF'S DATA REQUEST NO. 165</u>:

Regarding Exhibit Idaho Power/901 Noe/1, where the Company listed the following transmission additions:

- **Line 1: Station "Kimberly Lines and Substations;"**
- **Line 3: Station "Increase T342 to 700 MVA;"**
- **Line 5: Line "Victory Lines and Substations;"**
- **Line 6: Line "Kimberly Lines and Substations;"**

For each transmission addition above, please provide:

a) A description of the project;
b) A one-line diagram, which shall include such station or transmission line;
c) A breakdown of capital costs;
d) The ex ante financial analysis conducted by the Company prior to deciding to go forward with the project, including the present value of revenue requirement (PVRR) and the present value of benefits or savings in net power costs.
e) The ex post financial analysis conducted by the Company with the PVRR and present value of benefits in net power costs.
f) Has the Public Utility Commission of Oregon acknowledged this project in any Integrated Resource Plan? If "yes," please provide docket and order number indicating such acknowledgment. If not, please explain why the Company proceeded to build the project.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 165</u>:

a) **The response to Data Request No. 165(a) is confidential and will be provided separately in accordance with Protective Order No. 11-288 issued in this matter.**

b) Please see the confidential attachments for each substation or transmission line.

The files produced in response to Data Request No. 165(b) are confidential and will be provided separately in accordance with Protective Order No. 11-288 issued in this matter.

c) **Line 1: Station "Kimberly Lines and Substations"**

Labor	$41,565
Materials	$ 7,650
Vehicles	$ 2,106
Total	$51,321

Line 3: Station “Increase T342 to 700 MVA”

Labor	$ 55,108
Materials	$4,108,134
Vehicles	$ 8,435
Other	$ 7,927
Total	$4,179,604

Line 5: Line “Victory Lines and Substations”

Labor	$ 593,297
Materials	$1,016,505
Vehicles	$ 92,162
Other	$ 55,075
Total	$1,757,039

Line 6: Line “Kimberly Lines and Substations”

Labor	$ 380,070
Materials	$ 671,352
Vehicles	$ 60,869
Other	$ 36,375
Total	$1,148,666

d) As a regulated utility with an obligation to serve, Idaho Power does not have the option to reject a project that is needed in order to provide safe and reliable electrical service to its customers based on the results of a financial analysis; therefore, PVRR and present value of benefits or savings in net power costs are not performed for every individual project. Projects are identified by specific need (i.e., growth, compliance, reliability) and preferred alternatives are selected based on best operational fit and total project cost. The proposed projects then move through the budgeting process as discussed on page 19 of Darrel Anderson’s direct testimony.

e) As indicated in the Company’s response above, PVRR and present value of benefits in net power costs are not performed for this type of project.

f) The Integrated Resource Plan is geared toward identifying major capacity increases to the Company’s transmission or generation facilities. Distribution lines and substations are not identified in the Integrated Resource Plan process. The decision to proceed with this project was made using Idaho Power’s routine capital project process as described in response (d) above.

STAFF'S DATA REQUEST NO. 312:

Regarding the In Service dates of the following transmission additions represented in Exhibit Idaho Power/901 Noe/1:

Exhibit Line Number	Transmission Station / Transmission Line	Addition	Cost ($)	In service Date
Line 1	Transmission Station	Kimberly Lines and Substations	51,321	June 2011
Line 3	Transmission Station	Increase T342 to 700 MVA	4,179,604	June 2011
Line 5	Transmission Line	Victory Lines and Substations	1,757,039	November 2011
Line 6	Transmission Line	Kimberly Lines and Substations	1,148,666	June 2011

For each transmission addition above, please:

a) As of September 12, 2011, what is the current projected In Service Date for each of the above-identified Transmission Plant Additions?

b) For each transmission addition In Service Date that has changed from the date represented in the preceding table, provide an explanation of any delay or advance.

c) Assuming the transmission addition comes into service as projected above, would each of the transmission additions also be considered by the company as used and useful from an Oregon perspective? If not, which addition(s) would not be used and useful?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 312:

a) Updated In Service Dates for each project are provided in the table below.

Exhibit Line Number	Transmission Station / Transmission Line	Addition	Cost ($)	In service Date
Line 1	Transmission Station	Kimberly Lines and Substations	51,321	July 2011
Line 3	Transmission Station	Increase T342 to 700 MVA	4,179,604	June 2012
Line 5	Transmission Line	Victory Lines and Substations	1,757,039	July 2011
Line 6	Transmission Line	Kimberly Lines and Substations	1,148,666	July 2011

b) **Idaho Power/901, Noe/1 – Line 1**

The In Service Date was delayed due to the contractor not installing getaway conduit according to design. An Idaho Power crew followed up after the contractor and discovered the conduit did not line up, causing a two to three week delay in the project being placed In Service.

Idaho Power/901, Noe/1 – Line 3

The transformer for this project was damaged during transit by the manufacturer, causing a one-year delay on placing this project In Service.

Idaho Power/901, Noe/1 – Line 5

This project was completed ahead of estimated In Service Date.

Idaho Power/901, Noe/1 – Line 6

This is a transmission line project tied to a station project. There was a delay in the station project, causing a delay in the transmission line being energized.

c) Yes. If each of the transmission additions were to come on-line as originally projected, each would be considered by the Company to be “used and useful” from an Oregon perspective based upon their In Service Date.

STAFF'S DATA REQUEST NO. 372:

Regarding the following projects/plant additions represented in Exhibit Idaho Power/901 Noe/1,

Project/Plant Addition	Annualized Plant ($)	Net Annualizing Adjustments ($)	State
Victory Lines and Stations[1]	$ 1,757,039	$ 1,486,725	Idaho
Kimberly Lines and Stations[2]	$ 1,199,987	$ 553,840	Idaho
Total	$ 7,136,630	$ 3,969,613	

For each (emphasis added) project/plant addition, please:

a. Provide the number of Idaho Power's Oregon (emphasis added) customers by customer class (e.g., residential customers, commercial customers, industrial customers, etc.) that are served from such project/plant addition as of the most current date for which the Company has data. Please indicate the date and interval of time for which the data was valid.

b. Provide a one-line diagram identifying each project/plant addition and the distribution substations in Oregon (emphasis added) served from each project/plant addition.

c. Explain how each project/plant addition benefits Oregon (emphasis added) customers.

d. Provide historical data and one-line schematics of power flows demonstrating that each project/plant addition used to supply power to Oregon (emphasis added) customers. Please indicate the date and interval of time for which the data was valid.

e. Provide the voltage level of each project/plant addition.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 372:

a-d. As indicated in the table referenced in this response, "Victory Lines and Stations" and "Kimberly Lines and Stations" represent projects located in Idaho. Therefore, the information requested in subsections a through d is not pertinent to these projects. The referenced projects involve the construction of radial line additions to Idaho Power's electrical system required to serve native load and provide reliable transmission service to its customers.

As customers taking service from the Company's bulk electrical system, Idaho Power's Oregon customers are assigned or "allocated" a share of the total electrical system costs in the ratemaking process on the basis of the Oregon jurisdictional share of the monthly system peak demands. This approach has been applied by Idaho Power and accepted

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[1] See Line 5 of Exhibit Idaho Power/901 Noe/1.

[2] See Lines 1 and 6 of Exhibit Idaho Power/901 Noe/1.

by the Public Utility Commission of Oregon ("Commission") in prior general rate case proceedings and is consistent with the preferred cost allocation methodology endorsed by the National Association of Regulatory Utility Commissioners. Under this approach, the situs of electric plant in service is not relevant, only that the electric plant is providing service on the Company's bulk electrical system. The Company is not aware that the Commission has ever required or indicated a preference for an Oregon jurisdictional revenue requirement determination based upon the situs of electric plant and equipment.

e. The voltage level of the referenced projects is 138 kV.

CASE: UE 233
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

Exhibits in Support
Of Opening Testimony

December 7, 2011

STAFF EXHIBIT 704

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 11-288. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 233 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 233
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as Program Manager of the Economic and Policy Analysis section. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is included as Exhibit Staff/801.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I develop recommended cost of common equity[1] estimates for the rate-regulated property of Idaho Power Company ("Idaho Power" or "Company"). I provide a point estimate recommendation, as well as a range of estimates, of Idaho Power's cost of common equity for consideration by the Public Utility Commission of Oregon ("Commission") in establishing Idaho Power's authorized return on equity (ROE) within the Company's current general rate case in Docket No. UE 233. Additionally, I provide a recommended capital structure

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[1] Common equity, or common stock, is an "ownership" investment of, say, a corporation, where stockholders "have a general preemptive right to anything of value that the company may wish to distribute." Holders of common stock are the owners of the corporation, unlike holders of preferred stock or debt securities of the corporation. *See Principals of Corporate Finance*; Third Edition; Brealey and Myers; 1988, page 305. *See* also *Principles of Corporate Finance*; Tenth Edition; Brealey, Myers, and Allen; 2011, especially that on page 346, where common stock is characterized as having a residual claim on the firm's assets and cash flow in the presence of debt financing.

associated with the recommended ROE and the recommended rate of return (ROR) based on recommendations in my testimony and the recommended costs of long-term debt as presented in Exhibit Staff/700 Ordonez. The costs of long-term debt, of common equity, and Idaho Power's capital structure are collectively identified as issue S-0.

My testimony constitutes Staff's response, in part, to that provided by Idaho Power witnesses Avera (Idaho Power/400) and Keen (Idaho Power/500).

Q. DID YOU PREPARE ANY EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/802, consisting of two pages (my DCF Model 1 results) and Exhibit Staff/803, consisting of two pages (my DCF Model 2 results).

Q. HAVE YOU MADE DATA REQUESTS OF IDAHO POWER IN THIS PROCEEDING?

A. Yes. Twenty-eight of the 127 standard data requests currently on the PUC website directly relate to the Company's cost of equity or capital structure. Many of the 30 data requests relatingj to debt financing[2] also relate to either cost of equity, capital structure, or both.

Staff data request 378 seeks to obtain functional electronic spreadsheets of Exhibits Idaho Power/402, Idaho Power/403, Idaho Power/404, Idaho Power/405, Idaho Power/406, Idaho Power/407,

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[2] Nearly one-half (46%) of the Standard Data Requests are related to cost of capital.

Idaho Power/408, Idaho Power/409, and Idaho Power/410, as the Company versions of those exhibits did not have "all cell references and formulae intact," and therefore may not meet General Provision A of the Standard Data Requests.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- A. A summary of recommendations;
- B. A brief discussion of return and risk associated with investments in common stocks;
- C. A detailed discussion of my cost of equity estimation methodology, including the comparable companies used, the Discounted Cash Flow (DCF) models used, data utilized and its sources, sensitivity analyses using different assumptions or values of input data, and the implications of differing capital structures and a recommended ROE for Idaho Power;
- D. A discussion of Idaho Power's proposed capital structure and a capital structure recommendation for Idaho Power;
- E. A short discussion regarding Idaho Power's risks;
- F. A discussion of the peer utilities used by Idaho Power;
- G. A discussion of Idaho Power's DCF models and associated Company-recommended rates of return on common equity;[3] and

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[3] Reference to "common equity" and "equity" within this portion of testimony are meant to be synonymous. Similarly, the terms "common stock" and "stock" within this portion

H. A discussion of other methods used by Idaho Power to estimate the Company's cost of equity capital.

SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR ANALYSIS AND CONCLUSIONS.

A. My analysis includes the following:

- I select a group of peer electric companies comparable to Idaho Power in both degree of regulation and risk as perceived by the market.
- I present conclusive evidence that publicly traded and dividend-paying U.S. corporations smooth their dividends; i.e., such companies have earnings that are more volatile than dividends, and therefore have earnings growth rates that can be and currently are higher than their dividend growth rates.
- I use two multistage DCF models, with investment horizons of 25 years and terminal value calculations, with Value Line information to develop estimates of ROEs for both my peer utilities and those of Idaho Power witness Dr. Avera. The second of these two models uses an innovative approach to accommodate forecasted growth in earnings that differ from that of dividends.
- I argue that electric utilities are unlikely over a long-term future to grow as fast as the U.S. economy as measured by GDP. I provide

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of testimony are used synonymously and are equivalent to "common equity" and "equity."

evidence from the only provider of long-term growth estimates of the electric utility industry[4] that the industry will have a rate of growth through at least 2035 that is appreciably less than that of GDP.

- I include the use of forecasted long-term GDP growth as an upper limit on the growth rates of regulated electric utilities.
- I use an accepted method of adjusting the ROE results of each peer utility for capital structures that differ from that of Idaho Power.
- I conclude that use of Dr. Avera's peer utilities produces estimates of ROE that are generally higher than those produced by using my peer utilities.
- I present evidence that Dr. Avera's selected peer utilities, used in several of his ROE models, are much less regulated than is Idaho Power.
- I argue that the presence of material non-regulated lines of business in Dr. Avera's peer utilities as compared with those I use may account for the higher estimated growth rates for his peer utilities.

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. Table 1 (following) illustrates returns on long-term debt and common stock, as well as capital structure, as currently authorized, as proposed

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[4] The Department of Energy's (DOE) Energy Information Administration (EIA) is the only publicly available provider of long-term forecasts of the electric utility industry I have identified. I discuss these forecasts later in this testimony.

in Idaho Power's direct testimony, and as recommended by Staff in this testimony.

Table 1

Idaho Power Capital Structure and Component Returns

		Percent of Total	Rates of Return	Weighted Average
Currently Authorized (UE-213)				
Component				
Long Term Debt		50.20%	5.964%	2.994%
Preferred Stock				
Common Stock		49.80%	10.175%	5.067%
Total		100.00%		8.061%
Idaho Power Proposed (UE-233)				
Component				
Long Term Debt		48.824%	5.728%	2.797%
Preferred Stock				
Common Stock		51.176%	10.500%	5.373%
Total		100.00%		8.170%
Staff Recommended (UE-233)				
Component				
Long Term Debt		50.1%	5.623%	2.817%
Preferred Stock				0.000%
Common Stock		49.9%	9.500%	4.741%
Total		100.0%		7.558%

I recommend a range of return on equity for the Commission to consider of 9.0 to 9.7 percent, along with a point estimate of 9.5 percent, with both range and point estimate associated with a capital structure as proposed in my testimony, which is one of 50.1 percent long-term debt and 49.9 percent common stock. This results in my recommending a rate of return of 7.558 percent inclusive of Staff's recommended cost of long-term debt.[5] The 9.5 percent ROE and 7.558 percent ROR I recommend meet the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statue (ORS) 756.040. My recommendations are consistent with establishing “fair and reasonable rates” that are both “commensurate with the return on investments in other enterprises having corresponding risks” and “sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.”[6] A significant portion of this testimony discusses ROE estimates for other electric utilities and holding companies.

RISKS AND RETURNS OF COMMON EQUITY INVESTMENTS

Q. WHAT DOES “RISK” MEAN WITH RESPECT TO COMMON EQUITY INVESTMENTS?

A. The literature of finance[7] typically defines risk as the variability in outcomes, where outcomes are divergent investor returns[8] over some holding period when compared with an *a priori* expected return for the asset held over a like period. Risk has two aspects: unique risk and market risk. Unique risk is applicable only to the common stock of a

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[5] *See* Exhibit Staff/700 Ordonez for Staff’s recommended cost of long-term debt.

[6] *See* ORS 756.040(1)(a) and (b).

[7] This discussion follows that in *Principles of Corporate Finance*; Tenth Edition; 2011; by Brealey, Myers and Allen, especially that on page 163ff.

[8] Investor returns are <u>total</u> returns; i.e., those resulting from dividends received as well as from realized gains or losses due to security price changes.

specific company;[9] i.e., “unique” to that company. “Unsystematic risk,” “idiosyncratic risk,” “specific risk,” and “diversifiable risk” are other terms by which the concept of unique risk is known. Unique risk can potentially be eliminated by the addition of diversifying investments[10] to an investment portfolio. As emphasized by the authors of a widely used corporate finance textbook,[11] “[f]or a reasonably well-diversified portfolio, only market risk matters” (emphasis added).

Q. HOW IS THE MARKET RISK OF AN INDIVIDUAL STOCK MEASURED?

A. The market risk[12] of an individual stock,[13] in a well-diversified portfolio, is the sensitivity of the stock’s return to those of the stock market as a whole. This measure of sensitivity is termed “beta” and is conventionally represented by the Greek letter β, or beta.[14]

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[9] I recognize companies can and do have different classes of common stocks, which typically differ in voting rights.

[10] A diversifying investment in this context is one whose returns are imperfectly correlated with the portfolio as a whole.

[11] Brealey, Myers and Allen; *op. cit.*, page 170.

[12] Market risk is also known by the terms “systematic risk” and “undiversifiable risk.”

[13] In the current context “individual stock” refers to the common stock of a specific company and “stock market” refers to the market or markets where trading in such common stocks occurs.

[14] The beta (β) of an asset or portfolio is a number describing the relation of its returns with that of the market as a whole. An asset with a beta of zero (0) means that its returns are not at all correlated with the market; the returns of the asset are independent from those of the market. A positive beta means that the asset’s returns generally follow those of the market. A negative beta implies that the asset’s returns inversely follow those of the market; the asset generally decreases in value if the market goes up and vice versa.

The formula for the beta of an asset within a portfolio is

Q. WHAT IS A "WELL-DIVERSIFIED PORTFOLIO?"

A. A well-diversified stock portfolio is one whose dispersion of actual historical returns, measured by standard deviation, approaches that of the stock market as a whole. This implies, for a diversified investor, the primary source of investment uncertainty is with respect to market risk.

The stock market as a whole, by the standard definition, has a beta of 1.0, so a well-diversified portfolio also has a beta of 1.0 (or very nearly so). If a stock portfolio's returns are perfectly (and positively) correlated[15] with the stock market as a whole, the portfolio has a beta of exactly 1.0. Additionally, since the market beta is 1.0, the beta of the "average" stock is 1.0.

Q. HOW, WITHIN THE CONSTRUCT OF A WELL-DIVERSIFIED PORTFOLIO, ARE RISK AND RETURN RELATED?

A. The answer to this question forms a good deal of that part of finance theory concerned with investments.[16] A basic conclusion is that

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$$\beta_a = \frac{\mathrm{Cov}(r_a, r_p)}{\mathrm{Var}(r_p)},$$

where r_a measures the rate of return of the asset, r_p measures the rate of return of the portfolio, and Cov(r_a,r_p) is the covariance between the rates of return. In the Capital Asset Pricing Model (CAPM) formulation, the portfolio is the market portfolio that contains all risky assets, and so the r_p terms in the formula are replaced by r_m, the rate of return of the market.

Beta is also referred to as financial elasticity or correlated relative volatility, and can be thought of as a measure of the sensitivity of the asset's returns to market returns, and the asset's non-diversifiable risk (or systematic risk or market risk).

[15] Perfectly (and positively) correlated means the correlation coefficient (a statistical measure) between portfolio returns and market returns is +1.0.

[16] A working definition of investment theory might be that it is the body of knowledge used to support the decision-making process of choosing investments for various

investments with higher undiversifiable risks require, in well-functioning capital markets, a higher *a priori* expected rate of return than do investments having lower undiversifiable risks.

Q. WHY IS THE RELATIONSHIP BETWEEN RISK AND RETURN IMPORTANT TO CONSIDER WHEN ESTABLISHING AN AUTHORIZED RETURN ON EQUITY FOR A RATE OF RETURN REGULATED UTILITY?

A. Understanding this relationship serves to define boundaries around a fair rate of return on common equity for utilities operating under one or more rate of return regulatory regimes. The average annual return,[17] including dividends, of Standard & Poor's S&P 500 index[18] from 1926 through 2000 was 10.7 percent.[19, 20] This index has performed less

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purposes. Topics included are portfolio theory, a variety of asset pricing models, and the efficient market hypothesis.

[17] Average annual returns cited in my testimony, unless otherwise specified, are of the geometric mean construction. This construction provides an average rate which, multiplied by one plus itself *n* times ("compounded") where *n* is the number of periods of growth, equates the value of an investment with the value of the investment *n* periods forward. A geometric growth rate is sometimes referred to as compound annual growth rate (CAGR).

[18] The S&P 500 is a market capitalization-weighted index of 500 large companies and is often used as a proxy for the entire U.S. stock market. *See* the S&P 500 fact sheet at http://www.standardandpoors.com/servlet/BlobServer?blobheadername3=MDT-Type&blobcol=urldata&blobtable=MungoBlobs&blobheadervalue2=inline%3B+filename%3DFS_SP_500_LTR.pdf&blobheadername2=Content-Disposition&blobheadervalue1=application%2Fpdf&blobkey=id&blobheadername1=content-type&blobwhere=1244017995489&blobheadervalue3=UTF-8 (accessed November 28, 2011).

[19] *See* page 4 of "Long-Run Stock Returns: Participating in the Real Economy," by R. Ibbotson and P. Chen, *Financial Analysts Journal*, January/February 2003, Vol. 59, No. 1. The 10.7 percent annual average total return was calculated on a geometric basis; i.e., it is a compound annual growth rate (CAGR).

[20] *See also*, in Docket No. UE 215, Exhibit Staff/903, where the annual average total return of "large company stocks" over the period 1926 – 2008 on a geometric basis is

well in more recent years, with an average annual total return over the past five years of 0.25 percent as of November 28, 2011.[21]

Assuming the S&P 500 index is an adequate representation of the U.S. stock market,[22] the average beta of stocks in the index is (positive) 1.0. Beta values[23] from Value Line's *Investment Survey* (Value Line) for companies in both my and Idaho Power's groups of comparable companies[24] average less than 1.0, at 0.71 and 0.75, respectively. This indicates the comparable companies, whether mine or Idaho Power's, on average have materially less market risk than the

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9.6 percent.PGE provided this information as the company's response to Staff data request number 45 in UE 215.

[21] *See* certain returns for the S&P 500 at http://www.standardandpoors.com/indices/sp-500/en/us/?indexId=spusa-500-usduf--p-us-l-- (accessed November 28, 2011).

[22] Stocks in the S&P 500 index account for approximately 75 percent of the U.S. equity market's total value. *See* the fact sheet on this index at http://www.standardandpoors.com/servlet/BlobServer?blobheadername3=MDT-Type&blobcol=urldata&blobtable=MungoBlobs&blobheadervalue2=inline%3B+filename%3DFS_SP_500_LTR.pdf&blobheadername2=Content-Disposition&blobheadervalue1=application%2Fpdf&blobkey=id&blobheadername1=content-type&blobwhere=1244017995489&blobheadervalue3=UTF-8 (accessed November 28, 2011).

[23] Per Value Line at http://www.valueline.com/Tools/Glossary.aspx (accessed November 28, 2011), Value Line betas are based on "the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index." Notably, composition of the NYSE Composite Index is approximately 83% U.S. companies; i.e., a material portion of the index consists of non-U.S. stocks. This index has, as of November 28, 2011, 1,523 U.S. companies. *See* http://www.nyse.com/about/listed/nya_characteristics.shtml . Per Bloomberg at http://www.bloomberg.com/apps/quote?ticker=NYA:IND (accessed November 28, 2011), the NYSE Composite Index "encompasses 61% of the total market capitalization of all publicly traded companies around the world" (emphasis added). Per the NYSE, the Composite Index is composed of approximately 82 percent U.S. companies (by number) and approximately 69 percent by (presumably) market capitalization. *See* at http://www.nyse.com/about/listed/nya_characteristics.shtml (accessed November 29, 2011).

[24] I use the terms "peer utilities," "comparable companies," "peer companies," and "cohort companies" synonymously in this testimony. A discussion of my group of comparable companies and a brief discussion regarding certain attributes of Idaho Power's group of comparable companies appear later in this testimony.

stock market as a whole.[25] Moreover, "[f]or a reasonably well-diversified portfolio, only market risk matters" (emphasis added).[26] A seemingly logical conclusion is that a forward-looking long-term fair rate of return on equity (ROE), all else being equal,[27] is less than the historical (1926 forward) annual average return, including dividends, of the S&P 500 index. This would seem to hold whether the historical rate of return on the index is the 10.7 percent annual average rate from 1926 through 2000 or the lower (than 10.7 percent) annual average rate from 1926 through the more recent past; e.g., 9.6 percent through 2008. Less risk implies a lower expected return on common equity required by investors.[28]

STAFF'S COST OF EQUITY ANALYSIS

Q. DID YOU USE VALUES FROM COMPARABLE COMPANIES TO ESTIMATE PGE'S COST OF EQUITY?

A. Yes. My selection process for a group of peer companies begins by using the Peer Analytics screening capability in the SNL information

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[25] More precisely, they have—on average—materially less risk than the stocks comprising the New York Stock Exchange (NYSE).Composite Index as a whole.

[26] Brealey, Myers and Allen; *op. cit.*, page 170.

[27] I discuss the implications of relaxing certain *ceteris paribus* assumptions, such as that pertaining to capital structure, later in this testimony.

[28] The combination of rational investors and efficient capital markets imply risk associated with the unique, or diversifiable, risk of both my and Idaho Power's peer companies has been eliminated by investors holding diversified portfolios, with individual stock price reflecting this diversification from each individual company's unique risks. The remaining risk, that of market risk, is evaluated by investors to be materially less (betas of 0.71 and 0.75, respectively, versus 1.00 for the average U.S. stock) than that of the average company's common stock.

service. I applied seven screening criteria to the SNL database of 68 publicly traded companies in the power industry,[29] including the Boolean operators (“and;” “or”). I then applied three additional screening criteria and additional checks. The 10 screening criteria I used to select the group of peer companies are listed below.

1. In Power industry; and
2. Operating Status is “Current;” and
3. “Ticker” symbol is not “Not Available.” This criterion limits the results to publicly traded companies. And
4. S&P Long-term Issuer Rating of BBB+, BBB, or BBB-. This criterion eliminates companies having a long-term credit rating more than “one-step” different from the S&P Long-term Issuer Rating of BBB for Idaho Power. And
5. Compound Annual Growth Rate of Declared Dividends over the five year period ending in 2010 is greater than or equal to 0 percent. This criterion limits results to companies having no decline in dividends over the period 2006 through 2010. Or
6. “Ticker” is “POR.” This allows inclusion of Portland General Electric, which a) paid dividends over the period 2006 through 2010; and b) did not have a decline in declared dividends over this period. PGE was not screened-in with the preceding criterion, as the

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[29] Among the 68 companies are those engaged in lines of business other than electric distribution; e.g., merchant power producers. The 68 may also include one or more firms headquartered in Canada.

company did not pay a dividend in 2005.[30] The combination of this criterion with the preceding criterion effectively yielded those companies having paid a dividend in each of the years 2006 through 2010, which dividend was not reduced over this timeframe. After additional investigation I concluded PGE was the only company after application of the first four criteria for which both “a” and “b” were true, which is the result I wanted; i.e., to screen-in those companies declaring a dividend in each year of 2006 through 2010, where the dividend was not reduced or eliminated in any of these years from the level of the prior year.[31] And

7. The company is not a merger target. And
8. Electric utility revenue is 80 percent or more of total revenue. I made this calculation in Excel following output from SNL of data associated with the 35 companies resulting from the first seven criteria, which output included the companies’ 2010 values of electric utility revenue and total revenue from SNL’s database. While SNL’s database did not have a value for ALLETE’s electric

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[30] The lack of a declared dividend in 2005 results in PGE’s compound average annual rate of growth in declared dividends over the 2006 through 2010 period being “infinitely large,” which is the reason it was not screened-in by criterion 5.

[31] Dividend growth rates for companies excluded by this criterion, including companies re-establishing dividend payments previously eliminated, may be uncharacteristically high, even “exceptionally high.” *See*, in Docket No. UE 147, PPL/200 Hadaway/14 beginning at 16. I do not view PGE’s dividend growth rate, as projected by Value Line, of 3.0 percent over the period 2008 – 2010 to 2014 - 2016 to be materially different from the 3.3 percent average annual growth rate for my group of comparable companies.

utility revenue, page 6 of the company's 2010 Form 10-K filing[32] included that 92 percent of ALLETE's consolidated operating revenue was from regulated operations. Therefore, I did not exclude ALLETE based on this criterion.

9. A categorization of "regulated" by the Edison Electric Institute (EEI) in that organization's 2010 Financial Review.[33] EEI's "regulated" category includes "those companies having 80% of holding company assets are regulated." The list of companies categorized by EEI includes 61 "shareholder-owned electric utility holding companies."
10. The company is covered by Value Line. Value Line is a standard reference; is not associated with either the "buy" or "sell" side of the market; i.e., the company does not benefit from stock transactions as, say, broker/dealers benefit. Additionally, Value Line does not benefit from corporate financing activities the way investment banks or financial firms providing similar services benefit. The Value Line

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[32] I accessed the 10-K I used through SNL, at http://www.snl.com/Cache/A957F1767010754229.pdf?Y=10-K&KeySession=%7bBE2949DE-FFC8-4EE8-B222-16EC9543F722%7d&F=A957F1767010754229.HTML&CachePath=%5c%5cdmzdoc2%5cwebcache%24%5c&O=HTML&KeyOnlineUser=1000254110&T=ALE&S=HTML&PDF=1&D=12%2f31%2f2010 , on November 29, 2011. Note that SNL's service is restricted to licensees.

[33] *See* page 43 of the report, which is available at http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Pages/strategies.aspx (accessed November 29, 2011). EEI's categories of companies, including the number of companies listed in each in the 2010 report, are regulated (38), mostly regulated (19), and diversified (4). The respective category "break points" of the percent of total assets that are regulated, are ≥80 percent, 50 to 79 percent, and <50 percent; i.e., less than one-half of the assets of companies in the diversified category are regulated.

information I used is from their company Reports, the one-page-per-company information I believe to be available in any U.S. public library above some modest size at no charge to library patrons. U.S. investors, and specifically non-institutional investors, can—for the direct cost associated with transportation to and from their local public library—obtain the same Value Line information I used.

I performed additional checks on the 11 companies that passed screening criteria one through 10. I performed Web searches to determine if any remaining companies were involved with merger activities more recent that the data available from SNL or was involved in merger activities, but not as a merger target. This eliminated Northeast Utilities, which is merging with NSTAR.[34] I also reviewed Value Line information, screening out Empire District Electric Company as Value Line's September 23, 2011 report indicated the company, following the May, 2011 tornado that devastated parts of its Missouri service territory, suspended its dividend for the rest of 2011.[35, 36]

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[34] *See*, e.g., the online version of the Hartford Courant, which indicated in a story dated July 8, 2011, that the Federal Energy Regulatory Commission (FERC) approved this merger. The story is available at http://articles.courant.com/2011-07-08/business/hc-northeast-utilities-nstar-merger-20110708_1_northeast-utilities-nstar-merger-attorney-general-george-jepsen-utility-rates (accessed November 29, 2011).

[35] *See* Value Line's September 23, 2011 report on Empire District Electric. While the company, per Value Line, intends to restore its dividend in 2012, Value Line expects the 2011 amount to be one-half of the 2010 level.

[36] The tornado in May 2011 occurred after the publication dates of the Value Line reports used by Dr. Avera. The Value Line company reports he used are dated February 4, 2011 for those companies classified by Value Line as "West;" February 25, 2011 for those companies classified by Value Line as "East;" and March 25, 2011 for those companies classified by Value Line as "Central;" i.e., the May, 2011

ITC Holdings was excluded, as EEI does not categorize this firm (criterion 9); i.e., EEI presumably does not consider the company to be an electric utility or the holding company of an electric utility. Value Line's September 23, 2011 report describes ITC Holdings' business as engaging in "the transmission of electricity in the United States. The company operates primarily as a conduit, moving power from generators to local distribution systems..." and having "operations regulated by the Federal Energy Regulatory Commission" (FERC). Value Line's report includes that "ITC Holdings is not like other electric utilities. It is the sole publicly traded transmission-only company" (emphasis added) and "ITC's four subsidiaries are allowed very healthy returns on equity of 12.16% to 13.88%." Additionally, the Value Line report states that the company acquired Michigan Electric Transmission Company in 2006 and Interstate Power & Light's transmission assets in 2007. These attributes and acquisitions make ITC Holdings sufficiently different from the electric utilities whose business includes electricity distribution that I excluded the company.

Table 2 (following) lists the eight companies I found comparable to Idaho Power as well as those companies Idaho Power identified as "comparable."[37] All of the firms in this table are listed on the New York

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Midwest tornado occurred well after the date of the Value Line report covering Empire District Electric and therefore before the date the company suspended dividend payments.

[37] The list of peer utilities used by Idaho Power is discussed at Exhibit Idaho Power/400 Avera/24 through Avera/27 and listed in Exhibits Idaho Power/402, 403, 409,

Stock Exchange (NYSE) other than Otter Tail, which is listed on the National Association of Securities Dealer Automated Quotation system (NASDAQ).

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and 410. Note that Dr. Avera also uses a list of non-utility peer companies, which are listed in Exhibits Idaho Power/404 and 405.

Table 2

Companies Comparable to Idaho Power

	Company	Ticker	Staff's List	Idaho Power's List
1	ALLETE	ALE	✓	
2	American Electric Power	AEP	✓	✓
3	Ameren	AEE		✓
4	Avista	AVA		✓
5	Black Hills	BKH		✓
6	CenterPoint Energy	CNP		✓
7	Cleco	CNL	✓	✓
8	CMS Energy	CMS		✓
9	Constellation Energy	CEG		✓
10	DTE Energy	DTE		✓
11	Edison International	EIX		✓
12	Empire District	EDE		✓
13	Great Plains	GXP		✓
14	Hawaiian Electric	HE		✓
15	IDACORP	IDA	✓	✓
16	Integrys Energy	TEG		✓
17	ITC Holdings	ITC		✓
18	Otter Tail	OTTR		✓
19	Pepco Holdings	POM		✓
20	PG&E	PCG		✓
21	Pinnacle West Capital	PNW	✓	✓
22	Portland General Electric	POR	✓	✓
23	TECO Energy	TE		✓
24	UIL Holdings	UIL	✓	
25	Westar Energy	WR	✓	
26	Wisconsin Energy	WEC		

Table 3 (following) lists the 10 screening criteria I used and Idaho Power's values for each. I indicate "not applicable" for several criteria;

most of which result from the Company’s being wholly-owned by IDACORP and therefore not publicly traded. Note that these distill to essentially those publicly-traded U.S. operating local distribution electric utilities (or holding companies thereof) having a Long-term Issuer rating from S&P within the BBB± range, with 80 percent or more of their revenue classified as electric utility revenue and 80 percent or more of their assets classified as regulated.

Table 3

Staff Screening Criteria and Values for Idaho Power

Criterion	Idaho Power Value
1. Power industry?	Yes
2. “Current” operating status?	Yes
3. “Ticker” not “Not Available?”	Not applicable
4. S&P Long-term Issuer rating BBB+/BBB/BBB- ?	Yes (BBB)
5. Non-negative compound annual dividend growth rate?	Not applicable (but true of IDACORP since 2004)
6. Ticker is “POR”	Not applicable
7. Merger target?	No
8. Electric Utility Revenue ≥ 80%?	Yes (97.6% in 2010[38])
9. EEI “Regulated?”	Yes (IDACORP is “yes”[39])
10. Covered by Value Line?	No

Q. DOES IDAHO POWER CAPTURE MOST OF ITS REVENUES THROUGH OPERATING AS AN ELECTRIC UTILITY?

A. Yes. As EEI lists “regulated” as IDACORPs categorization (more than 80 percent of assets regulated) and Idaho Power’s revenue stream is almost entirely (97.6 percent in 2010) regulated, companies operating as electric utilities or holding companies having one or more electric utility subsidiaries must be predominantly, if not entirely, regulated to

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[38] SNL, accessed November 29, 2011, has electric utility revenue as $1,033,052 thousand and total revenue as $1,058,016 thousand for 2010. Idaho Power’s revenue stream is almost entirely (97.6 percent) regulated.

[39] I assume that, if IDACORP assets are more than 80 percent regulated, those of Idaho Power are also more than 80 percent regulated. This appears to be a valid assumption after reviewing the types of businesses other than Idaho Power consolidated into IDACORP reporting; i.e., most appear to be unregulated.

be comparable with Idaho Power. The Company's 2010 Form 10-K has on page five that Idaho Power (the electric utility) contributed 98.5 percent of IDACORP's (the holding company) net income in 2010.

Q. WHY DO YOU USE DIFFERENT COMPARABLE COMPANIES THAN IDAHO POWER?

A. I will discuss Idaho Power's peer utilities in more detail later in my testimony.

STAFF'S DISCOUNTED CASH FLOW MODELS

Q. WHAT TYPES OF MODELS DID YOU USE TO DEVELOP STAFF'S RECOMMENDED RETURN ON EQUITY FOR IDAHO POWER?

A. I rely primarily on two different multistage discounted cash flow models[40, 41] for estimating the expected return on common equity required by Idaho Power investors. I also update certain input parameter values for some of the models used by Idaho Power witness Dr. Avera and contrast the results with both his results and those from my two DCF models.

Q. WHAT IS A DISCOUNTED CASH FLOW MODEL?

A. A discounted cash flow, or DCF, model estimates the rate of return for an investment using cash flows over a suitable valuation timeframe. As

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[40] *See* Exhibit Staff/80X for the mathematical expressions of these multistage DCF models.

[41] *See*, in Docket No. UE 115, the Commission's discussion of multistage versus single stage DCF models in Order No. 01-777 at page 27.

used in return on equity studies, a DCF model provides an estimate of the expected annual rate of return investors require on a specific investment before they will invest.

The "cash flow" portion of these models refers to the assumption that an investor cares about the amounts and timing of money they pay and receive associated with, say, their investing in a company's stock. Note that the cash flows are those going to and coming from the investor, not to and from the company; i.e., the investor directly cares about cash flows he or she will experience and only indirectly about cash flows the company will experience. The typical pattern of cash flows used in DCF models can be characterized as: a) a cash outflow from the investor, as the investment is made; b) multiple cash inflows over time to the investor, as the company pays cash dividends; and c) a "terminal" cash flow to the investor, occurring at that time in the future when the stock is sold.[42] In a corporate structure,[43] dividends paid to the investor represent returns on capital[44] and the proceeds from selling the stock in the future represent both an additional return

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[42] These types of DCF models may be thought of as having a terminal valuation "stage."

[43] Limited partnerships and REITs are two examples of structures which may differ from this. *See* FERC Opinion 486-B for a discussion of Master Limited Partnerships in proxy groups of oil and natural gas pipeline firms for use in determining ROE.

[44] The reference here is to normal dividends; i.e., not special dividends. A special dividend is a non-recurring distribution of company assets, usually in the form of cash, to shareholders. Special dividends are typically large in comparison with normal dividends paid out by the company.

on investment as well as the return of investment.[45] I also refer to a DCF model involving the payment of dividends to investors as a Dividend Discount Model, distinct from other DCF models used for different purposes.[46] In other words, all dividend discount models are DCF models, but not the converse.[47]

The term "discount" refers to the assumption that investors have a positive time preference;[48] i.e., all else being equal, an investor prefers receiving a dollar today over receiving a dollar in a future period. To reflect this positive time preference, future cash flows are discounted by some factor and the further (more periods) into the future a cash flow occurs, the greater the numerical value by which it is discounted. In the absence of risk, the discount rate only reflects time preferences. As applied to risky investments, such as common stocks, it also incorporates risk.

The analytical result of a DCF model for estimating a company's cost of capital is the rate at which future periodic[49] cash inflows to the investor, as well as any terminal value realized at the end of the

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[45] This assumes that the cash received for selling the stock is greater than the price at which it was purchased.

[46] Discounted Cash Flow or DCF analysis is generally thought of in areas of corporate finance, such as capital budgeting, as a technique, not a model.

[47] I have seen each of the two terms used in the professional literature of financial economics for discounted dividend DCF models.

[48] This assumption might be less defensible in the current environment, in which some short-term interest rates appear to be negative on a real basis (after adjustment for expected future inflation) than it would be in more typical interest rate and inflation environments.

[49] And the terminal cash flow, if applicable.

investment horizon, are discounted such that they equal, in total, the current cash outflow, which is the price paid by the investor for the stock.[50, 51] In other words, the rate resulting from a DCF model is the rate which, when used to discount future cash flows, equates the present value of future (net) cash inflows with the (negative of[52] the) current cash outflow.

Q. PLEASE DESCRIBE THE FIRST OF THESE TWO DCF MODELS.

A. The first model is a conventional three-stage Discounted Dividend Model requiring for each comparable company the following values as inputs: a “current” market price per share of common stock; estimates of dividends per share[53] to be received in the years 2012 through 2016; an annual rate(s) of dividend growth over the 2017 through 2021 period; and a long-term growth rate applicable to dividends beyond 2022.[54] The three stages of the model refer to the 2012 through 2016 period (Stage 1, of five years), where I use Value Line’s forecasts of dividends per share; the 2017 through 2021 period (Stage 2, also of

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[50] This rate is known in most contexts as the internal rate of return, or IRR. *See*, e.g., Brealey, Meyers, and Allen; *op. cit.*, page 107ff. In some contexts of discussing DCF model results I use the terms IRR and ROE interchangeably, while in other contexts where I am describing an adjustment to an IRR that results in an ROE, I distinguish between the two terms. I trust my meaning is, in context, clear to the reader.

[51] *See* the additional discussion of price later in this testimony.

[52] “Negative of” as, to the investor, the present value of future cash flows is positive—a net inflow—while the initial cash transaction is an outflow, or “negative cash flow.”

[53] Each comparable company has its own price per share and estimated dividends per share. The long-term dividend growth rate is common across the comparable companies.

[54] This multistage DCF model directly applies the estimated long-term growth rate to dividends per share over the 2022 through 2036 timeframe. Dividends per share for the 2010 through 2015 period are based on information supplied by Value Line.

five years), where the rate of dividend growth converges from the average rate over the 2008 – 2010 to 2014 – 2016 period[55] to the growth rate of the third stage in 2021; and the 2022 through 2036 period (Stage 3, of 15 years). The model includes a terminal value calculation, in which I assume dividends per share grow indefinitely (“forever”) at the rate of growth in Stage 3.

Q. WHY DID YOU USE FIVE YEARS FOR STAGES ONE AND TWO AND 15 YEARS FOR STAGE THREE?

A. I use five years for Stage One as that is the timeframe for which Value Line estimates of future dividends are available. I use five years for Stage Two as that seems a reasonable length of time for individual companies’ dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a long-term dividend growth rate more representative of all electric utilities. I discuss the mechanics of this convergence below. I used 15 years for Stage Three, as the end of Stage Three (in 2036) covers a presumably relevant 25 year horizon for investors, given my inclusion of a terminal valuation of the price at which a company’s

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[55] This procedure, in which an average “base” is established by averaging the values of two or more periods, is used in Value Line’s Reports; e.g., *Annual Rates of Change* on the left hand side of a Report.

stock is sold in 2036.[56] I describe the methods I use for terminal valuation below.

Q. HOW DID YOU ESTABLISH THE "CURRENT" MARKET PRICE PER SHARE FOR EACH COMPARABLE COMPANY?

A. The "current" market price I used was the average of the closing prices for each comparable company (see Table 2) on the first trading day of the last three months; i.e., September 1st, October 3rd, and November 1st of 2011.[57] Using prices from multiple days with some time interval (approximately one month) in between minimizes the potential "noise," or likelihood of being atypical, in using a sample of but one recent price or of, say, two closing prices on consecutive trading days.

Q. IS PRICE IMPORTANT WITH RESPECT TO YOUR ANALYTICAL RESULTS?

A. Yes, and more generally to all DCF models incorporating price. As an analogy, consider a teeter-totter and its balance where both ends are at other than their extreme position; i.e., not all the way up and not all the way down, but in balance, with neither end on the ground. If the left hand side (LHS) of the teeter-totter is a stock's price and the right hand side (RHS) is the estimated future cash flows (dividends and the future selling price) accruing to the shareholder, the value of the IRR is the

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[56] Note that some institutional investors might have a considerably longer investment timeframe; e.g., life insurance companies may have an investment horizon exceeding 100 years; e.g., where an investment is made for 100 years to match an obligation expected in 100 years.

[57] These were accessed at Big Charts http://bigcharts.marketwatch.com/historical/default.asp .

"fulcrum," or the value at which the teeter-totter is in balance; where the future cash flows, discounted at the internal rate of return (IRR),[58] equal the stock's price.

As applied to a stock investment, if the discount rate of investors in the stock increases,[59] all else being equal (and, in particular, no change in estimated future dividends and expected future selling price of the stock), the stock price declines to maintain the balance. The balance is the stock price that results in the market for the stock being in equilibrium, given no change in other relevant variables.

Q. WHAT IF THE ESTIMATED FUTURE DIVIDENDS OR THE EXPECTED FUTURE SELLING PRICE OF THE STOCK DECLINE?

A. In a circumstance where either estimated future dividends or expected future selling price of the stock (or both) decline, all else (and, in particular the discount rate) being equal, the stock price declines to maintain the balance. In our teeter-totter analogy, these dynamics between the current stock price, future cash flows (future dividends and expected future selling price), and the discount rate is akin to the fulcrum point moving from one side of the teeter-totter to the other in order to maintain balance between the LHS and the RHS.

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[58] The discounted future values are added together to provide one value, which is the present value of the future cash flows. It is this present value that is equated to the stock price by the IRR.

[59] The discount rate can be thought of for our purposes here as the composite discount rate of all investors in the market.

Q. DO DISCOUNT RATES CHANGE?

A. Yes. Research concludes they do change, and not gradually. The author of a recent article on discount rates, Professor John Cochrane of the University of Chicago's Booth School of Business and the National Bureau of Economic Research (NBER), stated unequivocally that they do change in his 2011 Presidential Address to the American Finance Association: "Discount rates vary over *time* ("Discount rate," "risk premium," and "expected return" are all the same thing here.)"[60] (emphasis in the original).

Q. CAN YOU PROVIDE AN EXAMPLE OF THE IMPORTANCE OF PRICES?

A. Yes. Using closing prices from mid-month (September 15, October 14, and November 15) instead of those from the first trading day of the month, while holding all other input parameters constant, reduced the IRR by an average of 20 basis points for my peer utilities and by an average of 10 basis points for those of Idaho Power.

A sensitivity analysis with one of my DCF models demonstrates that current stock prices for my peer utilities would need to be 18 percent lower—for each company—for the IRR to equal the

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[60] Professor Cochrane's speech was published as an article in *The Journal of Finance*; Vol. LXVI, No. 4 (August, 2011) and is available at http://faculty.chicagobooth.edu/john.cochrane/research/papers/AFA_pres_speech.pdf (accessed December 3, 2011). This statement appears on page 1047. Professor Cochrane also discusses on page 1050 research that suggests "…that all price-dividend ratio volatility corresponds to variation in expected returns." If expected dividends (and the expected selling price; see above) are unchanged, this is tantamount to saying price changes result from changes in the discount rate.

10.4 percent Idaho Power recommends.[61] Another sensitivity analysis shows that stock prices of the peer utilities used by Idaho Power, using this DCF model, would need to be 24 percent lower to equal the 11.4 percent obtained by Dr. Avera in his DCF analysis using Value Line information.[62, 63]

Q. IS IT LIKELY THAT THERE WERE CLOSING PRICES ON A DIFFERENT DAY IN THESE THREE MONTHS THAT WOULD PROVIDE A <u>HIGHER</u> AVERAGE ROE?

A. Yes.

Q. IS IT LIKELY THAT THERE WERE CLOSING PRICES ON A DIFFERENT DAY IN THESE THREE MONTHS THAT WOULD PROVIDE A <u>LOWER</u> AVERAGE ROE?

A. Yes.

Q. AS I UNDERSTAND IT, YOU OBTAINED THE CLOSING PRICES AS OF THE FIRST DAY OF EACH OF THE THREE MOST RECENT MONTHS AND SUBSEQUENTLY OBTAINED THE CLOSING PRICES ON THE TRADING DAY CLOSEST TO MID-MONTH. DID

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[61] *See* Idaho Power/400 Avera/5. This is Dr. Avera's "bare bones" recommended ROE.

[62] *See* Idaho Power//402 Avera/1, "Average (g)" of column "(f)."

[63] Dr. Avera excluded the results of five of his peer utilities in his DCF analysis using Value Line estimates, four because the results were "too low" and one because the result was "too high." I will discuss this point later in my testimony. By comparison, all but two of the peer utilities used by Idaho Power were above 9.0 percent in this sensitivity analysis and the highest IRR value obtained was 13.0 percent. Note that I did not include the two companies having the lowest results in these calculations. I discuss the price of these two companies later in my testimony.

YOU REVIEW THE IMPACT OF PRICES ON ANY OTHER DAY OF THESE MONTHS?

A. No. This fact, in combination with the fact that the second, mid-month "sample" which yields a lower ROE for both my peer utilities on average and a lower ROE for those of Idaho Power on average, a set of prices I did not use, illustrates the conservative approach I have taken in estimating an ROE for Idaho Power in this proceeding.

Q. PLEASE DESCRIBE THE VALUE LINE DIVIDEND INFORMATION YOU USED AND HOW YOU USED IT.

Value Line provides three "sets" of reports for the electric utilities, one for each of three U.S. regions in which the company's operations are located; i.e., one for those in the "East," one for those in the "Central," and one for those in the "West." Value Line issues updated reports on a periodic basis throughout the course of a year. The reports I used for Value Line information are dated, respectively for the regions listed above, November 25, 2011, September 23, 2011, and November 4, 2011.

I used the 2012 value of annual dividends estimated by Value Line for each comparable company; the value indicated as the average for 2014 – 2016 for the 2015 value; interpolated values based on the 2012 and 2015 values for the 2013 and 2014 values;[64] and, for the 2016

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[64] My interpolation method used the average annual rate of growth over the period from 2012 to 2015 applied to the previous year's value; i.e., applied to the 2012 value to

value, the rate of annual growth calculated from a base of averaged 2008 – 2010 actual values to the 2014 – 2016 average value estimated by Value Line applied to the 2015 value.[65, 66] In other words, the dividend values for each of the years 2012 through 2016 were either the values estimated by Value Line (2012 and 2015) or interpolated between these two values (2013 and 2014) or derived from the rate of growth implied by the Value Line estimate of the average 2014 – 2016 dividend and a historical base of actual values for 2008, 2009, and 2010 (2016). For the four companies for which I calculate a negative average annual growth rate over the 2008 – 2010 through 2014 – 2016 timeframe,[67] I used the average annual rate of growth from Value Line's 2012 estimate to Value Line's estimated average 2014 – 2016 value (which latter value I used for 2015, as previously mentioned).

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obtain that for 2013 and applied to the 2013 value to obtain that for 2014. The results of this method vary slightly from those obtained if the change in value from 2015 to 2015 was split equally between the two intervening years.

[65] Value Line provides estimated annual rates of dividend growth on the same basis as I used; i.e., the annual average growth rate in dividends from the average of 2008 – 2010 values to the average of 2014 – 2016 values. I did not use these growth rates as Value Line rounds to the nearest one-half of one percent (50 basis points), although for most companies the two rates, Value Line's and the rate I calculated from Value Line's information (other than the four exceptions in Idaho Power's list noted in the following footnote), are the same value to one-tenth of one percent.

[66] Note that my average for the 2014 – 206 period may be slightly different than the value calculated by Value Line. This is expected by "go both ways," with some companies having a somewhat higher average than estimated by Value Line and some a somewhat lower average.

[67] Value Line estimates that three of Idaho Power's peer utilities will have <u>negative</u> dividend growth rates over the 2008 – 2010 to 2014 – 2016 timeframe, and a fourth (Great Plains) has a negative 0.1 percent annual average growth rate as calculated by me from Value Line values (Value Line indicates Great Plains' annual average growth rate is *nil*). Value Line estimates that the average 2014 – 2016 dividend will increase over the 2012 dividend for three of these four companies—Ameren, Constellation Energy, and Great Plains—while that of the fourth—Empire District—will not.

I derived dividend values for the years 2017 through 2021 by applying a rate of growth, geometrically converging from the average annual growth rate I calculated from the average of 2008 – 2010 actual dividends to the average of Value Line's estimated dividends for 2014 – 2016[68] to the rate I used as the long-term growth rate, to the dividend value for the preceding year. Note that the latter growth rate is greater than the former growth rate for all but one of my comparable companies (Cleco); i.e., this model has the annual rate of dividend growth <u>accelerating</u> from the rate I calculated from Value Line's estimated values for all but one of my peer utilities over the 2017 – 2021 period of Stage 2. In other words, the annual rate of growth "steps-up" over the course of Stage 2 (for seven of my eight peer utilities; for Cleco the growth rate "steps-down"). See columns three and four of Exhibit Staff/802 Storm/1.

Q. WHAT IS AND WHY DID YOU USE A "GEOMETRICALLY CONVERGING GROWTH RATE?"

A. It is reasonable to smooth or taper over the 2017 through 2021 Stage 2 timeframe, the annual rate of dividend growth from the rate specific to each company for 2016 over 2015 to the long-term growth rate common to all companies. This "smoothing" or "tapering" may be either

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[68] Note that this underlying growth rate for each company, at the beginning of Stage 2 and before application of the mechanics of convergence, is identical with that used for obtaining 2016 dividend values from the respective 2015 (average of 2014 – 2016) values estimated by Value Line (with the exception of the four companies in Idaho Power's list mentioned in the preceding footnote).

increasing (for seven of my peer utilities) or decreasing (Cleco) the annual rate of growth, hence "converging." The annual growth rate geometrically converges over the course of Stage 2 as the ratio of the long-term average annual growth rate to the average annual rate of growth for 2014 – 2016 over 2008 - 2010[69] is increased (or decreased) exponentially in each year of this timeframe.[70] A geometrically converging growth rate is the method I use for transitioning over multiple periods from one growth rate (for each company) to another (for all companies).

Q. WHAT IS THE TERMINAL VALUE YOU MENTIONED EARLIER?

A. Rather than extend the timeframe of DCF models to the limits of spreadsheet or other software's capability, I use a technique of terminal valuation to produce an explicit estimation of the stock price at the end of Stage 3 in 2036, which is then figuratively "sold," producing the terminal cash flow. This involves calculating the value of a growing

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[69] The four companies in Idaho Power's list of peer utilities listed in a prior footnote are exceptions to this, for which the initial growth rate in this period (the denominator in the ratio) is that used for 2016; i.e., the average annual rate of growth for 2014 – 2016 over 2012.

[70] This can be expressed mathematically as:

$$D_{t-1} \times (1 + G_{2016}) \times ((1 + G_{LT}) \,/\, (1 + G_{2016}))^{\frac{i}{5}}$$

where

D_{t-1} is the value of the preceding year's dividend;

G_{2016} is the growth rate from 2015 to 2016;

G_{LT} is the long-term growth rate applicable to 2022 through 2036; and

i is an index that is 1 for 2017, 2 for 2018, 3 for 2019, 4 for 2020, and 5 for 2021 (in which year convergence is complete as the exponent of the ratio is 5/5, which equals 1).

perpetuity[71] in 2036, when the stock is “sold,” and discounting this value back to the initial period.[72] This method of terminal valuation is commonly used in cost of capital DCF analyses.

As the outcomes of DCF models using a terminal valuation often have a large part of the outcome based on the terminal valuation,[73] I calculated the share of the present value, before addition of the (negatively valued) stock price, attributable to the terminal valuation in column 5 of Exhibit Staff/802. The proportion of total valuation (the current stock price) attributed to the terminal valuation is in the low- to mid-30 percent range, with the percentage being approximately 2.5 percent higher for my group of peer utilities versus those used by Idaho Power. An alternate way to state this is to say that roughly one-third of the estimated ROE is based on the estimated value of dividends to be paid after 2035.

Q. HOW DID YOU DETERMINE THE APPROPRIATE LONG-TERM GROWTH RATE FOR STAGE THREE?

A. Analysts often recommend projected long-term growth in nominal GDP as an appropriate rate of growth for electric utilities beyond the mid-

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[71] A perpetuity is similar to an annuity, except it has no defined lifespan; i.e., payments continue into perpetuity and, in this case of a growing perpetuity, the periodic amounts received by the investor increase over time.

[72] Calculating the value of a growing perpetuity is a standard technique in finance. *See* Brealey, Myers, and Allen; *op. cit.*, pages 33 and 91-92. The formula used to calculate this value also appears on the inside back cover of this title, as one of “some useful formulas.” Note that, in this location, the authors refer to the formula as “the “Gordon” model.”

[73] *See*, e.g., the cautionary statement in Brealey, Myers, and Allen; *op. cit.*, on page 92.

term future. While there is sufficient evidence to support, for any regionally diverse group of electric utilities, with each above some minimum size,[74] use of a growth rate for dividends that is less than the growth rate for long-term nominal GDP, I use such values as the rate of growth of dividends. This use, in and of itself given the use of realistic shorter-term growth rates, tends to make my ROE estimates conservative, which in this circumstance means higher than what might otherwise be warranted.

Using such a rate of growth for electric utility dividends as an upper bound is justified by the mathematical fact that any company growing at a rate greater than that of the economy as a whole will, after passage of a sufficient length of time, be the economy. See FERC's discussion on this topic in Opinion 396-B at page 9:

> *"First, the record shows that as companies reach maturity over the long-term, their growth slows, and their growth rate will approach that of the economy as a whole."*

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[74] I make this qualification as it may be possible to pick a very small number of the fastest growing electric utilities in the U.S. for which a reasonably longer-term estimate of growth is, on average, higher than an estimated rate of growth in GDP. I assume such electric utilities, if they exist in any number, are smaller in size than the average electric utility. Additionally, the common stock of such companies may not by publicly traded.

This reader of the preceding statement is curious as to which firms are growing more slowly than is "the economy as a whole," as mathematically, not all can be growing more rapidly.[75]

SLOW GROWTH IN THE ELECTRIC UTILITY INDUSTRY

Q. WHY DO YOU SAY THERE IS SUFFICIENT EVIDENCE TO SUPPORT…USING A GROWTH RATE FOR DIVIDENDS THAT IS LESS THAN THE GROWTH RATE FOR LONG-TERM NOMINAL GDP?

A. I have several reasons for saying this. The electric utility industry in the U.S. is a mature industry. Figure 1 (following) is a conceptual depiction of the successive phases of growth through which a product or service, a product (or service) line, or an industry pass.[76] The U.S. electric utility industry is well past the "high growth"[77] phase of the industry's lifecycle and is in the "mature" phase; i.e., the right-hand portion of the graph in Figure 1. This phase is characterized by slower growth and is well represented in the graph in Docket No. 210's Exhibit PPL/209

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[75] To me, some discussions on this point of regulated utility growth relative to that of GDP have a sense of illusory superiority and appear to be the regulatory cost of capital equivalent of fictional Lake Wobegon, where "…all the children are above average."

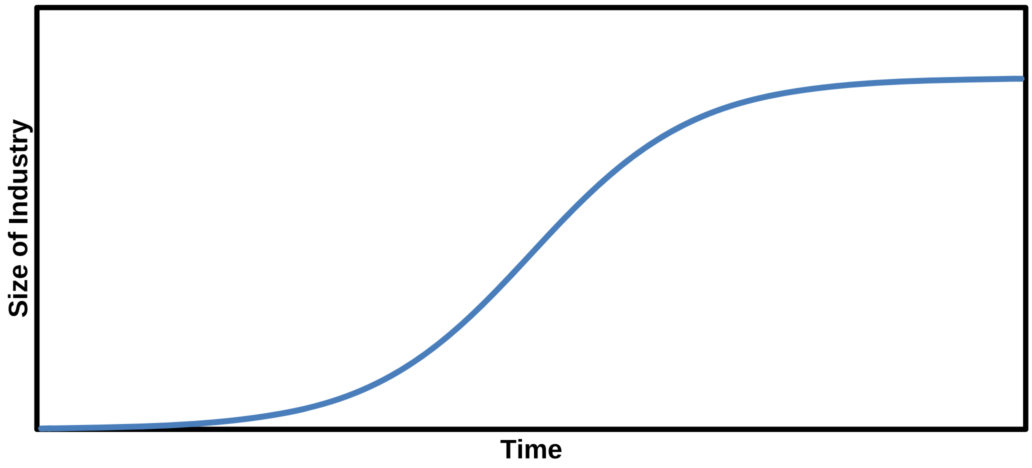
[76] The functional (mathematical) form of the equation producing this graph is a logistic function.

[77] The "high growth" phase is the steep section of the curve in the middle of the graph. Slower rates of growth pertain to both a nascent and to a mature industry, which are respectively positioned on the left and right portions of the curve.

Hadaway/23,[78] where total kilowatt hour (kWh) electricity sales, a unit measure, is clearly shown to be growing at a materially slower rate than real GDP over the 1984 through 2008 period.[79]

Figure 1

Industry Life Cycle



This slower rate of growth is also evident in Figure 2 (following), which shows not only the decline since the early 1950s, but the relatively low rates of growth forecast for years beyond 2011.

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[78] The graph is on page 26 of the cited document.

[79] Note in particular the "less than real GDP" rate of growth in kWh sales from, say, 1992 forward.

Figure 2[80]

Additionally, a 2007 presentation by Susan Tierney of the Analysis Group shows an overall decline in expenditures on electricity as a percent of U.S. GDP from 1983 through 2005.[81] I updated Tierney's graphic in Figure 3 (following) to include results through 2010.[82] Per

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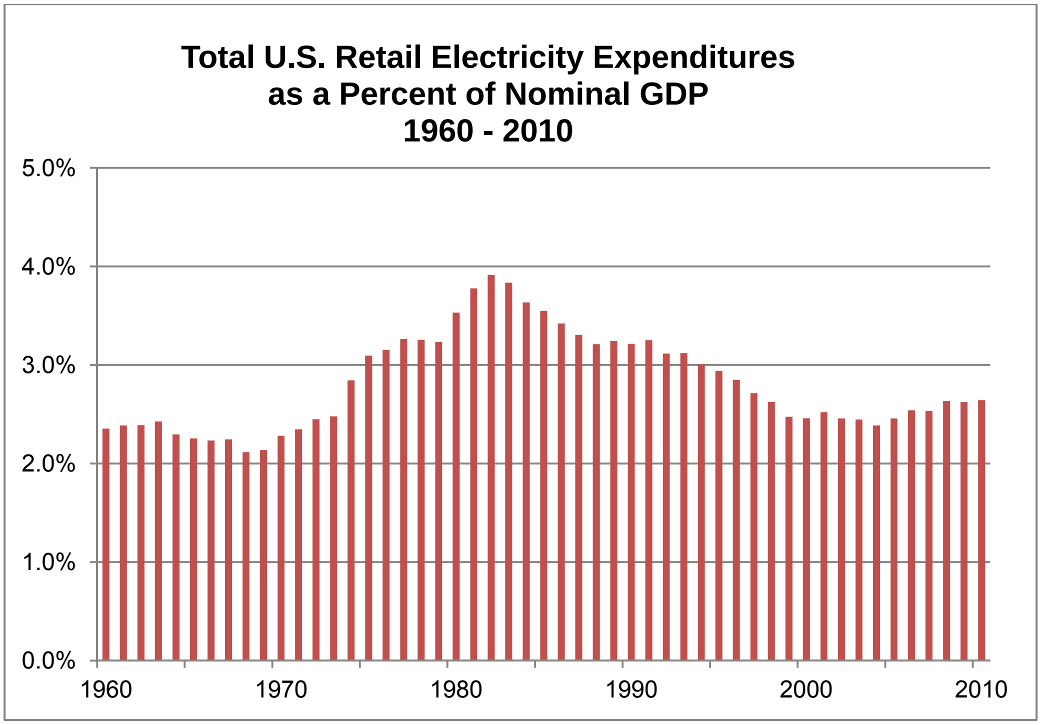
[80] Source: EIA's Annual Energy Outlook 2011's *Briefing Slides*, available at http://www.eia.gov/forecasts/aeo/index.cfm (accessed November 30, 2011).

[81] *See* Figure 6 on page 7 of Susan Tierney's "Decoding Developments in Today's Electric Industry — Ten Points in the Prism"; available from the Harvard Electricity Policy Group at http://www.hks.harvard.edu/hepg/Tierney%20-%20Decoding%20Electricity%20Prices.pdf (accessed November 30, 2011). In Figure 3 I have updated Tierney's chart through 2010 using underlying information available from the Bureau of Economic Analysis (BEA) at http://www.bea.gov/national/index.htm (accessed November 15, 2011) and EIA's Annual Energy Review 2011 Tables 8.9 *Electricity End Use, 1949-2010* and 8.10 *Average Retail Prices of Electricity, 1960-2010*, available at http://www.eia.gov/totalenergy/data/annual/#electricity (accessed November 30, 2011).

[82] Source data for Figure 4 are available from the Bureau of Economic Analysis (BEA) at http://www.bea.gov/national/index.htm (accessed November 15, 2011) and EIA's

Tierney, "…as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than what we spent during the 1980s."[83] This long-term secular trend, due to underlying structural change in the U.S. economy, will continue (see Figure 2).

Figure 3



Annual Energy Review 2011 Tables 8.9 *Electricity End Use, 1949-2010* and 8.10 *Average Retail Prices of Electricity, 1960-2010*, available at http://www.eia.gov/totalenergy/data/annual/#electricity (accessed November 30, 2011).

[83] Tierney; *op. cit.*, page 7.

Figure 4

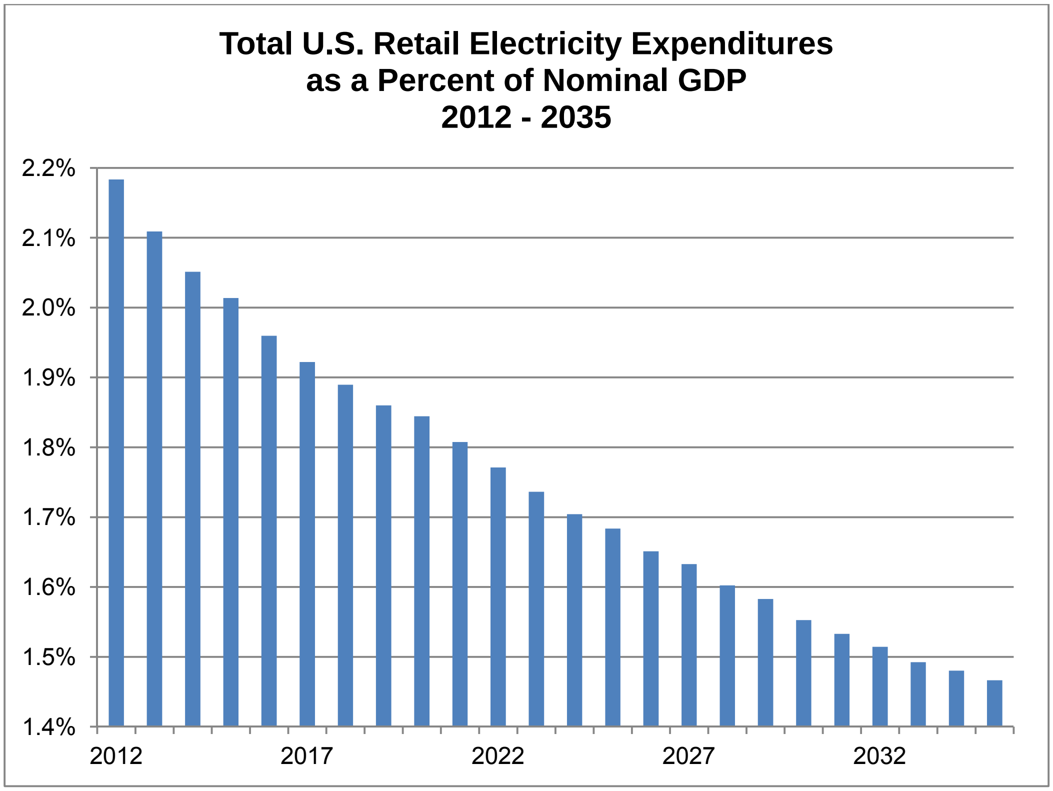


Figure 5

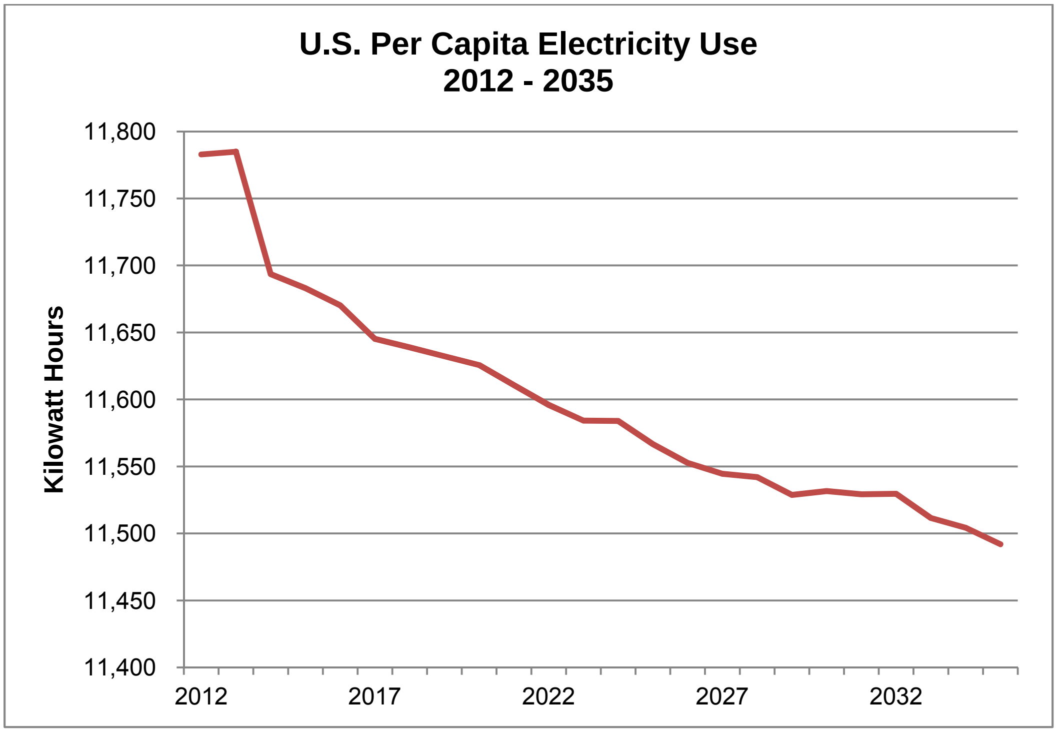


Figure 4, compiled using data from EIA,[84] depicts electricity expenditures as a percent of nominal GDP declining over the 2012 - 2035 period. Figure 5 depicts U.S. per capita electricity use declining over the period 2012 through 2035.[85] The implication of this information is clear: the long-term growth rate in revenue and earnings[86] for the electric utility industry will be less than the long-term growth rate of nominal GDP.[87]

A 30-year future in which electricity prices increase at a higher rate than inflation does not seem likely; in fact, the forecast "goes the other way." EIA forecasts retail electricity prices to increase over the period 2012 – 2035 at an average annual rate of 2.0 percent,[88] while the Consumer Price Index – All Urban (CPI) is forecast to increase at an

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[84] Data used in Figure 5 are from EIA's Annual Energy Outlook 2011, Tables *Electricity Supply, Disposition, Prices, and Emissions, Reference Case* and *Macroeconomic Indicators, Reference Case*. This information is available at http://www.eia.gov/oiaf/aeo/tablebrowser/ (accessed November 30, 2011).

[85] Data used in Figure 5 are from the same 2011 AEO tables used in Figure 4.

[86] Earnings growth is necessary for dividends to grow. I provide additional discussion on this point later in this testimony.

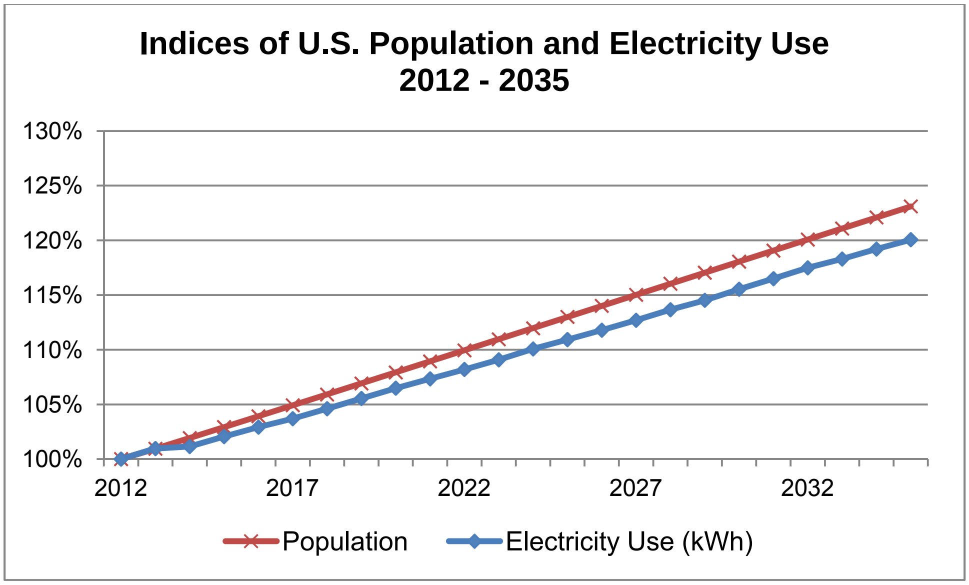
[87] The only way this is not possible is if electricity unit prices increase not only at a higher rate than general inflation, but also at a rate sufficiently high to more than offset the lower than real GDP rate of growth in electricity volumes. See also the graph "Cost of Electricity vs. Consumer Prices" in Docket No. 210's Exhibit PPL/209 Hadaway/17, where, by visual inspection, it appears the "electricity component of CPI" price measure has not risen at a rate greater than the rate of overall price inflation as measured by the Consumer Price Index (CPI) over the 1992 through 2008+ period. In other words, over the past 16 years, the price of electricity has increased at a rate similar to (not greater than) consumer prices generally.

[88] Prices are on a kilowatt-hour basis. Source: EIA's Annual Energy Outlook 2011, Tables *Electricity Supply, Disposition, Prices, and Emissions, Reference Case*. This information is available at http://www.eia.gov/oiaf/aeo/tablebrowser/ (accessed November 30, 2011).

average annual rate of 2.1 percent;[89] i.e., over the period 2012 – 2035, retail electricity prices are not expected to keep pace with inflation.

Electricity use over the period from 2012 through 2035 is growing, albeit slowly and at a rate similar to, but less than that of population. Figure 6[90] (following) plots the level of each over this period, with 2012 having a value of 100 percent for each. Population is forecast to grow at an average annual rate of 0.9 percent and electricity at a slightly slower average annual rate of 0.8 percent.

Figure 6



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[89] Source: EIA's Annual Energy Outlook 2011, Tables *Electricity Supply, Disposition, Prices, and Emissions, Reference Case* and *Macroeconomic Indicators, Reference Case*. This information is available at http://www.eia.gov/oiaf/aeo/tablebrowser/ (accessed November 30, 2011).

[90] Source: EIA's Annual Energy Outlook 2011, Tables *Electricity Supply, Disposition, Prices, and Emissions, Reference Case* and *Macroeconomic Indicators, Reference Case*. This information is available at http://www.eia.gov/oiaf/aeo/tablebrowser/ (accessed November 30, 2011).

Industry observers other than EIA see the electric utility industry as one of slower than average growth. From the February 26, 2009, Standard and Poor's *Industry Surveys – Electric Utilities*: "For firms in the S&P Electric Utilities index…shares tend to trade at a discount to the market multiple *because of the slow-growth nature of utilities' regulated operations*"[91] (emphasis added). Presumably, by "slow-growth nature," Standard and Poor's is making an implicit growth comparison with an average of all industries or with the economy as a whole. [92] Note that this "slow-growth nature" pertains to future growth; the stock market establishes prices on a forward-looking basis. While S&P may be describing historical growth, they must also be describing a "slow growth" future; otherwise market multiples for electric utility stocks would not trade at a discount to the market multiple.

It seems unlikely that electric utilities earnings will grow faster than revenues over the long-term; or alternatively stated, it is likely that electric utilities' earnings will grow at a similar rate as revenues. EIA forecasts electricity revenues to grow more slowly than nominal GDP, as shown in Figure 7 (following).[93] Over the 2012 through 2035

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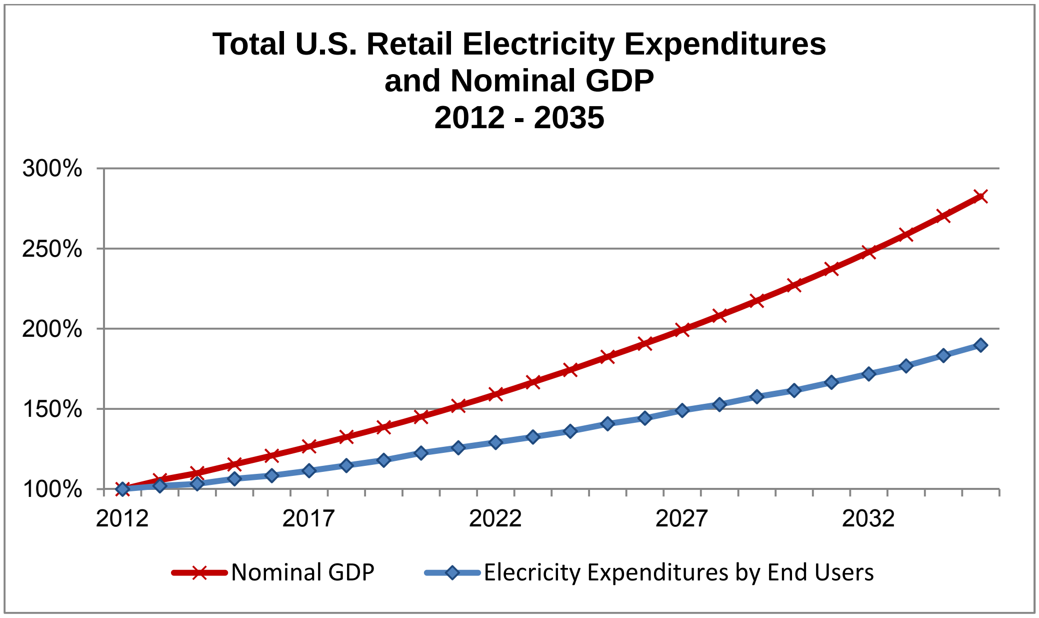
[91] *See,* in Docket No. 210, Exhibit PPL/209 Hadaway/28 (the last paragraph of page 26 of the document).

[92] Arguably, S&P is, contrary to my interpretation, comparing "slow-growth nature of utilities' regulated operations" with the growth for electric utilities overall or for electric utilities' non-regulated operations. This is one reason my screen of comparable companies includes a criterion that regulated assets account for at least 80 percent of total assets and at least 80 percent of total revenue is electric utility revenue.

[93] Data used in Figure 7 are from EIA's Annual Energy Outlook 2011, Tables *Electricity Supply, Disposition, Prices, and Emissions, Reference Case* and *Macroeconomic*

timeframe, EIA forecasts an annual average increase in electricity revenues from end users to increase at an average annual rate of 2.8 percent, while the agency forecasts nominal GDP to increase at an annual average rate of 4.6 percent. The difference between these rates of growth moderates somewhat over the end of this timeframe; over the period 2022 through 2035, electricity revenues are forecast to increase at an average annual rate of 3.0 percent while nominal GDP grows at an average annual rate of 4.5 percent.

Figure 7



To summarize, over the period 2012 through 2035, electricity use is forecast to grow more slowly than population; electricity prices are forecast to increase at a slower rate than consumer prices as

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Indicators, Reference Case. This information is available at http://www.eia.gov/oiaf/aeo/tablebrowser/ (accessed November 30, 2011).

measured by the CPI; and electricity expenditures (revenues from end users) are forecast to grow at a materially slower rate than nominal GDP.

As earnings growth is necessary over the long-term to support dividend growth, there is sufficient evidence to support the use of a growth rate for dividends that is less than the growth rate of long-term nominal GDP.

LONG-TERM GROWTH RATES

Q. DO YOU USE A RATE OF LONG-TERM GROWTH THAT IS LESS THAN GDP, GIVEN THE OUTLOOK FOR THE INDUSTRY YOU DESCRIBED ABOVE?

A. No; and that is one of the reasons my recommended ROE is conservative.

Q. WHAT LONG-TERM GROWTH RATE OR RATES DID YOU USE?

A. I use several. I first calculated the average annual historical rate of real GDP, as rate of inflation has changed over the past 60 years. Figure 8 (following) illustrates this using the Implicit GDP Price Deflator,[94] which is a very broad measure of inflation.

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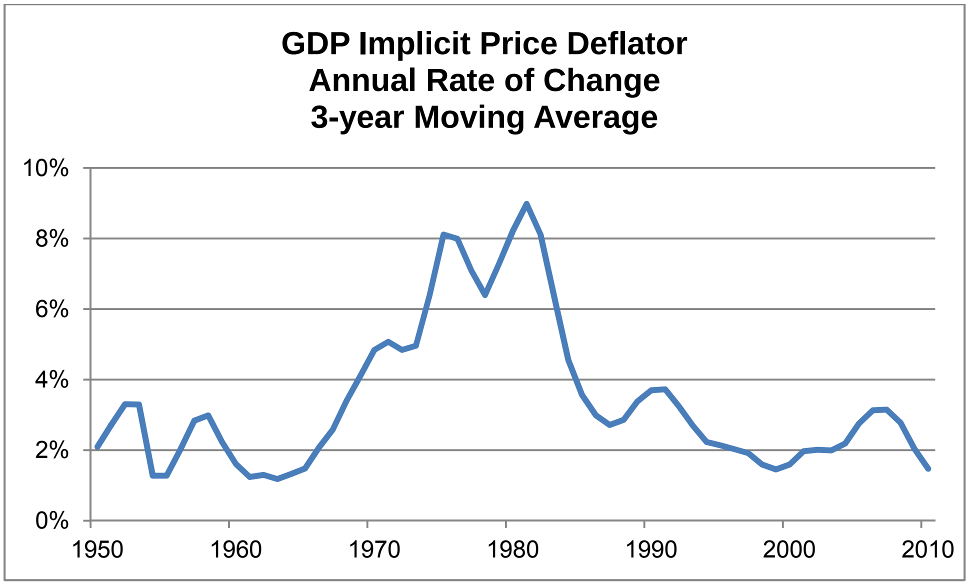
[94] The BEA defines an implicit price deflator as "…the ratio of the current-dollar value of a series, such as gross domestic product (GDP), to its corresponding chained-dollar value, multiplied by 100." *See* at http://www.bea.gov/faq/index.cfm?faq_id=513&searchQuery=implicit deflator&start=0&cat_id=0 (accessed December 1, 2011).

Figure 8



As can be seen, inflation heated-up beginning in the mid-1960s and declined dramatically in the mid- to late-1980s.[95] Therefore, rates of long-term growth based on historical nominal values of GDP include the impact of this more-or-less two decade experience in which the rate of inflation was relatively high when compared with the remaining four decades since 1950. For this reason, a more methodologically appealing approach is to use a growth rate of historical real GDP and appliqué an independently developed estimate of future inflation. I reviewed real GDP growth rates for a variety of periods. Table 4 (following) has the growth rates for certain periods over the past

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[95] As measured by the GDP Implicit Price Deflator and expressed in Figure X using a three-year moving average of annual rates of change in this index. The data underlying this chart is available from the Federal Reserve FRED site at http://research.stlouisfed.org/fred2/series/GDPDEF/downloaddata?cid=21 .

60 years. Due to the oil price shocks in the 1970s,[96] and the ensuing "stagflation," I chose 1980 through the most recently reported quarter (2011 Q3) as the period most applicable for estimating future growth in real GDP.[97]

Table 4

U.S. Real Gross Domestic Product

Historical Period	Annual Average Real GDP Growth[98]
1961 – 2010	3.1%
1971 – 2010	2.8%
1981 – 2010	2.6%
1991 – 2010	2.5%
2001 – 2010	1.4%

An ordinary least squares (OLS) regression of the natural logarithm of quarterly values of seasonally adjusted annual rates of real GDP[99]

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[96] *See* Perron's discussion of the impact of the 1973 oil price "shock" on the change in the trend rate of real GNP growth, including the observation that "…after that [1973] date, the slope of the trend function has sensibly decreased. This phenomenon is consistent with the much discussed slowdown in the growth rate of real GNP since the mid-seventies;" on page 1382 of "The Great Crash, the Oil Price Shock, and the Unit Root Hypothesis'" in *Econometrica*, Vol. 57, No. 6 (November,1989).

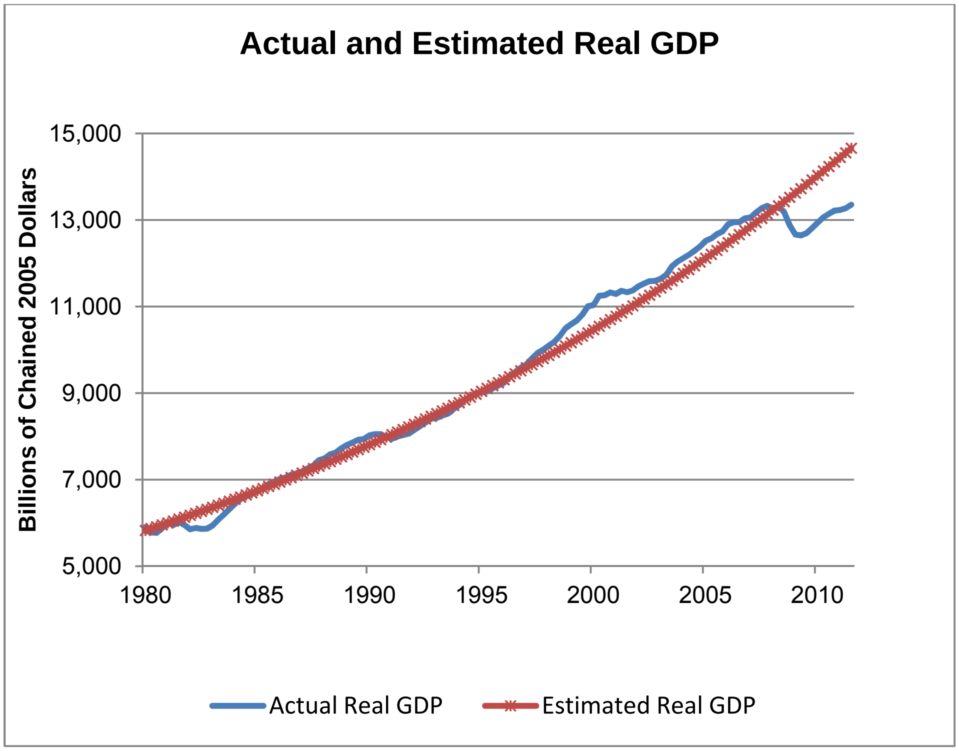
[97] Note that no statistical tests were conducted on this or any other period's values of real GDP.

[98] These rates are compound annual growth rates; i.e., the growth rate at which the beginning value, when annually compounded over the respective period by the growth rate, equals the value at the end of the period,

[99] Expressed in billions of chained 2005 dollars; i.e., the period for which the nominal value equaled the real value was 2005.

over the period 1980 Q1 through 2011 Q3,[100] provided a compound annual growth rate for real GDP over the period of 2.96 percent. Figure 9 (following) plots estimated values of real GDP based on this regression and the actual values.[101]

Figure 9



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[100] That is to say, the natural logarithms of annual values of real GDP were regressed against values for time; i.e., a semi-log regression model.

[101] *See* John Cochrane's "How Big is the Random Walk in GNP" from the October, 1988 *Journal of Political Economy* for an assessment of real GNP growth having mean-reversionary versus random walk qualities.

The average annual rate of growth over the 1980 through 2010 period is 2.6 percent, while the regression analysis yields 2.96 percent over a similar period.[102]

Q. HOW DID YOU TRANSFORM THE ESTIMATED 2.96 PERCENT ANNUAL GROWTH RATE FOR REAL GDP INTO AN ANNUAL GROWTH RATE FOR NOMINAL GDP?

A. As the purpose is to develop a forecast of the dollar value of dividends per share paid in future periods,[103] I developed a forecast of inflation using the TIPS[104] breakeven method of estimating inflationary expectations.[105] This involved constructing a forward curve of dollars, priced in terms of today's dollar;[106] i.e., a forecast of future price levels. This inflation forecast provided an average annual inflation rate forecast for 2022 through 2031 of 2.54 percent. An advantage of such a forecast is that it is actually "being made" by economic agents (investors) collectively having considerable amounts (trillions of dollars)

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[102] Limiting the regression to Q4 2010 (not shown) provided a similar result; i.e., the annual average rate of growth was five basis points lower.

[103] Future dividends are valued in nominal dollars.

[104] Treasury Inflation-Protected Securities (or TIPS) are the inflation-indexed notes and bonds issued by the U.S. Treasury. The principal amount of these securities is adjusted with changes in the Consumer Price Index. The coupon rate is constant, but generates a different amount of interest when multiplied by the inflation-adjusted principal, thus protecting the holder against (or compensating the holder for) inflation. The U.S. Treasury currently offers TIPS in five-, seven-, 10-, and 20-year maturities.

[105] *See* "Inflationary Expectations: How the Market Speaks," S. Kwan, *Federal Reserve Bank of San Francisco's Economic Letter*, Number 2005-25, October 3, 2005. *See also* "Empirical TIPS," R. Roll, *Financial Analysts Journal*, January/February 2004, Vol. 60, No. 1; pages 31 - 53

[106] This analysis used the U.S. Treasury securities' monthly average interest rates for the months of August and September, 2011, available in the Federal Reserve's Statistical Release H.15 at http://federalreserve.gov/releases/h15/data.htm .

at risk. The global market for debt securities issued by the U.S. Treasury is almost certainly the world's largest financial market for securities of a single issuer.

I multiplied the 2.54 percent estimated annual inflation rate by the estimated 2.96 percent annual rate of growth in real GDP to obtain an estimated long-term average annual growth rate in nominal GDP of 5.58 percent.[107,108]

Q. DID YOU USE ANY OTHER LONG-TERM GDP GROWTH RATES?

A. Yes. I reviewed a variety of governmental sources for forecasts of long-term GDP over the timeframe 2022 through 2036. The two forecasts matching my needs were from the Office of Management and Budget (OMB) and from EIA. The former provides a nominal GDP growth rate of 4.3 percent for 2021, which combines their forecast of a "steady state" 2.5 percent real GDP growth rate with their forecast of a 1.8 percent change in prices.[109]

I calculated an annual average growth rate in nominal GDP using EIA forecasts by first calculating annual values of nominal GDP from

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[107] Combining a forecast of real GDP with an inflation forecast to get a forecast of nominal GDP is not new. *See,* e.g., *New Regulatory Finance*; Roger A. Morin; 2006; page 311. While Dr. Morin has the two rates being added, the correct mathematical treatment is in the following footnote.

[108] By "compounding," or multiplying, the two rates; i.e., (1 + 0.0254) X (1 + 0.0296) – 1 = 0.0558, or 5.58 percent (rounded to two decimal places).

[109] *See* OMB's September 1, 2011 Mid-Session Review, Table 2 on page 9 at http://www.whitehouse.gov/sites/default/files/omb/budget/fy2012/assets/12msr.pdf (accessed November 28, 2011). OMB's reason for the forecast long-term growth rate being less than the historical average is, on page

EIA's forecast of real GDP and of a "Chain-type Price Index"[110] and using the nominal values of GDP to calculate an average annual rate of growth in nominal GDP of 4.5 percent over the 2022 through 2035 timeframe.

Q. HOW DID YOU USE THE THREE FORECASTS OF NOMINAL GDP?

A. I averaged the three forecasts by weighting the forecast based on history and the TIPS inflation forecast at 50 percent and the two governmental agency forecasts at 25 percent apiece. This is a conservative approach in that the forecasts of nominal GDP[111] by the two governmental agencies are "down-weighted" at 25 percent each and giving the forecast based on historical real GDP and the TIPS inflation forecast a 50 percent weight; i.e., my composite forecast is based one-half on the forecast having the largest average annual rate of growth in nominal GDP.

Q. ARE YOU AWARE OF ANY NON-GOVERNMENTAL SOURCE THAT PROVIDES FORECASTS COVERING THE PERIOD BEYOND 2020?

A. No. There is an exception in that the OMB document previously cited has the Blue Chip 2021 year over year forecast for real GDP at 2.6 percent and the GDP price index at 2.1 percent.[112] I did not incorporate

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[110] *See* EIA's Annual Energy Outlook 2011 Macroeconomic Indicators table for the Reference Case, available at http://www.eia.gov/oiaf/aeo/tablebrowser/ (accessed December 1, 2011).

[111] Or, in the case of the EIA forecast, of explicit values that when combined are a forecast of nominal GDP, as previously described.

[112] OMB 2011; *op. cit.*, page 12.

this exception, as OMB indicates a Blue Chip outlook for a long-term real GDP growth rate similar to that used by OMB; i.e., “All the forecasters have a similar expectation for the long-run growth rate, which is expected to be around 2-1/2 percent per year.” Additionally, the 4.55 percent average of the Blue Chip and CBO forecasts of nominal GDP for 2021 is essentially identical with the 4.53 percent OMB forecast.[113]

DISCOUNTED DIVIDENDS AND THE TIME VALUE OF MONEY

Q. ARE THERE ADDITIONAL FEATURES OF THIS DCF MODEL YOU WOULD LIKE TO DISCUSS?

A. Yes. One problem with developing discounted dividend models in a spreadsheet is how to account for the fact that most corporations paying dividends do so on a quarterly basis; i.e., four payments in each year. The analyst has the choice of either expanding the spreadsheet and modeling on a quarterly basis as opposed to the more commonly used annual basis or relying on mathematical calculations within the context of annual values as Microsoft Excel calculates IRRs assuming cash flows occur at the end of the period. As previously discussed investors are assumed to have a positive time preference, and the value of receiving four quarterly dividends at the end of each year,

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[113] OMB 2011; *op. cit.,* page 12.

which is how Excel works in an annual model, is less than the value of receiving them quarter by quarter.

Q. HOW DID YOU DEAL WITH THIS "TIMING ISSUE?"

A. While literature discusses several methods, I averaged the results of two annual model variants, which differ in the timing of cash flows.[114] The first variant is the conventional discounting of cash flows to yield an IRR, with the end-of year timing. The second variant accelerates the receipt of dividends by one year, as the end of one year is effectively the beginning of the next year.[115] Each model calculates an IRR, which I average by peer utility. This technique effectively changes the timing of receipt of dividends from all four quarterly dividends being received at the end of the year, to all four quarterly dividends being received in the middle of the year.

Q. ARE THERE ANY OTHER FEATURES OF THIS MODEL TO DISCUSS?

A. Yes. Another problem with cost of equity analyses is being able to compare the resulting ROEs (IRRs) between companies that may have very different capital structures. I make adjustments for the differences between the peer utilities' capital structures and my recommended Idaho Power capital structure for the 2011 test year of 50.1 percent

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[114] The first variant uses "beginning of year" (BOY) values and the second variant uses "end of year" (EOY) values.

[115] Receipt of the first dividend, for 2012, is at the same time the stock is purchased; therefore the initial cash flow, which in the first variant is the purchase of the stock, is in the second variant the sum of the negative price (cash outflow) and 2012 dividend (cash inflow).

long-term debt and 49.9 percent common equity.[116] I use the Hamada equation[117] to make this adjustment[118] for each individual peer utility, with the resulting adjustment to estimated ROE for each company in Table 5 (following).[119] The Hamada equation decomposes the beta of a company's stock into two parts: a measure of risk related to the company's business activities (the unlevered beta) and a measure of risk related to how the company finances those activities; i.e., the risk associated with the company's capital structure.

Adjustment for capital structure differences using the Hamada equation requires as inputs for each peer utility the observed capital structure, the income tax rate, the target capital structure, an assumed beta[120] of the company's long-term debt[121] and one of: the historical

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[116] I discuss the recommended capital structure late in this testimony.

[117] *See* Morin, *op. cit.*; pages 221ff. *See also* pages 4-8 of the January 15, 2004 rebuttal testimony of Robert G. Rosenberg in the New York jurisdiction's *Rochester Gas & Electric Corporation*, Case Nos. 03-E-0765, 02-E-0198, and 03-G-0766 and "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks;" Robert S. Hamada; *The Journal of Finance*, Vol. 27, No. 2 (May, 1972).

[118] *See* Brealey, Myers, and Allen; op. cit.; pages 484 – 486 and especially footnote 17.

[119] Note that using as historical rates a market rate of 11.0 percent and the intermediate government bond rate of 5.4 percent as the risk-free rate (implied risk premium 5.6 percent) coupled with the average of the average yields over the months of March and April of 2010 for the 10-year U.S. Treasury (3.79 percent), provided approximately the same results.

[120] An assumed beta as I have not seen an observed debt beta, although one could be constructed using observable market prices for a company's debt, assuming it is publicly traded.

[121] I assumed the long-term debt for each peer utility has a beta of 0.0. A sensitivity analysis assuming a beta of each peer utility's long-term debt has a beta of 0.3, while it did change individual companies' ROE adjusted for capital structure, it did not change the <u>average</u> adjusted ROE for either my peer utilities or for the peer utilities used by Idaho Power; i.e., the negative adjustments within each of the two groups of companies offset the positive adjustments in each group.

values for the risk-free rate and the market rate, or the historical risk premium. I used Value Line's 2011 estimates for each peer utilities for the first two parameters, and Staff's recommended 50.1 percent long-term debt – 49.9 percent common equity as the target capital structure. The Commission has previously provided guidance on adjustments to ROE for different capital structures, as in Order No. 01-777:

> *"It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly."*[122]

I used rates of return from page 23 of the 2009 Ibbotson SBBI Valuation Yearbook, supplied in Docket No. UE 215 by PGE in response to Staff data request 45, using the 3.7 percent average T-bill rate as the historical risk-free rate and the 9.6 percent average return on large company stock as the historical market return.[123]

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[122] *See* in Docket No. UE 115 Order No. 01-777 at 36.

[123] As a an analysis of the sensitivity of the adjustments for capital structure to use of different values of market premium, I also used an 8.3 percent market premium, the higher of the two values Dr. Avera uses. *See* Exhibit Idaho Power/406 Avera/1 – 2. Use of the 8.3 percent market premium also changed some individual peer utilities' ROE adjusted for capital structure and, while it did not change the average adjusted ROE for my peer utilities (the declines offset the increases), it reduced the average adjusted ROE for the peer utilities used by Idaho Power by 0.1 percent. I discuss Dr. Avera's market risk premia later in this testimony.

Table 5

Peer Utility[124]	ROE Adjustment using Hamada equation
ALLETE	0.4%
American Electric Power	-0.2%
Cleco	0.2%
IDACORP	0.2%
Pinnacle West Capital	0.1%
Portland General Electric	0.0%
UIL Holdings	-0.5%
Westar Energy	-0.2%
Average	0.0%

Q. WHAT ARE THE RESULTS OF THIS MODEL?

A. I will first discuss the differences between this model and my second DCF model and follow with a discussion of results from the two models.

Q. HOW DOES YOUR SECOND DCF MODEL DIFFER FROM THE FIRST MODEL?

A. The second model differs in one key aspect, and this difference is important.

Corporations have formal dividend policies, whether documented or not. As a general principle, and, as revealed in research dating back to John Lintner's pioneering research in the mid-1950s,[125, 126]

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[124] The capital structure adjustments for the peer utilities used by Idaho Power appear in Exhibits Staff/802 and Staff/803.

[125] *See* "Distribution of Incomes of Corporations Among Dividends, Retained Earnings, and Taxes;" John Lintner; *The American Economic Review*; Vol. 46, No.2. (May, 1956).

corporations are cautious with respect to changing the dollar amount of dividends paid. The results of Lintner's research have been characterized as concluding that:[127]

1. Managers target a long-term payout ratio[128] when determining dividend payout policy.
2. Dividends are "sticky;" i.e., managers are cautious about changing the level of dividends paid.
3. Dividends are tied to long-term sustainable earnings.
4. Dividends are "smoothed" from year to year; e.g., if it appears the company is capable of sustaining a higher dollar level of dividend payout, managers may adjust over several years as opposed to making an upward change in one year. Stated another way, if earnings increase over one or more years above some long-term trend, managers do not increase dividends by a similar (growth) rate.

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[126] John Lintner is commonly cited as one of four individuals who individually developed the Capital Asset Pricing Model (CAPM). The other three are Jack Treynor, William Sharpe, and Jan Mossin. This list is occasionally narrowed to Sharpe and Lintner; e.g., see page 25 of "The Capital Asset Pricing Model: Theory and Evidence;" by Fama and French; *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004). This article is available at http://www-personal.umich.edu/~kathrynd/JEP.FamaandFrench.pdf (accessed December 4, 2011).

[127] *See* "Payout policy in the 21st century;" Brav, *et. al.*; Journal of Financial Economics; 77 (2005); page 484.

[128] The payout ratio is the ratio of dividends paid in the period divided by earnings for the period. Payout policies are those corporate policies associated with the payment (or nonpayment) and level of dividends.

Recent research confirms Lintner's findings, with the exception that corporate managers were found to now place less emphasis on targeting the payout ratio (Lintner's number 1, above); e.g., "[n]inety percent of firms strongly or very strongly agree that they smooth dividends from year to year."[129] Payout policies are also conservative in that corporations have a tendency to change in response to permanent changes in earnings: over 65 percent of dividend-paying companies surveyed say stability of future earnings or a sustainable change in earnings are important or very important factors in making decisions about dividends.[130] In particular, the authors' found "cash cows" to be more likely than other firms surveyed to maintain a smooth dividend stream and to not make changes they may have to reverse in the future. The authors' "cash cows" appear similar in some regards to electric utilities.

Q. WHY ARE THE FINDINGS THAT COMPANIES CHANGE THE AMOUNT OF DIVIDENDS CAUTIOUSLY AND SMOOTH DIVIDENDS OVER TIME IMPORTANT?

A. The conventional discounted dividend DCF model assumes that the growth rate for certain parameters in the model are, for any given period, the same; e.g., dividends grow at the same rate as earnings

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[129] *Ibid.,* pages 497 – 507 (the quotation is from page 499). The authors surveyed 384 financial executives and conducted in-depth interviews with an additional 23. Their research included 256 public companies, of which 166 pay dividends.

[130] *Ibid*., page 499.

grow, which implies the payout ratio is constant in all periods. This is clearly not the case, based on the research discussed above, where corporate managers, on a year-to-year basis, allow the payout percentage to fluctuate and smooth the amount of dividends paid. It is also demonstrably not the case viewing Value Line's estimated dividends and earnings on per share bases to calculate annual average growth rates over the period 2008 – 2010 through 2014 - 2016,[131] as can be seen in Table 6 (following).

Table 6

Average Annual Rate of Growth

Per Share Dividends and Earnings based on Value Line Estimates[132]

2014 – 2016 over 2008 – 2010

	Dividend Growth Rate	Earnings Growth Rate
Staff's Peer Utilities		
ALLETE	1.9%	5.9%
American Electric Power	4.0%	4.7%
Cleco	9.5%	6.2%
IDACORP	3.8%	4.1%
Pinnacle West Capital	1.5%	4.0%
Portland General Electric	3.0%	7.6%
UIL Holdings	0.0%	3.2%
Westar Energy	3.1%	8.6%
Average	3.3%	5.5%

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[131] Recall the earlier discussion regarding dividend growth rates calculated from information provided by Value Line.

[132] For those peer utilities used by Idaho Power for which I had to adjust either the dividend or earnings growth rate, I discuss the adjustment in the related text.

Idaho Power's Peer Utilities		
American Electric Power	4.0%	4.7%
Ameren	0.0%	1.4%
Avista	9.0%	4.6%
Black Hills	1.5%	8.4%
CenterPoint Energy	2.9%	3.1%
Cleco	9.5%	6.2%
CMS Energy	13.8%	7.0%
Constellation Energy	1.4%	16.6%
DTE Energy	4.0%	4.6%
Edison International	1.9%	5.1%
Empire District	6.3%	6.9%
Great Plains	9.8%	5.9%
Hawaiian Electric	0.8%	11.1%
IDACORP	3.8%	4.1%
Integrys Energy	0.1%	9.1%
ITC Holdings	5.3%	13.8%
Otter Tail	1.5%	12.8%
Pepco Holdings	1.2%	2.7%
PG&E	4.5%	5.8%
Pinnacle West Capital	1.5%	4.0%
Portland General Electric	3.0%	7.6%
TECO Energy	4.5%	10.4%
UIL Holdings	0.0%	3.2%
Westar Energy	3.1%	8.6%
Wisconsin Energy	16.1%	8.6%
Average	4.4%	7.1%

Based on Value Line’s estimates, the average annual growth rate for earnings exceeds that of dividends by an average of 2.2 percent for my peer utilities and by an average of 2.7 percent for the peer utilities used by Idaho Power.

Q. WHICH GROWTH RATE IN PER SHARE VALUES IS MOST RELEVANT FOR ESTIMATING AN ELECTRIC UTILITY’S ROE USING A DISCOUNTED CASH FLOW MODEL?

A. Assuming the company pays a dividend and is expected to continue to do so, it is the growth rate in dividends per share—or, more precisely, the growth rate of the dollar amount of future dividends per share, which are directly related to growth rates[133] —that is most relevant to investors in the publicly traded stock of electric utilities using discounted dividend models to determine value. Dividends constitute a large portion of the value investors receive, both historically for large U.S. companies and on a prospective basis for the peer utilities used by me and those used by Idaho Power,[134, 135] and such investors never receive earnings. To the investor, there are only two periods in a multistage DCF model where the cash flows are not dividends: the initial purchase price (cash outflow) and the selling price at the end of the investment period (cash inflow).[136]

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[133] In a very real sense as I use them in my DCF model: either growth rates are derived from dividends, or dividends are derived from growth rates; i.e., given one, you also have the other.

[134] *See* support for the “large portion of the value received being dividends” in my discussion of my results later in this testimony. *See* also column 5 of Exhibit Staff/802.

[135] The 2008 Ibbotson Stocks, Bonds, Bills, and Inflation (SBBI) Classic Yearbook, states that a year-end 1925 investment in large company stocks, with dividends reinvested, had an average annual growth rate of 10.4 percent over the period 1926 through 2007. Capital appreciation (price increases) had an average annual growth rate of 6.0 percent. The 4.4 percent difference is largely due to dividends (average annual yield of 4.2 percent). *See* pages 61 – 63.

[136] The selling price would not be included if the model was extended in the number of periods to closely approach the result obtained from an indefinitely long stream of dividends. The growing perpetuity calculation establishes the selling price in DCF models using this method of terminal valuation.

Dr. Roger Morin, in the context of discussing in his *New Regulatory Finance* the use of historical data in DCF models has the following to say on the topic:

> *DCF proponents have variously based their historical computations on earnings per share, dividends per share, and book value per share. Of the three possible growth measures, growth in dividends per share is likely to be preferable, at least conceptually. DCF theory states clearly that it is expected future cash flows in the form of dividends that constitute investment value.*
>
> *However, since the ability to pay dividends stems from a company's ability to generate earnings, growth in earnings per share can be expected to strongly influence the market's dividend growth expectations. After all, dividend growth can only be sustained if there is growth in earnings. It is the expectation of earnings growth that is the principal driver of stock prices. On the down side [sic], using earnings growth as a surrogate for expected dividend growth can be problematic since historical earnings per share are frequently more volatile than dividends per share. Past growth rates of earnings per share tend to be very volatile and can sometimes lead to unreasonable results, such as negative growth rates.*****
>
> *****Under normal circumstances, dividend growth rates are not nearly as affected by year-to-year inconsistencies in accounting procedures as are earnings growth rates, and they are not as likely to be distorted by an unusually poor or bad year. Dividend growth is more stable than earnings growth because dividends reflect normalized long-term earnings rather than transitory earnings, because investors value stable*

> *dividends, and because companies are reluctant to cut dividends because of the information effect of dividend payments.*[137]

This passage confirms the research results reported above: dividends are less volatile than earnings—and they are less volatile because corporate managers smooth dividends from year to year and tie the amount of dividends to long-term sustainable (or normalized) earnings.

Q. MODIGLIANI AND MILLER'S (MM) "DIVIDEND IRRELEVANCE" THEOREM STATES THAT WHETHER AND HOW MUCH A FIRM PAYS IN DIVIDENDS DOES NOT AFFECT THE VALUE OF THE FIRM. HOW MIGHT THIS CONCLUSION BE RELATED TO THE QUESTION OF EARNINGS GROWTH RATES OR DIVIDEND GROWTH RATES?

A. First of all, MM's theorem[138] applies only in perfect capital markets with no taxes and, while in some regards highly competitive, modern capital markets are not perfect if only by the absence of perfect information;

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[137] *See The New Regulatory Finance*; Roger A. Morin, PhD; 2006. The passage cited is from page 284.

[138] *See "Dividend Policy, Growth and the Valuation of Shares*;" M.H. Miller and F. Modigliani; Journal of Business 34 (October 1961). Each of these two economists became (separately) Nobel laureates for work that included their work together. A concise discussion of dividend irrelevance and related topics can be found in Chapter 16, Payout Policy; Brealey, Myers, and Allen; *op. cit*.Their joint work is usually labeled as "MM" (or occasionally "M&M"), for their surname initials.

i.e., the presence of asymmetric information[139] alone implies they are not perfect. It is, however, a useful construct in which to think about payout policy. Dividend irrelevance implies that an investor is indifferent between receiving some amount(s) of periodic dividends and the price realized with the selling of the stock at the end of the investment timeframe and receiving no or smaller amount(s) of periodic dividends in exchange for realizing a larger price with the selling of the stock, subject to his or her own time preference as reflected in his or her personal discount rate (or rates). In the real world of actual companies and stocks, owners of stock in most electric utilities receive dividends and only part of their total cash received from owning stock is from the final sales price. For owners of stocks that never pay dividends, all of the total cash received comes from the final sales price.

Again using my teeter-totter analogy, the tradeoffs between the presence and amount of dividends versus the final selling price can be made in such a way that the teeter-tooter continues to be in balance with the same initial price and same discount rate; i.e., we are merely changing the number and/or sizes of the cash flows on the right hand side.

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[139] Asymmetric information is present if one party to a transaction has more or better information than another party to the transaction. I assume asymmetric information is present to some degree in real world stock markets.

Q. DR. AVERA DISCUSSES THE IMPORTANCE OF FUTURE EARNINGS AND OF FUTURE EARNINGS RELATIVE TO FUTURE DIVIDENDS IN ESTIMATING THE ROE OF AN ELECTRIC UTILITY USING DCF MODELS.[140] DO YOU BELIEVE EARNINGS ARE UNIMPORTANT?

A. No, earnings are important, as—and presumably agreeing with Dr. Avera on this point[141]—it is long-term growth in earnings that support long-term growth in dividends. Nevertheless, it is <u>dividends</u> that investors in publicly traded electric utilities explicitly receive, not earnings. It is cash flows to the investor that are used in discounted dividend DCF models, and those cash flows are, with the exception of the purchase price and the final selling price, dividends paid by the company to the investor.

Q. YOU SAID YOUR SECOND DCF MODEL DIFFERS FROM THE MODEL YOU DESCRIBED ABOVE "IN ONE KEY ASPECT." WHAT IS THIS ASPECT?

A. I developed and use the second model to overcome a shortcoming in conventional DCF discounted dividend models, including and perhaps especially the single-stage "Gordon" (constant) growth model. DCF models used for estimating the cost of equity assume the following are growing at the same rate: price, dividends, earnings, and book value.

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[140] *See* Exhibit Idaho Power/400 Avera/30 at line 21 through Avera/32 line 17.

[141] Exhibit Idaho Power/400 Avera/31 at line 8. As previously noted, I discuss Dr. Avera's use of estimated earnings growth rates later in this testimony.

This implies these models have, across all periods, a constant price-earnings (P/E) ratio, a constant earnings yield (earnings per share, or EPS, divided by price), and a constant payout ratio (dividends per share divided by EPS), the latter of which was discussed above. This shortcoming is present in those situations in which the assumption of earnings and dividends growing at the same rate is not reasonably met, or perhaps not met on average, which is the case for the growth rates in Table 7. Where the first model I described uses the growing perpetuity formula to calculate a sales price in 2036, my second model uses a P/E approach and assumes the P/E ratio is constant over the investment period.

To make use of the fact that Value Line has different estimates of the growth for earnings as compared with that for dividends, I use the dividend growth rate for dividends, which are still the cash flows being discounted in all periods other than the initial (purchase stock) period, and the earnings growth rate for price, which is not discounted when the stock is purchased (since no time in the investment period has yet elapsed), but is discounted when the stock is sold in 2036. To do this, I use my “current” price and the Value Line estimated 2012 earnings per share (EPS) value to calculate a forward P/E ratio. I then estimate the annual EPS for each of the years from 2012 through 2016 using the Value Line estimated EPS in the same manner as I did in the first model and do in this model for the estimated dividends per share (future dividends in this model have the same values by year as in the first model). Analogous with the geometrically converging growth rates previously described, I have the EPS growth rate geometrically converging in the Stage 2 period (2017 – 2021), from Value Line's average annual growth rate of 2008 – 2010 through 2014 – 2016 to the rate I used as the long-term growth rate for the Stage 3 period beginning in 2022.

The Stage 3 EPS annual growth rate is the same as the Stage 3 dividends per share annual growth rate.

Q. DID YOU HAVE TO MAKE ANY ADJUSTMENTS TO THE EARNINGS BASED ON VALUE LINE'S INFORMATION?

A. Yes. Similar to the issue previously discussed, where four of the peer utilities used by Idaho Power had negative average annual dividend growth rates over the 2008 – 2010 through 2014 – 2016 timeframe, the Value Line earnings information had negative calculated average annual rates of growth for two of the peer utilities used by Idaho Power: Ameren, which was one of the four with a negative dividend growth rate, and Edison International.

Q. HOW DID YOU HANDLE THE NEGATIVE GROWTH RATES FOR THESE TWO COMPANIES USED AS PEER UTILITIES BY IDAHO POWER?

A. I treated their earnings growth rates as I did the negative dividend growth rates of four companies used by Idaho Power as peer utilities: I used the 2015 over 2012 average annual growth rate. This changed Ameren's EPS growth rate to 1.4 percent and Edison International's to 5.1 percent.

Q. HOW DID YOU CALCULATE THE 2036 TERMINAL VALUE IN THIS MODEL?

A. I derived the selling price in 2036 by multiplying the P/E ratio from the beginning of the investment timeframe by the 2037 EPS.[142]

Q. DID YOU MAKE THE ADJUSTMENT FOR THE "TIMING ISSUE" AND FOR THE DIFFERENCES IN CAPITAL STRUCTURE YOU PROPOSE FOR IDAHO POWER VERSUS THAT OF THE PEER UTILITIES USED?

A. Yes; both of these were handled in the same way they were in the first DCF model I described.

Q. WHAT CAN YOU SAY ABOUT THIS MODEL THAT YOU CANNOT ABOUT THE FIRST DCF MODEL?

A. If forecasted growth in earnings per share is higher than forecasted dividends per share, the second model results in higher estimated ROEs (and vice-versa) This model incorporates Value Line's forecast of EPS values for the 2012 through 2016 timeframe and derives the selling price in 2036 from the basis of an assumed constant P/E ratio instead of a calculation of a growing perpetuity; i.e., it bases the

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[142] This is the only calculation involving the 2037 EPS value.

terminal value on the value of earnings, not dividends. It allows for different growth rates for EPS and dividends per share.

Q. IN DEVELOPING YOUR DCF MODELS, WHAT ARE YOU ASSUMING ABOUT INVESTORS' BEHAVIOR?

A. I assume that investors know and base investment decisions on the understandings that: a) earnings may grow over some period at a different—higher or lower—rate than dividends; b) the growth rate for earnings are more volatile than is the growth rate of dividends; c) it is dividends they receive as cash flows while they own the stock, growing at the dividend growth rate and not dividends growing at the earnings growth rate (where the two are different[143]); d) it is the long-term growth in earnings that allow for long-term growth in dividends; and e) they act as if they believe the value of a stock investment is derived from the cash flows, including selling price, that are realized from owning the stock.

I note that, as one example of the composition of shareholders of electric utilities, 68 percent of IDACORP common stock is held by institutional and mutual fund owners.[144] I assume such owners can afford a Value Line subscription and have access and motivation to

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[143] They are different for all of my peer utilities and for all but Ameren, the peer utility used by Idaho Power that Value Line forecasts to have negative growth rates for both dividends and earnings on a per share basis.

[144] *See* at http://finance.yahoo.com/q/mh?s=IDA+Major+Holders (accessed December 3, 2011).

acquire and understand the relevant findings of research in financial economics.

Q. DO INVESTORS CARE ABOUT INFLATION?

A. Yes; investors care about the purchasing power of their investments and therefore care about inflation and take likely future inflation into account. Arguably, if investors did not, the U.S. Treasury's TIPS notes and bonds[145] would not exist.

Q. HOW DOES THIS RELATE CURRENT PRICES TO FUTURE PRICES?

A. Current prices embed investors' expectations; i.e., prices of investments are forward-looking. This means that the current yield of bond incorporates investors' expectations of future yields[146] for that specific bond and similar investments. In other words, if interest rates are expected to increase prior to a bond reaching maturity, the effects of that increase are included in yield that investors', through the actions of the market, establish for the bond. This fact is captured by Brealey and Myers' "second lesson of market efficiency:" "In an efficient market you can trust prices. They impound all available information about the value of each security."[147]

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[145] Recall the earlier discussion of Treasury's Treasury Inflation Protected Securities (TIPS).

[146] Yields are the traditional means of expressing the price of fixed income securities (hat are not zero-coupon instruments; e.g., zero coupon bonds.

[147] Brealey and Myers; *op. cit.*, page 290.

This impounding of future prices is explicit in both of my DCF models and in that of many others, where the current price (or ROE, given the current price) is dependent upon a future price calculated as a terminal value.

Q. WHAT ARE THE RESULTS OF YOUR TWO DCF MODELS?

A. I refer to the first model I described as the Discounted Dividend Model with Terminal Valuation Based on P/E Ratio and the second as Discounted Dividend with Terminal Valuation Based on a Growing Perpetuity. Exhibit Staff/802 presents the results of the first model and Exhibit Staff/803 presents the results of the second model. Table 8 (following) also lists the ROE values after adjustment for my recommended capital structure for each model.

The first model, using the growing perpetuity calculation to estimate terminal value, did not have an IRR value that converged in Excel. The IRR calculation, whether performed in Excel or in my 25 year-old personal HP 12c financial calculator, is not an analytic result, achieved by using algebra, but a result of a numeric approach, which involves reiterative solutions until one is sufficiently “close.” Based on their respective values of input parameters (current price and future dividends) and the values of long-term growth I used, the IRR value failed to converge for two of the peer utilities used by Idaho Power: Constellation Energy and ITC Holdings. For this reason, the average adjusted ROE for the peer utilities used by Idaho Power is indicated as

"N/A," or not available. I tested for the price necessary for each company to have the IRR value of the remaining 23 peer utilities used by Idaho Power. For both companies the price necessary to achieve this level of IRR was less than 50 percent of the current price. As a lower price implies a higher IRR,[148] the implication is that the IRR value for each of these two companies, at their respective current price, is well below the average of the other 23 peer utilities used by Idaho Power.[149]

As can be seen in Table 7 (following), my peer utilities' adjusted ROE values, after adjusting the IRR results (column 1 in Exhibit Staff/802) for the difference between the peer utility's 2011 capital structure and my recommended capital structure for Idaho Power, are reasonably close in value to one another, varying from a low of 8.4 percent (IDACORP) to a high of 10.2 percent (Westar Energy), with both extremes in the second model. I did not consider removing any companies because their adjusted ROE was too low or too high. I also note that the 8.4 percent is considerably above the 5.728 percent cost of long-term debt proposed by Idaho Power,[150] and dramatically above (500 basis points) the 3.378 percent coupon 10-year maturity

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[148] Recall the earlier "teeter-tooter" discussion.

[149] *See* also my discussion later in this testimony of the portion of total value represented by the terminal value calculations.

[150] *See* Exhibit Idaho Power/502 Keen/1.

"replacement" utility bond at the credit rating matching that of Idaho Power for similar bonds used by Staff witness Ordonez.[151]

Table 7

		DCF Model 1 Adjusted ROE using Growing Perpetuity	DCF Model 2 Adjusted ROE using P/E Ratio
	Staff's Peer Utilities		
1	ALLETE	9.8%	10.1%
2	American Electric Power	9.7%	9.8%
3	Cleco	9.8%	9.8%
4	IDACORP	8.7%	8.4%
5	Pinnacle West Capital	9.5%	9.4%
6	Portland General Electric	9.4%	9.5%
7	UIL Holdings	8.8%	8.7%
8	Westar Energy	9.6%	10.2%
	Group Average	9.4%	9.5%

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[151] *See* Exhibit Staff/700 Ordonez regarding this *pro forma* bond.

	Idaho Power's Peer Utilities		
1	American Electric Power	9.7%	9.8%
2	Ameren	9.4%	9.1%
3	Avista	10.6%	10.5%
4	Black Hills	9.2%	9.6%
5	CenterPoint Energy	7.1%	7.0%
6	Cleco	9.8%	9.8%
7	CMS Energy	9.7%	9.7%
8	Constellation Energy	N/A	10.1%
9	DTE Energy	9.7%	9.7%
10	Edison International	7.7%	7.8%
11	Empire District	10.8%	11.4%
12	Great Plains	10.5%	10.6%
13	Hawaiian Electric	9.7%	10.7%
14	IDACORP	8.7%	8.4%
15	Integrys Energy	10.3%	10.7%
16	ITC Holdings	N/A	7.2%
17	Otter Tail	11.8%	12.9%
18	Pepco Holdings	10.3%	10.6%
19	PG&E	9.7%	9.9%
20	Pinnacle West Capital	9.5%	9.4%
21	Portland General Electric	9.4%	9.5%
22	TECO Energy	10.3%	10.8%
23	UIL Holdings	8.8%	8.7%
24	Westar Energy	9.6%	10.2%
25	Wisconsin Energy	10.7%	13.9%
	Group Average[152]	N/A	9.9%
	Average w/o Constellation Energy and ITC Holdings	9.8%	

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[152] Recall the Model 1 average for the peer utilities used by Idaho Power do not include Constellation Energy and ITC Holdings, as previously discussed.

Q. YOU PREVIOUSLY SAID "…DIVIDENDS CONSTITUTE A LARGE PORTION OF THE VALUE RECEIVED BY INVESTORS, BOTH HISTORICALLY FOR LARGE U.S. COMPANIES AND ON A PROSPECTIVE BASIS FOR THE PEER UTILITIES USED BY ME AND THOSE USED BY IDAHO POWER…" AND CLAIMED YOU WOULD PROVIDE SUPPORT FOR THIS CONCLUSION. WHAT SUPPORT DO YOU OFFER?

A. I discussed the historical portion of this statement in a prior footnote.

I calculated the proportion of the total discounted value of cash flows (dividends plus selling price in 2036) received by investors for each of the two timing variants of each of my two multistage DCF models, and averaged the results by peer utility by each model. The terminal value received by investors as a percent of the total discounted value received by investors subsequent to purchase of the peer utility stock is shown in column 5 of the "growing perpetuity" model (Model 1) and in column 9 of the "P/E ratio" model (Model 2). Table 8 (following) has some illustrative values for each of the two models and for the peer utilities used by Idaho Power, as well as for my peer utilities.

Note first that the average for each peer group, in each of the two models, is in the mid-30s percent range; i.e., between 33.0 percent (Idaho Power peer utilities in Model 1) to 36.4 percent (Idaho Power peer utilities in Model 2). As the Model 1 average result for the peer utilities used by Idaho Power does not include the values for two of the peer utilities (Constellation Energy and ITC Holdings), for reasons previously discussed, when I look at the difference between the Model 1 average result for my peer utilities versus the Model 2 average result for my peer utilities (a 0.5 percent difference) and then look at the Model 2 values for Constellation Energy (66.1 percent) and ITC Holdings (67.8 percent),[153] I conclude that if the Model 1 values for these two companies were available and reflected in the Model 1 average result for the peer utilities used by Idaho Power, all four average values would be very similar. I also note that these two companies are the lowest yielding companies used as a peer utility by either me or Idaho Power, at 2.5 percent and 1.9 percent for Constellation Energy and ITC Holdings, respectively. Conceivably the average values might range from 35.5 percent to 36.4 percent. Note also that, for stocks that do not currently pay a dividend and are not expected to initiate a dividend, the values would be 100 percent.

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[153] *See* Exhibit Staff/803 Storm/2.

Table 8

	Model 1	Model 2
Staff		
Peer Utilities Average	35.5%	36.0%
Max: IDACORP	44.6%	43.2%
Idaho Power		
Peer Utilities Average[154]	33.0%	36.4%
Max: Edison International (Model 1); ITC Holdings (Model 2)	47.7%	67.8%

Constellation Energy and ITC Holdings are the lowest yielding companies used as a peer utility by either me or Idaho Power, at 2.5 percent and 1.9 percent, respectively.[155]

I include this analysis to reinforce the impression of the importance of the terminal value calculation, and the extent to which this calculated value impacts the estimated ROE of companies, even those with significant dividend yields. In my "growing perpetuity" Model 1, it is dividend growth rates that drive terminal value; in my "P/E ratio" Model 2, it is earnings growth rates that drive terminal value.

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[154] The Model 1 Peer Utilities' Average value does not include values for either Constellation Energy or ITC Holdings. See the prior description regarding calculation of certain values for these two companies. See, however, the values for these two companies in Model 2.

[155] These two companies may be, at this time, the electric utility equivalents of the technology stock in the late 1990s which was said to be so richly price given the fundamentals of the company that the market was not only discounting the future into perpetuity, but also discounting the hereafter.

Q. DO YOUR MULTISTAGE DCF ANALYSES PRODUCE A RANGE OF RETURNS ON EQUITY?

A. Yes. Depending on the rate of long-term growth used for Stage 3 (years 2022 – 2036), the models produce a range of average adjusted ROE estimates.

Q. PLEASE DESCRIBE THE RESULTS OF USING THESE DIFFERENT LONG-TERM GROWTH RATES.

A. The results in Table 7, which provide my point estimate of 9.5 percent, stem from the use of the composite 5.0 percent long-term growth rate I discussed earlier in this testimony. I note that, due to the use of the regression-based historical real GDP growth rate over the 1980 through the third quarter of 2011 period, this rate is higher than the OMB forecast for a "steady state" 4.3 percent average annual rate of nominal GDP growth and higher than EIA's forecast of a 4.53 percent average annual rate of nominal GDP growth. I contend this makes my results more conservative (higher estimated ROE) than the straight use of the 4.41 percent average of the forecasts from OMB and EIA.

Using the 4.41 percent rate results in an average adjusted ROE for my peer utilities of 9.0 percent (Model 1) and 9.1 percent (Model 2). Using the 5.58 percent historical average results in an average adjusted ROE for my peer utilities of 9.9 percent for each of the two models. Strongly believing this to be an unduly high estimate of long-term growth in nominal GDP, I split the difference with my point estimate of 9.5 percent to arrive at the 9.7 percent upper end of my recommended range of ROE for Idaho Power.

I note in passing that using EIA's estimated annual average rate of growth in electricity expenditures by end users over the period 2022 through 2035 provides adjusted ROE results of 7.8 percent (Model 1) and 8.1 percent (Model 2).

I note again the conservatism embedded in using forecasted growth rates of long-term nominal GDP as long-term growth rates for electric utilities (for dividends or earnings per share). A lower assumed long-term rate of growth implies a lower ROE, all else being equal.

Q. WHAT THOUGHTS DO YOU HAVE REGARDING THE 9.8 PERCENT AND 9.9 PERCENT ADJUSTED ROE AVERAGES FOR THE PEER COMPANIES USED BY IDAHO POWER?

A. This result, where using the same methodology on the peer utilities of the energy utility result in an average adjusted ROE value materially exceeding that using my peer utilities, was somewhat surprising. Given the 9.8 percent and 10.1 percent results for ALLETE, the only peer utility I used that was not used by Idaho Power, my average results of my peer utilities are clearly less than the average of all the peer utilities used by Idaho Power; i.e., the seven of my peer utilities in the group used by Idaho Power are "pulling down" the average results of the Idaho Power group. Previous comparisons of different peer utility group provided that the two groups of peer utilities typically had similar average ROE estimates. I address the peer utilities used by Idaho Power later in this testimony.

Q. WHAT IS YOUR RECOMMENDED ROE FOR IDAHO POWER?

A. I recommend an ROE of 9.5 percent.

IDAHO POWER CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES IDAHO POWER REQUEST FOR RATEMAKING PURPOSES?

A. Idaho Power requests a capital structure of 48.824 percent long-term debt and 51.176 percent common equity.[156]

Q. HOW DOES THIS STRUCTURE COMPARE WITH THAT CURRENTLY AUTHORIZED AND WITH WHAT THE COMPANY HAS RECENTLY REPORTED?

A. The capital structure recommended by Idaho Power is materially different from that currently authorized, with the common equity component recommended by the company over 1.37 percent greater than that currently authorized.

Q. HOW DID YOU ARRIVE AT THE CAPITAL STRUCTURE YOU RECOMMEND?

A. Idaho Power's recommended capital structure, per Exhibit Idaho Power/502, is as of December 31, 2011—the end of the test year. I recommend the Commission view the capital structure as "linked" to

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[156] *See* Exhibit Idaho Power/502 Keen/1 and Table 1 of this testimony.

rate base, in that Staff uses an average of rate base over the test year, as it is “this capital structure” that pays for “that rate base.”

I arrived at the capital structure I recommend by using values reported by the Company in the three Form 10-Qs filed with the SEC this year as of the date of this testimony. I incorporate Idaho Power’s recommended values as found in Exhibit/502 by averaging the four dollar values for each of long-term debt and common equity: three actual results (one per quarter) and the December 31, 2011 pro forma values from Idaho Power. This yields my recommended capital structure.

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THE COMPOSITION OF IDAHO POWERS CAPITAL STRUCTURE?

A. I recommend the Commission authorize a capital structure composed of 50.1 percent long-term debt and 49.9 percent common equity.

Q. WHAT IS THE AVERAGE CAPITAL STRUCTURE OF YOUR PEER UTILITIES AND DOES THAT AVERAGE CAPITAL STRUCTURE CAUSE YOU TO MAKE AN ADJUSTMENT TO YOUR RECOMMENDED ROE FOR IDAHO POWER?

A. The average structure of my peer utilities, using Value Line’s estimated values for 2011, is 50.0 percent long-term debt; 49.9 percent common equity; and 0.1 percent preferred stock.

IDAHO POWER'S CASE FOR A ROE OF 10.5 PERCENT

RISK REVISITED

Q. DOES IDAHO POWER OFFER ANY TESTIMONY REGARDING THE RISK OF IDAHO POWER?

A. Yes. Company witnesses discuss risk at Exhibit Idaho Power/500 Keen/5 through Keen/28 and at Exhibit Idaho Power/400 Avera/6 through Avera/20.

Q. HOW RISKY WOULD IDAHO POWER'S COMMON STOCK BE, IF THE COMPANY'S STOCK WAS PUBLICLY TRADED?

A. Assuming essentially all of the Company's common stock was publicly traded, to mitigate any effect of any partial and material ownership by a corporate parent, the risk of Idaho Power's common stock would be similar to that of other electric utilities or utility holding companies.[157] The average unlevered beta[158] of my peer utilities is 0.42 and, by way of indirect but valid comparison, the unlevered beta of IDACORP is 0.40. Of the six other peer utilities, only one has an unlevered beta that is less than that of IDACORP. This strongly suggests Idaho Power, by far the largest component of IDACORP, has a business risk very comparable to the other electric utilities in my peer group. Figure 10[159] (following) depicts the separation of the risk of a common stock

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[157] *See* the discussion on risk and beta earlier in this testimony.

[158] Recall, in my discussion of the Hamada equation earlier in this testimony, that risk can be decomposed into business risk and risk due to debt financing.

[159] This figure is from Morin, *op. cit*., page 222, where it appears as Figure 7-2.

investment between business risk and the financial risk associated with debt financing.

Figure 10

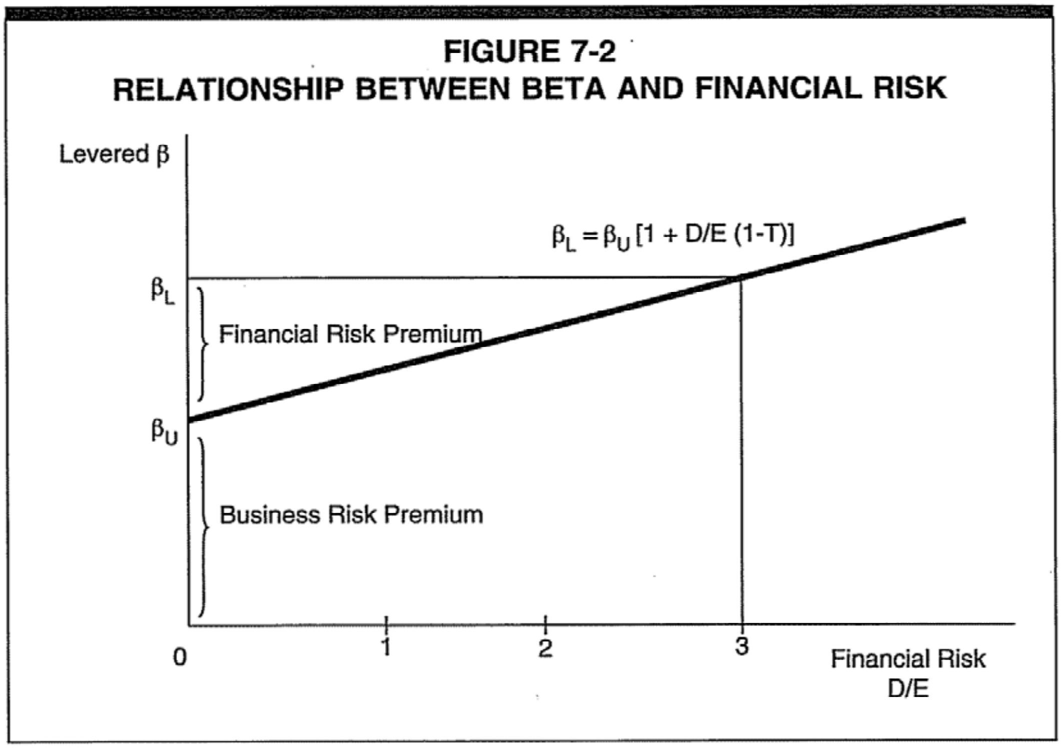

FIGURE 7-2
RELATIONSHIP BETWEEN BETA AND FINANCIAL RISK

PEER UTILITIES

Q. HOW DID DR. AVERA SELECT THE PEER UTILITIES USED BY IDAHO POWER?

A. Dr. Avera's criteria[160] were as follows:

1. Categorized by Value Line as being in its "Electric Utility Industry" groups.

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[160] *See* Idaho Power/400 Avera/24.

2. An S&P Corporate credit rating of “BBB-“ to “BBB+.”[161]
3. A Value Line Safety Rank of “2” or “3;” and
4. A Value Line Financial Strength Rating of “B+” to “B++.”

He also excluded FirstEnergy, Northeast Utilities, and Progress Energy, as “…they are currently involved in a major merger or acquisition.”

Q. HOW DO THE PEER UTILITIES RESULTING FROM DR. AVERA’S SCREENING CRITERIA COMPARE WITH YOUR PEER UTILITIES?

A. I will to review those companies included as peer utilities by Dr. Avera and not by me, as the only peer utility I used that is not included by Dr. Avera is ALLETE,[162] while I excluded 18 of the peer utilities he included. Table 9 (following) lists my reasons for excluding each of the 18 companies included by Idaho Power as a peer utility.

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[161] I am equating Dr. Avera’s “S&P corporate credit rating” with S&P’s Long-term Issuer Credit Rating, which the company defines as “…a forward-looking opinion about an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation…Issuer credit ratings can be either long term or short term. Short-term issuer credit ratings reflect the obligor's creditworthiness over a short-term time horizon.” *See* at http://www.standardandpoors.com/ratings/articles/en/us/?articleType=HTML&assetID=1245323088016 (accessed December 4, 2011).

[162] Presumably Dr. Avera did not include ALLETE as the company, per the September 23, 2011 Value Line report, had a Financial Strength Rating of A. Note that S&P has a BBB+ long-term Issuer credit rating on ALLETE since at least

Table 9

Why Staff Excluded 18 Companies Included by Idaho Power

Company	Reason(s) for Exclusion
Ameren	2009 dividend reduction
Avista	Below 80% revenue threshold
Black Hills	EEI “Mostly Regulated” & revenue threshold
CenterPoint Energy	Below 80% revenue threshold
CMS Energy	Below 80% revenue threshold
Constellation Energy	EEI “Diversified;” dividend decline; currently being acquired by Exelon; revenue threshold
DTE Energy	Below 80% revenue threshold
Edison International	EEI “Mostly Regulated;” revenue threshold
Empire District	2011 dividend reduction
Great Plains	2009 dividend reduction
Hawaiian Electric	EEI “Diversified”
Integrys Energy	Below 80% revenue threshold
ITC Holdings	EEI does not include; is transmission company; unusually high authorized ROEs
Otter Tail	Below 80% revenue threshold
Pepco Holdings	EEI “Mostly Regulated;” revenue threshold
PG&E	Below 80% revenue threshold
TECO Energy	Below 80% revenue threshold
Wisconsin Energy	“A-“ Issuer rating from S&P

I exclude Ameren, Empire District, and Great Plains as they had dividend cuts in, respectively, 2009, 2011, and 2009. Value Line is predicting no growth for Ameren’s dividend through the 2014 – 2016 timeframe. Great Plains reduced the company’s dividend by 50 percent in 2009. While Value Line estimates no increase in 2012, the average annual increase from 2012 through 2015 (average of 2014 – 2016) is 9.8 percent, which is the growth rate used in my DCF models.

Dr. Avera used a growth rate of 10.1 percent[163] in his constant growth DCF model. Empire District, due to the May, 2011 Midwest tornado previously mentioned, suspended its dividend prior to the third quarter. Value Line estimates a) a 50 percent reduction for 2011; b) a 56 percent increase in 2012 over 2011; and c) an average annual growth rate of 6.3 percent from 2012 through 2015 (average of 2014 – 2016). My DCF models used a 6.3 percent average annual dividend growth rate for 2012 through 2015, while Dr. Avera used a growth rate of 12.9 percent.

The Empire District and Great Plains results—my 6.3 percent growth rate and Dr. Avera's 12.9 percent, and my 9.8 percent and Dr. Avera's 10.1 percent, respectively—demonstrate the value of screening out companies having recent dividend declines: to do otherwise permits the calculation or forecast of near-term future growth rates that can easily exceed that which can be sustained over the long-term, and can exceed the growth rate in earnings per share: contrast the 9.8 percent dividend growth rate with the 5.9 percent EPS growth rate I used for Great Plains.[164], [165]

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[163] *See* Exhibit Idaho Power/402 Avera/1 column f for the Great Plains value.

[164] *See* Table 6.

[165] *See* my discussion of this point in a footnote to my screening criteria 5 and 6.

Q. I SEE IN TABLE 9 THAT YOU EXCLUDE SEVERAL FIRMS WITH ELECTRIC UTILITY REVENUE LESS THAN 80 PERCENT OF 2010 TOTAL REVENUE. PLEASE PROVIDE MORE INFORMATION REGARDING THESE COMPANIES, WHICH IDAHO POWER USED AS PEER COMPANIES.

A. Table 10 (following) lists, for the companies excluded by the 80 percent of revenue criteria, their 2010 Electric Utility Revenue as a percent of their 2010 Total Revenue.[166] I include IDACORP for a direct comparison. It is not clear to me that some of these firms are even remotely similar to Idaho Power in their primary line(s) of business or degree of regulation. Only three of the companies on this list received more than two-thirds of their 2010 revenue from their business as an electric utility: Edison International (78.9%), Pepco (69.2%), and PG&E (76.7%). All fall dramatically short of the 97.3 percent of IDACORP.[167] I note that Pepco and PG&E are also below my threshold of EEI's "Regulated" classification of assets (≥ 80% of assets are regulated).To the extent <u>structure</u>, due to owning non-regulated generating facilities, results in a relatively low percentage in Table 10, I argue that such a company is materially different than Idaho Power.

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[166] The revenue values for each company were obtained using SNL's Peer Analytics capability on November 23, 2011 (except for Constellation Energy, which were obtained December 4, 2011). I exported the values to an Excel spreadsheet, where I calculated the percentages.

[167] Recall the earlier discussion in a footnote regarding the regulatory classification of Idaho Power's <u>assets</u> versus those of IDACORP. A reasonable assumption would be that Idaho Power's revenue streams are at least as regulated as those on a consolidated basis of its parent IDACORP.

Table 10

	2010 Electric Utility Revenue as Percent of Total Revenue
Avista	62.3%
Black Hills	40.2%
CenterPoint Energy	24.9%
CMS Energy	58.0%
Constellation Energy	18.9%
DTE Energy	57.7%
Edison International	78.9%
IDACORP	**97.3%**
Integrys Energy	25.4%
Otter Tail	26.8%
PG&E	76.7%
Pepco Holdings	69.2%
TECO Energy	60.8%

Q. PLEASE DISCUSS THE REMAINING COMPANIES YOU EXCLUDED THAT WERE USED BY DR. AVERA.

A. I previously listed the reasons for excluding ITC Holdings: it is engaged in the business of transmission, not retail electric distribution; it is not classified by EEI; and Value Line notes that the company operates under a “formula-based ratemaking system” and that “ITC’s four subsidiaries are allowed very healthy returns on equity of 12.16% to

13.88%."[168] To me, these qualities make ITC Holdings a company quite different from Idaho Power.

I exclude Hawaiian Electric due to the other than "Regulated" classification by EEI. I note that Hawaiian Electric, while meeting the revenue threshold with 89.2 percent of 2010 total revenue coming as electric utility revenue, is diversified: its subsidiary bank generated more than 50 percent of the company's 2010 net income.[169]

Wisconsin Electric is screened out of my peer utilities as the company has an S&P Long-term Issuer Rating of "A-;" which is outside of the BBB± range I require.

Q. IS YOUR GROUP OF PEER UTILITIES MORE OR LESS LIKE IDAHO POWER THAN THE GROUP OF PEER UTILITIES USED BY DR. AVERA?

A. Each of my peer utilities is more like Idaho Power than many of his peer utilities, and arguably, this includes as many as 18 of his companies. Companies in my group are more like Idaho Power, for the reasons discussed above.

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[168] *See* Value Line's September 23, 2011 report on the company.

[169] *See* page 15 of Hawaiian Electric's 2010 10-K at http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDE0NjExfENoaWxkSUQ9NDI2MzA2fFR5cGU9MQ==&t=1 .

Q. WHAT ARE THE IMPACTS OF USING DR. AVERA'S PEER UTILITIES VERSUS USING YOUR PEER UTILITIES?

A. Dr. Avera uses his peer utilities in the following: his constant growth DCF model variants (Exhibits Idaho Power/402 and Idaho Power/403); his CAPM model variants (Exhibit Idaho Power/406 Avera/1 and Idaho Power/407 Avera/1) and his comparable earnings analysis (Exhibit Idaho Power/409).

One way to assess this use of different peer utilities uses values that appeared earlier in this testimony in Table 7: using my DCF models with his peer utilities. Table 7 shows that there is a 0.4 percent higher ROE using my growing perpetuity DCF model (Model 1) with his peer utilities[170] versus mine: 9.8 percent versus 9.4 percent.[171] It also shows a 0.5 percent higher ROE using my P/E ratio DCF model (Model 2) with his peer utilities versus mine: 9.9 percent versus 9.5 percent. Given that exactly the same information sources and modeling methodology was used for both groups of peer utilities, this is significant. My adherence to a requirement regarding the extent of regulated and/or electric utility business engaged in by each of my

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[170] This is using Value Line information on growth rates in each of our models; i.e., I using the average results in

[171] Note again that this model's average ROE for Dr. Avera's peer utilities does not include Constellation Energy or ITC Holdings for the reason previously discussed. Presumably, Dr. Avera would now exclude Constellation Energy, given the company is merging with Exelon. The merger agreement was approved by both companies' boards of directors on April 14, 2011 per the online *The Daily Record* at http://thedailyrecord.com/2011/04/28/constellation-energy-exelon-corp-to-merge-in-7-9-billion-deal/ (accessed December 4, 2011).

peer utilities effectively reduces the estimated ROE I use in my recommendation by 0.4 (Model 1: 9.8 percent to 9.4 percent) and 0.4 percent (Model 2: 9.9 percent to 9.5 percent) from the results using Dr. Avera's peer utlities. Stated differently, using my peer utilities instead of Dr. Avera's peer utilities decreases the estimated ROE by about 0.5 percent.

Q. DR. AVERA ONLY USES SEVEN OF YOUR EIGHT COMPANIES AS A PEER UTILITY. WHAT DO YOU HAVE TO SAY ABOUT ALLETE, THE COMPANY YOU INCLUDE, BUT DR. AVERA DOES NOT?

A. Inspection of Exhibits Staff/802 and Staff/803 reveals that not including ALLETE in my group would tend to <u>reduce</u> my ROE results, as ALLETE's adjusted ROE is higher than the average of my peer utilities in both Model 1 (9.8 percent versus the average of 9.4 percent) and Model 2 (10.1 percent versus the average of 9.5 percent). If ALLETE is removed from my group of peer utilities, the average estimated ROE in Model 1 is unchanged and the average ROE in Model 2 declines by 0.1 percent. After excluding ALLETE, my Model 1 result (9.4 percent) remains 0.4 percent lower and my Model 2 result (9.4 percent) is now 0.5 percent lower than his results.

Q. IS THERE ANOTHER COMPARISON YOU CAN MAKE BETWEEN THE RESULTS FROM THE TWO DIFFERENT GROUPS OF PEER UTILITIES?

A. Another and similar assessment is to use only the seven companies used as peer utilities by me and by Dr. Avera in his DCF model variants. Calculating the average ROEs of the seven common peer utilities, using the spreadsheet provided by Idaho Power in response to Staff data request 378, reduces the average ROE from the 11.4 percent in his Exhibit Idaho Power/402 to 9.9 percent using his Value Line estimated growth rates (column f); from 10.5 percent to 9.1 percent using his IBES estimated growth rates; from 10.4 percent to 9.3 percent using his Zacks estimated growth rates; and from 9.1 percent to 9.0 percent using his “br+sv” constant growth variant.

This is significant: if you reduce his peer companies to those seven most like Idaho Power, Dr. Avera’s constant growth DCF model variants’ highest average ROE is 9.9 percent, and the average of the four variants is reduced from 10.3 percent (average of 11.4, 10.5, 10.4, and 9.1 percent) to 9.3 percent (average of 9.9, 9.1, 9.3, and 9.0 percent); i.e., the average reduction across all four variants is 1.0 percent.

Q. DR. AVERA EXCLUDES THOSE COMPANIES WITH ESTIMATED ROES HE CONSIDERS TO BE TOO HIGH OR TOO LOW. DOES ADJUSTING FOR HIS EXCLUDED COMPANIES AND RESULTS CHANGE THE RESULTS YOU JUST DISCUSSED?

A. It does, but not by much. The only one of my seven companies Dr. Avera excludes, in any of his four variants, is Cleco in his IBES variant. After removing Cleco from the calculation, the average estimated ROE of my remaining six peer utilities is 9.5 percent, up from 9.1 percent in this variant. This effect is to change the average of his four constant growth DCF variants from 9.3 percent to 9.4 percent. Dr. Avera's constant growth DCF model variants, after placing more restrictions on "what is a peer utility" to Idaho Power, produce results that are, on average, equal to or less than the results from my multistage DCF models.

I note that the 9.9 percent average estimated ROE from his constant growth DCF model variant using Value Line growth rates still exceeds the 9.4 percent (Model 1) and 9.5 percent (Model 2) from my two multistage DCF models.

Q. WHAT ISSUES DO YOU HAVE WITH DR. AVERA'S CONSTANT GROWTH DCF MODEL RESULTS?

A. The constant growth DCF model has three inputs: a stock price in period "0" (the purchase price), an estimate of dividends paid in period "1," and a constant rate of growth applicable to the initial value of dividends.

The first issue I will discuss is simple. It is associated with changes to the information used in Dr. Avera's DCF model variants; i.e., changes in the values of the price and dividend parameters. Per

Exhibit Idaho Power/402 Avera/1, the footnote associated with column "a" indicates the prices were as of April 20, 2011.[172]

Q. WHAT IS THE IMPACT OF UPDATING THE PRICES TO THOSE YOU USED IN YOUR DCF MODELS?

A. I first updated Exhibit Idaho Power/402 for just those seven companies common in the two groups of peer utilities. This lowered the average ROE estimates to 9.7, 8.9 (9.4 without Cleco), 9.2, and 8.9 percent for, respectively, the Value Line, IBES, Zacks, and "br+sv" variants. The average estimated ROE for these seven peer utilities, using the updated prices in Dr. Avera's constant growth DCF model and across all four variants, is 9.2 percent (9.3 percent without Cleco in the IBES variant).

I then updated the prices for Dr. Avera's remaining peer utilities.

Q. WHAT ARE THE RESULTS OF UPDATING PRICES FOR ALL OF DR. AVERA'S PEER UTILITIES?

A. This update did not change the 11.4 percent average estimated ROE using Value Line growth rates from that in Exhibit Idaho Power/402. The average estimated ROEs for each of the three other variants declined by 0.1 percent.

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[172] *See* also Exhibit Idaho Power/400 Avera/29 at line 20, where the date of the prices is not clear ("…the corresponding stock price…"). Checking the closing price for Ameren on April 20, 2011 provided a price of $28.68, which matches the Ameren price in this exhibit.

Q. THE DIVIDEND YIELD IS NEXT YEAR'S DIVIDEND DIVIDED BY PRICE. DID YOU UPDATE DR. AVERA'S CONSTANT GROWTH MODEL FOR BOTH PRICE AND DIVIDEND?

A. Yes, subsequent to the update of prices discussed above. The average estimated ROE results for Dr. Avera's peer utilities did not change for any of the four variants. The results for the seven peer utilities common to both my group and Dr. Avera's group changed to 9.8 percent, 9.0 percent (9.4 percent without Cleco), 9.3 percent, and 9.0 percent for the Value Line, IBES, Zacks, and "br+sv" variants, respectively. The average of the four variants was 9.3 percent (9.4 percent without Cleco in the IBES variant).

Table 11 (following) shows the average estimated ROE results from Exhibit Idaho Power/402; those associated with updating Dr. Avera's constant growth DCF model with the prices and dividends used in my DCF models, as well as the average estimated ROEs of the two groups using my two multistage DCF models.

Table 11

Change	Peer Utilities[173]	Value Line	IBES	Zacks	"br+sv"	Average
Exhibit Idaho Power/402						
	Avera	11.4%	10.5%	10.4%	9.1%	10.3%
	Staff	9.9%	9.5%	9.3%	9.0%	9.4%
Price Update						
	Avera	11.4%	10.4%	10.3%	9.0%	10.3%
	Staff	9.7%	9.4%	9.2%	8.9%	9.3%
Price & Dividend Update						
	Avera	11.4%	10.5%	10.4%	9.1%	10.4%
	Staff	9.8%	9.4%	9.3%	9.0%	9.4%
Staff Mod. 1						
	Avera	9.8%				
	Staff	9.4%				
Staff Mod. 2	Avera	9.9%				
	Staff[174]	9.4%				

Q. WHAT DO YOU CONCLUDE FROM THE ROE RESULTS IN TABLE 11?

A. I conclude that, for each of the two peer utility groups, using the prices and dividends I used in my two DCF models in Dr. Avera's constant growth DCF model variants produces results similar to those of my two

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[173] Values for Staff's peer utilities are the average of the seven companies common to both sets of peer utilities; i.e., ALLETE is excluded. The values listed do not include Cleco in the IBES or Average columns.

[174] Does not include Constellation Energy or ITC Holdings. *See* the explanation regarding excluding these two companies earlier in this testimony.

multistage DCF models using the same growth rate. This conclusion serves to reinforce the differences in the two groups of peer utilities are behind most of the differences between Dr. Avera's DCF average results and my average results using my base case long-term rate of dividend growth.

I also refer to the reasons I exclude 18 companies Dr. Avera includes as peer utilities (see Table 9 above): either the company had a dividend cut sometime in the past five years (4 companies) or were engaged in businesses that on the whole are less regulated than Idaho Power (13 companies). Constellation Energy is in each of these two categories. The remaining two companies are ITC Holdings and Wisconsin power, each of which is discussed earlier in this testimony.

Q. CAN YOU CHARACTERIZE HOW THE PEER UTILITIES USED BY DR. AVERA ARE DIFFERENT FROM THOSE YOU USED?

A. Yes. Table 12 (following) has the average of the growth rates I used in my two DCF models for my eight peer utilities and by Dr. Avera in his DCF model variants for his 25 peer utilities. Note that Dr. Avera's average growth rates exclude, for each variant, the growth rates of those companies the estimated ROEs of which he excluded in Exhibit Idaho Power/402 Avera/1. Note also that, as both of my DCF models are multistage, I have separated the growth rate averages into that for the period 2013 – 2016 and the long-term growth rate applicable to the period beyond 2021.[175] Note in particular that the Staff 2013 – 2016 growth rates are based on Value Line's estimates of dividends and earnings.

Table 12

DCF Models' Average Annual Growth Rates

	Constant	2013 - 2016	2022 Forward
Avera			
Value Line (all 25)	7.0%		
Value Line (7 Staff cos.)[176]	5.4%		
IBES	5.8%		
Zacks	5.9%		
br+sv	4.6%		
Average	5.6%		
Staff			
Model 1		3.9%	5.0%
Model 2: Dividends		3.9%	5.0%
Model 2: Price & Earnings		4.7%	5.0%

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[175] The growth rates for my peer utilities for the period 2017 – 2021 vary for each company by year, converging from growth rates in Stage 1 to the long-term Stage 3 growth rate. This was described earlier in this testimony.

[176] This value is calculated using the Value Line information used by Dr. Avera for these seven peer utilities common to both of our peer groups of companies. Note that ALLETE's average earnings growth rate in my models is 6.8 percent, therefore it is likely that inclusion of ALLETE in this figure would serve to increase this value to an estimated value of approximately 5.6 percent: (7 x 5.4)+6.8) / 8.

Q. WHAT DO YOU CONCLUDE FROM THE AVERAGE GROWTH RATES IN TABLE 12?

A. I conclude that Value Line's average earnings growth rates have declined for my peer utilities between the time Dr. Avera obtained his information and the time I obtained mine (approximately seven months); i.e., the reduction from an estimated 5.4 percent to an estimated 4.7 percent.

I also conclude that earnings growth rates are higher than dividend growth rates, both as estimated by Value Line for my companies in Fall 2001. This is not surprising, given the earlier discussion on the prevalence of dividend smoothing as a feature of U.S. publicly traded corporations' payout policies and that the U.S. economy is (still) "rebounding" from the recession that began in 2007.

I also conclude that that his peer companies have different lines of business than do my peer companies, with less of their total business regulated than is the case for my peer companies.

As electric utilities are commonly known to have less earnings volatility than that of U.S. industries as a whole, I would expect that, in a period of economic expansion—even one that currently seems agonizingly slow on a national basis—industries and lines of business other than regulated electric utilities will have a greater acceleration in earnings, a higher rate of earnings growth, than electric utilities.

To the extent Dr. Avera's peer utilities, on average, engage in more of these industries or lines of unregulated businesses, I would expect their earnings to be more volatile than that of my peer utilities, which have more than 80 percent of both their assets in and revenue streams from regulated lines of business. I note again that Idaho Power's revenues are 97.6 percent from regulated activities.

Q. DOES YOUR ANALYSIS USING DR. AVERA'S CONSTANT GROWTH, SINGLE-STAGE DCF MEAN YOU ENDORSE THE USE OF SUCH DCF MODELS FOR ESTIMATING THE ROE OF ELECTRIC UTILITIES?

A. No; it does not. I note that the Commission has previously weighed-in on the use of such models.[177]

Q. DOES THIS MEAN YOU CONCUR WITH DR. AVERA'S CHOICES WITH RESPECT TO INFORMATION SOURCES AND USAGE?

A. No; it does not.

Q. DR. AVERA USES A SECOND GROUP OF COMPANIES IN HIS FOUR VARIANTS OF THE SINGLE-STAGE, CONSTANT GROWTH DCF MODEL. WHAT ARE YOUR THOUGHTS ON THE USE OF THESE COMPANIES AS A PROXY FOR IDAHO POWER?

A. Dr. Avera's "non-utility proxy group" of companies was developed by screening for those U.S. companies followed by Value Line that 1) pay

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[177] *See* Order No. 01-777 at 27, where the Commission in a previous docket rejected consideration of results from parties' single-stage DCF models. The Commission also rejected consideration results from parties' single-stage DCF models in Docket No. UE 116. *See* Order No. 01-787 at 24.

common dividends; 2) have a Safety Rank of “1;” 3) have a Financial Strength Rating of “B++” or greater; 4) have a beta of 0.85 or less; and 5) have investment grade credit ratings.[178] He uses this group of companies in his constant growth DCF model in Exhibits Idaho Power/404 Avera/1 and Idaho Power/405. Table 12 (following) has the averages for his utility proxy group and his non-utility proxy group.

Table 13[179]

Attribute	Utilities	Non-utilities
Dividend Yield	4.5%	2.8%
Earnings Growth Rates:		
Value Line	6.3%	8.7%
IBES	6.3%	9.2%
Zacks	10.4%	9.6%
br+sv	4.5%	11.3%
Average Growth Rate	6.9%	9.7%
ROE Estimates:		
Value Line	11.4%	11.9%
IBES	10.5%	12.4%
Zacks	10.4%	12.5%
br+sv	9.1%	12.1%
Average ROE	10.3%	12.2%

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[178] *See* Exhibit Idaho Power/400 Avera/25.

[179] Table values for dividend yield and the average ROE across all of the four DCF variants were derived from spreadsheet versions of Exhibits Idaho Power/402 (utilities) and Idaho Power/404 (non-utilities). Idaho Power provided the spreadsheet in response to Staff data request 378.

As can be seen in Table 13, the utilities' average dividend yield of 4.5 percent is 60.7 percent greater than that of the non-utilities at 2.8 percent. Additionally, the average rate of estimated growth in earnings per share for the utilities (6.9 percent) is 28.9 percent less than the average of the non-utilities (9.7 percent).

While Dr. Avera uses multiple screening criteria related to risk, he provides no analysis of the beta of these companies versus that of his utility companies. In other words, he presents no information on how the market, as measured by each company's beta, views the risks of these two groups of companies.[180] Additionally, he presents no analysis of the extent to which the beta measures for companies in either group are related to leverage (i.e., their capital structures) versus business risk, let alone any adjustment to calibrate with the capital structure of Idaho Power.

Q. WHAT DO YOU CONCLUDE FROM THIS COMPARISON?

A. While the two groups may have some broad similarities, such as paying dividends, the average dividend yields are significantly different. They are also materially different in terms of average growth estimates provided by the same organizations or derived using the same method (br+sv) and this is very important. Dr. Avera's non-utility companies are not, on average, comparable to Idaho Power.

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[180] See the earlier discussion of market risk and beta.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE RESULTS PRODUCED USING THESE NON-UTILITY COMPANIES?

A. I recommend the Commission disregard any ROE estimates resulting from the use of Dr. Avera's non-utility proxy group of companies.

Q. DR. AVERA PRESENTS THE RESULTS OF FOUR CAPITAL ASSET PRICING MODEL VARIANTS. WHAT ARE YOUR THOUGHTS REGARDING THESE MODELS AND THEIR RESULTS?

A. The four variants are the use of a "current" bond yield from April, 2011 and the use of a "projected" bond yield based on estimates made in February of 2011 (two estimates) and December, 2010 (one estimate). Dr. Avera uses each of the two bond yields for his utility proxy group and for his non-utility proxy group. As explained earlier in this testimony, the expected level of future bond yields are incorporated within current bond yields, and this is particularly true at the longer maturities, such as the 30-year Treasury used by Dr. Avera in all four variants. I recommend the Commission disregard the results of the two variants using the now approaching one-year old forecasts of 30-year Treasury bonds.[181] I also note that the yield on 30-year single-A utility bonds has declined from an average for the months of December, 2010 through February 2011 from 5.75 percent to an average of 4.16 percent in November, 2011.[182]

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[181] These two results are those in Exhibits Idaho Power/407 Avera/1 and Avera/2

[182] Source: Bloomberg (accessed December 5, 2011).

Consistent with my recommendation above that the Commission give little weight to any results produced using Dr. Avera's non-utility proxy group of companies, I recommend the Commission give little weight to the 10.0 percent estimated ROE from the CAPM using those companies.[183] The remaining CAPM is on Exhibit Idaho Power/406 Avera/1, and uses a "current" bond yield and Dr. Avera's utility group of companies.

Q. PLEASE DISCUSS THIS MODEL AND DR. AVERA'S RESULTS.

A. First, I want to discuss the use of the 30-year Treasury's yield as a risk-free rate. While agreeing with Dr. Avera that a 30 year timeframe is a reasonable one for the purpose of estimating the ROE of a rate-regulated electric utility such as Idaho Power,[184] I am troubled by two implications of doing so. The first is that the average yields of the 30-year Treasury (3.16 percent) and of the 30-year TIPS equivalent (1.01 percent) for the months of September and October of this year[185] indicate the market expects a 2.15 percent average annual rate of inflation over the next 30 years; i.e., the 30-year period ending in Fall 2031. This implies the real yield on the current 30-year Treasury, as of Fall 2011, is 1.0 percent.[186] The longer the maturity of a Treasury

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[183] *See* Exhibit Idaho Power/406 Avera/2.

[184] Recall that my two multistage DCF models use a timeframe of 25 years plus a terminal value calculation.

[185] From the Federal Reserve's H.15 report at http://federalreserve.gov/releases/h15/data.htm (accessed December 5, 2011).

[186] This is (1+.0316) / (1+.0215).

bond, the greater the exposure to the risk of unexpected inflation for the investor in that bond. Use of the 30-year Treasury is *de facto* incorporation of this risk; i.e., the 30-year Treasury bond used by Dr. Avera is not truly risk-free.

Q. WHAT IS THE SECOND IMPLICATION?

A. Dr. Avera's use of the yield of the 30-year Treasury leads to a "mismatch" between the relevant timeframes of his risk-free rate (30 years) and of his market return of 12.8 percent. This latter estimate, even if it is perfectly accurate, is based on analysts' earnings forecasts for no more than five years out (from early 2011). If the risk-free rate has a tenor of 30 years, the market return should also. Dr. Avera's 12.8 percent market annual return, if projected over the 30 years of his risk-free rate,[187] incorporates an average annual inflation rate estimated at 2.15 percent, as discussed above. This means the real return, and investors care about real returns,[188] on an average annual basis would be 10.4 percent.[189] The Ibbotson SBBI 2008 Classic Yearbook includes that the average annual nominal rate of return on large company stocks was 10.4 percent[190, 191] over the 1926

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[187] Note that, although Dr. Avera nowhere specifies the timeframe of this CAPM result, to not think of his result as long-term leads to the "mismatch."

[188] *See* the discussion on investors and inflation earlier in this testimony.

[189] This is (1+.128) / (1+.0215) - 1.

[190] Ibbotson SBBI 2008 Classic Yearbook; page 61.

[191] I believe it highly likely that Dr. Avera's group of dividend paying companies in the S&P 500 might be expected, over a 30 year timeframe, to grow more slowly that the

– 2007 timeframe and that the average annual rate of inflation over that same timeframe was 3.0 percent.[192] This implies an average annual historical real return on large company stock of 7.2 percent.[193] In other words, using the CAPM model in Exhibit Idaho Power/406 Avera/1, if the timeframe of the investment is matched to that of the risk-free rate, produces an average annual real rate of return on his utility peer company' stocks (10.4 percent) over the next 30 years that is 44 percent greater than the annual average return on large company stocks, after adjusting for the effects of inflation, over the 82 year period in the Ibbotson numbers (7.2 percent). I suggest this is unlikely. Additionally, and more to the point, I suggest investors know it is unlikely.

Recall also the earlier discussion of earnings growth versus dividend growth and the relevance of timeframe length. A group of large companies growing earnings over the next 30 years at an average annual rate of 12.8 percent are growing at approximately 250 percent of the projected rate of growth in nominal GDP growth.[194]

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average of the 500 stock index as a whole; i.e., the dividend-paying companies will grow more slowly than the companies that do not pay a dividend.

[192] *Ibid.*; page 75.

[193] Some may object to my use of geometric averages in this context. When considering an investment over a 30-year timeframe, geometric averages are highly relevant, perhaps more so than arithmetic averages. *See* Chapter 5 of *Investments*; by Bodie, Kane, and Marcus; Ninth Edition; 2011 and especially pages 153 – 154.

[194] Actually, 256 percent. That is, 0.128 / 0.05, or 2.56.

Acknowledging Dr. Avera's orientation from historical values, if I: 1) use his dividend yield of 2.3 percent; 2) a more realistic 30-year dividend growth rate of 5.0% (as used in my two DCF models and based on averaging the historical average since 1980 and governmental forecasts); 3) the current 30-year Treasury yield of 3.2 percent;[195] and 4) the current Value Line average beta of 0.74 for his utility proxy group of companies, I derive a 30-year CAPM result of: ((2.3%+5.0%)-3.2%) X 0.75 + 3.2% = 6.2%, where the market return is 7.3 percent (vs. 12.8 percent) and the market premium of 4.1 percent is about one-half of Dr. Avera's 8.3 percent and the "utility group" risk premium is therefore 3.0 percent (versus 6.3 percent).[196] If I then add a size premium of 1.01 percent, I have an adjusted CAPM result, using Dr. Avera's companies, updated interest rates, and a realistic 5.0 percent growth rate, of 7.2 percent.

Q. DOES THIS MEAN YOU AGREE WITH DR. AVERA'S SIZE ADJUSTMENT OR THE METHODOLOGIES HE USED IN THIS MODEL?

A. No.

Q. BASED ON YOUR REVIEW OF DR. AVERA'S CAPM AS DEPICTED IN EXHIBIT IDAHO POWER/406 AVERA/1 AND HIS RESULT OF

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[195] This is the average of the average 30-year Treasury bond yields for September and October of 2011; from the Federal Reserve's H.15 report at http://federalreserve.gov/releases/h15/data.htm (accessed December 5, 2011).

[196] Note that all values are in nominal terms.

11.8 PERCENT, WHAT DO YOU RECOMMEND TO THE COMMISSION?

A. I recommend the Commission give little weight to Dr. Avera's result in considering an ROE for Idaho Power.

Q. DR. AVERA DEVELOPS TWO VARIANTS OF A RISK PREMIUM MODEL. WHAT ARE YOUR THOUGHTS ON THESE?

A. I recommend the Commission give little weight to the results of the "projected" bond yield variant, for the reasons discussed previously.

Regarding Dr. Avera's risk premium model, if I use all of the parameter values used by Dr. Avera in Exhibit Idaho Power/408 Avera/1, but update his April 2011 BBB utility bond yield of 5.98 percent to the 4.16 percent yield of a 30-year single-A ("A") utility bond in November, 2011,[197] I get a resulting "Risk Premium Cost of Equity" of 8.91 percent, which is supportive of the results from my two DCF models.

Q. WHY DID YOU USE A SINGLE-A ("A") BOND YIELD, NOT THE TRIPLE B ("BBB") BOND YIELD USED BY DR. AVERA?

A. While Idaho Power's current S&P Long-term Issuer Rating is "BBB," the Company's first mortgage bonds, which account for 89 percent of Idaho Power's long-term debt,[198] are rated single-A ("A") by Moody's

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[197] Source: Bloomberg (accessed December 5, 2011).

[198] *See* Exhibit Idaho Power/503 Keen/1. This is $1,268.6 million (column 10 first mortgage bond total) divided by $1,425.9 billion (column 10 total debt capital).

and “A-“ by S&P.[199] Note that the 30-year single-A utility bond yield in April, 2011 was 5.59 percent, implying that the yield on utility bonds rated “BBB,” such as those used by Dr. Avera, have almost certainly declined as well. As both my peer utilities and Dr. Avera’s peer utilities (and Idaho Power) have, on average for the two groups, S&P Long-term Issuer ratings of BBB±,[200] it is a reasonable assumption that the average company in each of the two peer utilities also have single-A (“A”) ratings on their first mortgage bonds.

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING DR. AVERA’S RISK PREMIUM ROE RESULT OF 10.73 PERCENT?

A. I recommend the Commission give little weight to his result. I recommend the Commission consider the 8.91 percent estimated ROE I obtained by updating the interest rate and shifting to a bond more representative of those in Idaho Power’s current capital structure (89 percent) as supportive of the 9.5 percent ROE I recommend for Idaho Power.

Q. DOES YOUR UPDATING AND ADVOCATING COMMISSION ACKNOWLEDGEMENT OF YOUR UPDATED RESULT IMPLY YOU ARE SUPPORTIVE OF DR. AVERA’S METHODOLOGY WITH REGARD TO THIS RISK PREMIUM MODEL?

A. No.

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[199] *See* Exhibit Idaho Power/500 Keen/8,

[200] *See* Exhibit Idaho Power/400 Avera/24 and the description of my screening criteria earlier in this testimony.

Q. DR. AVERA USES A COMPARABLE EARNINGS ANALYSIS TO ESTIMATE A RECOMMENDED ROE FOR IDAHO POWER. WHAT ARE YOUR THOUGHTS ON THIS?

A. Given some of the changes from updating some of Dr. Avera's other analyses; my first thought was to update this one as well.

Q. WHAT WERE YOUR RESULTS?

A. I used the same Value Line reports used by Dr. Avera, but used the most recently available report for each company on both my and his lists of peer utilities as of late November, 2011.[201] The average of values in Dr. Avera's "Expected Return on Common Equity"column, while not shown in Exhibit Idaho Power/409 Avera/1, is 10.2 percent. His adjustment to "convert year-end return to an average rate of return"[202] averaged 0.2 percent (10.4 percent less 10.2 percent) for his group of peer utilities. My results of updating the Value Line information were 9.4 percent for my peer utilities and 9.7 percent for the peer utilities used by Dr. Avera, implying an "adjusted return on common equity" of 9.6 percent and 9.9 percent, respectively.

Q. DOES THIS IMPLY YOU ARE SUPPORTIVE OF THE METHODOLOGY AND INFORMATION USED BY DR. AVERA?

A. No.

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[201] *See* Exhibits Idaho Power/400 Avera/50 and Idaho Power/409 Avera/1, including footnote "a" in the latter exhibit. *See also* my description of information sources earlier in this testimony. I used Value Line's estimated average "Return on Common Equity" for the 2014 – 2016 timeframe.

[202] Idaho Power/409 Avera/1 footnote "b."

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING DR. AVERA'S ADJUSTED RESULT OF 10.4 PERCENT?

A. I recommend the Commission give little weight to Dr. Avera's 10.4 percent ROE result and acknowledge my updated adjusted ROE result of 9.6 percent for my peer utilities as supportive of the results from my two multistage discounted cash flow models.

Q. HOW WOULD YOU SUMMARIZE YOUR ANALYSIS OF THE MODELS AND METHODS USED BY DR. AVERA AND THE ESTIMATED ROE VALUES HE OBTAINED FROM THEM?

A. I recommend the Commission give little weight to Dr. Avera's results derived from using the non-utility proxy companies and from models using the future yield of a debt instrument. I recommend the Commission disregard his remaining CAPM result of 11.8 percent and his remaining Risk Premium result of 10.73 percent.

I recommend the Commission consider the 8.91 percent (Risk Premium) and 9.6 percent (Comparable Earnings) results[203] I obtained from Dr. Avera's models as being supportive of my 9.5 percent recommended ROE for Idaho Power.

I recommend the Commission consider the arguments presented in this testimony regarding the appropriate choice of companies as peer utilities with Idaho Power with respect to the 10.5 recommended ROE of Dr. Avera and the 9.5 percent ROE I recommend for Idaho Power.

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[203] The 9.6 percent is for my group of peer utilities.

Q. YOU HAVE CITED A NUMBER OF ARTICLES APPEARING IN PROFESSIONAL JOURNALS AND SEVERAL TEXTBOOKS COVERING TOPICS RELATED TO CORPORATE FINANCE OR INVESTMENTS. DO YOU ACCEPT ALL CONCLUSIONS MADE BY A SPECIFIC AUTHOR OR GROUP OF AUTHORS AS AUTHORITATIVE? IN OTHER WORDS, IF YOU FIND ONE OR MORE OF AN AUTHOR'S CONCLUSIONS TO BE AUTHORITATIVE, DO YOU NECESSARILY FIND OTHER CONCLUSIONS BY THE SAME AUTHOR AUTHORITATIVE?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME	Steven T. Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Program Manager, Economic Research and Financial Analysis Division
ADDRESS	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2148
EDUCATION	MBA; University of Oregon; Eugene, Oregon AB (Economics); Harvard; Cambridge, Massachusetts
EXPERIENCE	Employed by the Public Utility Commission of Oregon since October 2007, I am currently Program Manager of the Economic and Policy Analysis Section. My responsibilities include leading a team of analysts engaged in economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in multiple dockets. Prior regulatory experience includes four years in which my responsibilities included developing responses to data requests regarding the financial analysis of new products and services at US WEST Communications.
OTHER EXPERIENCE	I was a self-employed financial planner for eight years following an 18 year career in management positions engaged in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing (rate spread and rate design) and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct for 5 years. I was responsible for departmental budgeting and management reporting functions for three years at US West Direct and was responsible for corporate financial planning, analysis, and management reporting for one year at Electric Lightwave. I had seven years experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.

CASE: UE 233
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

December 7, 2011

UE 233 Idaho Power

Discounted Dividend Model
Three Stage DCF with Terminal Valuation based on Growing Perpetuity

		Estimated ROE[1] (IRR)	Average Recent Price	Dividend Yield @ Average Recent Price[2]	Average Annual 2017-21 Dividend Growth Rate[2]	Average Annual 2022-36 Dividend Growth Rate[2]	Terminal Value as % of Total Valuation[1]	2011 Common Equity % of Capital Structure	Average of 2011 Test Year Common Equity	Value Line Beta	Unlevered Beta	Beta Relevered to 2011 Test Year	ROE Adjustment (Hamada Equation)	ROE[1] Adjusted for Capital Structure Differences
		(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Staff's Peer Utilities													
1	ALLETE	9.4%	37.60	4.8%	3.7%	5.0%	35.2%	55.5%	49.9%	0.70	0.44	0.77	0.4%	9.8%
2	American Electric Power	9.9%	38.08	5.0%	4.6%	5.0%	31.6%	47.5%	49.9%	0.70	0.41	0.67	-0.2%	9.7%
3	Cleco	9.6%	34.69	3.5%	6.8%	5.0%	35.4%	53.5%	49.9%	0.65	0.42	0.69	0.2%	9.8%
4	IDACORP	8.4%	37.95	3.2%	4.5%	5.0%	44.6%	53.0%	49.9%	0.70	0.40	0.74	0.2%	8.7%
5	Pinnacle West Capital	9.5%	43.36	4.8%	3.6%	5.0%	34.6%	51.0%	49.9%	0.70	0.43	0.71	0.1%	9.5%
6	Portland General Electric	9.4%	23.60	4.6%	4.2%	5.0%	35.3%	49.5%	49.9%	0.75	0.42	0.74	0.0%	9.4%
7	UIL Holdings	9.3%	32.79	5.3%	3.0%	5.0%	35.3%	42.0%	49.9%	0.70	0.38	0.61	-0.5%	8.8%
8	Westar Energy	9.8%	26.20	5.0%	4.2%	5.0%	32.3%	47.5%	49.9%	0.75	0.42	0.72	-0.2%	9.6%
	Group Average	9.4%		4.5%	4.3%	5.0%	35.5%	49.9%	49.9%	0.71	0.42	0.71	0.0%	9.4%

UE 233 Idaho Power

Discounted Dividend Model
Three Stage DCF with Terminal Valuation based on Growing Perpetuity

		Estimated ROE[1] (IRR) (1)	Average Recent Price (2)	Dividend Yield @ Average Recent Price[2] (2)	Average Annual 2017-21 Dividend Growth Rate[2] (3)	Average Annual 2022-36 Dividend Growth Rate[2] (4)	Terminal Value as % of Total Valuation[1] (5)	2011 Common Equity % of Capital Structure (6)	Average of 2011 Test Year Common Equity (7)	Value Line Beta (8)	Unlevered Beta (9)	Beta Relevered to 2011 Test Year (10)	ROE Adjustment (Hamada Equation) (11)	ROE[1] Adjusted for Capital Structure Differences (12)
	Idaho Power's Peer Utilities													
1	American Electric Power	9.9%	38.08	5.0%	4.6%	5.0%	31.6%	47.5%	49.9%	0.70	0.41	0.67	-0.2%	9.7%
2	Ameren	9.2%	29.91	5.1%	3.0%	5.0%	36.3%	52.5%	49.9%	0.80	0.51	0.83	0.2%	9.4%
3	Avista	10.7%	24.36	4.8%	6.6%	5.0%	27.4%	49.0%	49.9%	0.70	0.42	0.69	-0.1%	10.6%
4	Black Hills	9.2%	30.87	4.8%	3.6%	5.0%	36.5%	50.0%	49.9%	0.85	0.51	0.85	0.0%	9.2%
5	CenterPoint Energy	8.9%	19.73	4.1%	4.2%	5.0%	39.5%	28.0%	49.9%	0.80	0.31	0.50	-1.8%	7.1%
6	Cleco	9.6%	34.69	3.5%	6.8%	5.0%	35.4%	53.5%	49.9%	0.65	0.42	0.69	0.2%	9.8%
7	CMS Energy	11.1%	19.65	4.7%	8.4%	5.0%	25.7%	30.5%	49.9%	0.75	0.31	0.50	-1.4%	9.7%
8	Constellation Energy	N/A	38.03	2.5%	3.5%	5.0%	N/A	67.5%	49.9%	0.80	0.61	1.01	1.2%	N/A
9	DTE Energy	9.8%	49.58	4.9%	4.6%	5.0%	32.2%	47.5%	49.9%	0.75	0.44	0.72	-0.2%	9.7%
10	Edison International	8.1%	38.00	3.4%	3.7%	5.0%	47.7%	44.5%	49.9%	0.80	0.43	0.73	-0.4%	7.7%
11	Empire District	10.8%	19.43	5.1%	5.5%	5.0%	26.6%	50.0%	49.9%	0.70	0.43	0.70	0.0%	10.8%
12	Great Plains	10.7%	19.37	4.3%	6.9%	5.0%	27.9%	47.5%	49.9%	0.75	0.43	0.72	-0.2%	10.5%
13	Hawaiian Electric	9.5%	23.87	5.2%	3.3%	5.0%	33.9%	53.5%	49.9%	0.70	0.45	0.74	0.2%	9.7%
14	IDACORP	8.4%	37.95	3.2%	4.5%	5.0%	44.6%	53.0%	49.9%	0.70	0.40	0.74	0.2%	8.7%
15	Integrys Energy	9.5%	49.14	5.5%	3.0%	5.0%	33.4%	60.0%	49.9%	0.90	0.64	1.03	0.8%	10.3%
16	ITC Holdings	N/A	74.80	1.9%	5.1%	5.0%	N/A	32.0%	49.9%	0.80	0.34	0.56	-1.4%	N/A
17	Otter Tail	10.8%	18.95	6.3%	3.6%	5.0%	25.2%	59.5%	49.9%	0.95	0.62	1.11	0.9%	11.8%
18	Pepco Holdings	10.2%	18.92	5.7%	3.5%	5.0%	29.3%	52.0%	49.9%	0.80	0.51	0.83	0.1%	10.3%
19	PG&E	9.7%	41.76	4.4%	4.8%	5.0%	33.4%	50.5%	49.9%	0.55	0.33	0.56	0.0%	9.7%
20	Pinnacle West Capital	9.5%	43.36	4.8%	3.6%	5.0%	34.6%	51.0%	49.9%	0.70	0.43	0.71	0.1%	9.5%
21	Portland General Electric	9.4%	23.60	4.6%	4.2%	5.0%	35.3%	49.5%	49.9%	0.75	0.42	0.74	0.0%	9.4%
22	TECO Energy	10.4%	17.56	5.1%	4.8%	5.0%	28.7%	49.0%	49.9%	0.85	0.51	0.84	-0.1%	10.3%
23	UIL Holdings	9.3%	32.79	5.3%	3.0%	5.0%	35.3%	42.0%	49.9%	0.70	0.38	0.61	-0.5%	8.8%
24	Westar Energy	9.8%	26.20	5.0%	4.2%	5.0%	32.3%	47.5%	49.9%	0.75	0.42	0.72	-0.2%	9.6%
25	Wisconsin Energy	11.0%	31.36	3.6%	9.3%	5.0%	27.2%	46.0%	49.9%	0.65	0.37	0.61	-0.2%	10.7%
	Group Average	9.9%		4.5%	4.7%	5.0%	N/A	48.5%	49.9%	0.75	0.44	0.74	-0.1%	N/A
	Average w/o Constellation Energy and ITC Holdings	9.9%		4.5%	4.6%	5.0%	33.0%	49.4%	49.9%	75.0%	44.4%	74.3%	0.0%	9.8%

Notes

1. Based on average of Beginning of Year values and End of Year values.
2. Based on End of Year values.

Displayed values have not been rounded.

CASE: UE 233
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Exhibits in Support
Of Opening Testimony

December 7, 2011

UE 233 Idaho Power

Three Stage DCF with Terminal Valuation Based on P/E Ratio

		Estimated ROE^1 (IRR) (1)	Average Recent Price (2)	Average Annual 2013-16 Dividend Growth Rate^2 (3)	Average Annual 2013-16 Earnings Growth Rate^2 (4)	Average Annual 2017-21 Dividend Growth Rate^2 (5)	Average Annual 2017-21 Earnings Growth Rate^2 (6)	Average Annual 2022-36 Dividend Growth Rate^2 (7)	Average Annual 2022-36 Earnings Growth Rate^2 (8)	Terminal Value as % of Total Valuation^1 (9)	2011 Common Equity % of Capital Structure (10)	Average of 2011 Test Year Common Equity (11)	Value Line Beta (12)	Unlevered Beta (13)	Beta Relevered to 2011 Test Year (14)	ROE Adjustment (Hamada Equation) (15)	ROE^1 Adjusted for Capital Structure Differences (16)
	Staff's Peer Utilities																
1	ALLETE	9.7%	37.60	2.5%	6.8%	3.7%	5.4%	5.0%	5.0%	37.1%	55.5%	49.9%	0.70	0.44	0.77	0.4%	10.1%
2	American Electric Power	10.0%	38.08	3.5%	4.8%	4.6%	4.9%	5.0%	5.0%	32.1%	47.5%	49.9%	0.70	0.41	0.67	-0.2%	9.8%
3	Cleco	9.6%	34.69	9.5%	5.0%	6.8%	5.5%	5.0%	5.0%	35.3%	53.5%	49.9%	0.65	0.42	0.69	0.2%	9.8%
4	IDACORP	8.2%	37.95	6.7%	3.0%	4.5%	4.6%	5.0%	5.0%	43.2%	53.0%	49.9%	0.70	0.40	0.74	0.2%	8.4%
5	Pinnacle West Capital	9.3%	43.36	2.7%	2.9%	3.6%	4.6%	5.0%	5.0%	33.9%	51.0%	49.9%	0.70	0.43	0.71	0.1%	9.4%
6	Portland General Electric	9.6%	23.60	3.4%	4.2%	4.2%	6.0%	5.0%	5.0%	36.3%	49.5%	49.9%	0.75	0.42	0.74	0.0%	9.5%
7	UIL Holdings	9.2%	32.79	0.0%	2.5%	3.0%	4.3%	5.0%	5.0%	34.7%	42.0%	49.9%	0.70	0.38	0.61	-0.5%	8.7%
8	Westar Energy	10.4%	26.20	3.0%	8.2%	4.2%	6.4%	5.0%	5.0%	35.9%	47.5%	49.9%	0.75	0.42	0.72	-0.2%	10.2%
	Group Average	9.5%		3.9%	4.7%	4.3%	5.2%	5.0%	5.0%	36.0%	49.9%	49.9%	0.71	0.42	0.71	0.0%	9.5%

UE 233 Idaho Power

Three Stage DCF with Terminal Valuation Based on P/E Ratio

		Estimated ROE[1] (IRR) (1)	Average Recent Price (2)	Average Annual 2013-16 Dividend Growth Rate[2] (3)	Average Annual 2013-16 Earnings Growth Rate[2] (4)	Average Annual 2017-21 Dividend Growth Rate[2] (5)	Average Annual 2017-21 Earnings Growth Rate[2] (6)	Average Annual 2022-36 Dividend Growth Rate[2] (7)	Average Annual 2022-36 Earnings Growth Rate[2] (8)	Terminal Value as % of Total Valuation[1] (9)	2011 Common Equity % of Capital Structure (10)	Average of 2011 Test Year Common Equity (11)	Value Line Beta (12)	Unlevered Beta (13)	Beta Relevered to 2011 Test Year (14)	ROE Adjustment (Hamada Equation) (15)	ROE[1] Adjusted for Capital Structure Differences (16)
	Idaho Power's Peer Utilities																
1	American Electric Power	10.0%	38.08	3.5%	4.8%	4.6%	4.9%	5.0%	5.0%	32.1%	47.5%	49.9%	0.70	0.41	0.67	-0.2%	9.8%
2	Ameren	8.9%	29.91	0.0%	1.4%	3.0%	3.5%	5.0%	5.0%	34.3%	52.5%	49.9%	0.80	0.51	0.83	0.2%	9.1%
3	Avista	10.6%	24.36	6.6%	3.8%	6.6%	4.8%	5.0%	5.0%	26.7%	49.0%	49.9%	0.70	0.42	0.69	-0.1%	10.5%
4	Black Hills	9.6%	30.87	1.5%	5.8%	3.6%	6.3%	5.0%	5.0%	38.7%	50.0%	49.9%	0.85	0.51	0.85	0.0%	9.6%
5	CenterPoint Energy	8.8%	19.73	3.7%	3.8%	4.2%	4.2%	5.0%	5.0%	38.7%	28.0%	49.9%	0.80	0.31	0.50	-1.8%	7.0%
6	Cleco	9.6%	34.69	9.5%	5.0%	6.8%	5.5%	5.0%	5.0%	35.3%	53.5%	49.9%	0.65	0.42	0.69	0.2%	9.8%
7	CMS Energy	11.1%	19.65	8.0%	4.8%	8.4%	5.8%	5.0%	5.0%	25.7%	30.5%	49.9%	0.75	0.31	0.50	-1.4%	9.7%
8	Constellation Energy	8.9%	38.03	1.4%	13.3%	3.5%	9.5%	5.0%	5.0%	66.1%	67.5%	49.9%	0.80	0.61	1.01	1.2%	10.1%
9	DTE Energy	9.8%	49.58	3.8%	4.4%	4.6%	4.9%	5.0%	5.0%	32.3%	47.5%	49.9%	0.75	0.44	0.72	-0.2%	9.7%
10	Edison International	8.2%	38.00	2.2%	5.1%	3.7%	5.0%	5.0%	5.0%	48.3%	44.5%	49.9%	0.80	0.43	0.73	-0.4%	7.8%
11	Empire District	11.4%	19.43	6.3%	12.9%	5.5%	5.7%	5.0%	5.0%	30.9%	50.0%	49.9%	0.70	0.43	0.70	0.0%	11.4%
12	Great Plains	10.8%	19.37	9.8%	6.3%	6.9%	5.4%	5.0%	5.0%	28.6%	47.5%	49.9%	0.75	0.43	0.72	-0.2%	10.6%
13	Hawaiian Electric	10.5%	23.87	1.4%	11.3%	3.3%	7.4%	5.0%	5.0%	39.5%	53.5%	49.9%	0.70	0.45	0.74	0.2%	10.7%
14	IDACORP	8.2%	37.95	6.7%	3.0%	4.5%	4.6%	5.0%	5.0%	43.2%	53.0%	49.9%	0.70	0.40	0.74	0.2%	8.4%
15	Integrys Energy	10.0%	49.14	0.0%	5.7%	3.0%	6.6%	5.0%	5.0%	36.0%	60.0%	49.9%	0.90	0.64	1.03	0.8%	10.7%
16	ITC Holdings	8.6%	74.80	5.8%	12.9%	5.1%	8.4%	5.0%	5.0%	67.8%	32.0%	49.9%	0.80	0.34	0.56	-1.4%	7.2%
17	Otter Tail	11.9%	18.95	2.6%	14.1%	3.6%	8.1%	5.0%	5.0%	32.1%	59.5%	49.9%	0.95	0.62	1.11	0.9%	12.9%
18	Pepco Holdings	10.5%	18.92	2.1%	9.0%	3.5%	4.1%	5.0%	5.0%	31.3%	52.0%	49.9%	0.80	0.51	0.83	0.1%	10.6%
19	PG&E	9.9%	41.76	6.0%	6.1%	4.8%	5.3%	5.0%	5.0%	34.6%	50.5%	49.9%	0.55	0.33	0.56	0.0%	9.9%
20	Pinnacle West Capital	9.3%	43.36	2.7%	2.9%	3.6%	4.6%	5.0%	5.0%	33.9%	51.0%	49.9%	0.70	0.43	0.71	0.1%	9.4%
21	Portland General Electric	9.6%	23.60	3.4%	4.2%	4.2%	6.0%	5.0%	5.0%	36.3%	49.5%	49.9%	0.75	0.42	0.74	0.0%	9.5%
22	TECO Energy	10.8%	17.56	5.4%	7.4%	4.8%	7.1%	5.0%	5.0%	31.9%	49.0%	49.9%	0.85	0.51	0.84	-0.1%	10.8%
23	UIL Holdings	9.2%	32.79	0.0%	2.5%	3.0%	4.3%	5.0%	5.0%	34.7%	42.0%	49.9%	0.70	0.38	0.61	-0.5%	8.7%
24	Westar Energy	10.4%	26.20	3.0%	8.2%	4.2%	6.4%	5.0%	5.0%	35.9%	47.5%	49.9%	0.75	0.42	0.72	-0.2%	10.2%
25	Wisconsin Energy	14.1%	20.23	13.9%	7.3%	9.3%	6.4%	5.0%	5.0%	14.9%	46.0%	49.9%	0.65	0.37	0.61	-0.2%	13.9%
	Group Average	10.0%		4.4%	6.6%	4.7%	5.8%	5.0%	5.0%	36.4%	48.5%	49.9%	0.75	0.44	0.74	-0.1%	9.9%

Notes

1. Based on average of Beginning of Year values and End of Year values.
2. Based on End of Year values.

Displayed values have not been rounded.

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony
Revenue Spread and Rate Design

December 7, 2011

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist, employed by the Economic Research and Financial Analysis Division (ERFA) of the Public Utility Commission of Oregon (OPUC). My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is included as Exhibit Staff/901.

Q. PLEASE CONVEY THE ESSENCE OF YOUR TESTIMONY.

A. On a *qualitative* basis (i.e., subject to the revenue requirement adjustments proposed by other OPUC staff members), and with a limited number of exceptions, this testimony supports the cost-of-service, revenue-spread, and rate-design proposals of Idaho Power (or Company) as contained in its original application. In order to accommodate an understanding of the direct effects of my recommendations – i.e., so they are not confounded with the effects of the various Staff accounting adjustments – what follows will generally relate to Idaho Power's unadjusted original application.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Topic 1 – Major Points and Recommendations of this Testimony

Topic 2 – General Cost of Service, Revenue Spread, and Rate Design Discussions

Topic 3 – An Affirmative Case for Seasonal Residential Rates

Q. DID YOU PREPARE EXHIBITS FOR THIS CASE?

A. Yes, they are listed as follows:

901 – Witness Qualification Statement

902 – Recommended Revenue Spread

903 – Alternative Seasonal Residential Rate Designs

904 – Monthly Residential Billing Comparisons

905 – Idaho Power's Response to Staff Data Request Regarding UM 1415 Straw Criteria Applied to Seasonal Rates

906 – Cascade Natural Gas Customers in Baker City and Ontario

TOPIC 1 – MAJOR POINTS AND RECOMMENDATIONS OF THIS TESTIMONY

Q. WHAT ARE THE MAIN POINTS OF YOUR TESTIMONY?

A. They are as follows:

- I accept Idaho Power's intra-jurisdictional cost-of-service study[1] for use in the cost-allocation modeling, with the following exceptions:
    - The $95 per kW-year cost estimate for a simple-cycle combustion turbine (CCCT) that is found in the current Idaho Power Integrated Resource Plan (IRP, *see* page 5) is substituted for the $38 figure used by the Company in this rate case application. The larger (i.e., $95) amount is within

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[1] OPUC Staff member, Irina Phillips, takes exception to a component of Idaho Power's *inter*-jurisdictional allocation of line transformer costs between Idaho and Oregon.

the range found in the most recent general rate case applications of PGE and PacifiCorp.

- Rather than splitting the embedded electricity production/generation costs into energy and capacity components and separately allocating those costs among the customer schedules, I allocate the generation cost total in the same proportion as those schedules' shares of the summed grand total of each schedule's summed marginal capacity and energy costs. This is the same approach found in the most recent general rate case applications of PGE and PacifiCorp. It avoids an arbitrary division of generation *plant* costs into energy and capacity components.[2]
- Rather than allocating transmission costs solely on the basis of peak demands, I allocate twenty-five percent of those costs on the basis of the customer schedules' allocations of marginal energy costs – reflecting the principle that much of the justification for transmission line investment lies in the opportunities provided therefrom for reducing fuel costs and market-purchase prices. The 75%-demand/25%-energy split is also what is used in PacifiCorp's inter-jurisdictional

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[2] Another advantage of the Staff alternative is that it avoids a situation where two utilities could have identical revenue requirements and identical marginal *and* embedded total production costs, but have different allocations of production costs due to having different *mixes* of embedded energy and production plant costs.

transmission cost allocation and is within the range found in recent general rate case applications of PGE and PacifiCorp.

- I accept Idaho Power's general revenue spread approach, with the following exception:
    - I propose an upper limit on the rate increase for any schedule that is equal to twice the overall average percentage increase, unless the awarded increase exceeds nine percent. In such a case, I recommend an upper limit equal to eighteen percent. I would note that in the last case, by stipulation the Irrigation Schedule 24-S received an increase of 27.96 percent, which was almost twice the overall average of 15.42 percent.[3]
- Staff's recommendation regarding the prices for each of the non-residential schedules is to adjust them down (or up) by a uniform percentage from what the Company has proposed so as to achieve whatever schedule revenue requirement this Commission ultimately rules.[4]
- Apart from the exceptions explained below, Staff endorses how the Company proposes to modify its Residential Tariff (Schedule 1). In particular, Staff endorses the Company's renewed petition in favor of

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[3] Even if set at twice the 14.67% requested average increase, the revenue requirement established for the irrigators would still be below the estimated cost-of-service for that class of customers.

[4] Staff contemplates that to produce the individual schedules' revenue requirements, Idaho Power will run its cost allocation model(s) after having entered whatever accounting and other adjustments are ordered by the Commission.

higher summer-season tail-block rates, with the inversion point at 1000 kWh rather than the 300 kWh in the current tariff.

- Staff recommends that the summer season's elevated tail-block prices not be limited to the months of June through August, and that a fourth high-cost month, September, be added. This modification better preserves the relationship between costs and rates and allows for a reduction in the initial block's price, which, per the Staff-endorsed Company proposal, would apply throughout the entire year. Due to this modification, the large majority of residential customers would, each and every month, enjoy lower bills than under the Company's proposal.[5] Exhibit Staff/903 shows Staff's proposed residential rates as compared to the Company's proposal, where both assume the revenue requirement contained in Idaho Power's application. Exhibit Staff/904 compares the monthly billing impacts under the two proposals given that same assumption. A reduced award by

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[5] Idaho Power's reluctance to seek a four-month summer season despite the substantial cost basis is understandable. Adding another month will mean added billing system costs for distinguishing the Oregon residential customers plus the public relations burden of explaining to the heavy September-use residential customers in Oregon why they would have to pay the higher rate while all the other customers, including the Idaho residential customers, are able to pay the lower, non-summer rate. Staff is advocating for the four-month season owing to our strong commitment to cost-based rates (see below) and to neutralize the (somewhat specious) argument that unless the summer rates apply to all of the high-cost summer-season months, there shouldn't be summer-seasonal rates at all. We note that Oregon residential customers already receive unique billing treatment, and as long as that is the case, the bills might as well do a much better job of being cost based. All things considered, adopting seasonal rates with a three-month summer season would be superior to declining to adopt seasonal rates at all.

this Commission will obviously scale down what is shown in those two exhibits.

- More specifically, my recommendation contains the following three steps, depending upon what the Commission rules for the Schedule 1 revenue requirement:
    - Start by setting the year-round initial-block for the energy price equal to what is now the post-300 kWh year-round price. Set the tail-block prices so as to preserve the winter and summer tail-block price differentials proposed by Idaho Power.[6]
    - Apply the balance of the established Schedule 1 revenue requirement to increasing the monthly customer charge up to a maximum of $9, and not the Company-requested $10.[7])
    - Apply any remaining Schedule 1 revenue requirement balance to a uniform cents-per-kWh increase in the energy prices.

Q. WHAT ARE THE BOTTOM-LINE CONSEQUENCES OF THE ALTERATIONS TO THE COMPANY'S COST-OF-SERVICE AND REVENUE SPREAD RECOMMENDATIONS THAT YOU DESCRIBE ABOVE?

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[6] In the event of a general rate reduction, cost-of-service balancing would still suggest something of an increase to residential and agricultural customers, to be offset by reductions to lighting, commercial, and industrial tariffs.

[7] Nine dollars is the amount currently in PGE's and PacifiCorp's Oregon residential tariff.

A. Exhibit Staff/902 shows my recommendations along with the Company's for direct comparison purposes. Under Staff's recommendations, revenue requirements are shifted away slightly from the Residential and Large Power Schedules (Nos. 1 and 19-T) and moved slightly to most of the other Schedules. Schedule 19-P (Large Power-Primary)[8] would go from receiving no increase to receiving a small increase.[9] As with Idaho Power's proposal, Area Lighting and General Service-Transmission (respectively, Schedules 15 and 9-T) would receive neither an increase nor a decrease. Depending upon the final revenue requirement established by this Commission, the Irrigation Schedule (24-S) may receive a much smaller rates increase than what is proposed in the Company's application.

TOPIC 2 – A BRIEF, GENERAL DISCUSSION OF COST OF SERVICE, REVENUE SPREAD, AND RATE DESIGN

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY FOR UTILITIES?

A. Cost-of-service studies attempt to determine the full cost of serving each of the different customer classes/rate schedules. The first step here in Oregon is to ascertain the marginal costs of providing generation,

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[8] Primary, or "-P," signifies taking electricity at the Primary voltage level, Secondary, or "-S," signifies taking electricity at the secondary voltage level, and Transmission, or "-T," signifies taking electricity directly from the transmission wires.

[9] As stated in the beginning of this testimony, the effects of my recommendations are shown as direct alterations of the Company's originally filed figures, and not to what may result from the accounting adjustments that will be part of a final Commission order. Accordingly, Schedule 19-P may warrant a decrease depending upon the final revenue requirement and the nature of the accounting adjustments embodied in it.

transmission, distribution, and miscellaneous customer-classified services[10] to the various customer classes. Relative shares of marginal costs are then translated to equivalent shares of the embedded, or accounting, costs of those same functions. Those shares sum to the total jurisdictional revenue requirement. “Revenue spread,” or “spreading of the revenue requirement,”[11] refers to how the utility’s entire revenue requirement is allocated to the various customer classes. The purpose of the cost-of-service study is to provide a guide to the revenue spread process.

Q. WHAT IS THE CONNECTION BETWEEN THE COST-OF-SERVICE STUDY AND THE “SPREADING OF THE REVENUE REQUIREMENT?”

A. If cost-of-service studies were uncontestable, and if concerns were absent about a particular rate class receiving an unusually burdensome rate increase, then each customer class could be merely assigned the portion of the overall revenue requirement that was determined by the cost-of-service study. Because those conditions are seldom (if ever) met, the result is class revenue requirements that depart from strict cost-of-service levels in various ways and for various reasons. Among other expedients, the revenue spread “adjustments” in a given general rate case will often include

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[10] Generation costs include market purchases; transmission refers to moving power from the generation sources to the area transformation sub-stations; distribution refers to the wires system that takes the power into the streets and neighborhoods; and customer costs refer primarily to the final step of bringing power to the customers’ premises (e.g., service “drops” and meters) and to reading the meters and processing the bills. As is often the case, Idaho Power classifies many accounts as “customer” because they don’t fit neatly into the other categories. But to the Company’s credit, most of those costs are allocated to all the schedules in proportion to their shares of the total of all the other marginal costs rather than using a large figure to justify inordinately high customer charges.

[11] “Rate spread” is another commonly used term for “revenue spread.”

the following: a) a particular customer class may be shielded from receiving a general increase that would take it all the way up to its full cost of service if the impact of such an increase is regarded as particularly onerous; b) some schedule(s) may receive no change in average rates even though the cost-of-service study would warrant a decrease; c) as a norm, most schedules may have their average rates increased by either a uniform percentage or by an amount that would place them at approximately a uniform relationship with the cost-of-service results; and, d) departing from the just-mentioned norm, some customer classes may receive a percentage overall rate increase that is at least as large as that received by some other class. All but the last of those measures appear in the revenue spread stipulation for this case.

Q. WHAT IS THE CONNECTION BETWEEN RATE DESIGN AND REVENUE SPREAD?

A. Rate design consists of the service price elements that comprise the various rate schedules/tariffs. If the test-year-projected sales volumes are achieved, revenues produced by the designed rates will precisely equal the respective schedules’ revenue targets as they were spelled out in the revenue spread process.

Q. A HOST OF DIFFERENT PRICES COULD BE COMBINED TO YIELD A PARTICULAR REVENUE TARGET. WHAT GUIDELINES ARE THERE FOR ESTABLISHING SPECIFIC PRICES?

A. In some instances you will see some functionalization of the prices – for example where a separate transmission price is set to recover the transmission costs that are allocated to a particular schedule, or where the customer charge is set to recover a designated portion of the allocated customer-categorized costs. But more fundamentally, there is a two-fold objective of rate design as applied to a customer class – it is to promote both equity and economic efficiency. Fortunately, both values tend to be achieved by basing prices on costs.

Q. IN SIMPLE ECONOMIC EFFICIENCY TERMS, WHAT ARE THE ADVANTAGES OF HAVING A PRICE OF ANYTHING REFLECT ITS COST?

A. If the price of a good or service is too high relative to its cost on the margin, that good or service will tend to be under-consumed in the sense that the cost of its production will be less than the relative value that would have been achieved had it been produced and consumed. Conversely, if the price of a good or service is too low relative to its cost on the margin, that good or service will tend to be over-consumed in the sense that the cost of its production will be greater than the relative value that is yielded by its consumption.

Q. YOU HAVE JUST PUT FORTH THE ECONOMIC EFFICIENCY ARGUMENT FOR HAVING PRICES ACCURATELY REFLECT COSTS. WHAT IS THE EQUITY ARGUMENT FOR THAT SAME KIND OF ACCURACY?

A. Equity in ratemaking usually refers to avoiding having some customer classes being subsidized by other classes by virtue of some customer classes' revenue requirement allocations exceeding costs while others' are beneath costs. However, there can also be a problem of customers' subsidizing other customers *within* the same schedule. Take the instant case of the rates for Idaho Power's residential customers in Oregon. If prices are the same year-round even though costs are greater in the summer, the upshot is for customers who are consuming electricity heavily in the summer season to be subsidized by customers whose use does not fall heavily in that high-cost season.[12] Equity can be viewed as having primacy over economic efficiency in the sense that even if there is no responsiveness by customers to prices that reflect costs (i.e., their consumption is fixed, whatever the price), there is an equity benefit in having customers pay for the costs they impose on the system. The relative limitations of seasonal rates for affecting consumer behavior can also be noted from Idaho Power's response to Staff's Data Request No. 369 (*see* Exhibit Staff/905), which asked the Company to address the Commission's Docket UM 1415 straw evaluation factors for time-varying-rates as they might apply to residential seasonal rates.

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[12] In the case where prices will exceed marginal costs throughout the entire year, the fairness objection to having a uniform price in the presence of much higher costs in some seasons than in others is that the customers in the lower-cost season(s) are being required to pay a greater share of the utility's embedded costs than are customers whose greater use is concentrated in the higher-cost season(s).

TOPIC 3 – AN AFFIRMATIVE CASE FOR SEASONAL RESIDENTIAL RATES

Q. FOR SOME TIME NOW, ALL OF IDAHO POWER'S MAJOR RATE SCHEDULES IN IDAHO, AND ALL BUT ITS RESIDENTIAL SCHEDULE IN OREGON, HAVE INCORPORATED SEASONALITY IN THEIR RATE DESIGNS (WITH THE ELEVATED RATES APPEARING IN THE SUMMER). IN ITS CURRENT RATE CASE, IDAHO POWER IS AGAIN SEEKING TO INCLUDE OREGON RESIDENTIAL CUSTOMERS WITH ALL OF ITS OTHER CUSTOMERS IN TERMS OF THEIR PAYING HIGHER SUMMER-SEASONAL RATES. WHAT IS THE BASIS FOR ADJUSTING RATES FOR SEASONALITY?

A. Due to its generation capacity's coming closest to exhaustion in the summertime, Idaho Power's summer loads (including September's) are viewed as the primary demand cost driver.[13] To a lesser extent and with some exceptions, Idaho Power's energy costs also tend to run higher in the summer than in the rest of the year. (*See* Exhibit Idaho Power/1005, Larkin/6, /8, and /10.) Incorporating seasonality in rate design enables the capturing of seasonal cost differences.

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[13] Demand costs (as opposed to energy costs) relate primarily to peak capacities of generation and transmission facilities.

Q. EVIDENCE IN THIS CASE SHOWS THAT LOADS FOR EASTERN OREGON RESIDENTIAL CUSTOMERS ARE WINTER PEAKING AND THAT THE CAUSE OF IDAHO POWER BEING SUMMER PEAKING OVERALL IS HEAVILY DUE TO AIR CONDITIONING LOADS (COMMERCIAL AND RESIDENTIAL—THE LATTER MOSTLY ON THE IDAHO SIDE) COINCIDING WITH THE AGRICULTURAL IRRIGATION SEASON.[14] THIS BEING THE CASE, IS IT APPROPRIATE TO DESIGN RATES FOR OREGON RESIDENTIAL CUSTOMERS THAT ARE HIGHER IN THE SUMMER THAN IN THE REST OF THE YEAR—I.E., EVEN THOUGH OREGON RESIDENTIAL LOADS AREN'T THE PRIMARY CAUSE OF THE HIGH SUMMER COST?

A. Yes. Idaho Power's generation and transmission cost allocations to the state of Oregon quite properly incorporate seasonal cost differences, with summer loads being tied to the largest allocations. All loads contribute to costs; summer loads by every customer class contribute to the overall costs of Idaho Power. Oregon residential customers' summer peak loads have a direct and overwhelming effect on the cost *allocation* to the Oregon residential class.[15] If summer prices do not reflect that season's incremental cost allocation, other residential customers will end up bearing some of the burden of the cost allocation that is based on the incremental summer load.

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[14] Page 401b of the 2010/Q3 FERC FORM No.1 shows June, July, August, and September as the four months having the highest peak loads.

[15] Idaho Power/1005 Larkin/8 shows over 95% of the marginal generation capacity costs being allocated to the four "summer" months.

Q. YOU HAVE BEEN REFERRING TO SUMMER LOADS AS BEING THE PRIMARY DEMAND COST DRIVER FOR IDAHO POWER. BUT DEMAND COSTS RELATE TO CAPACITY, OR PEAK-RELATED, COSTS AND NOT TO COSTS IN GENERAL. SO WHEN WE ARE SPEAKING OF RESIDENTIAL LOADS DRIVING SYSTEM COSTS, SHOULD WE BE CONCENTRATING ON WHAT CONTRIBUTES MOST TO THE SUMMER PEAKS FOR RESIDENTIAL CUSTOMERS – I.E., AIR-CONDITIONING LOADS, WHICH OCCUR ON HOT DAYS AND AT THE TIMES WHEN THE SYSTEM'S PRODUCTION CAPACITY IS MOST LIKELY TO BE STRESSED?

A. Yes.

Q. SHORT OF HAVING TIME-OF-DAY OR REAL-TIME PRICING,[16] HOW CAN YOU MAKE RESIDENTIAL RATES CAPTURE THE COSTS OF AIR-CONDITIONING LOADS WITHOUT PENALIZING OTHER LOADS?

A. As a general rule, "typical" residential customers' summer loads will not exceed 1000 kWh unless the customer is operating some kind of cooling appliance, and particularly a refrigerated air-conditioner. So to answer your question, the best way to capture air-conditioning load costs with a simple rate structure without "penalizing" conventional, off-peak loads (e.g., lighting, and most water-heating and television viewing) is to have an inverted rate structure and only charge the higher rate for usage beyond

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[16] Time-of-day rates are elevated during peak hours of the day and week. Real-time pricing typically bases prices on concurrent market prices, which will be very high during regional peak load periods. Time-of-day and real-time pricing require meters that keep track of energy consumption on an hourly basis throughout the billing cycle. Idaho Power currently has those meters installed for virtually all of its Oregon customers.

1000 kWh. An important element of Idaho Power's residential rate design proposal in this case is to move the residential rates inversion point from the 300 kWh in the current tariff to 1000 kWh.[17] The majority of Idaho Power's Oregon residential customers' loads do not exceed 1000 kWh in the summertime and so would experience lower monthly billings by having an extra portion of the revenue requirement placed on the post-1000 kWh summertime consumption.[18]

Q. THE COMMISSION'S UM 1415 DOCKET PLACED A LOT OF EMPHASIS ON THE POTENTIAL FOR SYSTEM COST SAVINGS DUE TO CUSTOMERS' SHIFTING THEIR LOADS AWAY FROM THE PEAK PERIODS IN RESPONSE TO PRICE SIGNALS. WHAT MIGHT BE THE RELEVANCE OF SEASONAL RATES IN A UM 1415 CONTEXT?

A. Higher summer rates won't cause loads to shift to the non-summer in the same manner that high daily peak-period rates will cause customers to shift some of their discretionary loads to the lower-priced periods of the day. But some system cost savings can still be expected to occur owing to the kind of summer-season rates advocated by the Staff and Company. In the short run, the basic price elasticity effect of the higher rate will encourage some reduction in consumption. The longer run effect has to do with the highly efficient evaporative coolers that have long been in use in arid, low-humidity

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[17] Staff made that recommendation in the previous general rate case for Idaho Power.

[18] Exhibit Staff/903 shows monthly Oregon residential bill frequencies based upon the 2008 data supplied in the last rate case.

areas such as Eastern Oregon.[19] The higher summer rates will act to discourage customers from substituting the far more energy-intensive refrigerated air-conditioning units for the evaporative coolers.

Q. A NUMBER OF PARTIES WHO SEEK TO REPRESENT THE INTERESTS OF LOW-INCOME AND OTHER VULNERABLE UTILITY CUSTOMERS RECENTLY EXPRESSED DISAPPROVAL OF TIME-VARYING RATES IN THEIR UM 1415 REMARKS. THOSE CONCERNS FOCUSED ON MANDATORY TIME-OF-DAY RATES, AND HOW THEY MAY AFFECT CUSTOMERS WHO RELIED ON ELECTRICITY FOR HEATING OR COOLING. ARE THEIR CONCERNS OF SUBSTANTIAL MERIT AS THEY MIGHT APPLY TO SEASONAL RATES (WHICH OBVIOUSLY MUST BE MANDATORY)?

A. No. A case is easily made that the *absence of a summer seasonal rate puts an unfair burden generally on lower-income residential customers.*

Q. PLEASE ELABORATE.

A. Properly elevating the summer rate enables the lowering of the winter rates. So the question becomes who benefits from the low summer rate and who is harmed by the higher winter rate. Obviously those who make extensive use of refrigerated air conditioning benefit from a low summer rate and those who heat with electricity are harmed by the higher winter rates.

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[19] The high efficiency of the evaporative cooling technology is dependent upon having the low humidity. Refrigerated air conditioning is more effective on the occasions when the humidity is elevated. Refrigerated air conditioning also integrates more readily with the ducting of the central heating system of a larger home (which is why this technology is often referred to as "central air conditioning" – such is its most common use, modern ductless heat pumps to the contrary).

Affluent people are far more likely to have refrigerated air-conditioning than are the poor.[20] That is because the former can more readily afford the cost of replacing the older evaporative coolers, or they will have the refrigerated air-conditioners installed in a manner integral with their heating systems in a new-construction context. The affluent also are less likely to occupy mobile homes, multi-family dwellings, and the cheaper, older houses in Eastern Oregon, which in turn are relatively more likely to be heated with electricity than with natural gas.[21] Whether or not the non-refrigerated-air-conditioning customers heat with electricity, they will tend to be winter peaking, if only because there is more lighting in the winter and even gas-fired furnaces require electricity to circulate the warmed air. The result of failing to have electricity prices that reflect the summer-seasonal cost differences would be to have the generally less affluent winter-peaking customers subsidize the more affluent heavy-summer-use customers who tend to utilize refrigerated air conditioning. I say “subsidize” in the sense of one set of customers’ rates being below relative costs forcing another set of customers to pay rates that exceed relative costs.

Q. MIGHT THERE BE SOME AFFLUENT RESIDENTIAL CUSTOMERS WHO EMPLOY EVAPORATIVE COOLERS AND SOME OF THE RELATIVELY POOR WHO HAPPEN TO HAVE THE MORE EXPENSIVE REFRIGERATED AIR-CONDITIONERS?

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[20] Refrigerated air-conditioning is a “normal good.” In economics terms, a normal good is a good for which consumption is increased as income increases.

[21] Cascade Natural Gas (or its predecessor) has been serving in the Baker City/Ontario area since the late 1950s. They currently serve over 6800 residential customers there, or about half of the Idaho Power total in that area. *See* Exhibit Staff/906.

A. Yes, there will always be demographic exceptions, but we are talking about the merits of cost-based rates and what is best/most just for the greatest number of people. I recognize that medical conditions, for example, may make it difficult for some at-risk customers to merely economize by turning up their thermostats in the summer months. But rather than distorting prices to accommodate the rare exceptions, the presumption is that when there is a genuine affordability concern, the efforts of state and local welfare/social service agencies will ensure against undue suffering in such circumstances.

Q. WHEN ELECTRIC RATES ARE ELEVATED, WHETHER AS PART OF A GENERAL INCREASE, A SEASONAL INCREASE, OR AS PART OF A RATE DESIGN REFORM (E.G., THE INTRODUCTION OF INVERTED RATES, WHICH DISPROPORTIONATELY AFFECT THE LARGER CONSUMERS WITHIN A SCHEDULE), A CERTAIN NUMBER OF CUSTOMERS CAN BE EXPECTED TO COMPLAIN. DOES THAT CONCERN YOU?

A. Yes. No one likes to see customers who are distressed. But as an economist concerned about conservation and economic efficiency, I take some encouragement in observing customers paying attention to price signals, even if it is “only” to complain. Recall that the focus of the seasonal rate proposal is to convey a more accurate price signal regarding high summertime energy costs. Given, for example, a desire to counter the expensive trend to install refrigerated air conditioning, there is something to be said about having messages delivered by any medium regarding the high summertime bills that can arise from high summertime use and prices that reflect the higher summertime costs.

As regards customer pushback in general, such can normally be counted upon whenever there is a change to the status quo. But the experience following the introduction of seasonal residential rates in Idaho (with Idaho Power) and Utah (with PacifiCorp) has not been such as to cause the utility commissions in either state to roll back the seasonal rates. The commissions are also well aware that while some customers may complain, the higher summer tail-block rates enable *all* of the customers to have lower rates throughout the remainder of the year.

Q. IN RECOGNITION OF THE HIGHER SUMMERTIME COSTS, THE COMMISSION HAS PREVIOUSLY ADOPTED SEASONAL RATES FOR IDAHO POWER'S MAJOR COMMERCIAL AND INDUSTRIAL SCHEDULES. CONTRARILY, AND IN ACCORDANCE WITH STAFF'S RECOMMENDATION IN AN EARLIER CASE, THE COMMISSION PREVIOUSLY REJECTED SEASONAL RATES FOR THE RESIDENTIAL SCHEDULE, APPARENTLY IN THE INTEREST OF TARIFF SIMPLICITY AND/OR UNDERSTANDABILITY. IN THE LAST GENERAL RATE CASE FOR IDAHO POWER (DOCKET UE 213), THE COMMISSION MADE "NO FINDINGS…ABOUT WHETHER WELL DESIGNED SEASONAL RATES MAY BE APPROPRIATE FOR THE OREGON RESIDENTIAL CUSTOMERS," AND INSTEAD POINTED TO

"A SEPARATE PROCEEDING [DOCKET NO. UM 1415] TO CONSIDER [RELATED] POLICY ISSUES…."[22] WHAT ARE YOUR THOUGHTS HERE?

A. In the latter referenced docket, Staff reiterated its strong support for cost-based rates – recognizing that there will always be trade-offs among the values of economic efficiency, equity, and tariff simplicity/understandability. Staff also noted that adoption of seasonal rates for Idaho Power does not constitute an industry-wide policy decision or application. I might also note, for example, that Staff did not propose seasonal residential rates for Portland General Electric in that company's last general rate case (Docket UE 215).

In this docket, and in recent rate cases involving other utilities, we are perhaps more sensitive to the economic efficiency and equity values of having rates that are more strictly cost-based as compared to rates that ignore seasonal variability in the interest of simplicity/understandability. Staff also recognizes that metering and billing costs must enter the economic efficiency calculus. Accordingly, while the diurnal time-of-use of loads also has costing ramifications, Staff has not blindly advocated mandatory time-of-use rates for residential customers. But seasonal rates require no special metering, and Idaho Power obviously is already set up to incorporate seasonality in its billing. As regard rates understandability, how difficult is it to comprehend that, due to high demands, utility costs are

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[22] *See* page 7 of Order No. 10-064.

higher in some seasons than in others? More difficult would be the understanding of the inverted rate design – i.e., why should prices go up rather than down with greater use? But that understandability *and simplicity* barrier has long been penetrated by this Commission in its adoption, for all three regulated electric utilities, of inverted rate structures for residential customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

December 7, 2011

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Oregon Public Utility Commission

TITLE: Senior Economist (3/4), Economic Research & Financial Analysis Division (ERFA)

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah’s Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after “retiring” to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an AVISTA General Rate Case (UG 181), the 2008 and 2008 PGE General Rate Cases (UE 197 and UE 215), the 2009 PacifiCorp General Rate Case (UE210), and the 2010 Idaho Power General Rate Case (UE 213).

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 902

Recommended Revenue Spread

December 7, 2011

Exhibit Staff/902

UE 233
IDAHO POWER COMPANY
OREGON JURISDICTION

Staff Revenue Spread Alternative: Elevating Generation Demand Marginal Costs; Classifying Transmission Marginal Costs as 75% Demand-Related and 25% Energy-Related; and Allocating Embedded Generation and Transmission Costs on the Basis of Simple-Summed Demand- and Energy-Related Marginal Costs

Compare with Idaho Power/1006 Larkin/1 and Idaho Power/1007 Larkin/4

		(A) TOTAL SYSTEM	(B) RESIDENTIAL	(C) GEN SRV	(D) GEN SRV SECONDARY	(E) GEN SRV PRIMARY	(F) GEN SRV TRANS	(G) AREA LIGHTING	(H) LG POWER PRIMARY	(J) LG POWER TRANS	(K) IRRIGATION SECONDARY	(L) UNMETERED GEN SERVICE	(M) MUNICIPAL ST LIGHT	(N) TRAFFIC CONTROL	
Line	Description		-1	-7	(9-S)	(9-P)	(9-T)	-15	(19-P)	(19-T)	(24-S)	-40	-41	-42	
1	**Normalized Sales (kWh)**	650,158,581	198,842,419	17,842,896	114,256,218	15,099,088	2,832,509	483,936	179,189,047	74,155,867	46,649,265	12,900	778,108	16,328	
2	**Current Revenue**	$39,873,591	$15,355,932	$1,559,400	$6,975,915	$798,102	$154,997	$112,462	$8,213,065	$3,123,393	$3,454,271	$972	$123,851	$1,231	
3															
4	**Demand Related Marginal Cost**														
5	Generation – Staff Alternative	$11,049,450	$4,082,443	$268,043	$1,671,178	$207,813	$35,425	$625	$1,790,415	$1,483,718	$1,508,400	$158	$1,035	$200	
6	Transmission – Staff Alternative	$12,432,118	$ 4,593,297	$ 301,584	$ 1,880,300	$ 233,817	$ 39,858	$ 703	$ 2,014,458	$ 1,669,382	$ 1,697,153	$ 177	$ 1,165	$ 225	
7	Distribution	$6,945,625	$3,215,110	$181,233	$1,319,947	$100,783	$0	$5,738	$798,946	$0	$1,314,267	$161	$9,350	$89	
8															
9	**Energy Related Marginal Cost**														
10	Generation Energy Related	$28,547,004	$8,940,577	$802,452	$5,140,232	$649,911	$117,743	$21,383	$7,662,010	$3,097,424	$2,079,568	$570	$34,414	$722	
11	Transmission Energy Related (Staff-Alt.)	$4,144,040	$ 1,297,863	$ 116,488	$ 746,184	$ 94,345	$ 17,092	$ 3,104	$ 1,112,259	$ 449,639	$ 301,881	$ 83	$ 4,996	$ 105	
12															
13	**Simple-Summed Energy-Related and Demand-Related Marginal Costs**														
14	Generation Marginal Costs: Staff-Alt. Alloc.	$39,596,454	$13,023,020	$1,070,495	$6,811,410	$857,724	$153,168	$22,008	$9,452,425	$4,581,142	$3,587,968	$728	$35,449	$922	
15	Transmission Marginal Costs: Staff-Alt. Alloc.	$16,576,157	$ 5,891,160	$ 418,072	$ 2,626,484	$ 328,162	$ 56,950	$ 3,807	$ 3,126,717	$ 2,119,021	$ 1,999,034	$ 260	$ 6,160	$ 330	
16															
17	**Customer Related Marginal Cost**	$2,805,903	$1,967,110	$385,570	$177,410	$6,719	$1,390	$0	$15,208	$2,535	$246,967	$228	$1,892	$873	
18															
19	**Total Functionalized Revenue Requirement**														
20	Generation – Total: Staff-Alt. Allocation														
21	Total: Staff-Alt. Allocation	$25,798,263	$ 8,484,883	$ 697,459	$ 4,437,835	$ 558,832	$ 99,793	$ 14,339	$ 6,158,535	$ 2,984,749	$ 2,337,667	$ 474	$ 23,096	$ 601	
22	Demand-Related: IPCo Allocation	$10,427,415	$3,852,618	$252,954	$1,577,097	$196,114	$33,431	$591	$1,689,621	$1,400,191	$1,423,483	$149	$977	$189	
23	Energy-Related: IPCo Allocation	$15,370,848	$4,813,964	$432,072	$2,767,706	$349,938	$63,397	$11,513	$4,125,532	$1,667,777	$1,119,722	$307	$18,530	$389	
24															
25	Transmission	$4,573,960	$1,625,584	$115,361	$724,742	$90,552	$15,715	$1,051	$862,774	$584,714	$551,606	$72	$1,700	$91	$4,573,960
26															
27	Distribution														
28	Demand-Related	$11,661,526	$5,398,087	$304,285	$2,216,157	$169,212	$0	$9,634	$1,341,411	$0	$2,206,620	$271	$15,698	$150	
29	Customer-Related														
30	Allocated	$3,249,479	$2,278,084	$446,524	$205,456	$7,781	$1,610	$0	$17,612	$2,935	$286,010	$264	$2,191	$1,011	
31	Direct Assignment	$438,190	$196,738	$35,868	$12,919	$72	$14	$82,755	$87	$14	$22,919	$43	$86,672	$87	
32															
33	**Total: Staff-Alternative Allocation**	$45,721,417	$ 17,983,376	$ 1,599,497	$ 7,597,109	$ 826,449	$ 117,132	$ 107,778	$ 8,380,419	$ 3,572,413	$ 5,404,822	$ 1,124	$ 129,357	$ 1,940	
34	Revenue Deficiency: Staff-Alt. Allocation	$5,847,826	$ 2,627,444	$ 40,097	$ 621,194	$ 28,347	$ (37,865)	$ (4,684)	$ 167,354	$ 449,020	$ 1,950,551	$ 152	$ 5,506	$ 709	$ 5,847,824
35	**% Increase Required by Staff-Alt. Alloc. Approach**	14.67%	17.11%	2.57%	8.90%	3.55%	-24.43%	-4.16%	2.04%	14.38%	56.47%	15.61%	4.45%	57.57%	Re-allocate
36	$ Increase Recommended by Staff	$ 5,847,824	$ 3,028,861	$ 75,800	$ 790,773	$ 46,795	$ -	$ -	$ 354,418	$ 528,762	$ 1,013,483	$ 177	$ 8,393	$ 361	$ 894,867
37	% Increase Recommended by Staff	14.67%	19.72%	4.86%	11.34%	5.86%	0.00%	0.00%	4.32%	16.93%	29.34%	18.19%	6.78%	29.34%	2.23%
38	**Average Rate Given Staff Recommendation ($/kWh)**	0.0703	0.0925	0.0916	0.0680	0.0560	0.0547	0.2324	0.0478	0.0492	0.0958	0.0891	0.1700	0.0975	
39															
40	**% Increase Required by IPCo Theory**	14.67%	18.75%	2.10%	8.31%	2.59%	-26.72%	-6.53%	-2.50%	15.08%	61.28%	13.57%	1.01%	55.42%	
41	% Increase Recommended by IPCo	14.67%	21.91%	4.82%	11.19%	5.32%	0.00%	0.00%	0.00%	18.15%	29.34%	16.60%	3.69%	29.34%	
42	$ Increase Recommended by IPCo	$ 5,847,826	$ 3,364,387	$ 75,119	$ 780,537	$ 42,428	$ -	$ -	$ -	$ 566,775	$ 1,013,483	$ 161	$ 4,574	$ 361	

BACKGROUND NOTE: IPCo classifies fuel, etc. and 54% (i.e., IPCo's system load factor) of generation embedded/accounting fixed/plant costs as energy-related and the remainder as demand-related, and then allocates the thus divided embedded generation costs in proportion to the separate allocation of the respective marginal demand- and energy-related costs. Marginal demand-related costs are based upon a very cheap combustion turbin and a peak-hour-deficiency-weighted five coincident peaks (June, July, August, September, December [5%]). Monthly marginal energy cost are estimated based upon increasing loads by 50 MWs -- 24-7.

DESCRIPTIONS OF STAFF'S ALTERATIONS:

1. Marginal generation capacity cost increased from $38/kW-Yr to $95 -- from the IPCo IRP and comparable to figure used in last PGE general rate case
2. Marginal transmission costs were divided as 75% demand-related, and allocated in the same proportion as demand-related marginal generation costs, and 25% energy-related an and allocated in the same proportion as energy-related marginal energy costs
3. Total embedded generation costs allocated in proportion to shares of summed marginal demand- and energy-related generation costs per the approach used in the last PGE general rate case
4. Total embedded transmission costs allocated in proportion to shares of summed marginal demand- and energy-related transmission costs per the approach used in the last IPCo general rate case
5. The maximum called-for increase is twice the overall average percentage increase **(assuming an overall final average not to exceed 9%)**.
6. Revenues not allocated due to the just-mentioned ceiling are re-allocated to the other schedules in proportion to their initial Staff-Alternative allocation (i.e., line 33
7. A zero percent increase is proposed for schedules for which a revenue requirement decrease was initially called for unless the above re-allocation led to a revenue deficienc

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 903

Alternative Seasonal Residential Rate Designs

December 7, 2011

UE 233
Idaho Power Company
Oregon Jurisdiction

Exhibit Staff/903

EFFECTS ON RESIDENTIAL PRICES OF VARIOUS SEASONALITY OPTIONS

			Revenues Assuming 2011 Test Year Projections					
			No Seasonality		Three-Month Summer		Four-Month Summer	
	2011 Test Year Projections		Rates	Revenues	Rates	Revenues	Rates	Revenues
Annual	Billing ≤ 1000 kWh =	127,937,820	$ 0.082222	$ 10,519,303				
	Billing > 1000 kWh =	70,904,599	$ 0.092653	$ 6,569,513				
Three-Month	Summer Billing ≤ 1,000 kWh =	30,880,485			$ 0.082222	$ 2,539,055		
	Summer Billing > 1,000 kWh =	10,872,779			$ 0.100310	$ 1,090,648		
	Non-Summer Billing ≤ 1,000 kWh =	97,057,335			$ 0.082222	$ 7,980,248		
	Non-Summer Billing > 1,000 kWh =	60,031,820			$ 0.091266	$ 5,478,864		
Four-Month	Summer Billing ≤ 1,000 kWh =	41,543,805					$ 0.081957	$ 3,404,789
	Summer Billing > 1,000 kWh =	14,627,251					$ 0.100310	$ 1,467,260
	Non-Summer Billing ≤ 1,000 kWh =	86,394,015					$ 0.081957	$ 7,080,559
	Non-Summer Billing > 1,000 kWh =	56,277,348					$ 0.091266	$ 5,136,208
	Total Annual Billed kWh's =	198,842,419						
	Customer-months =	162,935.0	$ 9.00	$ 1,466,415	$ 9.00	$ 1,466,415	$ 9.00	$ 1,466,415
	Number of Minimum Charges =	718.3	$ 3.00	$ 2,155	$ 3.00	$ 2,155	$ 3.00	$ 2,155
		Total =		**$ 18,557,386**		**$ 18,557,386**		**$ 18,557,386**

Source of Three-Month billing volumes and prices: Idaho Power/1101 Nemnich/1. Nine dollar customer charge is substituted for Company-requested $10.

Four-month billing volumes obtained by shifting September's volumes over to the summer. One thousand kWh split assumed to equal three-month summer average.
Source of September kWh volume: Idaho Power/1003 Larkin/7.

2008 Residential Bill Frequencies

Month	Share of residential customers with consumption less than or equal 1,000 kWh's
JAN	32%
FEB	33%
MAR	40%
APR	44%
MAY	57%
JUN	65%
JUL	52%
AUG	50%
SEP	57%
OCT	65%
NOV	52%
DEC	39%

Pricing Algorithms

1. Four-month summer: Use the same tail-block prices as the three-month summer; set the annual initial-block price to the value that yields the same total revenues as the Company's proposed three-month program.
2. Annual (i.e., no seasonality): Use the same initial-block rate as the year-round three-month summer program's; set the tail-block price to the value that yields the same total revenues as with the seasonal programs.

OBSERVATIONS

1. Comparing the four-month summer programs rates to the three-month summer program's: The year-round initial-block price is lower and the non-summer tail-block price is also lower. **The four-month option benefits all residential customers in the non-summer and the majority of customers in the summer.**
2. Comparing the annual/no-seasonality program's rates to the three-month summer programs: The year-round tail-block price is higher ; **the no seasonality approach thereby harms the majority of customers in the winter while only benefiting a minority of customers in the summer**.

NOTE: Downward trend in average residential consumption suggests, for 2011, slightly greater shares of customers with monthly loads below 1000 kWhs.

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 904

Monthly Residential Billing Comparisons

December 7, 2011

UE 233
IDAHO POWER COMPANY
OREGON JURISDICTION

Monthly Billing Comparisons
Residential Rate Design
Four-Month Summer Seasonal versus Year-round Rates

		Year-Round Alternative			Seasonal Rate Design: Four-Month Summer							
					Non-Summer (Eight Months)				Summer (Four Months)			
	Energy Used (kWh's)	Current Revenue (a)	Proposed Revenue (b)	Percent Difference (c)	Current Revenue (d)	Proposed Revenue (e)	Percent Difference (f)	Δ $ from Yr-Round (g)	Current Revenue (h)	Proposed Revenue (i)	Percent Difference (j)	Δ $ from Yr-Round (k)
	50	$11.01	$13.11	19.1%	$11.01	$13.10	18.9%	-$0.01	$11.01	$13.10	18.9%	-$0.01
	100	$14.03	$17.22	22.8%	$14.03	$17.20	22.6%	-$0.03	$14.03	$17.20	22.6%	-$0.03
	200	$20.05	$25.44	26.9%	$20.05	$25.39	26.6%	-$0.05	$20.05	$25.39	26.6%	-$0.05
	400	$33.46	$41.89	25.2%	$33.46	$41.78	24.9%	-$0.11	$33.46	$41.78	24.9%	-$0.11
	650	$51.94	$62.44	20.2%	$51.94	$62.27	19.9%	-$0.17	$51.94	$62.27	19.9%	-$0.17
	1,000	$77.79	$91.22	17.3%	$77.79	$90.96	16.9%	-$0.27	$77.79	$90.96	16.9%	-$0.27
Summer Avg.	1,039	$80.68	$94.84	17.6%	$80.68	$94.52	17.2%	-$0.32	$80.68	$94.87	17.6%	$0.03
	1,500	$114.74	$137.55	19.9%	$114.74	$136.59	19.0%	-$0.96	$114.74	$141.11	23.0%	$3.56
Winter Avg.	1,694	$129.07	$155.52	20.5%	$129.07	$154.30	19.5%	-$1.23	$129.07	$160.57	24.4%	$5.05
	2,500	$188.62	$230.20	22.0%	$188.62	$227.86	20.8%	-$2.35	$188.62	$241.42	28.0%	$11.22

						Four-Month Summer Seasonal Design						
	2009	Current		Year-Round		Non-Summer			Summer			Annual
Billing Component	Quantity	Price	Revenue	Price	Revenue	2009 Quantity	Price	Revenue	2009 Quantity	Price	Revenue	Revenue
Customer Charge	162,935	$ 8.00	$ 1,303,480	$ 9.00	$ 1,466,415	Annualized	$ 9.00		Annualized	$ 9.00		$ 1,466,415
Minimum Charge	718.3	$ 3.00	$ 2,155	$ 3.00	$ 2,155	Annualized	$ 3.00		Annualized	$ 3.00		$ 2,155
≤ 300 kWh's	47,023,144	$ 0.060253	$ 2,833,285									
> 300 kWh's	151,819,275	$ 0.073884	$ 11,217,015									
≤ 1,000 kWh's	127,937,820			$ 0.082222	$ 10,519,303	86,394,015	$ 0.081957	$ 7,080,594	41,543,805	$ 0.081957	$ 3,404,806	$ 10,485,400
> 1,000 kWh's	70,904,599			$ 0.092653	$ 6,569,524	56,277,348	$ 0.091266	$ 5,136,208	14,627,251	$ 0.100310	$ 1,467,260	$ 6,603,468
Energy Total	198,842,419		$ 15,355,936		$ 18,557,397	142,671,363			56,171,056			$ 18,557,438

INPUT SOURCES: Exhibits Idaho Power/1101 Nemnich/1 and Staff/903. Slight disparity in Four-Month's Design Annual Revenue due to rounding.

CALCULATION OF WINTER AND SUMMER SEASON RESIDENTIAL AVERAGE MONTHLY kWh USAGE

	Idaho Power's 2011 Projections (from Idaho Power/1003 Larkin/7)								
MONTH	December	January	February	Winter Total	June	July	August	September	Summer Total
kWh	21,242,706	25,031,030	22,616,711	68,890,447	11,297,392	13,847,628	16,608,244	14,471,792	56,225,056
Bills	13,599.2	13,546.5	13,531.3	40,677	13,524.7	13,541.3	13,509.0	13,544.2	54,119
Bill Average				1694					1039

NOTE: The indicated averages are above the respective medians (i.e., where half the bills are below and half are above).

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 905

Idaho Power's Response to Staff Data Request Regarding UM 1415 Straw Criteria As Applied to Seasonal Rates

December 7, 2011

IDAHO POWER®
An IDACORP Company

November 4, 2011

Subject: Docket No. UE 233
Idaho Power Company's Response to Staff's Data Request 369

STAFF'S DATA REQUEST NO. 369:

There currently exists in Oregon an open PUC docket, UM 1415, whose more recent purpose is to develop factors of consideration and utility directives that would assist the Commission in "evaluating whether or not to approve a proposed mandatory time varying rate." Working extensively from a number of straw proposals originated by the Commission, Staff has, for purposes of UM 1415, endorsed/proposed the following evaluation factors:

F-I. **The amount of demand-side resource and system benefits that can be tapped through a time-varying rate.**

F-2. **The extent to which an optional rate or alternative program can achieve those benefits.**

F-3. **The impact on customers (including secondary and/or non-price-related effects) of the proposed rate (e.g. rate shock, bill impacts on vulnerable populations, the choice between direct access and standard cost of service, etc.) and the ability of customers to respond to those impacts.**

F-4. **The means available to mitigate impacts on customers (e.g. phasing in of rate differentials, promoting equal-pay provisions, providing programmable equipment or software to enable customers to respond more easily, etc.).**

F-5. **The direct costs of implementing time-varying rates (e.g. IT costs, accounting, call-center and outreach burdens).**

F-6. **The ability to explain and communicate the rate to customers as well their general acceptance.**

F-7. **The cost differential between the relevant time periods, how robust the cost studies are, and whether customer response to the time-varying rate is expected to affect the cost differential over time.**

F-8. **The level of improvement in achieving rates that reflect cost causation.**

F-9. The yearly effects on utility power costs and revenues arising from the time-varying rate.

Please address each of those factors as they would relate to the residential seasonal rate structure that Idaho Power is proposing in this rate case.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 369</u>:

F-l. Idaho Power Company ("Idaho Power" or "Company") is not proposing that this rate proposal will result in a quantifiable demand-side resource. Rather, these rates were designed to accomplish the overall objectives of rate design. As indicated on page 2 of the Direct Testimony of Darlene Nemnich, ". . . the Company continues to maintain two important objectives with regard to rate design: (1) to establish prices that primarily reflect the costs of the services provided. . . ." As further explained on page 8, "The current residential rate design, which does not include a seasonal component, does not provide customers with any indication that the costs incurred by the Company to provide them energy service during the three summer months are significantly greater than the nine non-summer months."

The rates proposed reduce the intra-class subsidy created by the difference in cost between the summer and non-summer seasons.

F-2. Please see the Company's response to Staff's Data Request No. 369(F-1) above. Because the proposal is not designed to achieve quantifiable load reduction benefits, it is not applicable to look for other options.

F-3. Because this seasonal rate proposal accompanies a proposed rate increase as well as a proposed rate tier change, the impact from moving to seasonal rates is very small. Idaho Power is proposing a small seasonal differential between summer and non-summer rates.

It should be noted that residential customers generally use more energy in the winter months – they are a winter peaking class. The Company's proposal increases rates in the summer months more than the non-summer months. For a comparison of the billing impacts of residential customers at various usage levels of summer and non-summer rates please refer to Nemnich Exhibit 1102.

F-4. Idaho Power proposes three mitigation measures which together help ease the introduction of seasonal rates to the Oregon residential customers, who previously have not experienced seasonal rates. First, Idaho Power's proposed rate design moves the first tier Energy Charge from 0-300 kilowatt-hours ("kWh") to 0-1,000 kWh. In 2010, approximately 14.5 percent of all customers used 300 kWh a month or less while approximately 52 percent of customers used 1,000 kWh or less. More customers, those with lower usage levels, will not experience rates changes as they use more during the month.

Second, the Company proposes the rates on this first tier of 0-1,000 kWh be the same for both the summer and non-summer months. As explained on page 9 of the Direct Testimony of Darlene Nemnich, ". . . electric usage that falls in the first block is less likely to be discretionary usage where customers may have less ability to respond to price signals. Setting the first block Energy Charges the same year-round recognizes this limitation." This results in only usage over 1,000 kWh per month seeing any seasonal rate differentiation.

Lastly, even though the cost-of-service study for Oregon residential customers indicates that the per kWh cost differential of providing energy between summer and non-summer months is 61.6 percent (see Larkin Exhibit 1006, page 2, line 24), the Company is proposing only a small overall summer to non-summer rate differential of 1.46 percent. Please note these differentials represent the average of Energy Charge rates in the summer versus non-summer months. Because the rates for the first tier are the same all year-round and have no differential, the rates for the second tier of 1,000 kWh and above have larger differentials.

In addition, the Company offers a budget pay program where customers can sign up to pay the same amount every month. This is set once per year and reflects the previous 12 months of bills. Customers who have central air conditioning can also participate in the AC Cool Credit program and allow the utility to cycle their air conditioner during specific days of the summer. Participants receive $7 off of their bill each summer month.

F-5. There are no additional direct costs for implementing this seasonal rate proposal.

F-6. Please see the Company's response to the Citizens' Utility Board of Oregon's Data Request No. 26.

F-7. Idaho Power's currently approved class cost-of-service methodology in Oregon robustly reflects the seasonal nature of costs imposed on the Company's system. As described in the Direct Testimony of Matthew Larkin, Idaho Power/1000, Larkin/13, lines 20 through 22, "The marginal unit costs for the generation and transmission functional categories are prepared as monthly values to recognize that those cost categories vary by month and, to a greater extent, seasonally." As shown in Mr. Larkin's Exhibit 1006, page 2, the application of this methodology results in residential summer season energy unit costs of $0.11141 per kWh and non-summer season energy unit costs of $0.06894 per kWh. The differential between these two values is 61.6 percent.

As explained in the Company's response to Staff's Data Request No. 369(F-1) above, Idaho Power is not proposing that this rate proposal will result in a quantifiable demand-side resource. However, if customers do change their usage in the future, it will be captured in subsequent cost-of-service studies.

F-8. The implementation of the proposed seasonal rates would be an improvement by moving rates towards cost causation. As discussed in the Company's response to Staff's Data Request No. 369(F-4) above, the proposed rates reflect a seasonal differential of 1.46 percent showing movement toward the cost-of-service seasonal differential of 61.6 percent. This small movement provides introductory seasonal rates and helps to mitigate the impacts on customers who have not been on seasonal rates before.

F-9. The Company has not quantified the yearly effects on utility power costs and revenues arising from the proposed seasonal pricing.

CASE: UE 233
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 906

Cascade Natural Gas Customers In the Baker City and Ontario Areas

December 7, 2011

From: Rosales, Maryalice [Maryalice.Rosales@cngc.com]
Sent: Monday, November 28, 2011 12:08 PM
To: COMPTON George
Subject: FW: Cascade Natural Gas Corporations

From: Rosales, Maryalice
Sent: Monday, November 28, 2011 11:49 AM
To: 'george.compton@state.or.us'
Cc: Parvinen, Michael; Abrahamson, Jim; Rivas, Chris
Subject: Cascade Natural Gas Corporations

1. How many residential customers does Cascade have in the Ontario-Baker City region? (Idaho Power has approximately 13 thousand.)

Residential	2007	2008	2009	2010	2011
Baker City	3239	3269	3273	3325	3339
Ontario	3495	3495	3479	3532	3537

2. How long has Cascade (along with its predecessor if applicable) been serving residential customers in that same region?
    a) Cascade been serving Baker City since 1956
    b) Cascade been serving Ontario since 1958

3. What is the annual growth rate for new residential gas connections.
    a) In the last 5 years, Baker City has an annual growth of .62%.
    b) In the last 5 years, Ontario has an annual growth of .24%.

If you have any questions regarding this matter, please contact Christina Rivas at 509-734-4502.

Thank you,

Maryalice Rosales
Regulatory Analyst I

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