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June 20, 2012

Via FedEx and Electronic Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFICORP 2013 Request for a General Rate Revision
Docket No. UE 246

Dear Filing Center:

Enclosed please find an original and one (1) copy of the Direct Testimony and Confidential Exhibits of Michael C. Deen; five (5) copies of the Direct Testimony and Non-Confidential and /or Redacted Exhibits of Michael C. Deen; and an original and five (5) copies of the Direct Testimony and Exhibits of Michael Gorman, on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket. Confidential copies on yellow paper are being provided to those parties who have signed the Protective Order No. 12-060.

Please also find one (1) CD containing the confidential testimony and exhibits, three (3) CDs containing the confidential workpapers of Michael C. Deen and Michael Gorman, and three (3) CDs containing the non-confidential workpapers of Michael C. Deen and Michael Gorman. All backup workpapers are also being provided concurrently on CD to Staff and PacifiCorp.

Please return one file-stamped copy of the Direct Testimony of Michael Deen in the self-addressed, stamped envelope provided.

Thank you for your assistance, and please do not hesitate to contact our office if you have any questions.

Sincerely yours,

/s/ Sarah A. Kohler
Sarah A. Kohler
Paralegal

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Testimony and Exhibits on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail where paper service has been waived.

Dated at Portland, Oregon, this 20th day of June, 2012.

/s/ Sarah A. Kohler
Sarah A. Kohler

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BEFORE THE OREGON PUBLIC UTILITY COMMISSION

UE 246

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2013 Request for General Rate Revision	)
	)

DIRECT TESTIMONY OF MICHAEL C. DEEN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 20, 2012

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael C. Deen, and my business address is 900 Washington Street, Suite 780, Vancouver, Washington 98660. I am employed by Regulatory and Cogeneration Services, Inc. ("RCS"), a utility rate and consulting firm.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I have been involved in the electric utility industry for about 6 years. During that time, I have served as an analyst and expert on a variety of power supply, cost, ratemaking, and policy topics, primarily regarding the Bonneville Power Administration and other utilities in the Pacific Northwest. I have also testified before the Washington Utilities and Transportation Commission in proceedings related to Puget Sound Energy, Avista, and PacifiCorp. A further description of my educational background and work experience can be found in Exhibit ICNU/101. I recently provided testimony before the Oregon Public Utility Commission (the "Commission") in PacifiCorp's concurrent UE 245 Transition Adjustment Mechanism ("TAM") docket.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp (the "Company").

Q. WHAT TOPICS WILL THIS TESTIMONY ADDRESS?

A. This testimony is divided into seven sections, addressing: 1) Introduction and Summary; 2) Revenue Requirement Adjustments; 3) Power Cost Adjustment Mechanism; 4)

Transition Adjustment Mechanism; 5) Mona-to-Oquirrh Transmission Investment; 6) Marginal Cost Study; and 7) Rate Spread and Design.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. PacifiCorp is proposing about a $54.3 million rate increase, with about $41.2 million effective on January 1, 2013, and $13.1 million related to the Mona-to-Oquirrh transmission line effective sometime in the spring of 2013. The following table summarizes the impact of the four revenue requirement adjustments proposed in this testimony and also the impact of the ICNU cost of capital recommendations sponsored by Mr. Gorman in Exhibits ICNU/200 to ICNU/220. This does not represent ICNU's final position in this case, because ICNU will review the proposals of other parties and make a final recommendation in its post-hearing briefs.

Adjustment (in millions)	Impact (Oregon)
Cost of Capital	$36.8
Mona-to-Oquirrh	$13.1
O&M Cost Escalation	$8.1
OATT Revenues	$0.8
Legal Costs	$0.3
Total	$59.1

Below is a brief description of the recommendations addressed in this testimony:

- **Revenue Requirement Adjustments.** ICNU is recommending three changes to the Company's proposed costs.
    - **O&M Cost Escalation (non-labor).** ICNU is proposing to remove the Company's adjustment of base year non-labor operations & maintenance ("O&M") expenses for unspecified, indexed inflation factors. The effect of this adjustment is to lower Oregon allocated expense levels by approximately $7.8 million. This translates to a revenue requirement reduction of approximately $8.1 million, Oregon basis.
    - **OATT Revenues.** ICNU proposes to include $0.8 million in incremental revenues from the Company's Federal Energy Regulatory Commission ("FERC") Docket No. ER11-3643 proceeding to raise its Open Access

Transmission Tariff ("OATT") rates. This lowers the revenue requirement by approximately the same amount.

- **Legal Expenses.** ICNU proposes to remove certain outside legal expenses found to be in error, excessive or did not benefit customers. The effect of this adjustment is to lower Oregon allocated expense levels and the revenue requirement by approximately $0.3 million.

- **Power Cost Adjustment Mechanism.** ICNU is critical of PacifiCorp's rationale for its proposed Power Cost Adjustment Mechanism ("PCAM") and suggests that the Commission reject the proposal as filed. If the Commission wishes to pursue a PCAM for PacifiCorp in this proceeding, it should include consumer protections more stringent than those in the mechanism granted to Portland General Electric Company ("PGE") and it should coincide with elimination of the TAM process in its current form.
- **Transition Adjustment Mechanism.** ICNU recommends that the Commission eliminate the TAM in its current form after this year. The TAM has not promoted direct access and rather served as a vehicle for PacifiCorp to substantially raise the level of Net Power Costs ("NPC") included in rates without any benefit to consumers. The TAM is also unnecessary for direct access.
- **Mona-to-Oquirrh Transmission Project.** ICNU opposes the Company's proposed rate treatment of this transmission project. ICNU does not see the need for special ratemaking consideration in this instance.
- **Marginal Cost Study**. ICNU recommends certain updates and changes to the implementation of PacifiCorp's long run incremental cost study used as the cost basis for allocation of rate increases.
- **Rate Spread Rate Design**. ICNU presents rate spread recommendations based on the results of the ICNU Marginal Cost Study. ICNU recommends changes to base rates be set using the results of the ICNU Marginal Cost Study. ICNU further recommends that class cost-based increases be capped at 1.5 times the system average increase. A class-specific rate mitigation proposal should be developed once the final size of the overall rate increase or decrease is more clearly defined.

II. REVENUE REQUIREMENT ADJUSTMENTS

O&M Expense Escalation (Non-Labor)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ESCALATION ADJUSTMENT TO NON-LABOR O&M EXPENSES?

A. The Company's projected non-labor, non-NPC O&M expenses for the rate period contain a cost escalation component to reflect projected inflation for the period extending from June 2011 through December 2013. To apply this escalator, the Company starts with actual non-labor expenses from the base period of July 2010 to June 2011. The Company then applies a series of escalation factors to its base-period costs of materials and services using indices for electric utility costs produced by Global Insights. These specific indices and their corresponding FERC accounts are detailed in Confidential Exhibit PAC/1107.

Q. PLEASE EXPLAIN ICNU'S OBJECTIONS TO THIS ADJUSTMENT.

A. Regulatory pricing schemes that serve to reinforce inflation should be rejected. When projections of inflation are built into regulated prices such as utility rates, the regulatory mechanism serves to help make inflation a self-fulfilling prophesy. This is particularly inappropriate given the current state of our economy.

A second concern is the incentives related to building a nebulous cost cushion into the Company's test period costs. Allowing this type of systemic increase in rates that is not tied to any specific, measurable change in costs goes beyond the basic rationale of a future test year, which is to mitigate the effects of regulatory lag. The best evidence of the Company's actual non-labor O&M expenses is actual costs in the base year. The cost increases that are represented by the escalation factors may or may not come to pass. Regardless, the Company should always strive to improve its O&M efficiency and thereby limit the net impact of any potential inflation on its O&M budgets.

Allowing an automatic inflation increase could also reduce PacifiCorp's incentive to reduce costs through efficiency improvements. PacifiCorp's proposal does not account for efficiencies that could reduce or lower its costs during the test period. ICNU does not believe it is reasonable or appropriate to simply inflate actual base period expenditures by an index and pass these costs through to customers. The Company has many other opportunities to make specific adjustments to its O&M material and service costs from the base period to the extent it can demonstrate a likely and prudent change in costs. Finally, given the Company's propensity to file nearly annual rate cases, this approach is unwarranted and harmful to customers.

Q. ARE THERE EXAMPLES IN THIS CASE OF NON-LABOR O&M EXPENSE INCREASES BY THE COMPANY NOT RELATED TO INFLATION?

A. Mr. Tallman's testimony in this proceeding, Exhibit PAC/400, is a good example. This testimony addresses a number of changes to non-labor O&M expenses to the Company's hydro and wind generation facilities. Without addressing the merits of any of the specific adjustments in PAC/400, this is the proper process for the Company to propose O&M adjustments from the historical base year to the future test period. The changes are driven by specific materials, contracts, etc., and not the result of blanket, hypothetical escalations.

Q. UNDER WHAT CIRCUMSTANCES MIGHT AN INFLATION ADJUSTMENT TO NON-LABOR O&M EXPENSES BE APPROPRIATE?

A. Some adjustment might be advisable in an environment of major, systemic inflation such as occurred during the late 1970s and early 1980s in the United States. However, inflation in the current economic environment is nowhere near those historic levels. Despite occasional spikes in some food and oil related prices, the prospects for core inflation, which includes these relatively volatile components is low. For example, the Minutes of the Federal Reserve Open Market Committee for January 24-25, 2012, indicate a central tendency forecast for core inflation in 2012 in the range of 1.5 to 1.8%, and 1.5 to 2.0% for 2013. Summary of Economic Projections at 1.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING NON-LABOR O&M ESCALATION.

A. PacifiCorp's blanket escalation adjustment to non-labor O&M should be removed. Any incremental changes to base year expense levels in these accounts should be made on the basis of specific information. The impact of this adjustment is to reduce the Oregon allocated costs in this proceeding by approximately $7.8 million on an expense basis.

OATT Revenues

Q. DOES ICNU AGREE WITH THE LEVEL OF THIRD PARTY OATT REVENUES INCLUDED BY THE COMPANY IN THIS PROCEEDING?

A. No. As a general matter, the Company treats OATT revenues received from third parties as an offset to costs for its retail consumers. However, the Company is currently receiving revenues from its FERC Docket No. ER11-3643 filing that it is not crediting to customers in this proceeding. In its response to ICNU Data Request ("DR") 4.3, attached as Exhibit ICNU/102, Deen/1, the Company quantified these incremental revenues at approximately $3 million total on a system basis exclusive of any short-term or non-firm revenues. This equates to approximately $0.8 million on an Oregon allocated basis. It is important to note that this incremental revenue value is conservative, because the Company's response includes only OATT revenues from long-term contracts, and not increased revenues from short-term firm or non-firm OATT sales at higher rates authorized in ER11-3643. ICNU presumes these revenues were excluded from the Company's response to the variable nature of short term transmission sales.

Q. WHAT IS ICNU'S PROPOSAL FOR THE TREATMENT OF THESE REVENUES?

A. ICNU recommends that the $0.8 million be included as an offset to costs in this case pending a final ruling by FERC or settlement amongst the parties to ER11-3643. ICNU believes this is an equitable and conservative result as it does not include all potential revenues from the OATT increases. If a final ruling or settlement occurs, the Company should update its OATT revenue assumptions to include the outcome of the final action.

<u>Legal Costs</u>

Q. WHAT ADJUSTMENT IS ICNU PROPOSING REGARDING PACIFICORP'S LEGAL COSTS IN THIS PROCEEDING?

A. ICNU is proposing to remove certain outside legal expenses and settlement costs from the test year for cases in which Company was found liable and its expenditures appear excessive. ICNU is also proposing to remove a mistaken "Tax Management & Planning" legal expense identified in response to ICNU DR 6.1. This response is attached as Confidential Exhibit ICNU/109, Deen/1.

The outside legal expenses for cases in which PacifiCorp was found liable are related to the USA Power, LLC, et al. v. PacifiCorp et al. case involving the Currant Creek power plant and also to the Rough and Ready Paper v. PacifiCorp case in a breach of contract claim. The settlement costs are related to the Rough and Ready Paper proceeding, and appear to be related to a situation in which PacifiCorp was found to have illegally overcharged an interconnection customer. These costs were identified in response to ICNU DRs 6.1 and 6.8, attached as Confidential Exhibit ICNU/109, Deen/1-5.

ICNU takes the position that it is fundamentally inappropriate for the Company to pass on costs to consumers that the Company incurred as a result of illegal actions. PacifiCorp engaged in the actions found to be illegal, and shareholders should be responsible for all these costs.

Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT?

A. The combined effect of removing these erroneous or inappropriate legal costs is to reduce the Oregon allocated costs in this proceeding by approximately $0.3 million on an expense basis.

III. POWER COST ADJUSTMENT MECHANISM

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS PROCEEDING REGARDING A POWER COST ADJUSTMENT MECHANISM?

A. As described in Exhibit PAC/900, the Company is proposing to implement a dollar for dollar PCAM for prudently incurred NPC. The Company is not suggesting any deadbands, sharing, or earnings tests associated with the proposed PCAM.

Q. WHAT IS THE COMPANY'S RATIONALE FOR ITS PROPOSED PCAM STRUCTURE?

A. As described at great length in PAC/900, the Company's fundamental rationale for the proposed PCAM is an alleged under-recovery of power costs in recent years, particularly since the passage of Senate Bill ("SB") 838 in Oregon. The Company's basic explanation for its alleged inability to recover its projected NPC is that Company's operations do not have the same "certainty and perfect foresight" as the Company's GRID model used to project NPC and wind integration costs, and the claim that the Company has agreed to settle the TAM at lower than realistic levels to "minimize the adversarial nature of the TAM." PAC/900, Duvall/17.

Regarding the impact of wind generation, the Company has experienced growth of wind generation on its system from 135 MW in 2006 to over 2,375 MW at the end of 2011. Id. at 18. The growth is projected to continue to over 3,350 MW by 2025. Id. The Company cites a number of power cost modeling and operational challenges related to wind integration. The Company also cites to various sections of SB 838 to justify the proposed PCAM.

Finally, the Company also cites four "benefits" to customers from the Company's proposed PCAM design. These include a more streamlined regulatory process for NPC recovery; a "balanced" outcome between the Company and customers for under or over-recovery; the notion that customers will receive benefits and pay costs of wind generation more accurately through time; and finally that the PCAM "may" allow the Company to lower the common equity component of its capital structure at some point. PAC/900, Duvall/29-30.

Q. DO YOU AGREE THAT THE PCAM WILL BENEFIT CUSTOMERS?

A. No. ICNU is also not persuaded that the "benefits" espoused by PacifiCorp will come to pass in a timely fashion, or at all. ICNU is skeptical that a "streamlined" regulatory process will not simply result in less thorough review of the prudency and level of NPC in the Company's rates. Given the foregoing problems highlighted with the Company's rationale for the proposed PCAM, ICNU is also skeptical that the proposed PCAM would provide a more balanced outcome between the Company and customers or result in customers somehow more accurately paying for and receiving the benefits of generation. The Company made similar claims of benefits and streamlined processes when it sought approval of the TAM, and all of the alleged "benefits" failed to materialize. Finally, the prospect that the Company "may" at some point in the future reduce the equity component of its capital structure is extremely vague in terms both timing and impact (even if it did come to pass). The Company should make a proposal to reduce its cost of capital concurrent with any PCAM so that it can be evaluated as a complete package.

Q. DOES ICNU AGREE THAT PACIFICORP HAS SHOWN THAT IT IS SYSTEMATICALLY UNABLE TO COLLECT ITS ACTUAL NPC?

A. No. PacifiCorp's reasoning for the need, benefit, and structure of its proposed PCAM is unpersuasive on a number of points. ICNU is not convinced that the Company has a systematic issue in NPC recovery that requires special rate treatment in Oregon. A wide variety of factors may drive differences between normalized power costs that are projected in a rate proceeding and actual results of business operations. Weather, loads, market conditions, resource performance, and many other factors across the Company's various jurisdictional service territories could be driving results. PacifiCorp's actual net power costs are also unaudited and have not been shown to be reasonable or prudent. PacifiCorp has also failed to demonstrate that any alleged under-recovery of NPC is related to Oregon, Utah, or other states. It would require a much more rigorous presentation by the Company to show that, on a normalized basis, it is unable to recover an appropriate level of NPC in rates under the current regulatory framework and to further identify a causal mechanism.

Q. PLEASE RESPOND TO PACIFICORP'S ARGUMENTS THAT A PCAM IS NEEDED BECAUSE OF INCREASES IN RENEWABLE RESOURCES.

A. The Company has failed to attribute the causation of its alleged system wide NPC under-recovery to the Oregon Renewable Portfolio Standard ("RPS") or renewable resource integration generally. SB 838 includes an automatic adjustment clause that allows deferrals and eliminates any potential regulatory lag related to the fixed costs of its renewable resources. SB 838 has actually reduced PacifiCorp's risk of under-recovery of its costs. As a threshold matter, the Company admits that it is unable to isolate and quantify the effect of its renewable resources on its actual NPC relative to forecast NPC. Also, although there is some correlation in the Company's alleged system wide NPC under-recovery from 2007 through 2011 and the growth of renewables on its system, it is hardly consistent with the notion that increasing wind integration is driving PacifiCorp to ever greater under-recovery of NPC in rates. The following table is taken from data presented in Table 8 of PAC/900 and shows the alleged difference between the final updated NPC in various rate proceedings to the actual NPC recovered in rates.

PacifiCorp System NPC in Rates vs. Claimed Actual NPC ($000s)					
	2007 UE 179	2008 UE 191	2009 UE 199	2010 UE 207	2011 UE 216
Final Update	$874,951	$987,823	$1,134,565	$1,092,321	$1,288,694
Diff. from In Rates	$111,932	$120,863	$31,109	$137,109	$135,233
Percentage	12.8%	12.2%	2.7%	12.6%	10.5%

PAC/900, Duvall/16. This table shows that the nominal amount of alleged system NPC recovery has remained relatively constant (with a notable dip in 2009) during the timeframe in which wind generation on the PacifiCorp system increased from near zero to over 2,375 MW at the end of 2011. Further, as a percentage, the alleged under-recovery was actually less in 2011 than in 2007 after an over 17-fold increase in wind generation on the PacifiCorp system. There are a wide variety of issues affecting PacifiCorp's NPC recover across its entire system, of which Oregon is only part. PacifiCorp has not demonstrated that wind generation, even with its challenges, is at the cause of its alleged NPC recovery issue let alone operations to support the Oregon jurisdiction and the requirements SB 838 specifically.

Also, to whatever extent that the growth of wind generation may be causing PacifiCorp operational or power cost modeling issues, the issue may very well be significantly lower in the future. This is due to the fact that although wind integration increased by over 2000 MW between 2006 and 2011, PacifiCorp is forecasting a growth of only an additional 1000 MW by 2025. This is a much slower rate of growth and will constitute a lower percentage change in the composition of PacifiCorp's resource portfolio. The types of issues described by PacifiCorp may decrease rather than increase over time as PacifiCorp gains more experience operating and modeling wind resources.

Q. WHAT IS ICNU'S RECOMMENDATION REGARDING THE PROPOSED PCAM IN THIS PROCEEDING?

A. As described, PacifiCorp has failed to show that its system-wide under-recovery of NPC is due to integration of renewables in general or to the requirements imposed by SB 838 specifically. ICNU also does not believe the Company has shown that it is unable to collect appropriate levels of NPC in rates on a normalized basis in general. As such, PacifiCorp has failed to justify the need for the proposed PCAM generally or as a requirement of SB 838. The Company has particularly failed to prove that SB 838 requires the implementation of a PCAM without consumer protections such as cost sharing, deadbands, or an earnings test. Also, it is worth noting that in spite of whatever PacifiCorp's NPC difficulties may be, the Company is still earning an 8.5% normalized return on equity in this proceeding prior to any Commission authorized rate change. Given these deficiencies in PacifiCorp's rationale for the proposed Oregon PCAM, ICNU recommends that the Commission reject the PCAM as filed.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. While ICNU strongly opposes the adoption of a PCAM for PacifiCorp, if the Commission does decide to pursue some form of PCAM in this proceeding, then the mechanism should include at a minimum all of the consumer protections contained approved PGE's mechanism in Docket No. UE 180 (i.e., asymmetric deadbands, sharing bands, and an earning review including a 100 basis point deadband around the authorized return on equity). ICNU believes that consumer protections for a PacifiCorp PCAM should be even more robust than the Commission approved for PGE. This is because, as a multi-jurisdictional utility (with a relatively small portion of load in Oregon), the Company's NPC results will most likely be driven by operations to serve other jurisdictions. For this reason ICNU recommends that cost sharing for a PacifiCorp PCAM be set at 75% to consumers and 25% to the Company after the deadband. This will help to insulate Oregon consumers from subsidizing the outcomes of PacifiCorp's service to other jurisdictions. ICNU's calculations of these parameters are included in Exhibit ICNU/104, using PacifiCorp's as filed rate base and capital structure.

Further, the adoption of a PCAM for PacifiCorp in this proceeding would have to go hand in hand with elimination or substantial revision of the TAM process, as discussed later in this testimony. PacifiCorp does not need two power cost mechanisms to insulate itself from power cost changes.

Q. PLEASE FURTHER DESCRIBE THE PURPOSE AND IMPORTANCE OF ICNU'S RECOMMENDED CONSUMER PROTECTIONS IN A PCAM.

A. The Commission described and accepted the rationale for an earnings test, asymmetric deadbands, and cost sharing in a PCAM in Order No. 07-015 in Docket No. UE-180, pages 26-27. The fundamental purpose of the earnings test is to protect consumers from paying for higher than expected power costs when the Company's earnings are reasonable while also protecting the Company from refunding power costs when its earnings are otherwise unreasonably low.

A deadband is set in a PCAM to ensure that the Company absorbs variations in power costs incurred in the normal course of business. A utility's normal return on equity constitutes compensation for events occurring in the normal course of business. Further, an asymmetric deadband is important to ensure revenue neutrality in a region heavily dependent on hydro power, as the replacement costs of hydro power in poor water years will outweigh the benefit of additional hydro energy in good years. Thus, the purpose of a PCAM is to protect a utility from extreme power cost fluctuations and not to provide dollar for dollar recovery of actual costs.

Finally, a cost sharing mechanism for costs outside of the deadband (i.e., a certain percentages of costs being borne by the Company and customers) provides incentive for the Company to continue to manage its costs effectively under unusual circumstances, but to also provide cost sharing for events beyond the normal course of business.

IV. TRANSITION ADJUSTMENT MECHANISM

Q. ARE YOU ADDRESSING WHETHER THE TAM SHOULD BE ELIMINATED OR MODIFIED?

A. Yes. The TAM should be eliminated and replaced with a more streamlined mechanism that allows customers to choose direct access, but does not adjust net power costs for regulated customers on an annual basis. The TAM has failed to achieve its basic purposes and has instead served as single issue, power cost-only rate proceeding that only benefits PacifiCorp. There is no need to increase power costs on an annual basis for all customers to set transition adjustment credits or charges, and the Commission should adopt a simpler mechanism that will accurately set transition credits and charges without harming the vast majority of customers that will remain on cost-of-service rates. The TAM should be eliminated regardless of whether a PCAM is adopted for PacifiCorp.

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE OREGON DIRECT ACCESS REQUIREMENTS.

A. SB 1149 requires PacifiCorp and Portland General Electric Company ("PGE") to allow certain customers the option to select "direct access," which means the ability of the customer to purchase electricity and ancillary services from an entity other than their distribution utility (i.e., PacifiCorp or PGE). One of the requirements related to direct access relevant to the TAM is that the Commission may include transition credits or charges for those customers who select direct access.

Q. PLEASE BRIEFLY DESCRIBE THE TAM.

A. The TAM has two main substantive elements. First, the TAM resets PacifiCorp's estimated net variable power costs for the subsequent calendar year for cost of service customers. The Company also updates multi-state cost allocation factors and customer loads. The TAM has resulted in a rate increase for customers every year it has been in effect, regardless of whether market prices have increased or decreased. Second, the TAM estimates the value of any power that PacifiCorp would no longer need to use to serve any customers that selected direct access. The value of this estimated "freed up" power is used to calculate transition credits for those customers that select direct access.

The most relevant procedural aspect of the TAM is that there is an expedited rate case procedural process that provides Staff and intervenors less time to review or challenge the accuracy or reasonableness of the filing. The TAM is also a "moving target" rate case in which the Company frequently updates its costs and includes new contracts and other updates throughout the case so that the exact rate impact is not known until after the Commission issues its final order. Parties are provided extremely limited discovery and no formal opportunity to submit testimony regarding cost updates that occur at the end of the year.

Q. HAS PACIFICORP ALWAYS USED THE TAM TO SET TRANSITION ADJUSTMENT CREDITS OR CHARGES?

A. No. My understanding is that, during the first few years after the passage of SB 1149, PacifiCorp set transition credits without a TAM. Therefore, transition credits or charges can be, and have been, set without a full TAM proceeding or simultaneously increasing net variable power costs.

Q. WHEN WAS THE TAM ADOPTED?

A. The TAM was adopted for PacifiCorp in 2005 as part of PacifiCorp's general rate case (Docket No. UE 170). PacifiCorp proposed to model its TAM based on PGE's then-current resource valuation mechanism. The proposed TAM was controversial, and the Commission ultimately adopted PacifiCorp's proposal, with some modifications proposed by Staff. Re PacifiCorp, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005). The Commission expressed concern about the one-sided nature of the TAM, and stated that it was open to changes in the future. Specifically the Commission stated:

> Having adopted the TAM, however, we believe that further investigation is necessary into some of the concerns raised by the parties. We are somewhat concerned about establishing the TAM with its annual update because there is a certain amount of one-sidedness to PacifiCorp's annual updates without concomitant adjustments by intervenors and Staff. We will continue to look at the TAM and investigate to whatever extent we believe is necessary.

Id.

Q. THE COMMISSION STATED THAT IT BELIEVED FURTHER INVESTIGATION WAS WARRANTED REGARDING SOME OF THE CONCERNS RAISED BY THE PARTIES. WHAT WERE SOME OF THE CONCERNS RAISED BY THE PARTIES?

A. Both ICNU and the Citizens' Utility Board of Oregon ("CUB") raised substantive and procedural concerns regarding PacifiCorp's TAM proposal. On substantive grounds, ICNU and CUB objected to updating the net variable power costs for cost-of-service customers as unnecessary to setting transition credits, shifting risk of power cost increases to customers, and resulting in significant disputes about the scope and prudence of inputs included in the Company's power cost model. On a procedural basis, ICNU and CUB objected on the grounds that there would be insufficient time and opportunity to review PacifiCorp's costs, especially those in the Company's final updates.

PacifiCorp disputed ICNU's and CUB's criticisms. For example, PacifiCorp argued that the TAM did not shift any risk of power cost changes from the Company to rate payers. PacifiCorp stated that the TAM would allow customers to benefit in periods of low net power costs, and that if there was "a downward trend in future natural gas prices, then customers would benefit from the Company's annual net power cost updates as prices would be reduced to coincide with up-to-date costs." Re PacifiCorp, Docket No. UE 170, PPL/702, Omohundro/3. Staff agreed that the TAM shifted power cost risk to customers, but recommended that the TAM should still be adopted because Staff believed that the risk shift was not that great, the TAM could accurately set transition credits and charges, and other problems could be managed. Re PacifiCorp, Docket No. UE 170, PPL/700, Galbraith/12.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE TAM PROCEEDINGS THAT HAVE OCCURRED TO DATE.

A. There have been seven completed TAM proceedings, including those filed as part of a PacifiCorp general rate proceeding. Each TAM proceeding has resulted in an overall rate increase, with industrial rate increases varying from 0.5% to 8.4%. Customers often experienced other rate increases in these years related to general rate cases, the renewable adjustment clause, the Klamath surcharge, and other factors. In each TAM proceeding, PacifiCorp initially sought a higher rate increase than it was ultimately allowed. Exhibit ICNU/102, Deen/2-3 is a copy of a PacifiCorp response to ICNU DR 5.1 in Docket No. UE 245 that is a partial summary of PacifiCorp's TAM filings and the associated rate impact.

My understanding is that another major area of dispute has been the scope of PacifiCorp's updates, all which normally occur after Staff and intervenors have filed their responsive testimony. These updates can include significant cost increases, which are difficult to review and analyze with the shortened schedule and no opportunity to submit written testimony in response. The most difficult update is the Company's November update, which is filed after the close of evidence and the Commission issues the "final" order in the case. Staff and intervenors are provided very little time to conduct discovery, no opportunity to submit responsive testimony, and the process for challenging any aspect of the final update is unclear and has been subject to dispute in prior TAMs. In the last two TAMs (Docket Nos. UE 207 and 227), PacifiCorp has agreed to remove certain cost increases that were identified by ICNU in the discovery process, and, in a number of TAMs ICNU has filed deferred accounting petitions, because there is no formal process to review or challenge an update. The final update process has been very contentious, with PacifiCorp challenging ICNU's ability to file a deferral, investigate certain costs, and sometimes refusing to answer discovery requests. The parties in TAM proceedings have litigated some issues, and have entered into "TAM guidelines," which have narrowed the scope of updates. Nevertheless, these final updates are procedurally unfair to customers.

Q. HAVE THE TAM GUIDELINES ELIMINATED THE DISPUTES ABOUT THE SCOPE OF UPDATES AND APPROPRIATE ISSUES TO ADDRESS IN A TAM?

A. No. For example, in last year's TAM (Docket No. UE 227) there were a number of disputes about the scope of issues that could be considered appropriate in a TAM proceeding.

One major issue in Docket No. UE 227 was that the Company projected a substantial increase of 7.5% in its system load. This higher system load growth resulted in an increase in system wide net power costs of $164 million. PacifiCorp did not include the corresponding additional revenues that would be derived from its higher sales associated with the load growth, which in an ordinary rate proceeding would have partially offset the higher net power costs. Including the costs of higher system load growth without the additional revenues provides the Company with an incentive to increase the retail sales level to drive up net power costs resulting in a higher net power costs per unit recovery while maintaining the fixed cost recovery at greater per unit charges than would be the case if the higher sales level had simultaneously been reflected in the fixed cost recovery determination. This incentive is just the opposite in a general rate case where a lower load forecast produces a higher resulting per unit rate for recovering fixed costs which are substantially greater than the Company's variable costs. Thus, the stand alone TAM process provides PacifiCorp an opportunity to inflate its system load growth estimates.

Even though PacifiCorp's load forecasts were inaccurate and challenged by both Staff and ICNU, the Company's initial position was that the TAM Guidelines did not permit Staff or ICNU to challenge their accuracy. Therefore, the TAM included an institutional bias that encouraged the Company to file inaccurately high load growth forecasts, but the parties could not challenge those forecasts. A settlement between Staff and PacifiCorp was reached, but it did not resolve the issue of whether PacifiCorp's load forecasts can be challenged. Re PacifiCorp, Docket No. UE 227, Order No. 11-435 at Appendix A at 3-4 (Nov. 4, 2011). The Commission, however, did decline to offset the net power cost rate increase associated with higher load growth with the increased sales margins associated with the higher load growth, because the Commission concluded that this issue should be raised in a general rate case. Re PacifiCorp, Docket No. UE 227, Order No. 11-435 at 6. Thus, as currently structured, the TAM allows PacifiCorp to increase rates even if its actual costs have not increased, because the TAM only recognizes the increased costs associated with load growth, but not the increased revenues. At a minimum, the TAM should be changed to remove this incentive to inflate load forecasts in stand-alone TAMs by incorporating additional revenues.

Another controversial issue in Docket No. UE 227 was PacifiCorp's updates after the final order in the proceeding. First, PacifiCorp changed the manner in which the forward price curve was calculated after the close of the hearing and the final order, which resulted in a $1.4 million increase in rates to customers. ICNU/102, Deen/2-3. After ICNU identified the change, PacifiCorp eventually agreed to use the original forward price curve methodology. Second, ICNU conducted discovery upon a number of recently executed, but not yet approved, contracts. ICNU did not complete its review of PacifiCorp's final update because the Commission concluded that the TAM Guidelines required parties to complete their analysis of PacifiCorp's final update in less than three weeks. See Re PacifiCorp, Docket No. UE 227, Order No. 11-516 (Dec 21, 2011). Given that the parties do not have an adequate opportunity to conduct discovery or review the final updates, there should be not be a final update that sets power costs. Parties should be provided the right to challenge through discovery, testimony, and an evidentiary hearing any contracts or costs that are used to set rates.

Q. HOW HAS THE TAM WORKED FOR DIRECT ACCESS?

A. It has been a failure in setting credits for direct access. In January 2012, only 0.6% of eligible customers have selected PacifiCorp's direct access program. Exhibit ICNU/105, Deen/1. These numbers have not significantly changed, and over the last six years has been only 0.6% to 0.7% of eligible customer loads. Id. at 1-6. Based on PacifiCorp's filing in this case, 0.6% of non-residential loads would represent approximately 5 average megawatts ("aMW") in 2013. There is no need for the parties to expend considerable time and resources in a TAM proceeding, or set transition adjustment credits or charges for less than 1% of eligible customers to select direct access. The TAM has essentially become a power-cost-only rate proceeding that has minimal to no impact in protecting non-direct access customers from the costs of customers switching to direct access. Since there are so few direct access customers, there is no need for a TAM to set credits or to protect non-direct access customers.

Q. WHAT DOES ICNU RECOMMEND IN LIEU OF THE TAM?

A. There are a number of possibilities. A simple method would be to set the transition charges or credits under the same basic method as is currently employed, but to do so in the context of a general rate case. ICNU believes this option would work well under the current circumstances, particularly if paired with an automatic review of the procedure if the Company reaches a critical threshold of open access. Finally, if the Company is granted a fair and balanced PCAM in this proceeding, Schedule 294 and 295 charges could be further updated on the basis of the changes in the Company's actual power costs in the event the Company has not filed a rate case in a given year.

Q. WILL HAVING TRANSITION CREDITS OR CHARGES SET ON THE BASIS OF POWER COSTS FROM A PREVIOUS YEAR CREATE AN INCENTIVE FOR "GAMING"?

A. No. I find it highly unlikely that power costs from the most recent rate case, particularly if adjusted by an annual PCAM filing, would be so out of line with market expectations that it would incent eligible load to go to direct access. In fact, given the inherent uncertainty in predicting future power prices, there are many scenarios in which customers could lose money by attempting to "game" market conditions in their choice to take direct access. The history of PacifiCorp's direct access program demonstrates a very low level of customer interest and participation and therefore a considerable amount of effort is being expended, to the detriment of customers, to deal with a problem that has not materialized.

Q. IS ICNU OPEN TO EXPLORING ANY OTHER AVENUES TOWARDS PROMOTING OPEN ACCESS?

A. Very much. ICNU is currently working with parties in other venues to explore the possibility of promoting open access in Oregon using the model of Puget Sound Energy ("PSE") in Washington. With PSE's 448/449 schedules, customers are given a one-time option to go to open access with no right to return. A permanent or long-term opt out option would eliminate or significantly mitigate any concerns over gaming of open access decisions.

Q. PLEASE SUMMARIZE ICNU'S RECOMMENDATIONS REGARDING THE TAM PROCESS.

A. Given the level of participation in open access by PacifiCorp's customers (on the order of 5 aMW or less), the TAM has been, at best, a waste of utility, party, and Commission resources, and has resulted in continuous rate increases to consumers without any tangible benefit. Parties have wasted huge amounts of resources litigating TAM issues that have nothing to do with direct access. PacifiCorp spent a significant amount on outside legal fees alone in last year's TAM. Confidential Exhibit ICNU/103, Deen/1.[11/]

ICNU's basic recommendation is that the Commission eliminate the TAM in its current form after this year and, going forward, set transition credit or charges on the basis of Company's most recent general rate case. This recommendation comes with the caveat that the Commission should reevaluate the necessity of an annual process if PacifiCorp direct access load reaches a critical level (such as 50 aMW per year).

ICNU is further open to exploring additional options for setting transition adjustments, such as linking adjustments to a potential PCAM or some process that does not change rates for non-direct access customers. Open access options akin to PSE's 448/449 schedules in which customers must make a one-time or other long-term election to move to open access should also be considered.

V. MONA-TO-OQUIRRH TRANSMISSION INVESTMENT

Q. WHAT IS THE COMPANY'S PROPOSED TREATMENT OF ITS CURRENTLY INCOMPLETE MONA-TO-OQUIRRH TRANSMISSION PROJECT?

A. As discussed in PAC/1100, Dalley/14, and PAC/1300, Griffith/15-16, PacifiCorp is proposing a separate rate mechanism to recover costs from its as yet incomplete Mona-to-Oquirrh transmission investment as soon as the project becomes used and useful (anticipated at or before June 2013). The overall impact of this project on the Oregon revenue requirement is estimated at approximately $13.1 million. PAC/1100, Dalley/14.

[11/] ICNU believes that PacifiCorp's outside legal TAM expenses are excessive and imprudent, but ICNU is not challenging them, because PacifiCorp is only seeking recovery of a small portion of its outside legal costs related to the TAM in this case. Confidential Exhibit ICNU/103, Deen/1.

Q. DOES ICNU AGREE THAT THIS INVESTMENT REQUIRES SPECIAL RATEMAKING TREATMENT FOR THE COMPANY?

A. Absolutely not. There is nothing unique about the circumstances or magnitude of this project to warrant special-issue ratemaking. This is a basic issue of regulatory lag and the Commission should reject the Company's proposal and make a prudency and ratemaking determination on the project when it is used and useful. As previously discussed in this testimony, the Company has been filing practically annual rate cases for many years, so any regulatory lag issue would very likely be short lived. Further, at present the Company is earning a robust 8.5% return on equity on a normalized basis before any approved increases from this or the concurrent UE 245 TAM proceeding. PacifiCorp is not planning to pass back to customers any cost decreases that have occurred in the past or will occur in the future. For example, PacifiCorp's capital costs have declined considerably since the last rate case, and may continue to decline given the state of the global capital markets. PacifiCorp is not proposing to pass back any of those savings that have occurred in the past or may occur at the time the Mona-to-Oquirrh line becomes operational. PacifiCorp's proposal is also inappropriate because it is seeking approval of its costs before they have been completed. Given these factors, the Commission should deny the Company's requested treatment in this proceeding.

VI. MARGINAL COST STUDY

Q. HAVE YOU REVIEWED THE COMPANY'S MARGINAL COST STUDY IN THIS PROCEEDING?

A. Yes. I have reviewed the Company's Marginal Cost Study in this proceeding as described in the testimony of Mr. Paice, PAC/1200, and variously presented and summarized in exhibits PAC/1201 through PAC/1207. I have also reviewed the workpapers, models, and discovery associated with the Marginal Cost Study. The changes proposed in this section do not affect the overall size of any Commission-approved increase, but rather how that increase is allocated among the various customer classes in base rates.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS REGARDING THE MARGINAL COST STUDY.

A. I recommend several changes to PacifiCorp's study of marginal costs ("Marginal Cost Study") to more accurately capture the long run incremental cost of serving PacifiCorp's Oregon jurisdictional customers. The specific recommendations are:

- The avoided cost assumptions in the Company's initially filed Marginal Cost Study are significantly out of date, particularly with regard to natural gas prices. ICNU recommends that the study be updated to reflect more recent assumptions, such as those provided in response to OPUC Staff Data Request 271.

- Marginal cost analysis requires a proper matching between the per unit marginal cost assignment and the cost causation unit. PacifiCorp's Marginal Cost Study substantially understates capacity related costs by relying on the use of 12 monthly coincident peaks ("12 CP") for determining the marginal demand-related costs for generation, transmission, and distribution.

    a. The marginal demand-related costs of distribution substations and feeders should be calculated using Oregon jurisdictional class non-coincident peaks ("1 NCP").

    b. The marginal demand-related costs of generation and transmission should be calculated using Oregon class load levels within 95% of the Oregon jurisdictional peak for the rate year ("95% CP").

- In calculating the marginal costs of distribution feeders, a commitment-related component should be part of every branch segment.

The following table indicates the cost based changes from incorporating all of my recommendations as compared to the Company's results. Note that these changes include the Company's proposed cost revisions in both this proceeding and the UE 245 TAM docket addressing the Company's NPC. Given that the results of the marginal cost of service analysis affect rate spread and rate design proposals, it is important to consider the entire rate and cost context. The incremental impact of each of my suggested changes on the cost based rate change for the major classes is summarized in Exhibit ICNU/106.

Cost-Based Change Comparison (Prior to Mitigation -$000s)					
Schedule	**PacifiCorp**	**ICNU**	**Difference**	**PacifiCorp Change**	**ICNU Change**
4	$26,733	$51,842	$25,109	4.74%	9.18%
23 Sec	($2,717)	($4,958)	($2,241)	-2.27%	-4.13%
23 Pri	$60	$105	$45	41.81%	72.78%
28 Sec	$10,175	$3,720	($6,455)	6.36%	2.33%
28 Pri	$173	$210	$36	12.52%	15.14%
30 Sec	$4,622	($1,343)	($5,965)	5.06%	-1.47%
30 Pri	$264	($42)	($305)	3.92%	-0.62%
48 Sec	$3,009	($147)	($3,156)	6.66%	-0.33%
48 Pri	$5,603	($1,623)	($7,226)	5.19%	-1.50%
48 Trn	$1,976	($2,364)	($4,340)	4.12%	-4.93%
41	($1,955)	$2,874	$4,829	-7.84%	11.52%
Lighting	$18	($312)	($331)	0.69%	-11.60%
Total	$47,962	$47,962	($0)	4.09%	4.09%

<u>Avoided Cost Assumptions</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO UPDATE THE AVOIDED COST ASSUMPTIONS IN THE MARGINAL COST STUDY.

A. The avoided cost data supporting the Marginal Cost Study in the Company's initial filing was from the Company's avoided cost filing of March 4, 2010. The natural gas prices from this filing for the time period of 2013 through 2032 ranged from $6.86 to $10.02 per MMBtu. The Company's most recent avoided cost filing of March 21, 2012, assumes 2013 through 2032 prices ranging from $3.96 to $8.50 per MMBtu. This is much more consistent with current information available from NYMEX on forward market activity at Henry Hub, as shown in Exhibit ICNU/107. It is also more consistent with the most recent official Annual Energy Outlook from 2011, which projects forward prices during the 2013-2032 period ranging from $4.25 through $9.15 per MMBtu average for delivery in the contiguous United States.

Given the importance of these types of assumptions in determining the most appropriate possible long-run marginal costs, ICNU recommends using the Company's recently filed avoided cost data in this proceeding. As such, ICNU has incorporated the updated Marginal Cost Study model provided in response to OPUC DR 271 (1st Supplemental) as the base for ICNU's other recommended changes. The Company's responses to OPUC DR 271 are incorporated in Exhibit ICNU/102, Deen/4-6.

Peak Demand Selection: Distribution Costs

Q. DO YOU AGREE WITH PACIFICORP'S USE OF 12CP PEAK DEMANDS IN THE MARGINAL COST ANALYSIS?

A. No. PacifiCorp's use of 12CP factors for the derivation of demand-related marginal costs related to generation, transmission, and distribution costs is not appropriate. In performing a Marginal Cost Study, it is essential that there be consistency in the derivation of per unit marginal cost and the cost causation unit (customers, energy, peak, etc.) to which the cost is applied. To illustrate this matching concept, consider PacifiCorp's Marginal Cost Study with regard to distribution substations. PacifiCorp derives a marginal cost of substation investment based upon the incremental capacity (MVa or KVa) and the expected cost of additions for the period of 2011 through 2015. The resulting value is $227/KVa in 2011 dollars. Using a carrying charge rate of 10.23%, PacifiCorp's annual per unit marginal cost for distribution substation investment is $24.12/kW. This marginal demand cost should be applied to the peak demand placed on each distribution substation. By using this measure of demand, there is a proper matching of the marginal costs with the cost causation factor.

In contrast, PacifiCorp's Marginal Cost Study uses the average of the twelve monthly coincident peaks as the cost causation unit. This value understates the marginal distribution costs in two respects. First, by averaging twelve peaks, the value of the true marginal cost unit is diluted by 11 irrelevant values. Secondly, using system coincident peaks ignores the localized diversity that occurs within a service territory. Absent having the most accurate metric (class loads at each substation peak), a reasonable and most often used alternative is class non-coincident demand levels as acknowledged by the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual, pages 142-143, attached as Exhibit ICNU/110. The following table compares PacifiCorp's 12 CP jurisdictional demands with the class 1 NCP demands, which I derived based on hourly class data supplied by PacifiCorp in response to ICNU DR 4.1. It is apparent that use of a 12CP factor for distribution investment understates the capacity-related costs by a substantial sum.

Distribution Demand Comparison (MWs)		
Major Class	**PacifiCorp 12CP Demand**	**ICNU Class NCP Demand**
Sch 4	995	1,374
Sch 23	163	225
Sch 28	318	420
Sch 30	195	242
Sch 48	321	553
Sch 41	22	117
Total:	**2,015**	**2,930**

To more accurately assess the marginal cost of serving the various customer classes with regard to distribution facilities, I recommend that the class NCP values shown in the above table be used in the Marginal Cost Study instead of PacifiCorp's 12CP jurisdictional values. The impact of using ICNU's demand related changes is shown in Exhibit ICNU/106.

Peak Demand Selection: Generation and Transmission Costs

Q. WHAT 12CP DEMAND DID PACIFICORP USE FOR MARGINAL GENERATION AND TRANSMISSION COSTS?

A. My understanding is that, similar to previous cases, PacifiCorp's 12CP system values are based on Oregon jurisdictional class contributions to the twelve monthly system coincident peaks. These same demands were used for both generation and transmission marginal cost assignment.

Q. DO YOU AGREE WITH THIS METHOD?

A. No. I disagree with the Company's approach in two respects. First, I strongly disagree with the use of a 12CP value for transmission and generation marginal cost assignment. Fundamentally generation and transmission must be sized to meet the maximum loads of a utility. Second, I also take issue with the Company's use of overall system peaks rather than Oregon jurisdictional peaks.

Q. PLEASE EXPLAIN.

A. PacifiCorp's service territory is not contiguous. The eastern area includes Utah, parts of Idaho, and Wyoming. The western area includes portions of Oregon, Washington, and Northern California. Physically, the two parts are isolated by hundreds of miles. The two portions are electrically connected through high voltage transmission lines but much of this transfer capability is over facilities owned by others. Consequently, although

PacifiCorp asserts it operates and plans the system on an integrated basis, it must also address the "local" reliability needs of each area as well. This need for eastern and western area-specific peak reliability is evidenced in PacifiCorp's own Integrated Resource Plan, which delineates resource capacity by eastern and western control areas and includes limited transfer capabilities between geographic areas.

Q. WHAT IS THE GENERAL ISSUE WITH USING A 12CP VALUE FOR MARGINAL DEMAND-RELATED COST ASSIGNMENT OF GENERATION AND TRANSMISSION?

A. Similar to the issues described for distribution costs, the use of 12CP for demand-related transmission and generation cost assignment creates a fundamental mismatch between the unit of cost causation and the marginal cost unit. Again, given that utilities must meet actual peak demand and not averages, the use of a 12CP factor for demand-related costs is not appropriate. The following table shows the relationship of PacifiCorp's Oregon monthly peak loads to the annual peak.

Month	Oregon MW	Percent of OR Peak
January	2,357,014	100%
February	2,185,028	93%
March	2,004,630	85%
April	2,029,233	86%
May	1,775,806	75%
June	1,976,813	84%
July	2,175,783	92%
August	2,323,386	99%
September	2,067,173	88%
October	1,939,822	82%
November	2,284,388	97%
December	2,159,240	92%
Average	**2,106,526**	**89%**

This table shows that the use of a 12CP will significantly understate the actual marginal demand-related costs on PacifiCorp's system.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COINCIDENT PEAKS USED TO DETERMINE DEMAND RELATED GENERATION AND TRANSMISSION MARGINAL COST?

A. I recommend that the Oregon peak hours within 95% of the jurisdictional peak be used for this purpose (95% CP). My analysis shows that there are 18 hours within 95% of the jurisdictional peak. These hours represent primarily a mix of January (10 hours) and August (7 hours) and one November hour. Given the shape of monthly peaks depicted above, I believe this represents an appropriate mix of winter and summer hours. Also, the use of 18 hours provides a greater diversity of hours to appropriately capture the class contributions to typical peak situations. Also, the mix of summer and winter hours reflects a balance between local reliability requirements and the diversity within PacifiCorp's overall system. The impact of ICNU's demand-related changes alone is shown in Exhibit ICNU/106.

<u>Distribution Circuit Commitment Costs</u>

Q. HOW HAS PACIFICORP DETERMINED THE MARGINAL COST OF DISTRIBUTION CIRCUITS?

A. PacifiCorp uses a hypothetical distribution circuit configuration to assign and derive marginal distribution feeder costs for the major customer classes. Customers are assigned along the hypothetical distribution circuit on seven different branches (<u>i.e.</u>, hypothetical typical segments of the distribution system radiating from a substation). The total costs of the circuit are derived on the basis of average distribution circuit characteristics and construction costs in Oregon. As part of this process, PacifiCorp classifies costs between commitment and demand components for five of the seven segments. The commitment portion is derived based upon the smallest conductor and pole used to simply provide each customer with access to the electricity but irrespective of the customer's actual load requirements with all remaining costs classified as demand-related.

Proper distribution cost allocation should include a customer-related component. This is because in any distribution element, there are economies of scale such that, as the size of the customer increases, the per-unit cost of serving that customer decreases. This fundamental cost structure cannot be captured with the use of a single metric such as kilowatts of demand.

Q. WHERE IS YOUR SPECIFIC DISAGREEMENT WITH PACIFICORP'S DISTRIBUTION CIRCUIT COST ASSIGNMENT?

A. I strongly disagree with the critical assumption that there is no customer-related component for the segments 6 & 7 that PacifiCorp classifies as being only demand-related. As the following table shows, the overwhelming majority of customers are connected on these two segments (6 & 7), which are the segments of the distribution circuit closest to the substation. Branches 1-5 are more distant radial segments of the distribution circuit.

PacifiCorp Oregon Distribution Circuit Model

Customer Distribution

	Branches 1 - 5	**Branches 6 & 7**	**Total**	**Customer Component**
Res - Sch 4	47,141	429,199	476,340	9.9%
GS - Sch 23 - 0-15 kW	7,709	58,473	66,182	11.6%
GS - Sch 23 - 15+ kW	1,230	9,327	10,557	11.7%
GS - Sch 23 - Primary	6	42	48	12.6%
GS - Sch 28 - 0-50 kW	300	4,126	4,426	6.8%
GS - Sch 28 - 51-100 kW	238	3,272	3,510	6.8%

GS - Sch 28 - > 101kW	138	1,902	2,040	6.8%
GS - Sch 28 - Primary	3	51	54	5.5%
GS - Sch 30 - 0-300 kW	8	216	224	3.6%
GS - Sch 30 - 301+ kW	22	551	573	3.8%
GS - Sch 30 - Primary	2	52	54	3.7%
Irrigation - Sch 41	2,688	5,624	8,312	32.3%
LPS - Sch 48T - 1 - 4 MW	4	108	112	3.6%
LPS - Sch 48T - 1 - 4 MW	2	63	65	3.1%
Total	**59,491**	**513,006**	**572,496**	**10.4%**

Under PacifiCorp's method, only a very limited number of customers (10%) have distribution circuit commitment costs. The remaining 90% of customers only have distribution circuit demand-related costs. The same method of calculating commitment costs that PacifiCorp has applied to branches 1-5 should be applied to branches 6 and 7. Irrespective of the customers' load or location on these segments, there are economies of scale in attaching different size customers to the distribution system. This should be recognized by applying PacifiCorp's minimal cost method across all seven branches of the distribution feeder model.

ICNU Marginal Cost Study Results

Q. HAVE YOU PREPARED A MARGINAL COST STUDY THAT INCORPORATES ALL OF YOUR RECOMMENDATIONS?

A. Yes. The following table shows the overall difference in the PacifiCorp and ICNU Marginal Cost Study methods based on total functional marginal cost levels. The ICNU study on net contains about $131 million less in total marginal costs. This difference is comprised of a reduction of about $266 million from updating the avoided cost assumptions combined with $105 million increase in costs from ICNU's demand factor recommendations and a $31 million increase from ICNU's distribution commitment cost recommendation.

Marginal Cost Study Comparison (Dollars in 000s)			
Category	**PacifiCorp**	**ICNU**	**Difference**
Generation	$1,041,918	$808,866	($233,051)
Transmission	$305,971	$348,322	$42,352
Distribution	$485,837	$545,724	$59,886
Customer - Billing	$19,571	$19,571	$0
Customer - Metering	$22,202	$22,202	$0
Customer - Other	$6,058	$6,058	$0
Total	**$1,881,557**	**$1,750,743**	**($130,814)**

Exhibit ICNU/108 presents the results of the ICNU Marginal Cost Study by customer class along with the cost based rate changes. A cost-based rate change comparison between the PacifiCorp and ICNU studies was previously presented in this testimony. Again, these changes do not affect the overall size of any rate change, but rather the cost basis for allocating a rate increase to base rates among customer classes. The ICNU Marginal Cost Study should be used as the basis for rate spread of any Commission approved increase among customer classes.

VII. RATE SPREAD AND RATE DESIGN

Q. HOW IS PACIFICORP PLANNING TO SPREAD THE PROPOSED RATE INCREASE?

A. As described in Exhibit PAC/1300, the Company is proposing to spread the rate increase to the base rates of the various customer classes using the unbundled cost results. ICNU supports this concept as being consistent with previous Commission rulings. However, the appropriate study to use as a starting point for rate spread purposes is the ICNU Marginal Cost Study as presented in this testimony and in Exhibit ICNU/108.

Q. DO YOU PROPOSE ANY LIMITATIONS ON THE APPLICATION OF COST-BASED CHANGES TO RATES?

A. Yes, this is appropriate when the application of cost-based increases would otherwise result in unacceptably large increases. ICNU proposes that the overall cost based increase on classes be capped at 1.5 times the average system average increase on a net basis. In addition, ICNU proposes that this cap be calculated taking into account both any increases from this proceeding, as well as any approved increases in the UE 245 TAM docket. Further, ICNU does not recommend that any class receive a rate decrease if an overall rate increase is approved by the Commission. These caps should be implemented using the rate mitigation adjustment.

Q. HOW DO YOU RECOMMEND ANY APPROVED INCREASE BE SPREAD RESULTING FROM THE TWO DOCKETS?

A. To illustrate ICNU's capping proposal, assume that the Commission were to grant a $10 million increase in the present docket and a $5 million increase in the UE 245 TAM proceeding (totaling $15 million). The Company's present base rates are about $1,173 million. Therefore the system average increase would be about 1.3% from the two dockets, resulting in an approximate 1.9% increase cap (1.3% multiplied by 1.5). This combined change should then be used to determine the class percentage caps. ICNU recommends that the cap of 1.5 times the average combined increase be applied to all customer classes. A class-specific mitigation allocation proposal will be presented by ICNU once the overall increases are known with greater certainty.

Q. DOES ICNU HAVE ANY ADDITIONAL RATE DESIGN RECOMMENDATIONS AT THIS TIME?

A. No. ICNU is not proposing any other changes to the Company's basic rate design proposal at this time (aside from comments on the proposed PCAM and Mona-to-Oquirrh treatment already discussed in this testimony). ICNU reserves the right to address other rate design issues later in this proceeding in response to proposals by other parties.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/101

QUALIFICATIONS OF MICHAEL C. DEEN

June 20, 2012

QUALIFICATION STATEMENT OF
MICHAEL C. DEEN
WITNESS FOR INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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

A. My name is Michael Deen. I am employed by Regulatory and Cogeneration Services, Inc. ("RCS"). RCS is a utility rate and consulting firm providing services primarily to large industrial customers. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. in Psychology from Reed College in May, 2006. I have completed coursework in statistics, data analysis, research design, and economics.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. After graduating from Reed, I was employed as a Research Analyst at McCullough Research, a consulting firm in Portland, Oregon specializing in energy policy and litigation support. While at McCullough Research, my duties included the modeling and analysis of both Western and national energy markets. I also provided analysis for use in several proceedings surrounding Enron's role in the Western Energy Crisis of 2000-2001.

From November 2007, through July of 2011, I was employed as a policy analyst at the Public Power Council ("PPC"). PPC is a non-profit trade association representing the interests of consumer-owned utilities buying wholesale power and transmission services from the Bonneville Power Administration ("BPA"). At PPC, I worked extensively on computer modeling relating to the Residential Exchange Program and other BPA rate issues. I also provided analysis and commentary for PPC in a variety of Bonneville processes.

I also was involved in modeling efforts surrounding the potential economic impacts of various greenhouse gas mitigation proposals on Western electricity markets.

Q. PLEASE STATE YOUR EXPERIENCE AS A WITNESS IN PREVIOUS PROCEEDINGS.

A. I have previously testified in the BPA WP-07 Supplemental, WP-10, TR-10, BP-12 and REP-12 rate proceedings. I have also testified on behalf of ICNU in before the Washington Utilities and Transportation Commission in proceedings regarding Puget Sound Energy, PacifiCorp, and Avista. I recently testified before the Oregon Public Utility Commission (the "Commission") in the PacifiCorp UE 245 Transition Adjustment Mechanism docket.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	)	Docket No. UE 246

EXHIBIT ICNU/102

PACIFICORP RESPONSES TO
ICNU UE 246 DR 4.3;
ICNU UE 245 DR 5.1; and
OPUC DR 271

June 20, 2012

ICNU Data Request 4.3

Please quantify the effect on the Company's revenues in the rate year if the Company were to be granted its full proposed OATT changes in FERC Docket No. ER11-3643. Please provide this information for the Company as a whole as well as the Oregon jurisdictional impact.

Response to ICNU Data Request 4.3

The customer impact statement accompanying the Company's transmission rate case filing in FERC Docket No. ER11-3643 shows OATT revenues using the proposed rates applied to historic loads (Attachment E, Exhibit No. PAC-8, available on the Company's OASIS website at: http://www.oasis.pacificorp.com/oasis/ppw/RateCase2011_FERCFiling.html).

According to that impact statement, the Company expects approximately $1.3 million in incremental annual third-party transmission revenues and $1.7 million in incremental annual ancillary service revenues under the proposed rates, exclusive of any short-term or non-firm revenues, on a company-wide basis. Assuming the full requested increase is granted in FERC Docket No. ER11-3643, this increase in revenue credits would amount to approximately $0.77 million ($3 million x 25.77% SG factor) on an Oregon-allocated basis.

ICNU Data Request 5.1

For each transition adjustment mechanism proceeding, please provide:

(a) The Company's initial proposed power cost and rate increase (dollar amount, and overall and industrial percentage);
(b) The power cost and rate increase included in the final update (dollar amount, and overall and industrial percentage);
(c) The final actual power cost and rate increase (dollar amount, and overall and industrial percentage); and
(d) Identify any changes and the power cost amount that were made by the Company between the final update and the actual rate increase.

Response to ICNU Data Request 5.1

The Company objects to this request because the requested information is publicly available. Without waiving this objection, please refer to Attachment ICNU 5.1.

Pacific Power
State of Oregon
UE 245 TAM

	Docket	UE 170 (1)	UE 179 (1) (2)	UE 191	UE 199	UE 207	UE 216	UE 227
	Final Rates Effective	1/1/2006	1/1/2007	1/1/2008	1/1/2009	1/1/2010	1/1/2011	1/1/2012
Initial filing								
Total NPC	$ Millions	$813.9	$863.1	$1,004.1	$1,128.5	$1,100.5	$1,278.2	$1,557.7
Overall Rate Change	($000)	Not	Not	$35,851	$41,161	$20,571	$69,169	$61,645
	Base %	tracked	tracked	4.0%	4.5%	2.2%	7.2%	5.3%
	Net %	separately	separately	3.9%	4.4%	2.1%	7.0%	5.2%
Large General Service Rate Change (Sch 48)	($000)	from GRC	from GRC	$7,755	$8,904	$3,823	$12,230	$13,359
	Base %			5.5%	6.1%	3.0%	9.6%	6.9%
	Net %			5.5%	6.2%	2.9%	9.8%	7.3%
Final November Update (3)								
Total NPC prior to settlement adjustments	$ Millions	$ 796.5	$875.0	$987.8	$1,134.6	$1,092.3	$1,288.7	$1,496.9
Impact of Settlement Adjustments	$ Millions		(42.1)	(7.6)	(91.2)	(63.6)	(44.8)	(32.3)
Total NPC, Final November Update	$ Millions	$796.5	$832.8	$980.2	$1,043.3	$1,028.8	$1,243.9	$1,464.5
Overall Rate Change	($000)	$2,912	$10,000	$22,422	$9,198	$3,743	$60,881	$51,261
	Base %	0.4%	1.2%	2.5%	1.0%	0.4%	6.3%	4.4%
	Net %	0.4%	1.2%	2.5%	0.9%	0.4%	6.1%	4.4%
Large General Service Rate Change (Sch 48)	($000)	$690	$2,163	$4,850	$2,106	$696	$10,749	$10,643
	Base %	0.5%	1.7%	3.5%	1.3%	0.5%	8.4%	5.8%
	Net %	0.5%	1.7%	3.5%	1.3%	0.5%	8.6%	6.1%
Final Rate Change (4)								
Total NPC	$ Millions	$796.5	$832.8	$980.2	$1,043.3	$1,028.8	$1,237.0	$1,463.1
Overall Rate Change	($000)	No Change	No Change	No Change	No Change	No Change	$59,758	$50,959
	Base %	from Final	from Final	from Final	from Final	from Final	6.2%	4.4%
	Net %	Update	Update	Update	Update	Update	6.0%	4.4%
Large General Service Rate Change (Sch 48)	($000)						$10,541	$10,569
	Base %						8.3%	5.7%
	Net %						8.4%	6.1%
Changes made between final update and actual rate increase:								
Total NPC	$ Millions						$ (6.9)	$ (1.4)
Apply provisions of UM1355							$ (2.6)	
Kennecott price change per new contract							$ (4.3)	
Hourly price scalar updates								$ (1.4)

(1) Prior to 2006, net power cost increases were requested as part of a GRC when a GRC was filed. The TAM adjustment made in November reflects the incremental change only

(2) Final Net Variable Power Costs and final TAM increase were capped as part of an approved settlement.

(3) Final November Update total NPC does not include settlement adjustments.

(4) Final November Rate Change total NPC includes settlement adjustments.

OPUC Data Request 271

Regarding Staff's Data Request 161, part "a":

"Regarding Exhibit PAC/1207, Tab 1 "Procedures," PacifiCorp Marginal Cost Study & Circuit Model Procedures," where the Company represented:

'The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations."

a. *Please provide the Company's most recent avoided cost study including a description of each underlying assumption used in the study.*

If there are information sources used as input for preparing the Company's most recent avoided cost calculations, please identify each such specific information source and provide a copy of each such specific source document in portable document format (PDF) files, MS Word file, MS Excel workbook (with cell references and formulae intact) or any other common document format indicating the specific page, section, etc.'"

To which the Company responded:

a. *"The Company's marginal cost of service study used the most recent avoided cost study that had been approved by the Commission and was in effect at the time of filing. For the most recently filed avoided cost study, please refer to Attachment OPUC 161-1, and Attachment OPUC 161-2 for the Company's avoided cost replacement filing dated March 21, 2012."*

Please update the Company's cost of service study using information from the avoided cost study approved by the Commission in Order No. 12-106 entered on March 27, 2012.[1]

Please provide all pages and workpapers associated with this updated cost of service study, in electronic spreadsheet format with all formulae and cell references intact, and identify each source of values used in support of the updated cost of service study.

1st Supplemental Response to OPUC Data Request 271

OPUC staff members and Company personnel met Tuesday, May 15, 2012, to discuss updating the marginal cost of service study. Please refer to Attachment OPUC 271 1st Supplemental for an updated electronic copy of the study.

---

[1] See http://apps.puc.state.or.us/orders/2012ords/12-106.pdf

OPUC Data Request 271

Regarding Staff's Data Request 161, part "a":

"Regarding Exhibit PAC/1207, Tab 1 "Procedures," PacifiCorp Marginal Cost Study & Circuit Model Procedures," where the Company represented:

'The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations."

a. *Please provide the Company's most recent avoided cost study including a description of each underlying assumption used in the study.*

If there are information sources used as input for preparing the Company's most recent avoided cost calculations, please identify each such specific information source and provide a copy of each such specific source document in portable document format (PDF) files, MS Word file, MS Excel workbook (with cell references and formulae intact) or any other common document format indicating the specific page, section, etc.'"

To which the Company responded:

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Please update the Company's cost of service study using information from the avoided cost study approved by the Commission in Order No. 12-106 entered on March 27, 2012.[1]

Please provide all pages and workpapers associated with this updated cost of service study, in electronic spreadsheet format with all formulae and cell references intact, and identify each source of values used in support of the updated cost of service study.

Response to OPUC Data Request 271

OPUC staff members and Company personnel are meeting on Tuesday, May 15, 2012, to discuss updating the marginal cost of service study. Attachment OPUC 271 contains an electronic copy of the updated study.

[1] See http://apps.puc.state.or.us/orders/2012ords/12-106.pdf

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2013 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	34.02	44.11	47.46	34.02	109.29	112.67
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	34.03	44.11	47.46	34.03	104.77	108.14
5	15+ kW	(sec)	34.03	44.11	47.46	34.03	102.94	106.32
6	Primary	(pri)	33.06	42.83	46.12	33.06	95.42	98.45
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	34.03	44.11	47.46	34.03	107.17	110.56
10	51-100 kW	(sec)	34.02	44.11	47.46	34.02	103.87	107.25
11	> 101kW	(sec)	34.02	44.11	47.46	34.02	100.92	104.30
12	Primary	(pri)	33.04	42.88	46.12	33.04	94.81	98.12
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	34.03	44.11	47.46	34.03	95.91	99.30
16	301+ kW	(sec)	34.02	44.11	47.46	34.02	95.07	98.45
17	Primary	(pri)	33.07	42.87	46.12	33.07	94.55	97.82
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	34.02	44.11	47.46	34.02	94.59	97.97
21	1 - 4 MW	(pri)	33.07	42.87	46.12	33.07	88.95	92.23
22	> 4 MW	(sec)	34.03	44.11	47.46	34.03	86.28	89.64
23	> 4 MW	(pri)	33.07	42.87	46.12	33.07	80.76	84.03
24								
25	Trans	(trn)	32.33	41.91	45.09	32.33	67.36	70.56
26								
27								
28	Schedule 41- Irrigation	(sec)	34.03	44.11	47.46	34.03	100.95	104.31

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(C) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2013 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
(D) Column (A)
(E) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(F) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2013 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'

Energy costs include both generation and transmission energy-related costs.

Pacific Power
State of Oregon
UE 245 TAM

		Docket	UE 170 (1)	UE 179 (1) (2)	UE 191	UE 199	UE 207	UE 216	UE 227
		Final Rates Effective	**1/1/2006**	**1/1/2007**	**1/1/2008**	**1/1/2009**	**1/1/2010**	**1/1/2011**	**1/1/2012**
Initial filing									
	Total NPC	$ Millions	$813.9	$863.1	$1,004.1	$1,128.5	$1,100.5	$1,278.2	$1,557.7
	Overall Rate Change	($000)	Not	Not	$35,851	$41,161	$20,571	$69,169	$61,645
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		Net %	separately	separately	3.9%	4.4%	2.1%	7.0%	5.2%
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		Base %			5.5%	6.1%	3.0%	9.6%	6.9%
		Net %			5.5%	6.2%	2.9%	9.8%	7.3%
Final November Update (3)									
	Total NPC prior to settlement adjustments	$ Millions	$ 796.5	$875.0	$987.8	$1,134.6	$1,092.3	$1,288.7	$1,496.9
	Impact of Settlement Adjustments	$ Millions		(42.1)	(7.6)	(91.2)	(63.6)	(44.8)	(32.3)
	Total NPC, Final November Update	$ Millions	$796.5	$832.8	$980.2	$1,043.3	$1,028.8	$1,243.9	$1,464.5
	Overall Rate Change	($000)	$2,912	$10,000	$22,422	$9,198	$3,743	$60,881	$51,261
		Base %	0.4%	1.2%	2.5%	1.0%	0.4%	6.3%	4.4%
		Net %	0.4%	1.2%	2.5%	0.9%	0.4%	6.1%	4.4%
	Large General Service Rate Change (Sch 48)	($000)	$690	$2,163	$4,850	$2,106	$696	$10,749	$10,643
		Base %	0.5%	1.7%	3.5%	1.3%	0.5%	8.4%	5.8%
		Net %	0.5%	1.7%	3.5%	1.3%	0.5%	8.6%	6.1%
Final Rate Change (4)									
	Total NPC	$ Millions	$796.5	$832.8	$980.2	$1,043.3	$1,028.8	$1,237.0	$1,463.1
	Overall Rate Change	($000)	No Change	No Change	No Change	No Change	No Change	$59,758	$50,959
		Base %	from Final	from Final	from Final	from Final	from Final	6.2%	4.4%
		Net %	Update	Update	Update	Update	Update	6.0%	4.4%
	Large General Service Rate Change (Sch 48)	($000)						$10,541	$10,569
		Base %						8.3%	5.7%
		Net %						8.4%	6.1%
Changes made between final update and actual rate increase:									
	Total NPC	$ Millions						$ (6.9)	$ (1.4)
	Apply provisions of UM1355							$ (2.6)	
	Kennecott price change per new contract							$ (4.3)	
	Hourly price scalar updates								$ (1.4)

(1) Prior to 2006, net power cost increases were requested as part of a GRC when a GRC was filed. The TAM adjustment made in November reflects the incremental change only

(2) Final Net Variable Power Costs and final TAM increase were capped as part of an approved settlement.

(3) Final November Update total NPC does not include settlement adjustments.

(4) Final November Rate Change total NPC includes settlement adjustments.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

CONFIDENTIAL EXHIBIT ICNU/103

PACIFICORP TAM OUTSIDE LEGAL EXPENSES

REDACTED VERSION

June 20, 2012

PacifiCorp TAM Outside Legal Expenses

Order	Object Description	FERC	Expense Category	Cost Element Name	Cumulative $
PPL10205	OR - 2012 TAM (UE 216)	9280000	Legal Fees	[redacted]	[redacted]
PPL10205	OR - 2012 TAM (UE 216)	9280000	Legal Fees	[redacted]	[redacted]
PPL10205	OR - 2012 TAM (UE 216)	9280000	Legal Fees	[redacted]	[redacted]
				Total:	[redacted]

PacifiCorp TAM Outside Legal Expenses (In Test Year) [redacted]

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/104

ICNU PCAM DEADBAND EXAMPLE

June 20, 2012

ICNU PCAM Deadband Example

2013 Rate Base		3,253,958,859
ROE Lower Bound		0.75%
ROE Upper Bound		1.50%
Total Taxes		0.3974
Equity Percentage		52.80%
Deadband Lower Bound	$	21,383,467
Deadband Upper Bound	$	42,766,934

Oregon allocated NPC outside the deadband would then be split on the basis of 75%-25% between customers and the Company, subject to a 100 basis points earnings test on the Company's authorized return on equity.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/105

OPUC DIRECT ACCESS STATUS REPORTS
JANUARY 2007 – JANUARY 2012

June 20, 2012

Status Report

Oregon Electric Industry Restructuring
(January, 2012)

Portfolio Options*	PGE	PP&L
Fixed Renewable	12,560	9,992
Renewable Usage	67,922	24,689
Renewable Future****		
Habitat		4,445
Habitat Rider***	8,862	
Time-of-use	2,485	1,655
Eligible Customers	809,172	554,839**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January 1, 2011.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.
**** Renewable Future was closed to additional enrollments as of June 1, 2007. This program ended December 2011 and customers transitioned to other programs.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 3
Registered Electricity Service Aggregators: 4

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	86.1%	5.2%	8.7%
PP&L	99.2%	0.2%	0.6%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
(503) 378-6917

Status Report

Oregon Electric Industry Restructuring
(January, 2011)

Portfolio Options*	PGE	PP&L
Fixed Renewable	12,944	9,586
Renewable Usage	62,402	23,978
Renewable Future	2,405	
Habitat		4,715
Habitat Rider***	9,230	
Time-of-use	2,085	1,699
Eligible Customers	805,210	552,965**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January 1, 2010.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 5
Registered Electricity Service Aggregators: 3

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	86.4%	4.4%	9.2%
PP&L	99.3%	0.0%	0.7%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
(503) 378-6917

Status Report

Oregon Electric Industry Restructuring
(January, 2010)

Portfolio Options*	PGE	PP&L
Fixed Renewable	12,536	9,029
Renewable Usage	57,546	22,163
Renewable Future	2,581	
Habitat		4,760
Habitat Rider***	9,240	
Time-of-use	2,130	1,787
Eligible Customers	800,542	548,164**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January 1, 2009.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 5
Registered Electricity Service Aggregators: 3

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	82.1%	0.9%	17.0%
PP&L	99.3%	0.0%	0.7%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
(503) 378-6917

Status Report

Oregon Electric Industry Restructuring
(January, 2009)

Portfolio Options*	PGE	PP&L
Fixed Renewable	11,885	8,510
Renewable Usage	54,462	21,100
Renewable Future	2,763	
Habitat		4,742
Habitat Rider***	9,341	
Time-of-use	2,047	1,690
Eligible Customers	796,149	548,164**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January 1, 2008.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 5
Registered Electricity Service Aggregators: 4

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	77.6%	1.8%	20.6%
PP&L	99.3%	0.0%	0.7%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
(503) 378-6917

Status Report

Oregon Electric Industry Restructuring (January, 2008)

Portfolio Options*	PGE	PP&L
Fixed Renewable	10,476	7,086
Renewable Usage	47,929	19,304
Renewable Future	3,023	
Habitat		4,487
Habitat Rider***	9,180	
Time-of-use	1,936	1,569
Eligible Customers	789,038	545,942**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January, 2007.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 6
Registered Electricity Service Aggregators: 5

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	81.4%	0.3%	18.3%
PP&L	99.3%	0.1%	0.6%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
(503) 378-6917

Status Report

Oregon Electric Industry Restructuring
(January, 2007)

Portfolio Options*	PGE	PP&L
Fixed Renewable	9,610	6,260
Renewable Usage	40,584	15,649
Habitat	8,698	3,718
Time-of-use	1,816	1,557
Eligible Customers	777,925	544,186**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
**As of November 30, 2006.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 6
Registered Electricity Service Aggregators: 5

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	91.9%	0.4%	7.7%
PP&L	99.2%	0.1%	0.7%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
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BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of	)	
PACIFIC POWER & LIGHT (dba PACIFICORP)	)	Docket No. UE 246
2013 Request for a General Rate Revision	)	

EXHIBIT ICNU/106

COMPARISON OF ICNU MARGINAL COST STUDY ADJUSTMENTS

June 20, 2012

Comparison of ICNU Marginal Cost Study Adjustments

($000s)

Schedule	PacifiCorp As Filed	Avoided Costs	Demand Factors	Commitment Costs
4	$26,733	$29,008	$49,110	$31,633
23 Sec	($2,717)	($2,660)	($5,067)	($2,618)
23 Pri	$60	$59	$108	$58
28 Sec	$10,175	$10,984	$4,881	$9,705
28 Pri	$173	$176	$224	$169
30 Sec	$4,622	$4,344	($833)	$3,777
30 Pri	$264	$274	($8)	$236
48 Sec	$3,009	$2,890	$100	$2,633
48 Pri	$5,603	$4,652	($1,266)	$4,297
48 Trn	$1,976	$610	($2,364)	$610
41	($1,955)	($2,254)	$3,326	($2,347)
Lighting	$18	($120)	($248)	($193)
Total	$47,962	$47,962	$47,962	$47,962

Schedule	PacifiCorp As Filed	Avoided Costs	Demand Factors	Commitment Costs
4	4.74%	5.14%	8.70%	5.60%
23 Sec	-2.27%	-2.22%	-4.23%	-2.18%
23 Pri	41.81%	40.90%	74.89%	40.60%
28 Sec	6.36%	6.87%	3.05%	6.07%
28 Pri	12.52%	12.69%	16.16%	12.22%
30 Sec	5.06%	4.75%	-0.91%	4.13%
30 Pri	3.92%	4.07%	-0.12%	3.51%
48 Sec	6.66%	6.39%	0.22%	5.82%
48 Pri	5.19%	4.31%	-1.17%	3.98%
48 Trn	4.12%	1.27%	-4.93%	1.27%
41	-7.84%	-9.04%	13.33%	-9.41%
Lighting	0.69%	-4.48%	-9.23%	-7.17%
Total	4.09%	4.09%	4.09%	4.09%

Note: "Demand Factors" and "Commitment Costs" scenarios are incremental to updated "Avoided Costs" scenario.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/107

HENRY HUB NATURAL GAS FUTURES

June 20, 2012

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CME Group

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Trade Date: 6/12/2012

Globex Futures | Open Outcry Futures

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Month	Charts	**Last**	Change	Prior Settle	Open	High	Low	Volume	Hi / Lo Limit	Updated
Jul 2012		2.215 a	-0.003	2.218	2.262	2.285	2.198	111,231	3.799 0.799	4:21:10 PM CT 6/11/2012
Aug 2012		2.284 a	+0.021	2.263	2.305	2.327	2.245	45,225	3.844 0.844	4:21:10 PM CT 6/11/2012
Sep 2012		2.303 a	-0.004	2.307	2.347	2.366	2.292	60,173	3.886 0.886	4:21:10 PM CT 6/11/2012
Oct 2012		2.440 a	+0.027	2.413	2.465	2.469	2.397	41,822	3.993 0.993	4:21:10 PM CT 6/11/2012
Nov 2012		2.723 a	-0.006	2.729	2.771	2.771	2.715	19,803	4.293 1.293	4:21:10 PM CT 6/11/2012
Dec 2012		3.100 a	+0.044	3.056	3.101	3.102	3.045	16,264	4.616 1.616	4:21:10 PM CT 6/11/2012
Jan 2013		3.198 a	-0.006	3.204	3.240	3.247	3.193	14,637	4.764 1.764	4:21:10 PM CT 6/11/2012
Feb 2013		3.216	-0.007	3.223	3.242	3.267	3.216	1,623	4.784 1.784	4:21:10 PM CT 6/11/2012
Mar 2013		3.198 a	-0.005	3.203	3.213	3.246	3.194 a	4,181	4.763 1.763	4:21:10 PM CT 6/11/2012
Apr 2013		3.189 a	-0.003	3.192	3.215	3.233	3.186	4,007	4.750 1.750	4:21:10 PM CT 6/11/2012
May 2013		3.232 a	-0.004	3.236	3.260	3.266	3.231 a	830	4.793 1.793	4:21:10 PM CT 6/11/2012
Jun 2013		3.279 b	-0.003	3.282	3.305	3.312	3.275	881	4.839 1.839	4:21:10 PM CT 6/11/2012
Jul 2013		3.330 b	-0.002	3.332	3.355	3.361	3.330	520	4.887 1.887	4:21:10 PM CT 6/11/2012
Aug 2013		3.348 a	-0.003	3.351	3.376	3.376	3.345 a	312	4.905 1.905	4:21:10 PM CT 6/11/2012
Sep 2013		3.351 b	-0.003	3.354	3.377	3.377	3.351	413	4.908 1.908	4:21:10 PM CT 6/11/2012
Oct 2013		3.393 a	-0.001	3.394	3.426	3.429	3.385	2,109	4.948 1.948	4:21:10 PM CT 6/11/2012
Nov 2013		3.529 a	-0.002	3.531	3.533	3.552	3.526	827	5.079 2.079	4:21:10 PM CT 6/11/2012
Dec 2013		3.752 b	-0.002	3.754	3.772	3.772	3.749	336	5.298 2.298	4:21:10 PM CT 6/11/2012
Jan 2014		3.863	-0.005	3.868	3.876	3.888 b	3.863	1,266	5.410 2.410	4:21:10 PM CT 6/11/2012
Feb 2014		3.847 b	-0.003	3.850	3.870	3.870	3.846 a	10	5.392 2.392	4:21:10 PM CT 6/11/2012
Mar 2014		3.781	+0.001	3.780	3.805	3.805	3.781	20	5.322 2.322	4:21:10 PM CT 6/11/2012
Apr 2014		3.612 a	-0.002	3.614	3.642	3.642	3.612 a	22	5.156 2.156	4:21:10 PM CT 6/11/2012
May 2014		3.650	+0.021	3.629	3.650	3.650	3.650	4	5.169 2.169	4:21:10 PM CT 6/11/2012
Jun 2014		3.680	+0.020	3.660	3.680	3.680	3.680	1	5.200 2.200	4:21:10 PM CT 6/11/2012
Jul 2014		3.713	+0.010	3.703	3.713	3.713	3.713	0	5.243 2.243	4:21:10 PM CT 6/11/2012
Aug 2014		-	-	3.725	-	-	-	0	5.265 2.265	4:21:10 PM CT 6/11/2012
Sep 2014		3.745	+0.017	3.728	3.745	3.745	3.745	0	5.268 2.268	4:21:10 PM CT 6/11/2012
Oct 2014		3.774	+0.010	3.764	3.774	3.774	3.774	0	5.304 2.304	4:21:10 PM CT 6/11/2012
Nov 2014		3.862	+0.006	3.856	3.862	3.862	3.862	3	5.395	4:21:10 PM CT

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									2.395	6/11/2012
Dec 2014		4.055	+0.007	4.048	4.055	4.055	4.055	0	5.587 2.587	4:21:10 PM CT 6/11/2012
Jan 2015		4.150	+0.005	4.145	4.150	4.150	4.150	0	5.682 2.682	4:21:11 PM CT 6/11/2012
Feb 2015		4.130	+0.015	4.115	4.130	4.130	4.130	0	5.652 2.652	4:21:11 PM CT 6/11/2012
Mar 2015		4.045	+0.005	4.040	4.045	4.045	4.045	0	5.577 2.577	4:21:11 PM CT 6/11/2012
Apr 2015		3.846	+0.006	3.840	3.846	3.846	3.846	0	5.377 2.377	4:21:11 PM CT 6/11/2012
May 2015		3.858	+0.003	3.855	3.858	3.858	3.858	0	5.392 2.392	4:21:11 PM CT 6/11/2012
Jun 2015		3.884	+0.003	3.881	3.884	3.884	3.884	0	5.418 2.418	4:21:11 PM CT 6/11/2012
Jul 2015		3.921	+0.003	3.918	3.921	3.921	3.921	0	5.455 2.455	4:21:11 PM CT 6/11/2012
Aug 2015		3.941	+0.003	3.938	3.941	3.941	3.941	0	5.475 2.475	4:21:11 PM CT 6/11/2012
Sep 2015		3.944	+0.003	3.941	3.944	3.944	3.944	0	5.478 2.478	4:21:11 PM CT 6/11/2012
Oct 2015		3.981	+0.003	3.978	3.981	3.981	3.981	4	5.515 2.515	4:21:11 PM CT 6/11/2012
Nov 2015		4.069	+0.003	4.066	4.069	4.069	4.069	0	5.603 2.603	4:21:11 PM CT 6/11/2012
Dec 2015		4.259	+0.003	4.256	4.255	4.259	4.250	6	5.793 2.793	4:21:11 PM CT 6/11/2012
Jan 2016		4.354	+0.003	4.351	4.354	4.354	4.354	0	5.888 2.888	4:21:11 PM CT 6/11/2012
Feb 2016		-	-	4.323	-	-	-	0	5.860 2.860	4:21:11 PM CT 6/11/2012
Mar 2016		4.245	+0.002	4.243	4.245	4.245	4.245	0	5.780 2.780	4:21:11 PM CT 6/11/2012
Apr 2016		4.043	+0.002	4.041	4.043	4.043	4.043	0	5.578 2.578	4:21:11 PM CT 6/11/2012
May 2016		4.058	+0.002	4.056	4.058	4.058	4.058	0	5.593 2.593	4:21:11 PM CT 6/11/2012
Jun 2016		4.084	+0.002	4.082	4.084	4.084	4.084	0	5.619 2.619	4:21:11 PM CT 6/11/2012
Jul 2016		4.118	+0.001	4.117	4.118	4.118	4.118	2	5.654 2.654	4:21:11 PM CT 6/11/2012
Aug 2016		4.144	+0.007	4.137	4.144	4.144	4.144	3	5.674 2.674	4:21:11 PM CT 6/11/2012
Sep 2016		4.148	+0.007	4.141	4.148	4.148	4.148	4	5.678 2.678	4:21:11 PM CT 6/11/2012
Oct 2016		-	-	4.178	-	-	-	0	5.715 2.715	4:21:11 PM CT 6/11/2012
Nov 2016		-	-	4.268	-	-	-	0	5.805 2.805	4:21:11 PM CT 6/11/2012
Dec 2016		-	-	4.460	-	-	-	0	5.997 2.997	4:21:11 PM CT 6/11/2012
Jan 2017		-	-	4.552	-	-	-	0	6.089 3.089	4:21:11 PM CT 6/11/2012
Feb 2017		-	-	4.524	-	-	-	0	6.061 3.061	4:21:11 PM CT 6/11/2012
Mar 2017		-	-	4.444	-	-	-	0	5.981 2.981	4:21:11 PM CT 6/11/2012
Apr 2017		-	-	4.242	-	-	-	0	5.779 2.779	4:21:11 PM CT 6/11/2012
May 2017		-	-	4.257	-	-	-	0	5.794 2.794	4:21:11 PM CT 6/11/2012
Jun 2017		-	-	4.282	-	-	-	0	5.819 2.819	4:21:11 PM CT 6/11/2012
Jul 2017		-	-	4.317	-	-	-	0	5.854 2.854	4:21:11 PM CT 6/11/2012
Aug 2017		-	-	4.339	-	-	-	0	5.876 2.876	4:21:11 PM CT 6/11/2012
Sep 2017		-	-	4.343	-	-	-	0	5.880 2.880	4:21:11 PM CT 6/11/2012
Oct 2017		-	-	4.379	-	-	-	0	5.916 2.916	4:21:11 PM CT 6/11/2012
Nov 2017		-	-	4.473	-	-	-	0	6.010 3.010	4:21:11 PM CT 6/11/2012
Dec 2017		-	-	4.663	-	-	-	0	6.200 3.200	4:21:11 PM CT 6/11/2012
Jan 2018		-	-	4.759	-	-	-	0	6.296 3.296	4:21:11 PM CT 6/11/2012
Feb 2018		-	-	4.731	-	-	-	0	6.268 3.268	4:21:11 PM CT 6/11/2012

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Mar 2018		-	-	4.653	-	-	-	0	6.190 3.190	4:21:11 PM CT 6/11/2012
Apr 2018		-	-	4.451	-	-	-	0	5.988 2.988	4:21:11 PM CT 6/11/2012
May 2018		-	-	4.461	-	-	-	0	5.998 2.998	4:21:11 PM CT 6/11/2012
Jun 2018		-	-	4.486	-	-	-	0	6.023 3.023	4:21:11 PM CT 6/11/2012
Jul 2018		-	-	4.521	-	-	-	0	6.058 3.058	4:21:11 PM CT 6/11/2012
Aug 2018		-	-	4.546	-	-	-	0	6.083 3.083	4:21:11 PM CT 6/11/2012
Sep 2018		-	-	4.551	-	-	-	0	6.088 3.088	4:21:11 PM CT 6/11/2012
Oct 2018		-	-	4.588	-	-	-	0	6.125 3.125	4:21:11 PM CT 6/11/2012
Nov 2018		-	-	4.683	-	-	-	0	6.220 3.220	4:21:11 PM CT 6/11/2012
Dec 2018		-	-	4.878	-	-	-	0	6.415 3.415	4:21:11 PM CT 6/11/2012
Jan 2019		-	-	4.978	-	-	-	0	6.515 3.515	4:21:11 PM CT 6/11/2012
Feb 2019		-	-	4.950	-	-	-	0	6.487 3.487	4:21:11 PM CT 6/11/2012
Mar 2019		-	-	4.872	-	-	-	0	6.409 3.409	4:21:11 PM CT 6/11/2012
Apr 2019		-	-	4.662	-	-	-	0	6.199 3.199	4:21:11 PM CT 6/11/2012
May 2019		-	-	4.672	-	-	-	0	6.209 3.209	4:21:11 PM CT 6/11/2012
Jun 2019		-	-	4.697	-	-	-	0	6.234 3.234	4:21:11 PM CT 6/11/2012
Jul 2019		-	-	4.732	-	-	-	0	6.269 3.269	4:21:11 PM CT 6/11/2012
Aug 2019		-	-	4.757	-	-	-	0	6.294 3.294	4:21:11 PM CT 6/11/2012
Sep 2019		-	-	4.767	-	-	-	0	6.304 3.304	4:21:11 PM CT 6/11/2012
Oct 2019		-	-	4.812	-	-	-	0	6.349 3.349	4:21:11 PM CT 6/11/2012
Nov 2019		-	-	4.912	-	-	-	0	6.449 3.449	4:21:11 PM CT 6/11/2012
Dec 2019		-	-	5.110	-	-	-	0	6.647 3.647	4:21:11 PM CT 6/11/2012
Jan 2020		-	-	5.215	-	-	-	0	6.752 3.752	4:21:11 PM CT 6/11/2012
Feb 2020		-	-	5.188	-	-	-	0	6.725 3.725	4:21:11 PM CT 6/11/2012
Mar 2020		-	-	5.110	-	-	-	0	6.647 3.647	4:21:11 PM CT 6/11/2012
Apr 2020		-	-	4.880	-	-	-	0	6.417 3.417	4:21:11 PM CT 6/11/2012
May 2020		-	-	4.890	-	-	-	0	6.427 3.427	4:21:11 PM CT 6/11/2012
Jun 2020		-	-	4.915	-	-	-	0	6.452 3.452	4:21:11 PM CT 6/11/2012
Jul 2020		-	-	4.950	-	-	-	0	6.487 3.487	4:21:11 PM CT 6/11/2012
Aug 2020		-	-	4.977	-	-	-	0	6.514 3.514	4:21:11 PM CT 6/11/2012
Sep 2020		-	-	4.987	-	-	-	0	6.524 3.524	4:21:11 PM CT 6/11/2012
Oct 2020		-	-	5.035	-	-	-	0	6.572 3.572	4:21:11 PM CT 6/11/2012
Nov 2020		-	-	5.145	-	-	-	0	6.682 3.682	4:21:11 PM CT 6/11/2012
Dec 2020		-	-	5.350	-	-	-	0	6.887 3.887	4:21:11 PM CT 6/11/2012
Jan 2021		-	-	-	-	-	-	0	-	-
Feb 2021		-	-	-	-	-	-	0	-	-
Mar 2021		-	-	-	-	-	-	0	-	-
Apr 2021		-	-	-	-	-	-	0	-	-
May 2021		-	-	-	-	-	-	0	-	-
Jun 2021										

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[illegible]		-	-	-	-	-	-	0	-	-
Jul 2021		-	-	-	-	-	-	0	-	-
Aug 2021		-	-	-	-	-	-	0	-	-
Sep 2021		-	-	-	-	-	-	0	-	-
Oct 2021		-	-	-	-	-	-	0	-	-
Nov 2021		-	-	-	-	-	-	0	-	-
Dec 2021		-	-	-	-	-	-	0	-	-
Jan 2022		-	-	-	-	-	-	0	-	-
Feb 2022		-	-	-	-	-	-	0	-	-
Mar 2022		-	-	-	-	-	-	0	-	-
Apr 2022		-	-	-	-	-	-	0	-	-
May 2022		-	-	-	-	-	-	0	-	-
Jun 2022		-	-	2.429	-	-	-	0	No Limit	4:15:00 PM CT 6/1/2012

Icon Key: Options Price Chart

Market data explanation/disclaimer

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BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/108

ICNU MARGINAL COST STUDY RESULTS

June 20, 2012

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2013 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	33.25	43.11	46.37	33.25	122.84	126.15
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	33.25	43.11	46.37	33.25	110.47	113.78
5	15+ kW	(sec)	33.25	43.10	46.37	33.25	105.43	108.74
6	Primary	(pri)	32.31	42.07	45.07	32.31	180.32	183.79
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	33.25	43.11	46.37	33.25	107.23	110.54
10	51-100 kW	(sec)	33.25	43.11	46.37	33.25	105.72	109.02
11	> 101kW	(sec)	33.25	43.11	46.37	33.25	103.15	106.46
12	Primary	(pri)	32.30	41.87	45.07	32.30	109.66	112.83
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	33.25	43.10	46.37	33.25	95.72	99.02
16	301+ kW	(sec)	33.25	43.11	46.37	33.25	93.99	97.29
17	Primary	(pri)	32.32	41.89	45.07	32.32	95.18	98.40
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	33.25	43.10	46.37	33.25	93.31	96.61
21	1 - 4 MW	(pri)	32.32	41.89	45.07	32.32	87.69	90.89
22	> 4 MW	(sec)	33.25	43.11	46.37	33.25	87.52	90.79
23	> 4 MW	(pri)	32.32	41.89	45.07	32.32	80.59	83.79
24								
25	Trans	(trn)	31.60	40.96	44.06	31.60	65.57	68.70
26								
27								
28	Schedule 41- Irrigation	(sec)	33.26	43.11	46.37	33.26	171.05	174.34

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(C) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2013 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
(D) Column (A)
(E) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(F) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2013 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2013 Dollars

			(A)	(B)
			1 Year	10 & 20 Year
Line	Description		1&3 Phase	1&3 Phase
1	Res - Schedule 4	(sec)	$15.61	$41.55
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	17.83	51.52
5	15+ kW	(sec)	30.70	71.18
6	Primary	(pri)	143.23	161.59
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	34.20	112.24
10	51-100 kW	(sec)	35.28	121.65
11	> 101kW	(sec)	72.72	164.55
12	Primary	(pri)	146.56	158.59
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	85.31	191.61
16	301+ kW	(sec)	127.01	233.28
17	Primary	(pri)	159.18	166.84
18				
19	Total			
20	1 - 4 MW	(sec)	400.97	508.17
21	1 - 4 MW	(pri)	221.88	227.36
22	> 4 MW	(sec)	400.97	502.69
23	> 4 MW	(pri)	221.88	221.88
24	Trans	(trn)	4,401.97	4,401.97
25				
26				
27	Schedule 41- Irrigation	(sec)	11.14	129.92
28	Schedule 41- Irrigation	(sec)	11.14	129.92

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead and maintenance, service drops, service drop overhead and maintenance, customer accounting and informational expenses, and billing expenses.

Sources:
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2013 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrigation Sch 41
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Billing Units																		
	Demand																		
1	Peak MW @ Meter	System	1,156	103	83	0	73	111	150	3	30	147	14	81	69	7	146	85	24
2		Distribution	1,374	127	97	1	97	140	176	7	39	186	17	112	91	14	191	0	117
3		Transformer	3,144	179	129	2	160	190	248	13	49	244	21	143	119	15	241	157	121
4																			
5	Demand Loss Factor		1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.1106	1.0792	1.1106	1.1106	1.0792	1.1106	1.0792	1.1106	1.0792	1.0426	1.1106
6																			
7	Peak MW @ Generator	System	1,284	114	92	0	81	123	166	3	33	164	16	90	74	8	158	89	27
8		Distribution	1,526	141	107	1	108	155	195	8	43	206	19	124	98	15	207	N/A	130
9		Transformer	3,492	199	144	N/A	177	210	276	N/A	54	271	N/A	158	N/A	17	N/A	N/A	135
10																			
11	Energy																		
12	Energy - Annual MWh	@ Meter	5,400,866	589,821	502,774	1,331	426,951	647,714	893,140	18,795	200,164	1,014,139	89,386	565,086	496,681	52,957	1,093,266	795,520	210,342
13	Energy Loss Factor		1.1001	1.1001	1.1001	1.0690	1.1001	1.1001	1.1001	1.0690	1.1001	1.1001	1.0690	1.1001	1.0690	1.1001	1.0690	1.0453	1.1001
14	Energy - Annual MWh	@ Generator	5,941,277	648,838	553,082	1,423	469,671	712,525	982,508	20,093	220,193	1,115,613	95,557	621,629	530,972	58,256	1,168,746	831,533	231,389
15																			
16	Customer																		
17	Annual Customers		479,457	64,929	10,357	48	4,332	3,436	1,997	52	215	549	51	107	63	2	30	6	8,090
18	Average Customers																		3,154
19																			
20	Unit Costs																		
21																			
22	Generation	$ / System Peak kW	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16	$99.16
23	Transmission	$ / System Peak kW	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92	$121.92
24	Poles, Cond., Subst.	$ / Dist. kW	$89.61	$98.53	$98.53	$98.53	$82.30	$82.30	$82.30	$82.30	$71.03	$71.03	$71.03	$65.28	$65.28	$36.15	$36.39	$0.00	$158.27
25	Transformers	$ / Xfmr kW	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$0.00	$2.93	$0.00	$2.93	$0.00	$0.00	$2.93
26																			
27	Energy - @ Generator																		
28	Generation	$ / kWh	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928	$0.03928
29	Transmission	$ / kWh	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287
30																			
31	Poles	$ / Cust / Year	$120.07	$147.74	$147.74	$147.74	$96.82	$96.82	$96.82	$96.82	$61.61	$61.61	$61.61	$44.05	$44.05	$0.00	$0.00	$0.00	$336.11
32	Conductor	$ / Cust / Year	$58.98	$72.58	$72.58	$72.58	$47.57	$47.57	$47.57	$47.57	$30.27	$30.27	$30.27	$21.63	$21.63	$0.00	$0.00	$0.00	$165.12
33	Transformers	$ / Cust / Year	$132.30	$183.96	$265.37	$0.00	$792.15	$892.07	$957.54	$0.00	$1,183.68	$1,183.48	$0.00	$1,220.71	$0.00	$1,220.71	$0.00	$0.00	$924.08
34	Service Drop	$ / Cust / Year	$98.48	$127.03	$266.93	$0.00	269.46	280.04	541.36	-	539.40	1,039.69	-	$3,509.42	$0.00	$3,509.42	$0.00	$0.00	$0.00
35	Meters	$ / Cust / Year	$18.51	$19.48	$33.97	$1,651.28	33.51	35.90	223.94	1,651.28	225.47	225.50	1,651.28	$290.85	$1,651.28	$290.85	$1,651.28	$51,812	$34.18
36	Meter Reading	$ / Cust / Year	$15.64	$22.21	$22.21	$22.21	38.63	38.63	38.63	38.63	66.31	66.31	66.31	172.81	$172.81	$172.81	$172.81	$172.81	$48.95
37	Billing & Collections	$ / Cust / Year	$34.55	$32.82	$32.82	$32.82	35.58	35.58	35.58	35.58	35.58	35.58	35.58	131.63	$131.63	$131.63	$131.63	$131.63	$32.82
38	Uncollectables	$ / Cust / Year	$9.52	$2.05	$2.05	$2.05	20.59	20.59	20.59	20.59	136.23	136.23	136.23	645.55	$645.55	$645.55	$645.55	$645.55	$5.60
39	Customer Service / Other	$ / Cust / Year	$10.58	$10.43	$10.43	$10.43	12.58	12.58	12.58	12.58	20.75	20.75	20.75	61.34	$61.34	$61.34	$61.34	$61.34	$12.16
40	Total Commitment & Billing	$ / Cust / Year	$498.63	$618.29	$854.10	$1,939.10	$1,346.89	$1,459.78	$1,974.61	$1,903.05	$2,299.30	$2,799.42	$2,002.03	$6,098.00	$2,728.30	$6,032.31	$2,662.61	$52,824	$1,559.02

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) `Customer Loads12 Months Ended December 2013'
Lines 5 & 13 Tab 16.1 (Losses:) `Energy Loss Factors'
Lines 12 & 17 Tab 17.2 (Cust Data 2:) `Customers and MWh's12 Months Ended December 2013 - Normalized'
Line 22 Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 23 Tab 5.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'
Line 24 Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'
Line 28 Tab 4.1 (Energy:) `Marginal Generation Energy Costs'
Line 29 Tab 2.6 (Table 6:) `Marginal Cost of Transmission Investment and Associated Expenses'
Lines 31 - 39 Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

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Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2013 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	Sch 41	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation	$250,033	$127,328	$11,351	$9,132	$23	$8,078	$12,187	$16,501	$294	$3,276	$16,242	$1,542	$8,887	$7,333	$789	$15,618	$8,791	$2,661	
2	Transmission	$307,423	$156,553	$13,956	$11,228	$29	$9,932	$14,985	$20,289	$362	$4,028	$19,970	$1,895	$10,927	$9,016	$971	$19,202	$10,808	$3,272	
3	Distribution																			
4	Poles	$68,959	$37,399	$4,096	$3,124	$39	$2,235	$3,224	$4,051	$156	$647	$3,078	$280	$1,485	$1,175	$11	$174	$0	$7,784	
5	Conductor	$88,326	$47,597	$4,996	$3,810	$48	$2,976	$4,293	$5,393	$207	$959	$4,567	$415	$2,411	$1,905	$23	$335	$0	$8,392	
6	Substations	$104,625	$51,782	$4,775	$3,641	$45	$3,656	$5,272	$6,624	$255	$1,468	$6,990	$635	$4,216	$3,332	$511	$7,011	$0	$4,413	
7	Subtotal: Pole, Cond, Subs	$261,910	$136,777	$13,867	$10,576	$133	$8,867	$12,789	$16,068	$618	$3,075	$14,635	$1,330	$8,112	$6,411	$544	$7,520	$0	$20,589	
8	Transformers	$15,020	$10,216	$584	$421	$0	$519	$616	$806	$0	$159	$793	$0	$464	$0	$48	$0	$0	$394	
9	Distribution subtotal	$276,930	$146,993	$14,451	$10,996	$133	$9,386	$13,405	$16,874	$618	$3,234	$15,428	$1,330	$8,576	$6,411	$592	$7,520	$0	$20,983	
10																				
11	Total Demand Related	$834,386	$430,874	$39,758	$31,356	$185	$27,396	$40,577	$53,664	$1,274	$10,538	$51,640	$4,767	$28,390	$22,760	$2,352	$42,340	$19,599	$26,916	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$558,833	$233,373	$25,486	$21,725	$56	$18,449	$27,988	$38,593	$789	$8,649	$43,821	$3,753	$24,418	$20,857	$2,288	$45,908	$32,663	$9,089	$928
16	Transmission Energy Related	$40,899	$17,080	$1,865	$1,590	$4	$1,350	$2,048	$2,824	$58	$633	$3,207	$275	$1,787	$1,526	$167	$3,360	$2,390	$665	$68
17	Total Energy	$599,733	$250,453	$27,352	$23,315	$60	$19,799	$30,036	$41,417	$847	$9,282	$47,028	$4,028	$26,205	$22,383	$2,456	$49,268	$35,053	$9,754	$996
18																				
19	Customer Related Marginal Cost																			
20	Poles	$75,524	$57,567	$9,592	$1,530	$7	$419	$332	$193	$6	$13	$34	$3	$4	$3	$0	$0	$0	$2,719	$3,103
21	Conductor	$35,636	$28,278	$4,712	$751	$3	$207	$163	$96	$3	$7	$17	$1	$3	$1	$0	$0	$0	$1,336	$58
22	Transformers	$95,126	$63,435	$11,945	$2,748	$0	$3,432	$3,065	$1,912	$0	$255	$650	$0	$131	$0	$3	$0	$0	$7,476	$75
23	Service Drops	$62,508	$47,215	$8,248	$2,764	$0	$1,167	$962	$1,082	$0	$115	$571	$0	$376	$0	$7	$0	$0	$0	
24	Meters	$12,405	$8,876	$1,265	$352	$79	$145	$123	$447	$86	$48	$124	$84	$31	$104	$1	$50	$311	$276	$2
25	Meter Reading	$9,797	$7,498	$1,442	$230	$1	$167	$133	$77	$2	$14	$36	$3	$18	$11	$0	$5	$1	$154	$2
26	Billing & Collections	$19,571	$16,564	$2,131	$340	$2	$154	$122	$71	$2	$8	$20	$2	$14	$8	$0	$4	$1	$103	$25
27	Uncollectables	$5,185	$4,566	$133	$21	$0	$89	$71	$41	$1	$29	$75	$7	$69	$41	$1	$19	$4	$18	$0
28	Customer Service / Other	$6,058	$5,073	$677	$108	$1	$55	$43	$25	$1	$4	$11	$1	$7	$4	$0	$2	$0	$38	$7
29	Total Commitment & Billing Rel.	$321,810	$239,072	$40,145	$8,845	$92	$5,836	$5,015	$3,943	$100	$494	$1,537	$102	$653	$172	$12	$80	$317	$12,122	$3,273
30																				
31	Total Revenue @ Full MC																			
32	Generation	$808,866	$360,701	$36,837	$30,857	$79	$26,527	$40,175	$55,094	$1,083	$11,925	$60,063	$5,295	$33,305	$28,190	$3,077	$61,526	$41,454	$11,750	$928
33	Transmission	$348,322	$173,633	$15,821	$12,818	$33	$11,282	$17,033	$23,113	$420	$4,661	$23,177	$2,170	$12,714	$10,542	$1,138	$22,562	$13,198	$3,937	$68
34	Distribution	$545,724	$343,488	$48,947	$18,790	$142	$14,612	$17,927	$20,155	$626	$3,623	$16,700	$1,334	$9,090	$6,416	$602	$7,520	$0	$32,514	$3,236
35	Customer - Billing	$19,571	$16,564	$2,131	$340	$2	$154	$122	$71	$2	$8	$20	$2	$14	$8	$0	$4	$1	$103	$25
36	Customer - Metering	$22,202	$16,375	$2,707	$582	$80	$313	$256	$524	$88	$63	$160	$88	$50	$115	$1	$55	$312	$431	$4
37	Customer - Other	$6,058	$5,073	$677	$108	$1	$55	$43	$25	$1	$4	$11	$1	$7	$4	$0	$2	$0	$38	$7
38	Revenue (less Uncollectables)	$1,750,743	$915,834	$107,121	$63,495	$337	$52,942	$75,557	$98,983	$2,219	$20,284	$100,131	$8,890	$55,178	$45,275	$4,819	$91,669	$54,965	$48,774	$4,269
39																				
40	Customer - Uncollectables	$5,185	$4,566	$133	$21	$0	$89	$71	$41	$1	$29	$75	$7	$69	$41	$1	$19	$4	$18	$0
41	Total Revenue	$1,755,928	$920,400	$107,254	$63,516	$337	$53,031	$75,628	$99,024	$2,221	$20,313	$100,206	$8,897	$55,247	$45,315	$4,820	$91,688	$54,969	$48,792	$4,269

Source: Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 7) x (Table 3, Row 22)/1000
Line 2 Transmission (Table 3, Row 7) x (Table 3, Row 23)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 8) x (Table 7, Row 1 - 3) x (1 + .4066) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 9) x (Table 7, Row 7) x (1 + .4066) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 14) x (Table 3, Row 28 - 29)
Lines 20-29 Commitment Related (Table 3, Row 17) x (Table 7, Row 13 - 27) including O&M Adders

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Table 5

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs
In Nominal Dollars

Year			(A) Resource Cost (Mills / kWh) (B) + (C)	(B) Energy Only (Mills / kWh)	(C) Capacity Only (Mills / kWh)	(D) Capacity Only ($ / kW)
2013			52.49	30.23	22.26	$98.47
2014			55.81	33.13	22.68	$100.34
2015			58.06	34.93	23.13	$102.34
2016			60.43	36.86	23.57	$104.29
2017			63.16	39.14	24.02	$106.28
2018			66.60	42.12	24.48	$108.30
2019			69.87	44.95	24.92	$110.25
2020			69.44	44.10	25.34	$112.12
2021			72.25	46.45	25.80	$114.14
2022			76.67	50.41	26.26	$116.19
2023			79.15	52.41	26.74	$118.28
2024			78.86	51.64	27.22	$120.41
2025			80.94	53.23	27.71	$122.58
2026			83.85	55.65	28.20	$124.77
2027			86.55	57.81	28.74	$127.15
2028			88.76	59.47	29.29	$129.57
2029			90.70	60.86	29.84	$132.02
2030			91.96	61.55	30.41	$134.54
2031			93.48	62.46	31.02	$137.24
2032			95.26	63.65	31.61	$139.84
2013	**1 year -**					
|	Sum of PV Costs	@ 7.92%	52.49	30.23	22.26	$98.47
2013 - 2017	**5 year -**					
|	Sum of PV Costs	@ 7.92%	248.70	149.10	99.60	$440.64
|	Annual Cost	@ 22.41%	55.73	33.41	22.32	$98.75
2013 - 2022	**10 years -**					
|	Sum of PV Costs	@ 7.92%	457.01	282.82	174.19	$770.72
|	Annual Cost	@ 12.84%	58.68	36.31	22.37	$98.96
2013 - 2032	**20 years -**					
|	Sum of PV Costs	@ 7.92%	747.74	476.07	271.67	$1,201.96
|	Annual Cost	@ 8.25%	61.69	39.28	22.41	$99.16

Footnotes:
(B) Tab 4.1 (Energy:) `Marginal Generation Energy Costs'
(C) Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 3.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item	$'s	
1	Growth Related Investments - (2013 to 2017 in $000's)	$1,004,694	
2			
3	System Growth MW's from 2013 to 2017	791	MW
4			
5	Marginal Investment (growth invest / kW)	$1,270.11	/ kW
6			
7	Annualized Investment x 8.39%	106.56	/ kW
8	Admin. & General Factor x 1.41%	17.91	
9	Annual O&M Expenses x 1.395%	17.72	/ kW
10	Annualized Marginal Cost	$142.19	/ kW
11			
12	Marginal Cost of Demand-Related Transmission	$121.92	/ kW
13			
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	$20.27	/ kW
15	Marginal Cost of Energy-Related Transmission	$0.00287	/ kWh
16	$20.27 / (8760 x 80.49% LF))		

Sources:
Tab 5.2 (Transm2:) `2013-2017 Forecasted Transmission'
Tab 5.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'

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Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
2013 Dollars

Line	Description		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
	Demand Related Costs ($/kW)																		
1	Poles		17.42	20.69	20.69	20.69	14.75	14.75	14.75	14.75	10.62	10.62	10.62	8.50	8.50	0.54	0.60	NA	42.54
2	Conductors		22.17	25.24	25.24	25.24	$19.64	19.64	19.64	19.64	15.76	15.76	15.76	13.79	13.79	1.04	1.15	NA	45.86
3	Substation		24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	24.12	NA	24.12
4	Dist. O&M @ of Total Investment	40.66%	25.90	28.48	28.48	28.48	23.79	23.79	23.79	23.79	20.53	20.53	20.53	18.87	18.87	10.45	10.52	NA	45.75
5	Total $/ Dist. kW		$89.61	$98.53	$98.53	$98.53	$82.30	$82.30	$82.30	$82.30	$71.03	$71.03	$71.03	$65.28	$65.28	$36.15	$36.39	-	$158.27
6																			
7	Transformers		2.08	2.08	2.08	NA	2.08	2.08	2.08	NA	2.08	2.08	NA	2.08	NA	2.08	NA	NA	2.08
8	Dist. O&M @ of Total Investment	40.66%	0.85	0.85	0.85	NA	0.85	0.85	0.85	NA	0.85	0.85	NA	0.85	NA	0.85	NA	NA	0.85
9	Total $/ Transformer kW		$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$2.93	$0.00	$2.93	$2.93	$0.00	$2.93	$0.00	$2.93	$0.00	$0.00	$2.93
10																			
11																			
12	Commitment Related Costs ($/Customer)																		
13	Poles		85.36	105.03	105.03	105.03	68.83	68.83	68.83	68.83	43.80	43.80	43.80	31.32	31.32	-	-	NA	238.95
14	Conductors		41.93	51.60	51.60	51.60	33.82	33.82	33.82	33.82	21.52	21.52	21.52	15.38	15.38	-	-	NA	117.39
15	Transformers		94.06	130.78	188.66	NA	563.16	634.20	680.75	NA	841.52	841.37	NA	867.84	NA	867.84	NA	NA	656.96
16	Dist. O&M @ of Total Investment	40.66%	90.00	116.86	140.40	63.69	270.72	299.60	318.53	41.74	368.72	368.66	26.56	371.85	18.99	352.87	-	NA	412.01
17	Total Commitment Related		$311.35	$404.27	$485.69	$220.32	$936.53	$1,036.45	$1,101.93	$144.39	$1,275.56	$1,275.35	$91.88	$1,286.39	$65.69	$1,220.71	$0.00	$0.00	$1,425.31
18																			
19	Billing Related Costs ($/Customer/Yr)																		
20	Service Drop		70.01	90.31	189.77	NA	191.57	199.09	384.87	NA	383.48	739.15	NA	$2,494.97	NA	$2,494.97	NA	NA	NA
21	Service Drop O&M @	40.66%	28.47	36.72	77.16	NA	77.89	80.95	156.49	NA	155.92	300.54	NA	1,014.45	NA	1,014.45	NA	NA	NA
22	Meter		11.69	12.30	21.45	$1,042.67	21.16	22.67	141.40	1,042.67	142.37	142.39	1,042.67	$183.65	$1,042.67	$183.65	$1,042.67	$32,716.00	21.58
23	Meter O&M at	58.37%	6.82	7.18	12.52	608.61	12.35	13.23	82.54	608.61	83.10	83.11	608.61	107.20	608.61	107.20	608.61	19,096.33	12.60
24	Meter Reading		15.64	22.21	22.21	22.21	38.63	38.63	38.63	38.63	$66.31	$66.31	$66.31	172.81	172.81	172.81	172.81	172.81	48.95
25	Billing & Collections		34.55	32.82	32.82	32.82	35.58	35.58	35.58	35.58	$35.58	$35.58	$35.58	131.63	131.63	131.63	131.63	131.63	32.82
26	Uncollectables		9.52	2.05	2.05	2.05	20.59	20.59	20.59	20.59	$136.23	$136.23	$136.23	645.55	645.55	645.55	645.55	645.55	5.60
27	Customer Service / Other		10.58	10.43	10.43	10.43	12.58	12.58	12.58	12.58	20.75	20.75	20.75	61.34	61.34	61.34	61.34	61.34	12.16
28	Total Billing Related		$187.28	$214.02	$368.41	$1,718.79	$410.35	$423.32	$872.68	$1,758.66	$1,023.74	$1,524.06	$1,910.15	$4,811.60	$2,662.61	$4,811.60	$2,662.61	$52,823.66	$133.71
29																			
30																			
31	Monthly Billing Related (Line 28 / 12)		$15.61	$17.83	$30.70	$143.23	$34.20	$35.28	$72.72	$146.56	$85.31	$127.01	$159.18	$400.97	$221.88	$400.97	$221.88	$4,401.97	$11.14
32																			
33	Total Distribution (Comm & Billing Costs)		$498.63	$618.29	$854.10	$1,939.11	$1,346.89	$1,459.77	$1,974.61	$1,903.05	$2,299.30	$2,799.42	$2,002.03	$6,097.99	$2,728.30	$6,032.31	$2,662.61	$52,823.66	$1,559.02
34	Line 17 + Line 28																		
35	Monthly Commitment & Bill (Line 33 / 12)		$41.55	$51.52	$71.18	$161.59	$112.24	$121.65	$164.55	$158.59	$191.61	$233.28	$166.84	$508.17	$227.36	$502.69	$221.88	$4,401.97	$129.92

Sources: Lines
Line 1 - 2 Tab 7.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 3 Tab 6.1 (Dist Sub 1:) `Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 40.66%
Tab 9.1 (Dist OM:) `Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 40.66% Factor)
Line 7 Tab 8.2 (XFMR 2:) `Transformer Demand Costs'
Line 13 - 14 Tab 7.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 15 Tab 8.1 (XFMR 1:) `Transformer Commitment Costs'
Line 20 Tab 10.1 (Services 1:) `Weighted Average Installed Service Drop Costs'
Line 22 Tab 11.1 (Meters 1:) `Weighted Average Installed Meter Costs'
Line 23 Tab 11.5 (Meters 5:) `Distribution Meters Expense Loading Factor' (for 58.37% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) `Summary of Customer Accounting Expense By Schedule'

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2013 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential (sec)	(B) General Service Sch 23 (sec)	(C) General Service Sch 23 (pri)	(D) General Service Sch 28 (sec)	(E) General Service Sch 28 (pri)	(F) General Service Sch 30 (sec)	(G) General Service Sch 30 (pri)	(H) Large Power Service Sch 48T (sec)	(I) Large Power Service Sch 48T (pri)	(J) Large Power Service Sch 48T (trn)	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
1	**Total Operating Revenues**	$1,172,659	$564,491	$119,925	$144	$159,882	$1,384	$91,384	$6,735	$45,205	$107,902	$47,976	$24,939.978	$2,690
2	**MWh**	13,020,247	5,400,866	1,092,595	1,331	1,967,805	18,795	1,214,303	89,386	618,043	1,589,947	795,520	210,342	$21,313
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$808,866	$360,701	$67,694	$79	$121,796	$1,083	$71,988	$5,295	$36,382	$89,716	$41,454	$11,750	$928
6	Transmission	$348,322	$173,633	$28,639	$33	$51,429	$420	$27,838	$2,170	$13,853	$33,104	$13,198	$3,937	$68
7	Distribution	$545,726	$343,488	$67,738	$142	$52,694	$626	$20,323	$1,334	$9,692	$13,936	$0	$32,514	$3,238
8	Customer - Billing	$19,571	$16,564	$2,471	$2	$347	$2	$27	$2	$14	$12	$1	$103	$25
9	Customer - Metering	$22,200	$16,375	$3,289	$80	$1,093	$88	$223	$88	$51	$170	$312	$431	$2
10	Customer - Other	$6,058	$5,073	$785	$1	$123	$1	$16	$1	$7	$6	$0	$38	$7
11	Total	$1,750,743	$915,834	$170,616	$337	$227,482	$2,219	$120,416	$8,890	$59,997	$136,943	$54,965	$48,774	$4,269
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	44.59%	8.37%	0.01%	15.06%	0.13%	8.90%	0.65%	4.50%	11.09%	5.12%	1.45%	0.11%
16	Transmission	100.00%	49.85%	8.22%	0.01%	14.76%	0.12%	7.99%	0.62%	3.98%	9.50%	3.79%	1.13%	0.02%
17	Distribution	100.00%	62.94%	12.41%	0.03%	9.66%	0.11%	3.72%	0.24%	1.78%	2.55%	0.00%	5.96%	0.59%
18	Ancillary Service	100.00%	44.59%	8.37%	0.01%	15.06%	0.13%	8.90%	0.65%	4.50%	11.09%	5.12%	1.45%	0.11%
19	Customer - Billing	100.00%	84.64%	12.63%	0.01%	1.78%	0.01%	0.14%	0.01%	0.07%	0.06%	0.00%	0.53%	0.13%
20	Customer - Metering	100.00%	73.76%	14.81%	0.36%	4.92%	0.40%	1.00%	0.39%	0.23%	0.76%	1.40%	1.94%	0.01%
21	Customer - Other	100.00%	83.74%	12.96%	0.01%	2.03%	0.01%	0.26%	0.02%	0.11%	0.09%	0.01%	0.63%	0.12%
22	Embedded DSM - (MWh)	100.00%	41.48%	8.39%	0.01%	15.11%	0.14%	9.33%	0.69%	4.75%	12.21%	6.11%	1.62%	0.16%
23	Regulatory & Franchise	100.00%	48.14%	10.23%	0.01%	13.63%	0.12%	7.79%	0.57%	3.85%	9.20%	4.09%	2.13%	0.23%
24														
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$732,202	$326,514	$61,278	$71	$110,252	$981	$65,165	$4,794	$32,934	$81,213	$37,525	$10,636	$840
28	Transmission	$158,120	$78,820	$13,001	$15	$23,346	$191	$12,637	$985	$6,288	$15,028	$5,991	$1,787	$31
29	Distribution	$233,848	$147,187	$29,026	$61	$22,580	$268	$8,709	$572	$4,153	$5,971	$0	$13,933	$1,388
30	Ancillary Services	$10,581	$4,718	$885	$1	$1,593	$14	$942	$69	$476	$1,174	$542	$154	$12
31	Customer - Billing	$12,200	$10,325	$1,540	$1	$217	$1	$17	$1	$9	$8	$0	$65	$16
32	Customer - Metering	$25,982	$19,164	$3,849	$94	$1,279	$103	$261	$103	$59	$199	$365	$504	$3
33	Customer - Other	$18,671	$15,636	$2,420	$2	$379	$2	$49	$3	$21	$18	$1	$118	$23
34	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$29,019	$13,969	$2,968	$4	$3,956	$34	$2,261	$167	$1,119	$2,670	$1,187	$617	$67
36	Total	$1,220,621	$616,334	$114,968	$249	$163,602	$1,594	$90,041	$6,693	$45,058	$106,279	$45,612	$27,814	$2,378
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	96.07%	91.59%	104.31%	57.88%	97.73%	86.85%	101.49%	100.62%	100.33%	101.53%	105.18%	89.67%	113.12%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$47,962	$51,842	($4,958)	$105	$3,720	$210	($1,343)	($42)	($147)	($1,623)	($2,364)	$2,874	($312)
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	4.09%	9.18%	-4.13%	72.78%	2.33%	15.14%	-1.47%	-0.62%	-0.33%	-1.50%	-4.93%	11.52%	-11.60%
46	(Line 41 / Line 1)													

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of	)	
PACIFIC POWER & LIGHT (dba PACIFICORP)	)	Docket No. UE 246
2013 Request for a General Rate Revision	)	

CONFIDENTIAL EXHIBIT ICNU/109

EXCERPT OF PACIFICORP RESPONSES TO ICNU DRs 6.1 & 6.8

REDACTED VERSION

June 20, 2012

ICNU Data Request 6.1

Please refer to the response to ICNU DR 2.34. For each item with an "Oregon Allocated Amount" above $40,000, please provide: 1) average and actual billing rates; and 2) any court or administrative orders, verdicts or decisions establishing the amount that PacifiCorp is liable, including but not limited to orders that the Company is challenging or appealing.

Response to ICNU Data Request 6.1

Please refer to Confidential Attachment ICNU 6.1-1 for a list of items from ICNU DR 2.34 with an Oregon allocated amount above $40,000.

1) Please refer to column I in Confidential Attachment ICNU 6.1-1.

2) Please refer to column J in Confidential Attachment ICNU 6.1-1 for the requested information and/or references to Attachment ICNU 6.1-2 for the requested documents.

   The cost object "11635 - Tax Management & Planning" in the Company's response to ICNU 2.34 included $57,963.45 of costs allocated to Oregon. The Company inadvertently included $56,878.11 of Oregon allocated costs that should have been booked below the line instead of to account 923. As seen in Confidential Attachment ICNU 2.34, account 923 has been escalated by 5.89%. The Company agrees to remove the escalated amount, approximately $60,228, in its rebuttal filing. The remaining Oregon allocated amount of $1,085.34 is related to tax hedging policy and Idaho property tax appeals.

Information in Confidential Attachment ICNU 6.1-1 is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

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ICNU Data Request 6.8

Please provide all administrative and court orders, decisions or verdicts over the past five years in which PacifiCorp was found liable for more than $50,000. Please identify whether the costs associated with any of those proceedings are included in the test year, and provide the total amount of the costs and the amount of the costs included in the test period, including a breakdown of the costs, in the categories of outside legal fees, internal legal fees, outside consultants, and internal employees.

Response to ICNU Data Request 6.8

In the past five years PacifiCorp was found liable for more than $50,000 in the following proceedings:

- Rough and Ready – Please refer to Attachment ICNU 6.1-2 for a copy of the order. Refer to cost object PPL03181 in Confidential Attachment ICNU 6.1-1 for outside legal fees allocated to Oregon in the test year. Please refer to Confidential Attachment ICNU 6.8-1 for the settlement costs recorded in the test year.
- FERC Non-Public Investigation – Please refer to Attachment ICNU 6.1-2 for copy of order. Refer to cost object PPL10023 in Confidential Attachment ICNU 6.1-1 for outside legal fees allocated to Oregon in the test year. No settlement costs were recorded above the line in the test year.
- USA Power – Please refer to Attachment ICNU 6.5 for a copy of the order. Refer to cost object PCE01998 in Confidential Attachment ICNU 6.1-1 for outside legal fees allocated to Oregon in the test year.
- Migratory Bird Act – Please refer to Confidential Attachment ICNU 6.8-2 for a copy of the order. There were no outside legal fees allocated to Oregon in the test year.

There were not any outside consultants. Internal legal costs and internal employee costs are not tracked by matter for non-regulatory proceedings.

Information in Confidential Attachments ICNU 6.8-1 and 6.8-2 is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

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BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/110

EXCERPT OF NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL

June 20, 2012

ICNU/110
Deen/1

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
Facsimile No. (202) 898-2213

Price: $25.00

The functional subtraction method, in which it is possible to remove all non-demand related costs including the minimum grid, provides the most straightforward calculation. An analyst who employs the engineering method would have to determine individually for each facility which portion of the facility or the investment was incurred to serve customers and what proportion was incurred to serve demand. In both cases, the capacity costs are annualized and adjusted for operation and maintenance costs and for indirect costs. Absent special operation and maintenance studies, it is reasonable to divide O&M costs between customer and demand components on the assumption that they are proportional to the split in the distribution investment. Again, as in the transmission calculation, further adjustments can also be made to account for the losses and the energy component of the distribution cost using the methods outlined above. See Table 10-4.

TABLE 10-4
Demand Related Marginal Cost of Distribution
Minimum Grid vs. Customer Specific Equipment Methodologies
(1988 $)

Description	Minimum Grid $ per KW	Customer Specific Equipment $ per KW
Distribution Investment per KW change in Load (From Tables 10-3A & 10-3B)	159.13	203.54
Annual Cost (*13.08%)	20.82	26.62
Demand Related O&M Expense	5.69	9.17
General Plant Loading	0.80	1.02
Working Capital	0.37	0.47
Total Annual Costs of Distribution/KW	27.67	37.28
Loss Adjustment (1.107%)	30.63	41.27

B. Non-Coincident Peak Demand

To calculate the marginal demand related distribution cost for a particular customer class, the analyst needs to determine, using available load data, the increase in peak demand on the distribution system due to a 1 KW increase in the maximum demand of the class. The peak demand on the distribution system is referred to as the non-coincident peak demand.

Unfortunately, most load research studies have tended to focus on the structure of class demands at the generation and at the customer levels and, therefore, very little is known about the demands on the mid-stream components of the transmission and distribution systems. Consequently, analysts have resorted to various simplifying assumptions in order to determine transmission and distribution system non-coincident peaks. For power systems which depend for the most part on their own resources, it is often assumed that the class composition of the transmission system non-coincident peak demand is identical to the composition of the coincident peak demand at the generation level. This assumption may need to be amended for power systems with important interconnections with other systems.

Unlike the transmission system, however, secondary distribution systems are designed to meet load growth in particular localities. This means, of course, that the non-coincident peak on any portion of the secondary system reflects the combined load of the customers served from it. Because of zoning and land use regulations, load on any particular portion of the secondary system will generally be dominated by either residential or commercial customers. (Industrial customers are more likely to be served directly from the primary distribution system.) This suggests that a close relationship exists between an increase in the maximum demand of the residential or commercial class and the increase in the secondary non-coincident peak (i.e., coincident factor close to unity) for any particular locality. Where customer classes served from the secondary distribution system are mixed this result needs to be amended to take account of the diversity between the classes. As the residential class far out-numbers the commercial class on most systems, the secondary distribution system as a whole will be primarily responsive to residential loads.

Logically, the class demand at the time of peak on the primary distribution system must lie between the previously determined transmission and secondary distribution class demands and it is common to take the statistical average of the two demands.

C. Allocation of Costs to Time Periods

Most analysts assume that the customer related marginal distribution costs do not vary by season or by time of day.

The method adopted to attribute marginal demand related distribution costs depends on the load characteristics of the distribution network. When distribution system components experience maximum demand during the peak costing period identified in the generation analysis, the allocation methods employed for generation (uniform allocation across peak period, probability of excess demand, loss of load probability), and sometimes simply the generation allocation factors themselves, can be used to attribute distribution costs to time periods. As noted above in the discussion on the allocation of transmission costs, if the generation allocators are used it may be necessary to adjust for the effect of the ambient temperature on line capacity and, therefore, on the seasonal allo-

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2013 Request for a General Rate Revision.	)

DIRECT TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 20, 2012

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are provided in Exhibit ICNU/201.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp dba Pacific Power ("PacifiCorp" or the "Company").

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH THIS TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/201 through ICNU/220.

Q. WHAT IS THE SUBJECT OF YOUR DIRECT TESTIMONY?

A. I will recommend a fair return on common equity, and overall rate of return ("ROR") for PacifiCorp.

I. SUMMARY

Q. PLEASE SUMMARIZE YOUR ROR RECOMMENDATIONS.

A. I recommend the Public Utility Commission of Oregon (the "Commission") award PacifiCorp a return on common equity of 9.20%, which is the midpoint of my recommended range of 9.13% to 9.25%, and an overall ROR of 7.29%. Exhibit ICNU/202. The Oregon revenue requirement impact of my recommended 9.20% return on equity ("ROE") is $28.5 million.

I also recommend adjustments to the Company's proposed capital structure. I propose to remove common equity supporting non-utility assets from the capital structure used to develop the overall ROR applied to PacifiCorp's utility cost of service. My capital structure removes the common equity supporting non-utility investments for the period ending December 31, 2012, used to develop the ratemaking capital structure. In addition, I also reflected the new financing activities described in the rebuttal testimony of Mr. Williams in PacifiCorp's current Wyoming rate case filing.[1/] The Oregon revenue requirement impact of my proposed capital structure is a $8.3 million reduction in PacifiCorp's proposed revenue increase, and the combined impact of my overall ROR recommendation is $36.8 million.

My recommended ROE and proposed capital structure will provide PacifiCorp with an opportunity to realize cash flow financial coverages and balance sheet strength that conservatively support PacifiCorp's current bond rating. Consequently, my recommended ROE represents fair compensation for PacifiCorp's investment risk, and it will preserve the Company's financial integrity and credit standing.

I will also respond to PacifiCorp witness Dr. Samuel Hadaway's proposed ROE of 10.2%. For the reasons discussed below, Dr. Hadaway's recommended ROE is excessive and should be rejected.

Q. DOES YOUR RECOMMENDED ROE REFLECT PACIFICORP'S EXISTING INVESTMENT RISK?

A. Yes. My recommended ROE reflects fair compensation for PacifiCorp's existing investment risk including its regulatory mechanism used to recover its cost of service and financial position. These factors are reflected in PacifiCorp's existing bond rating and

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[1/] Re Rocky Mountain Power 2011 General Rate Case, Wyoming Public Service Commission, Docket No. 20000-405-ER-11, Rebuttal Testimony of Bruce N. Williams.

other risk factors used to select a comparable risk proxy group. If the Commission modified PacifiCorp's existing regulatory mechanisms to reduce PacifiCorp's investment risk, then any related risk reduction should be considered in determining a fair risk-adjusted ROE for PacifiCorp.

Q. HOW DID YOU ESTIMATE PACIFICORP'S CURRENT MARKET COST OF EQUITY?

A. I performed analyses using three Discounted Cash Flow ("DCF") models, a Risk Premium ("RP") study, and a Capital Asset Pricing Model ("CAPM"). These analyses used a proxy group of publicly traded companies that have investment risk similar to PacifiCorp. Based on these assessments, I estimate PacifiCorp's current market cost of equity to be 9.20%.

Q. HOW DOES YOUR RECOMMENDED ROE COMPARE TO PACIFICORP'S LAST AUTHORIZED ROE?

A. On December 14, 2010, the Commission issued its final order in PacifiCorp's 2010 general rate case and approved a settlement, which included an ROE of 10.13%. Re PacifiCorp, Docket No. UE 217, Order No. 10-473 at 2.

My recommended ROE is lower in this case than the ROE included in the settlement to PacifiCorp's rate case from December 2010. However, this lower ROE is justified based on clear evidence that capital market costs today are much lower than they were in 2010 when the rate settlement process took place and when the rate settlement was ultimately approved.

Q. DO YOU BELIEVE MARKET COSTS OF CAPITAL ARE LOWER TODAY THAN THEY WERE IN PACIFICORP'S LAST RATE CASE?

A. Yes. Market costs of capital have declined since PacifiCorp's last rate case. This is illustrated by a comparison of bond yields in this case and the last case, and is evident from cost of capital estimates in this case versus the last case. In Table 1, I show the change in utility bond yields.

TABLE 1

Capital Costs – PacifiCorp Rate Cases

Description	**Current Case**[1]	**Docket No. UE 217**	**Yield Change**
"A" Rated Utility Bond Yields	4.43%	5.26%	0.83%
"Baa" Rated Utility Bond Yields	5.04%	5.76%	0.72%
13-Week Period Ending	06/01/2012	12/10/2010	

Source:
[1] Exhibit ICNU/216, Gorman/1.

As shown in the table above, the current market cost of debt for "A" (by Standard & Poor's, "S&P") and "Baa" (by Moody's) rated utility bond yields has decreased in this case relative to PacifiCorp's last rate case. The current "A" rated utility bond yield is 0.83 percentage points lower now than it was in PacifiCorp's last rate case. Also, the current "Baa" utility bond yield is 0.72 percentage points lower than during PacifiCorp's last rate case.

Utility bond yields have declined by approximately 75 to 80 basis points since PacifiCorp's last rate case. This decline in utility bond yields suggests that PacifiCorp's cost of capital is lower now than it was in its 2010 rate case.

Q. IS THERE OTHER EVIDENCE OF THE DECLINE IN MARKET COST OF EQUITY SINCE PACIFICORP'S LAST RATE CASE?

A. Yes. This is evident from PacifiCorp's case itself. In PacifiCorp's last general rate case, Dr. Hadaway proposed an ROE of 10.6% in his direct filing. Re PacifiCorp, Docket No. UE 217, PPL/200, Hadaway/2. In its current rate case, PacifiCorp is proposing an ROE of 10.2%. Re PacifiCorp, Docket No. UE 246, PacifiCorp's Initial Filing at 3 (Mar. 1, 2012). Hence, the Company has acknowledged that the cost of capital has decreased by 40 basis points.

II. RATE OF RETURN

Electric Utility Industry Market Outlook

Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A. I begin my estimate of a fair ROE for PacifiCorp by reviewing the market's assessment of electric utility industry investment risk, credit standing and stock price performance in general. I used this information to get a sense of the market's perception of the risk characteristics of electric utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to PacifiCorp's utility operations.

Based on the assessments described below, I find the credit rating outlook of the industry to be strong and supportive of the industry's financial integrity, and electric utilities' stocks have exhibited strong price performance over the last several years.

Based on this review of credit outlooks and stock price performance, I conclude that the market has again embraced the electric utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities.

Q. PLEASE DESCRIBE THE ELECTRIC UTILITIES' CREDIT RATING OUTLOOK.

A. Electric utilities' credit rating outlook has improved over the recent past and is now stable. S&P recently provided an assessment of the credit rating of U.S. electric utilities. S&P's commentary included the following:

> **Solid Industry Fundamentals Support Stable Outlook**
>
> The U.S. electric utility sector performed well through 2011, and found it easier to access the capital markets than did most other corporate issuers.
>
> Investor appetite for electric utility debt remains healthy, and deals have been oversubscribed. Credit fundamentals indicate that most, if not all, electric utilities should continue to have ample access to funding sources and credit. Some firms may issue common stock to partially fund construction spending, which would help to support the capital structure balance. In addition, many utilities are accessing short-term credit markets through commercial paper programs at very low rates.[2/]

Similarly, Fitch states:

> **Electric Utilities: Stable**
>
> Fitch's Outlook for the electric utility sector in 2012 remains stable. The sector benefits from low interest rates, modest inflationary pressures, open capital markets, and low natural gas and power prices. Fitch expects these conditions to persist into 2013.
>
> The favorable funding environment helps to offset any stress that would otherwise result during an extended period of high projected capital investment. Capex is expected to remain elevated, increasing 5%–6% over 2011 levels.[3/]

Value Line also continues to characterize utility stock investments as a safe haven:

> **Conclusion**
>
> With most of 2011 completed, it seems almost certain that electric utility stocks will have outperformed the broader market averages when the year is over. As of mid-December, the Value Line Utility Average is up slightly, while the Value Line GeometricAverage is down about 14%. Electric utility stocks have long been viewed as a safe haven in volatile markets, due in large part to their generous dividend yields.[4/]

The Edison Electric Institute ("EEI") also opined as follows:

> There was little change during 2011 in the industry's long-term outlook. Many regulated utilities are engaged in capital spending programs that

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2/ *Standard & Poor's RatingsDirect on the Global Credit Portal*: "Industry Economic And Ratings Outlook: Continued Ratings Stability Expected For U.S. Regulated Electric Utilities In 2012," January 25, 2012 at 4-5.

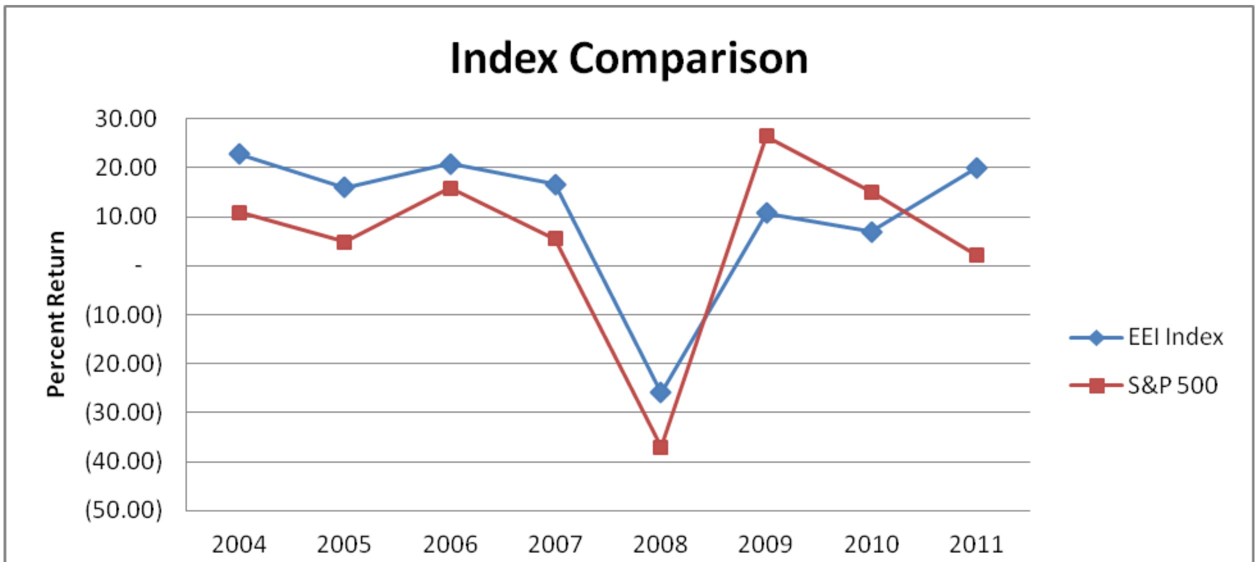
3/ *FitchRatings*: "2012 Outlook: Utilities, Power, and Gas," December 5, 2011 at 10.

4/ *Value Line Investment Survey*, December 23, 2011 at 901.

> should, according to Wall Street analysts, help drive slow but steady earnings growth over the next several years. New EPA regulations may boost capex by 30% in the years ahead, relative to EEI's latest capex survey estimates.[5]

Q. PLEASE DESCRIBE ELECTRIC UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVEN YEARS.

A. As shown in the graph below, the EEI has recorded electric utility stock price performance compared to the market. The EEI data shows that its Electric Utility Index has outperformed the market, with a few exceptions, triggered by the recent state of the economic environment.



Source: EEI Q4 2011 Stock Performance Financial Update, at Page 1.

During 2009 and 2010, the EEI Index underperformed the market, which is not unusual for stocks that are considered "safe havens" during periods of market turbulence.

In 2011, the EEI Index outperformed the market. EEI states the following:

> **Commentary**
>
> The EEI Index produced a positive 20% return during 2011, its strongest annual gain since 2006, outperforming the broad market after two

---

[5] *EEI Q4 2011 Stock Performance* at 1.

> consecutive years of underperformance as stocks rebounded from the lows reached during 2008 financial crisis.
>
> * * *
>
> The strength of the EEI Index in 2011 is no surprise, highlighting the industry's traditional role as a defensive investment following its reemphasis in recent years of core regulated businesses with slow but predictable earnings growth and steady dividends. In fact, the industry's average dividend yield exceeded 4% during the year, leading that of all other U.S. business sectors.[6/]

PacifiCorp Investment Risk

Q. PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF PACIFICORP.

A. The market assessment of PacifiCorp's investment risk is best described by credit rating analysts' reports. PacifiCorp's current senior secured bond ratings from S&P and Moody's are "A" and "A2," respectively.[7/]

Specifically, S&P states the following:

> **Rationale**
>
> The 'A-' corporate credit rating (CCR) on PacifiCorp reflects what Standard & Poor's Ratings Services views as a significant financial profile and is supported by PacifiCorp's modest use of leverage to finance a large capital program and parent MidAmerican Energy Holdings Co.'s (MEHC; BBB+/Stable) willingness to deploy equity into PacifiCorp as needed to support the company's capital structure as it expands its rate base. Since acquiring the company in 2006, MEHC has provided $1.06 billion in equity support for the utility's capital needs.
>
> PacifiCorp's excellent business profile benefits from the geographical, market, and regulatory diversity provided by its six-state service territory. PacifiCorp provides power to retail customers under the name Rocky Mountain Power in Utah, Wyoming, and Idaho, and as Pacific Power in Oregon, Washington, and California. Utah and Oregon are the most

6/ *EEI Q4 2011 Stock Performance* at 1 and 4-5.
7/ PAC/200, Hadaway/2.

> important markets for the company, providing around 42% and 24% of annual retail sales, respectively, as of year-end 2010.[8/]

Similarly, Moody's states:

> **Summary Rating Rationale**
>
> PacifiCorp's ratings are supported by the stability of the utility's regulated cash flows, the geographically diverse and relatively constructive regulatory environments in which it operates, the diversification of its generation portfolio, and solid credit metrics.
>
> * * *
>
> Reasonably supportive regulatory environment
>
> PacifiCorp's rating recognizes the rate-regulated nature of its electric utilities which generate stable and predictable cash flows. PacifiCorp operates in regulatory jurisdictions that Moody's considers as average in terms of framework, consistency and predictability of decisions along with an expectation of timely recovery of costs and investments. This "average" assessment is in line with Moody's views of most U.S. state jurisdictions compared to regulatory environments elsewhere in the world.[9/]

Fitch states:

> **Key Rating Drivers**
>
> **Ratings Affirmed:** On Sept. 29, 2011, Fitch Ratings affirmed PacifiCorp's (PPW) ratings with a Stable Rating Outlook. PPW's ratings and outlook reflect the electric utility's solid credit-protection measures, a diversified service territory, a generally balanced regulatory environment, and relatively predictable operating earnings and cash flow characteristics.
>
> * * *
>
> **Ring-Fence Provisions:** Structural protections insulate PPW in the event of financial stress at intermediate holding company MidAmerican Energy Holdings Co. (MEHC, IDR 'BBB+'/Outlook Stable) without impeding the parent's ability to infuse capital into PPW.
>
> **Regulation Key:** Timely recovery of large capital investment program in rates is crucial to PPW's credit quality in Fitch's view. The ratings

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[8/] *Standard & Poor's RatingsDirect on the Global Credit Portal*: "PacifiCorp," October 3, 2011 at 2 and 3, provided by PacifiCorp in Mr. Williams' Exhibit PAC/302.

[9/] *Moody's Investors Service Credit Opinion*: "PacifiCorp," May 9, 2011.

> assume recovery of capital and operating costs in rates will support credit metrics consistent with the company's 'BBB' IDR and Stable Outlook.
>
> * * *
>
> **Improved Risk Profile:** Since being acquired by MidAmerican Energy Holdings Company (MEHC) in 2006, the utility's business risk has been improved by the adoption of rate mechanisms designed to reduce regulatory lag and facilitate timely recovery of fuel and purchased power costs.[10/]

PacifiCorp's Proposed Capital Structure

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY REQUESTING TO USE TO DEVELOP ITS OVERALL ROR FOR ELECTRIC OPERATIONS IN THIS PROCEEDING?

A. PacifiCorp's December 2012 forecasted capital structure, as supported by PacifiCorp witness Mr. Bruce N. Williams, is shown below in Table 2.

TABLE 2

PacifiCorp's Proposed Capital Structure

Description	Percent of Total Capital
Long-Term Debt	46.9%
Preferred Stock	0.3%
Common Equity	52.8%
Total Capital Structure	100.0%

Source: Exhibit PAC/300, Williams/2.

Q. IS PACIFICORP'S PROPOSED CAPITAL STRUCTURE REASONABLE?

A. No. PacifiCorp's proposed capital structure reflects common equity investments supporting non-utility assets, and Mr. Williams' proposed normalization adjustments increase the common equity ratio from the last quarter of 2011 to year-end 2012.

10/ *FitchRatings Corporates*: "PacifiCorp," November 16, 2011.

However, the increase to the year-end equity ratio is not known and measurable, and likely will be mitigated by a planned debt issuance.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO PACIFICORP'S PROPOSED CAPITAL STRUCTURE?

A. Yes. I propose two adjustments to PacifiCorp's proposed capital structure. First, I propose an adjustment to remove common equity supporting PacifiCorp's investments in non-regulated utility investments. And second, I propose an adjustment to Mr. Williams' normalization adjustments.

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO REMOVE COMMON EQUITY SUPPORTING NON-UTILITY INVESTMENTS.

A. I propose to remove the common equity supporting non-utility investments from PacifiCorp's proposed capital structure. Mr. Williams projected a capital structure described at page 2 of his testimony. At page 13 of his testimony, Mr. Williams described that he developed his proposed capital structure by reflecting known and measurable changes, which represent actual and forecasted activities since December 31, 2011.

I removed common equity supporting non-utility investments recorded on PacifiCorp's FERC Form 1. PacifiCorp outlined this investment in response to ICNU data request 3.8 in Attachment 3.8a. These non-utility investments include net Non-Utility Property and Investments in Subsidiary Companies, and Other Investments. The amount of PacifiCorp's non-utility investments has been relatively stable through 2011 and the first quarter of 2012. Removing the common equity supporting these will leave only the amount of common equity supporting utility plant and equipment in my proposed capital structure.

Q. WHY IS IT REASONABLE TO ASSUME THAT THE NON-REGULATED INVESTMENTS ARE SUPPORTED WITH ONLY COMMON EQUITY CAPITAL?

A. It is not reasonable to assume that utility debt is being used to fund investments in non-utility assets. PacifiCorp has both secured and unsecured utility bond debt issuances recorded on its balance sheet and included in the development of its test year capital structure. It would increase the investment risk on these debt securities if PacifiCorp was not dedicating these debt securities to its low-risk utility operations. If it was issuing utility debt to invest in non-regulated properties, that would likely increase its investment risk exposure and increase its cost of debt. I do not believe PacifiCorp has undertaken this, and I do not believe it would be appropriate for it to do so.

Q. PLEASE DESCRIBE MR. WILLIAMS' CAPITAL STRUCTURE NORMALIZATION ADJUSTMENTS.

A. Mr. Williams reprices several debt securities that will be matured in 2013 with current issues and projects an increase in common equity by additional retained earnings throughout 2012. The effect of Mr. Williams' assumptions is an increase in the common equity ratio from the end of first quarter actual 2012 through year-end 2012. Specifically, as shown on my Exhibit ICNU/202, Gorman/2, PacifiCorp's actual common equity ratio at the end of the first quarter 2012, after all common equity supporting non-regulated investments has been removed, was at 50.5%. However, the Company's projected increase in common equity throughout the end of the calendar year would increase that common equity ratio to 52.8%.

Q. DOES MR. WILLIAMS' NORMALIZATION ADJUSTMENT PRODUCE A REASONABLE RESULT?

A. No. The Company's year-end 2012 capital structure reflects projections of a buildup of retained earnings which is an estimate of net income plus dividends paid out to

PacifiCorp's parent company. The amount of retained earnings and the actual level of dividends paid are factors which are not known with certainty, and therefore are not known and measurable. Further, the combined assumptions employed by Mr. Williams increased the common equity based on these uncertain buildups to retained earnings will be offset shortly after year-end as PacifiCorp goes forward with the planned 2013 bond issue. It is reasonable to believe that this procedure will be repeated over time, and that PacifiCorp's normal capital structure will reflect full compilation of all PacifiCorp's planned 2013 bond issuances, including refinancings at updated interest rates, and additional bond financing to be used with additional buildups of retained earnings to fund growth in rate base. The Company is planning a debt issue in the first quarter of 2013 which Mr. Williams did not reflect with his other 2013 adjustments. When the planned 2013 debt issue is included, PacifiCorp's common equity ratio at year-end is comparable to the actual ratio at the end of the first quarter of 2012.

Q. WHAT IS YOUR PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. My proposed capital structure is shown below in Table 3. My proposed rate base starts with Mr. Williams' normalized adjustments to 2012 rate base, removes the common equity supporting non-utility investments, and includes a $400 million bond issue, offset by a $10 million maturity payment planned for around the beginning of 2013. The combination of all these factors produces a capital structure mix which is reasonably comparable to PacifiCorp's actual capital structure mix in the first quarter of 2012. This capital structure is shown in Table 3 below.

TABLE 3

Proposed Capital Structure

Description	Percent of Total Capital
Long-Term Debt	49.5%
Preferred Stock	0.3%
Common Equity	50.2%
Total Capital Structure	100.0%

Source: Exhibit ICNU/202.

This capital structure reflects all normalization adjustments planned for 2013, Mr. Williams' projected buildup in retained earnings, and elimination of common equity supporting non-utility plant investment. The resulting capital structure is generally consistent with Mr. Williams' statement that PacifiCorp's long-term capital structure mix is generally 50% equity and 50% long-term debt. Therefore, I believe this capital structure is reasonable and consistent with PacifiCorp's actual test year capitalization mix.

Q. WILL YOUR PROPOSED CAPITAL STRUCTURE SUPPORT PACIFICORP'S FINANCIAL INTEGRITY AND CREDIT RATING?

A. Yes. As I will discuss later in my testimony, my proposed capital structure is consistent with PacifiCorp's current credit rating and will support PacifiCorp's financial integrity.

Q. IS CAPITAL STRUCTURE MANAGEMENT AN IMPORTANT OBJECTIVE FOR A UTILITY?

A. Yes. A utility managing its capital structure is important to balance its obligations to minimize its cost of capital, while at the same time support its financial integrity and access to capital. This balance requires a utility to manage its capital structure to maintain a reasonable balance of common equity and debt such that cost of capital is minimized and its credit rating is preserved.

A capital structure too heavily weighted with debt will result in an increase in its financial risk and likely drive up its overall cost of capital. Conversely, a capital structure too heavily weighted with common equity will unnecessarily increase its overall cost of capital, because common equity is the most expensive form of capital. For example, an authorized ROE of 9.0%, adjusted for income tax has a revenue requirement cost of 14.4%.[11/] Conversely, current debt interest rates are around 4.5%, and the interest expense is tax deductible. Therefore, the revenue requirement cost of debt capital is 4.5%. As such, common equity is three times more expensive than debt capital. However, insufficient common equity capital will drive up the utility's financial risk and increase its cost of debt and equity capital.

<u>Return on Equity</u>

Q. PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A. A utility's cost of common equity is the return investors require on an investment in the utility. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: *Bluefield Water Works & Improvement Co. v. Public Serv. Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[11/] $9.0\% \div \frac{(1)}{(1 - \text{Tax Rate})}$ (assuming a 38% composite tax rate)

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q. PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE THE COST OF COMMON EQUITY FOR PACIFICORP.

A. I have used several models based on financial theory to estimate PacifiCorp's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using analyst growth data; (2) a sustainable growth DCF model; (3) a multi-stage growth DCF model; (4) an RP model; and (5) a CAPM. I have applied these models to a group of publicly traded utilities that I have determined share investment risk similar to PacifiCorp's.

Q. HOW DID YOU SELECT A UTILITY PROXY GROUP SIMILAR IN INVESTMENT RISK TO PACIFICORP TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY?

A. I relied on the same utility proxy group used by PacifiCorp witness Dr. Hadaway to estimate PacifiCorp's ROE.

Q. HOW DOES THE PROXY GROUP INVESTMENT RISK COMPARE TO PACIFICORP'S INVESTMENT RISK?

A. The proxy group is shown on Exhibit ICNU/203. This proxy group has an average senior secured credit rating from S&P of "A-," which is a notch lower than S&P's senior secured credit rating for PacifiCorp. The proxy group's senior secured credit rating from Moody's is "A2," which is identical to PacifiCorp's senior secured credit rating from Moody's of "A2." The proxy group has comparable investment risk to PacifiCorp.

The proxy group has an average common equity ratio of 46.3% (including short-term debt) from *AUS Utility Reports* ("AUS") and 48.9% (excluding short-term debt) from *Value Line* in 2011. The proxy group's common equity ratio is slightly lower but comparable to my proposed common equity ratio of 50.2% excluding short-term debt.

I also compared PacifiCorp's business risk to the business risk of the proxy group based on S&P's ranking methodology. PacifiCorp has an S&P business risk profile of "Excellent," which is identical to the S&P business risk profile of the proxy group. The S&P business risk profile score indicates that PacifiCorp's business risk is comparable to that of the proxy group.[12/]

Based on these proxy group selection criteria, I believe that my proxy group reasonably approximates the investment risk of PacifiCorp, and can be used to estimate a fair ROE for PacifiCorp.

<u>Discounted Cash Flow Model</u>

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required ROR or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; . \; . \; . \; . \; \frac{D_\infty}{(1+K)^\infty} \text{ where} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞

12/ S&P ranks the business risk of a utility company as part of its corporate credit rating review. S&P considers total investment risk in assigning bond ratings to issuers, including utility companies. In analyzing total investment risk, S&P considers both the business risk and the financial risk of a corporate entity, including a utility company. S&P's business risk profile score is based on a six-notch credit rating starting with "Vulnerable" (highest risk) to "Excellent" (lowest risk). The business risk of most utility companies falls within the lowest risk category, "Excellent," or the category one notch lower (more risk), "Strong." *Standard & Poor's:* "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A. As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q. WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ended June 1, 2012. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflect current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q. WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A. I used the most recently paid quarterly dividend, as reported in *The Value Line Investment Survey*.[13/] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q. WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[14/] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence observable stock prices than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL Financial, and Reuters. All such projections were available on June 1, 2012, and all were reported online.

13/ *The Value Line Investment Survey*, March 23, May 4, and May 25, 2012.

14/ See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

Each consensus growth rate projection is based on a survey of security analysts. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is more representative of general market expectations. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q. WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. The growth rates I used in my DCF analysis are shown in Exhibit ICNU/204. The average growth rate for my proxy group is 4.99%.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. As shown in Exhibit ICNU/205, the average and median constant growth DCF returns for my proxy group are 9.28% and 9.29%, respectively.

Q. DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A. Yes. The three- to five-year growth rates are in line with the long-term sustainable growth rate. Therefore, I believe my constant growth DCF analysis using analysts' three- to five-year growth rates reflects reasonable growth outlooks and the DCF results are also reasonable. Nevertheless, I consider other DCF methodologies in order to enhance the information available to accurately estimate PacifiCorp's current market return on common equity.

Sustainable Growth DCF

Q. PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A. A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings. The payout ratios of the proxy group are shown on my Exhibit ICNU/206. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market to book ratio and on *Value Line's* three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit ICNU/207, Gorman/1, the average sustainable growth rate for the proxy group using this internal growth rate model is 4.90%.

Q. WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit ICNU/208. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results of 9.18% and 8.89%, respectively.

Multi-Stage Growth DCF Model

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A. Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q. PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A. The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the United States Gross

Domestic Product ("U.S. GDP") growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP of 4.9%.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE GROWTH RATE FOR A UTILITY?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the overall economy. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas. The Energy Information Administration ("EIA") has observed that utility sales growth is less than U.S. GDP growth, as shown in Exhibit ICNU/209. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative, albeit overstated, proxy for electric utility sales growth, rate base growth, and earnings growth. Therefore, GDP growth is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q. IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A. Yes. This concept is supported in both published analyst literature and academic work. Specifically, in a textbook entitled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to

> grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[15]

Q. HOW DID YOU DETERMINE THE CONSENSUS REASONABLE, SUSTAINABLE LONG-TERM GROWTH RATE?

A. I relied on the consensus analysts' projections of long-term GDP growth. *The Blue Chip Financial Forecasts* publishes consensus economists' GDP growth projections twice a year. Based on its latest issue, the consensus economists' published GDP growth rate outlook is 5.1% to 4.7% over the next ten years.[16]

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rate of 4.9%, as published by *Blue Chip Financial Forecasts,* as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts'* projections provide real GDP growth projections of 2.8% and 2.5%, and GDP inflation of 2.2% and 2.1%[17] over the 5-year and 10-year projection periods, respectively. This consensus GDP growth forecast represents the most likely views of market participants because it is based on published consensus economist projections.

Q. DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A. Yes. The U.S. EIA in its Annual Energy Outlook projects the real GDP out until 2035. In its 2011 Annual Report, the EIA projects real GDP through 2035 to be in the range of 2.1% to 3.2%, with a midpoint or reference case of 2.7%.[18]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth of 3.3% to 2.4% during the next

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[15] "Fundamentals of Financial Management," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298.

[16] *Blue Chip Financial Forecasts*, June 1, 2012 at 14.

[17] GDP growth is the product of real and inflation GDP growth.

[18] *DOE/EIA Annual Energy Outlook 2011 With Projections to 2035*, April 2011 at 58.

five and 10 years, respectively, with GDP price inflation of 1.9% to 2.0%.[19] The CBO's real GDP projections are higher than the consensus but its GDP inflation is lower than the consensus economists.

The real GDP and nominal GDP growth projections made by the U.S. EIA and those made by the CBO support the use of the consensus analyst 5-year and 10-year projected GDP growth outlooks as a reasonable market assessment of long-term prospective GDP growth.

Q. WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A. I relied on the same 13-week stock price and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The transition period begins in year six and ends in year ten. For the long-term sustainable growth rate starting in year 11, I used 4.9%, the average of the consensus economists' 5-year and 10-year projected nominal GDP growth rates.

Q. WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A. As shown in Exhibit ICNU/210, the average and median DCF returns on equity for my proxy group are 9.22% and 9.39%, respectively.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A. The results from my DCF analyses are summarized in Table 4 below:

TABLE 4

Summary of DCF Results

[19] *CBO: The Budget and Economic Outlook: Fiscal Years 2012 to 2022*, January 2012.

Description	Estimates
Constant Growth DCF Model (Analysts' Growth)	9.28%
Constant Growth DCF Model (Sustainable Growth)	9.18%
Multi-Stage Growth DCF Model	9.22%

My DCF studies indicate a ROE within the range of 9.20% to 9.30%, with a midpoint of 9.25%.

Risk Premium Model

Q. PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A. This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through 2011. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields. I selected the period 1986 through 2011 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit ICNU/211, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit ICNU/212, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.23%. Of the 26 observations, 20 indicated risk premiums fall in the range of 4.41% to 6.13%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown in Exhibit ICNU/213, the average indicated equity risk premium over contemporary Moody's utility bond yields was 3.81% over the period 1986 through 2011. The indicated equity risk premium estimates based on this analysis primarily fall in the range of 3.03% to 4.62% over this time period.

Q. DO YOU BELIEVE THAT THESE EQUITY RISK PREMIUM ESTIMATES ARE BASED ON A TIME PERIOD THAT IS TOO LONG OR TOO SHORT TO DRAW ACCURATE RESULTS CONCERNING CONTEMPORARY MARKET CONDITIONS?

A. No. Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data. Conversely, studies have recommended that use of "actual achieved return data" should be based on very long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. However, these short-term abnormal actual returns would be smoothed over time and the achieved actual returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual returns, and, thus, need not encompass very long time periods.

Q. BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE PACIFICORP'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A. The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit ICNU/214. On that exhibit, I show the yield spread between utility bonds and Treasury bonds over the last 32 years. As shown in this exhibit, the 2008 utility bond yield spreads over Treasury bonds for "A" rated and "Baa" rated utility bonds are 2.25% and 2.97%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for 2009 are 1.97% and 2.99%, respectively. In 2010, these spreads declined to 1.21% and 1.71%, respectively. In 2011, they declined further to 1.13% and 1.65%, respectively. These utility bond yield spreads over Treasury bond yields are now lower than the 32-year average spreads of 1.58% and 1.98%, respectively.

A current 13-week average "A" rated utility bond yield of 4.33%, when compared to the current Treasury bond yield of 3.09% as shown in Exhibit ICNU/215, Gorman/1, implies a yield spread of around 1.22%. This current utility bond yield spread is lower than the 32-year average spread for "A" utility bonds of 1.24%. The current spread for the "Baa" utility yields of 1.90 is also lower than the 32-year average spread of 1.96%.

These utility bond yield spreads are clear evidence that the market considers the utility industry to be a relatively low risk investment and demonstrates that utilities continue to have strong access to capital.

Q. HOW DID YOU ESTIMATE PACIFICORP'S COST OF COMMON EQUITY WITH THIS RISK PREMIUM MODEL?

A. I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. The 13-week average 30-year Treasury bond yield, ending June 1, 2012 was 3.09%, as shown in Exhibit ICNU/215, Gorman/1. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 3.70%, and a 10-year Treasury bond yield to be 2.70%.[20/] Using the projected 30-year bond yield of 3.70%, and a Treasury bond risk premium of 4.41% to 6.13%, as developed above, produces an estimated common equity return in the range of 8.11% (3.70% + 4.41%) to 9.83% (3.70% + 6.13%). I recommend an equity risk premium of 9.26%, rounded to 9.30%. This estimate is based on giving two-thirds weight to my high-end risk premium estimate of 9.83%, and one-third weight to my low-end risk premium estimate of 8.11%. I believe this weighting is appropriate given the unusually large yield spreads between Treasury bond and "Baa" utility bond yields.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "A" rated utility bonds for the period ending June 1, 2012 of 4.33%. Adding the utility equity risk premium of 3.03% to 4.62%, as developed above, to an "A" rated bond yield of 4.40%, produces a cost of equity in the range of 7.36% (4.33% + 3.03%) to 8.95% (4.33% + 4.62%). Again, recognizing the unusually low Treasury yield and wide Treasury to utility bond yield spreads, I recommend a risk premium of 8.95%.

My risk premium analyses produce a return estimate in the range of 8.95% to 9.30%, with a midpoint estimate of 9.13%.

<u>Capital Asset Pricing Model ("CAPM")</u>

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM method of analysis is based upon the theory that the market-required ROR for a security is equal to the risk-free rate, plus a risk premium associated with the

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[20/] *Blue Chip Financial Forecasts*, June 1, 2012 at 2.

specific security. This relationship between risk and return can be expressed mathematically as follows:

$$R_i = R_f + B_i \times (R_m - R_f) \text{ where:}$$

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as non-systematic risks. In a broad sense, systematic risks are market risks, and non-systematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A. The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q. WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A. As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.70%.[21/] The current 30-year Treasury bond yield is 3.10%. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.70% for my CAPM analysis.

Q. WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A. Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common-stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

[21/] *Blue Chip Financial Forecasts*, June 1, 2012 at 2.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit ICNU/216, the proxy group average *Value Line* beta estimate is 0.72.

Q. HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A. I derived two market risk premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Morningstar's *Stocks, Bonds, Bills and Inflation 2012 Classic Yearbook* publication estimates the historical arithmetic average real market return over the period 1926 to 2011 as 8.6%.[22/] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.4%.[23/] Using these estimates, the expected market return is 11.21%.[24/] The market risk premium then is the difference between the 11.21% expected market return, and my 3.70% risk-free rate estimate, or 7.50%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2012 Classic Yearbook*. Over the period 1926 through 2011, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 11.8%,[25/] and the total return on long-term

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22/ *Morningstar, Inc. Ibbotson SBBI 2012 Classic Yearbook* at 84.

23/ *Blue Chip Financial Forecasts*, June 1, 2012 at 2.

24/ $\{\ [\ (1 + 0.086) * (1 + 0.024)\ ] - 1\ \} * 100.$

25/ *Morningstar, Inc. Ibbotson SBBI 2012 Classic Yearbook* at 83.

Treasury bonds was 6.1%.[26/] The indicated market risk premium is 5.7% (11.8% - 6.1% = 5.7%). The average of my market risk premium estimates is 6.60% (7.50% to 5.70%).

Q. HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY MORNINGSTAR?

A. Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 5.9% to 6.6%. My market risk premium falls in the range of 5.7% to 7.5%. My average market risk premium of 6.6% is at the high end of Morningstar's range.

Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2011. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate. I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's range is based on several methodologies. First, Morningstar estimates a market risk premium of 6.6% based on the difference between the total

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26/ Id.

market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange (the "NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.4% and not 6.6%. Third, if only the two deciles of the largest companies included in the NYSE were considered, the market risk premium would be 5.9%.[27/]

Finally, Morningstar found that the 6.6% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable. Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Morningstar published a long-horizon supply-side market risk premium of 6.1%.[28/]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit ICNU/217, based on Morningstar's high-end market risk premium of 6.6%, a risk-free rate of 3.7%, and a beta of 0.72, my CAPM analysis produces a return of 8.45% (rounded to 8.50%).

ROE Summary

Q. BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR PACIFICORP?

A. Based on my analyses, I estimate PacifiCorp's current market cost of equity to be 9.20%.

27/ Morningstar observes that the S&P 500 and the NYSE Decile 1-2 are both large capitalization benchmarks. *Morningstar, Inc. Ibbotson SBBI 2012 Valuation Yearbook* at 54.

28/ Id. at 66.

TABLE 5 Return on Common Equity Summary	
Description	**Results**
DCF	9.25%
Risk Premium	9.13%
CAPM	8.50%

My recommended return on common equity of 9.20% is approximately at the midpoint of my recommended range of 9.13% to 9.25% that is based on my DCF and Risk Premium results.

<u>Financial Integrity</u>

Q. WILL YOUR RECOMMENDED OVERALL ROR SUPPORT AN INVESTMENT GRADE BOND RATING FOR PACIFICORP?

A. Yes. I have reached this conclusion by comparing the key credit rating financial ratios for PacifiCorp, at my proposed ROE and capital structure, to S&P's benchmark financial ratios using S&P's new credit metric ranges.

Q. PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A. S&P publishes a matrix of financial ratios that correspond to its assessment of the business risk of the utility company and related bond rating. On May 27, 2009, S&P expanded its matrix criteria[29/] by including additional business and financial risk categories. Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most electric utilities have a business risk profile of "Excellent" or "Strong." The financial

[29/] S&P updated its original 2007 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the electric utilities have a financial risk profile of "Aggressive." PacifiCorp has an "Excellent" business risk profile and a "Significant" financial risk profile.

Q. PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A. S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of PacifiCorp's total credit risk exposure. S&P publishes a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The three primary financial ratio benchmarks it relies on in its credit rating process include: (1) Total Debt to Total Capital; (2) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (3) Funds From Operations ("FFO") to Total Debt.

Q. HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR ROR RECOMMENDATIONS?

A. I calculated each of S&P's financial ratios based on PacifiCorp's cost of service for its Oregon jurisdictional electric operations. While S&P would normally look at total consolidated PacifiCorp financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in PacifiCorp's Oregon regulated utility operations. Hence, I am attempting to determine whether my proposed ROR will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and PacifiCorp's financial integrity.

Q. DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT ("OBSD")?

A. Yes. As shown in Exhibit ICNU/218, Gorman/4, I estimated off-balance sheet debt equivalents of $275.8 million attributed to PacifiCorp's operating leases and purchased power agreements ("PPA") as available online from Standard & Poor's RatingsDirect. S&P includes other off-balance sheet debt adjustments which I did not include in my analysis. S&P's inclusion of intermediate hybrids,[30] post-retirement benefits, and accrued interest not reported on the Company's debt and asset retirement obligations, were not included in my analysis. Each of these factors are either reflected in PacifiCorp's cost of service, or I could not find evidence that they relate to regulated utility operations. As such, I did not include them in the metrics to judge the reasonableness of my ROR for retail operations in Oregon in this proceeding.

Q. PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS FOR PACIFICORP.

A. The S&P financial metric calculations for PacifiCorp at a 9.20% return are developed on Exhibit ICNU/218, Gorman/1.

PacifiCorp's adjusted total debt ratio is approximately 51%. This is at the low end of the "Aggressive" utility guideline range of 50% to 60%. This total debt ratio will support an investment grade bond rating.

As shown on Exhibit ICNU/218, Gorman/1, column 1, based on an equity return of 9.20%, PacifiCorp will be provided an opportunity to produce a debt to EBITDA ratio

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[30] This was included but not in the OBS calculation. Refer to Exhibit ICNU/218, Gorman/4, where the 50% of Preferred was included as debt-like instruments.

of 3.0x. This is at the low end of S&P's "Significant" guideline range of 3.0x to 4.0x.[31/] This ratio also supports an investment grade credit rating.

Finally, PacifiCorp's retail operations FFO to total debt coverage at a 9.20% equity return would be 26%, which is within the "Significant" metric guideline range of 20% to 30%. The FFO/total debt ratio will support an investment grade bond rating.

At my recommended ROE of 9.20% and proposed capital structure, PacifiCorp's financial credit metrics are supportive of its current "A" utility bond rating.

III. RESPONSE TO PACIFICORP WITNESS DR. SAMUEL HADAWAY

Q. WHAT RETURN ON COMMON EQUITY IS PACIFICORP PROPOSING FOR THIS PROCEEDING?

A. PacifiCorp is proposing to set rates based on a ROE of 10.20%. PacifiCorp's ROE proposal is based on the analysis and judgment of Dr. Samuel Hadaway. Dr. Hadaway's results are summarized at page 32 of his direct testimony. PAC/200, Hadaway/32.

Q. DO DR. HADAWAY'S METHODOLOGIES SUPPORT HIS 10.20% ROE FOR HIS PROXY GROUP?

A. No. As discussed in detail below, Dr. Hadaway's own analyses would support a ROE in the range of 9.0% to 10.0% if it is adjusted to reflect current market data and his models are properly applied. These adjustments to Dr. Hadaway's ROE estimates support my recommended ROE.

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY DR. HADAWAY TO SUPPORT HIS RETURN ON COMMON EQUITY RECOMMENDATION.

A. Dr. Hadaway develops his return on common equity recommendation using three versions of the DCF model, and two utility risk premium analyses. I have summarized Dr. Hadaway's results in Table 6 under column 1. Under column 2, I show the results of

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[31/] *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009 at 4.

Dr. Hadaway's analyses adjusted for updated data and more reasonable application of the models.

As shown in Table 6, using consensus economists' projection of GDP growth rather than Dr. Hadaway's inflated GDP growth estimates, his own DCF analyses would support a ROE for PacifiCorp in the range of 9.1% to 10.0%. Proper adjustments to Dr. Hadaway's utility risk premium estimates to reflect the unadjusted equity risk premium would reduce this estimate from 9.6% to 9.0%. Therefore, Dr. Hadaway's ROE estimate with reasonable adjustments will produce a ROE for PacifiCorp in the range of 9.0% to 10.0%. However, a majority of the adjusted results fall in the range of 9.2% to 9.6%.

TABLE 6

Summary of Dr. Hadaway's ROE Estimate

Description	**Hadaway Results[1] (1)**	**Adjusted Hadaway Results[2] (2)**
DCF Analysis		
Constant Growth (Analysts' Growth)	9.6% - 10.0%	9.6% - 10.0%
Constant Growth (GDP Growth)	10.1% - 10.2%	9.2% - 9.3%
Multi-Stage Growth Model	9.9% - 10.0%	9.1% - 9.2%
Indicated DCF Range	9.6% - 10.2%	9.1% - 10.0%
Risk Premium Analysis		
Forecasted Utility Debt + Equity Risk Premium	9.7%	Reject
Current Utility Debt + Equity Risk Premium	9.6%	9.0%
Risk Premium Estimate	9.6%	9.0%
Recommended ROE	10.2%	
Adjusted ROE Range		9.0% - 10.0%

Sources:
[1] Exhibit PAC/200, Hadaway/32.
[2] Exhibit ICNU/219.

Q. PLEASE DESCRIBE DR. HADAWAY'S CONSTANT GROWTH DCF ANALYSIS.

A. Dr. Hadaway's adjusted constant growth DCF analysis is shown on his Exhibit PAC/206. As shown on that exhibit, Dr. Hadaway's constant growth DCF analysis is based on a recent stock price, an annualized dividend and an average of three growth rates: (1) *Value Line*; (2) Zacks; and (3) Thomson.

Q. ARE DR. HADAWAY'S DCF ESTIMATES RELIABLE?

A. No. His GDP growth rate used in his constant growth and multi-stage growth models is based on an inflated GDP growth rate of 5.8%. PAC/206, Hadaway/3. This GDP growth is excessive and not reflective of current market expectations.

Q. HOW DID DR. HADAWAY DEVELOP HIS GDP GROWTH RATE?

A. He states that the GDP growth rate is based on the achieved GDP growth over the last 10, 20, 30, 40, 50, and 60-year periods. Id. at 5. Dr. Hadaway's projected GDP growth rate is unreasonable. Historical GDP growth over the last 20 and 40-year periods was strongly influenced by the actual inflation rate experienced over that time period.

Q. WHY IS DR. HADAWAY'S DCF ESTIMATE EXCESSIVE IN COMPARISON TO THAT OF PUBLISHED MARKET ANALYSTS?

A. The consensus economists' projected GDP growth rate is much lower than the GDP growth rate used by Dr. Hadaway in his DCF analysis. A comparison of Dr. Hadaway's GDP growth rate and consensus economists' projected GDP growth over the next five and 10 years is shown in Table 7. As shown in this table, Dr. Hadaway's GDP rate of 5.8% reflects real GDP of 2.7% and an inflation adjusted GDP of 3.0%. However, consensus economists' projections of nominal GDP include GDP inflation projections over the next 5 and 10 years of 2.2% and 2.1%, respectively.[32/]

As is clearly evident in Table 7, Dr. Hadaway's historical GDP growth reflects historical inflation, which is much higher than, and not representative of, consensus market expected forward-looking inflation.

TABLE 7

GDP Projections

Description	**GDP Inflation**	**Real GDP**	**Nominal GDP**
Dr. Hadaway	3.0%	2.7%	5.8%
Consensus 5-Year Projection	2.2%	2.8%	5.1%
Consensus 10-Year Projection	2.1%	2.5%	4.7%

Source: *Blue Chip Financial Forecasts*, June 1, 2012 at 14.

As such, Dr. Hadaway's 5.8% nominal GDP growth rate is not reflective of consensus market expectations and should be rejected. Indeed, Dr. Hadaway's 5.8% GDP growth rate outlook is inconsistent with the consensus of economists' independent projections of future long-term GDP growth, and also inconsistent with projections made by the U.S. Energy Information Administration, and Congressional Budget Office as referenced in my testimony above where I describe the parameters used in my own multi-stage growth DCF analyses. Those agencies also project real GDP in line with what Dr. Hadaway and his consensus projections include, however their outlook for future inflation is much lower than Dr. Hadaway, and much more consistent with the consensus independent economists' projections discussed in Table 7 above. For all these reasons, Dr.

32/ *Blue Chip Financial Forecasts*, June 1, 2012 at 14.

Hadaway's GDP growth outlook rate projections are simply out of line and out of touch with the consensus market outlooks.

Q. HOW WOULD DR. HADAWAY'S DCF ANALYSES CHANGE IF CURRENT MARKET-BASED GDP GROWTH RATE PROJECTIONS ARE INCLUDED IN HIS ANALYSIS RATHER THAN HIS EXCESSIVE GDP GROWTH RATE?

A. As shown in Exhibit ICNU/219, Gorman/1, I updated Dr. Hadaway's DCF analyses using more recent market data and a GDP growth rate of 4.9%. This GDP growth rate is the consensus economists' 5- and 10-year projected growth rate of the GDP as published in the *Blue Chip Financial Forecasts*. As shown in Exhibit ICNU/219, using this consensus economists' projected GDP growth rate, reduces Dr. Hadaway's long-term GDP growth DCF result from 10.2% to 9.3% and his multi-stage DCF from 10.0% to 9.2%.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO DR. HADAWAY'S DCF STUDIES.

A. Using a more reasonable GDP growth rate reduces the average DCF result produced by Dr. Hadaway's studies from 10.0% down to 9.4%. Dr. Hadaway's original estimates and these updated and adjusted results are shown below in Table 8.

TABLE 8

Adjusted Hadaway DCF

Description	**Range Average Hadaway DCF**	**Adjusted DCF**
Constant Growth (Analysts' Growth)	9.8%	9.8%
Constant Growth (GDP Growth)	10.2%	9.3%
Multi-Stage Growth Model	10.0%	9.2%
Average	10.0%	9.4%

As shown above in Table 8, using a consensus economists' GDP forecast, rather than the GDP forecast derived by Dr. Hadaway, would support an ROE no higher than 9.4%.

Q. PLEASE DESCRIBE DR. HADAWAY'S UTILITY RISK PREMIUM ANALYSIS.

A. Dr. Hadaway's utility bond yield versus authorized return on common equity risk premium is shown in Exhibit PAC/207. As shown in this exhibit, Dr. Hadaway estimated an annual equity risk premium by subtracting Moody's average bond yield from the electric utility regulatory commission authorized return on common equity over the period 1980 through 2011. Based on this analysis, Dr. Hadaway estimates an average indicated equity risk premium over current utility bond yields of 3.33%.

Dr. Hadaway then adjusts this average equity risk premium using a regression analysis based on an expectation that there is an ongoing inverse relationship between interest rates and equity risk premiums. Based on this regression analysis, Dr. Hadaway increases his equity risk premium from 3.33%, up to 5.08% and 5.18% relative to projected and current "A" bond yield of 4.62% and 4.37%, respectively. He then adds these inflated equity risk premiums to the projected and current "A" rated utility bond yield of 4.62% and 4.37% to produce an ROE of 9.70% and 9.55%, respectively.

Q. ARE DR. HADAWAY'S UTILITY RISK PREMIUM ANALYSES REASONABLE?

A. No. Dr. Hadaway develops a forward-looking risk premium model, relying on forecasted interest rates and volatile utility spreads, which are highly uncertain and produce inaccurate results. Further, Dr. Hadaway's proposal to adjust the actual equity risk premium of 3.33% to reflect the inverse relationship between interest rates and utility risk premiums to 5.08% and 5.18% is unreasonable. This adjustment is inappropriate and not consistent with academic literature that finds that this relationship should change with risk changes and not simply changes to interest rates.

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. HADAWAY'S FORECASTED UTILITY BOND YIELD OF 4.62%?

A. Yes. Dr. Hadaway develops his forecasted utility bond yield based on the 3-month historical spread of A-rated utility bond yields and 30-year Treasury yields of 1.32% added to his projected long-term Treasury yield of 3.3%. This approach is unreasonable, because Dr. Hadaway relies on projected interest rates with historical yield spreads. The accuracy of his interest rate projections is highly problematic, and he provides no support for his assumption that yield spreads will stay flat if Treasury yields increase. This yield spread relationship is volatile and uncertain, as are interest rate projections. Indeed, while interest rates have been projected to increase over the last several years, those increased interest rate projections have turned out to be wrong.

Q. WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A. Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit ICNU/220 illustrates this point. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years in the future. In Column 1, I show the actual Treasury yield and, in Column 2, I show the projected yield two years out.

As shown in Columns 1 and 2, over the last several years Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show what the Treasury yield actually turned out to be two years after the forecast. Under Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in this exhibit, over the last several years, economists consistently have been projecting that interest rates will increase. However, as demonstrated under Column 5, those yield projections have turned out to be overstated in virtually every case. Indeed, actual Treasury yields have decreased or remained flat over the last five years, rather than increase as the economists' projections indicated. As such, current observable interest rates are just as likely to predict future interest rates as are economists' projections.

Q. WHY IS DR. HADAWAY'S USE OF A SIMPLE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS NOT REASONABLE?

A. Dr. Hadaway's belief that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship between these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[33/]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. Interest rate volatility currently is much lower than it was in the 1980s.[34/] As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

33/ "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

34/ *Morningstar SBBI, 2009 Yearbook* at 95-96.

In today's marketplace, interest rate variability is not as extreme as it was during the 1980s. Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, not simply changes to interest rates.

Importantly, Dr. Hadaway's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology that does not produce accurate or reliable risk premium estimates. His results should be rejected by the Commission.

Q. HOW WILL DR. HADAWAY'S RISK PREMIUM RESULTS CHANGE IF MORE REASONABLE MARKET DATA IS CONSIDERED?

A. Using Dr. Hadaway's projected equity risk premium adjusted for an inverse relationship of 5.08%, relative to the current observable "A" rated utility bond yield of 4.40%, would indicate an ROE of 9.48%. This return estimate is much closer to my recommended ROE for PacifiCorp than his recommended 10.2% ROE. Alternatively, modifying his equity risk premiums to consider yield spreads, rather than simply the inverse relationship between equity risk premiums and interest rates, would also reduce the level of equity risk premium estimated by Dr. Hadaway. Simply observing the highest equity risk premiums authorized over the last five years would indicate an average equity risk premium of 4.57%. (This is based on the last five years, excluding 2008, which had an abnormally low equity risk premium.) Relying on an equity risk premium of 4.40%, relative to current observable utility bond yields of 4.57%, or Dr. Hadaway's projected "A" rated utility bond yield of 4.62%, would indicate a return on common equity for PacifiCorp in the range of 8.97% to 9.02%, or 9.0%.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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EXHIBIT ICNU/201

QUALIFICATIONS OF MICHAEL P. GORMAN

JUNE 20, 2012

Qualifications of Michael P. Gorman

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and a managing principal with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. In April 1995 the firm of Brubaker & Associates, Inc. ("BAI") was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory Commissions in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Commission of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory Commission of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q. PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A. I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

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EXHIBIT ICNU/202

RATE OF RETURN

JUNE 20, 2012

PacifiCorp

Rate of Return
Adjusted Capital Structure

Line	Description	Weight (1)	Cost (2)	Weighted Cost (3)
1	Long-Term Debt*	49.5%	5.37%	2.66%
2	Preferred Stock	0.3%	5.43%	0.02%
3	Common Equity**	50.2%	**9.20%**	4.62%
4	**Total**	**100.0%**		**7.29%**

Sources and Notes:
Exhibit PAC/300, Williams/2, adjusted to remove common equity supporting non-utility assets.

* The long-term debt balance reflects the projected financing activities as outlined in Wyoming Public Service Commission Docket No. 20000-405-ER-11, Rebuttal Testimony of Bruce N. Williams.

** Exhibit ICNU/202, Gorman/2.

PacifiCorp

Rate of Return
Adjusted Capital Structure

End of Year 2012

Line	Description	Amount (Million)[1] (1)	Weight (2)	Adjust. (3)	Adjusted Amount (4)	Adjusted Weight (5)
1	Long-Term Debt	$ 6,804	47.0%	$ 390 [2]	$ 7,194	49.5%
2	Preferred Stock	$ 41	0.3%		$ 41	0.3%
3	Common Equity	$ 7,647	52.8%	$ (349) [3]	$ 7,298	50.2%
4	**Total**	**$ 14,492**	100.0%	$ 41	$ 14,533	100.0%

Actual as of 03/31/2012

Line	Description	Amount (Million)[4] (1)	Weight (2)	Adjust. (3)	Adjusted Amount (4)	Adjusted Weight (5)
5	Long-Term Debt	$ 6,831	48.0%		$ 6,831	49.2%
6	Preferred Stock	$ 41	0.3%		$ 41	0.3%
7	Common Equity	$ 7,371	51.8%	$ (349) [3]	$ 7,023	50.5%
8	**Total**	**$ 14,243**	100.0%	$ (349)	$ 13,894	100.0%

Sources:

[1] Exhibit PAC/300, Willams/18.

[2] Reflects a projected $400 million issuance less $10 million projected maturities.

[3] Attachment ICNU 3.8a.

[4] FERC Form 3-Q, filed on May 30, 2012.

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EXHIBIT ICNU/203

PROXY GROUP

JUNE 20, 2012

PacifiCorp

Proxy Group

Line	Company	Credit Ratings[1] S&P (1)	Credit Ratings[1] Moody's (2)	Common Equity Ratios AUS[1] (3)	Common Equity Ratios Value Line[2] (4)	S&P Business Risk Score[3] (5)
1	ALLETE	A-	Baa1	55.5%	55.7%	Strong
2	Alliant Energy Co.	A-	A2	51.2%	50.9%	Excellent
3	Avista Corp	A-	Baa1	44.3%	48.6%	Excellent
4	Black Hills Corp	BBB+	A3	42.6%	48.6%	Strong
5	DTE Energy Co.	A	A2	46.2%	49.4%	Strong
6	Edison Internat.	BBB+	A1	39.8%	40.6%	Strong
7	IDACORP	A-	A2	51.7%	54.4%	Excellent
8	Portland General	A-	A3	48.5%	50.4%	Excellent
9	SCANA Corp.	A-	A3	42.3%	45.7%	Excellent
10	Sempra Energy	A+	Aa3	46.2%	49.2%	Strong
11	Southern Co.	A	A2	47.9%	47.1%	Excellent
12	Vectren Corp.	A-	A2	44.2%	48.4%	Excellent
13	Wisconsin Energy	A-	A1	42.8%	46.0%	Excellent
14	Xcel Energy Inc.	A	A3	45.6%	48.9%	Excellent
15	**Average**	**A-**	**A2**	**46.3%**	**48.9%**	**Excellent**
16	PacifiCorp	A[4]	A2[4]		50.2%[5]	Excellent

Sources:
[1] *AUS Utility Reports* , May 2012.
[2] *The Value Line Investment Survey,* March 23, May 4, and May 25, 2012.
[3] *S&P RatingsDirect:* "U.S. Regulated Electric Utilities, Strongest To Weakest," April 20, 2012.
[4] Exhibit PAC/200, Hadaway/2.
[5] Exhibit ICNU/200, Gorman/14, Table 3.

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EXHIBIT ICNU/204

GROWTH RATES

JUNE 20, 2012

PacifiCorp

Consensus Analysts' Growth Rates

		Zacks		SNL		Reuters		Average of
Line	Company	Estimated Growth %[1]	Number of Estimates	Estimated Growth %[2]	Number of Estimates	Estimated Growth %[3]	Number of Estimates	Growth Rates
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ALLETE	5.00%	N/A	4.70%	2	6.50%	2	5.40%
2	Alliant Energy Co.	6.18%	N/A	6.40%	4	5.94%	5	6.17%
3	Avista Corp	4.67%	N/A	5.00%	1	4.50%	2	4.72%
4	Black Hills Corp	6.00%	N/A	6.00%	1	6.00%	1	6.00%
5	DTE Energy Co.	4.43%	N/A	4.30%	4	3.83%	5	4.19%
6	Edison Internat.	1.47%	N/A	2.90%	5	2.40%	7	2.26%
7	IDACORP	5.00%	N/A	4.50%	2	4.50%	2	4.67%
8	Portland General	4.76%	N/A	4.50%	4	4.60%	8	4.62%
9	SCANA Corp.	4.11%	N/A	4.70%	3	4.72%	4	4.51%
10	Sempra Energy	7.00%	N/A	6.30%	4	6.70%	3	6.67%
11	Southern Co.	5.10%	N/A	5.40%	7	5.54%	9	5.35%
12	Vectren Corp.	4.33%	N/A	5.00%	2	5.00%	2	4.78%
13	Wisconsin Energy	5.30%	N/A	5.00%	5	6.23%	7	5.51%
14	Xcel Energy Inc.	5.00%	N/A	5.00%	8	5.08%	12	5.03%
15	**Average**	**4.88%**	**N/A**	**4.98%**	**4**	**5.11%**	**5**	**4.99%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on June 1, 2012.
[2] SNL Interactive, http://www.snl.com/, downloaded on June 1, 2012.
[3] Reuters, http://www.reuters.com/, downloaded on June 1, 2012.

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EXHIBIT ICNU/205

CONSTANT GROWTH DCF MODEL

JUNE 20, 2012

PacifiCorp

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE	$40.45	5.40%	$1.84	4.79%	10.19%
2	Alliant Energy Co.	$43.53	6.17%	$1.80	4.39%	10.56%
3	Avista Corp	$25.51	4.72%	$1.16	4.76%	9.49%
4	Black Hills Corp	$32.80	6.00%	$1.48	4.78%	10.78%
5	DTE Energy Co.	$55.40	4.19%	$2.35	4.42%	8.61%
6	Edison Internat.	$43.26	2.26%	$1.30	3.07%	5.33%
7	IDACORP	$39.96	4.67%	$1.32	3.46%	8.12%
8	Portland General	$24.93	4.62%	$1.06	4.45%	9.07%
9	SCANA Corp.	$45.43	4.51%	$1.98	4.55%	9.06%
10	Sempra Energy	$62.19	6.67%	$2.40	4.12%	10.78%
11	Southern Co.	$45.14	5.35%	$1.96	4.57%	9.92%
12	Vectren Corp.	$28.94	4.78%	$1.40	5.07%	9.84%
13	Wisconsin Energy	$35.76	5.51%	$1.20	3.54%	9.05%
14	Xcel Energy Inc.	$26.80	5.03%	$1.04	4.08%	9.10%
15	**Average**	**$39.29**	**4.99%**	**$1.59**	**4.29%**	**9.28%**
16	**Median**					**9.29%**

Sources:
[1] SNL Financial, downloaded on June 4, 2012.
[2] Exhibit ICNU/204.
[3] *The Value Line Investment Survey,* March 23, May 4, and May 25, 2012.

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EXHIBIT ICNU/206

PAYOUT RATIOS

JUNE 20, 2012

PacifiCorp

Payout Ratios

Line	Company	Dividends Per Share 2011 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2011 (3)	Earnings Per Share Projected (4)	Payout Ratio 2011 (5)	Payout Ratio Projected (6)
1	ALLETE	$1.78	$2.00	$2.65	$3.25	67.17%	61.54%
2	Alliant Energy Co.	$1.70	$2.20	$2.75	$3.60	61.82%	61.11%
3	Avista Corp	$1.10	$1.40	$1.72	$2.25	63.95%	62.22%
4	Black Hills Corp	$1.46	$1.60	$1.01	$2.50	144.55%	64.00%
5	DTE Energy Co.	$2.32	$2.80	$3.67	$4.50	63.22%	62.22%
6	Edison Internat.	$1.29	$1.50	$3.23	$3.50	39.94%	42.86%
7	IDACORP	$1.20	$1.90	$3.36	$3.55	35.71%	53.52%
8	Portland General	$1.06	$1.25	$1.95	$2.25	54.36%	55.56%
9	SCANA Corp.	$1.94	$2.15	$2.97	$3.75	65.32%	57.33%
10	Sempra Energy	$1.92	$2.80	$4.47	$5.75	42.95%	48.70%
11	Southern Co.	$1.87	$2.25	$2.55	$3.25	73.33%	69.23%
12	Vectren Corp.	$1.39	$1.60	$1.73	$2.50	80.35%	64.00%
13	Wisconsin Energy	$1.04	$1.80	$2.18	$2.75	47.71%	65.45%
14	Xcel Energy Inc.	$1.03	$1.35	$1.72	$2.25	59.88%	60.00%
15	**Average**	**$1.51**	**$1.90**	**$2.57**	**$3.26**	**64.30%**	**59.12%**

Source:
The Value Line Investment Survey, March 23, May 4, and May 25, 2012.

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EXHIBIT ICNU/207

SUSTAINABLE GROWTH RATE

JUNE 20, 2012

PacifiCorp

Sustainable Growth Rate

Line	Company	3 to 5 Year Projections: Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Sustainable Growth Rate (11)
1	ALLETE	$2.00	$3.25	$34.50	3.69%	9.42%	1.02	9.59%	61.54%	38.46%	3.69%	4.48%
2	Alliant Energy Co.	$2.20	$3.60	$32.35	3.57%	11.13%	1.02	11.32%	61.11%	38.89%	4.40%	5.07%
3	Avista Corp	$1.40	$2.25	$24.00	3.41%	9.38%	1.02	9.53%	62.22%	37.78%	3.60%	3.99%
4	Black Hills Corp	$1.60	$2.50	$31.00	2.40%	8.06%	1.01	8.16%	64.00%	36.00%	2.94%	3.05%
5	DTE Energy Co.	$2.80	$4.50	$49.25	3.53%	9.14%	1.02	9.30%	62.22%	37.78%	3.51%	4.08%
6	Edison Internat.	$1.50	$3.50	$39.00	4.79%	8.97%	1.02	9.18%	42.86%	57.14%	5.25%	5.25%
7	IDACORP	$1.90	$3.55	$43.20	5.41%	8.22%	1.03	8.43%	53.52%	46.48%	3.92%	4.03%
8	Portland General	$1.25	$2.25	$26.50	3.73%	8.49%	1.02	8.65%	55.56%	44.44%	3.84%	3.89%
9	SCANA Corp.	$2.15	$3.75	$39.50	5.71%	9.49%	1.03	9.76%	57.33%	42.67%	4.16%	6.93%
10	Sempra Energy	$2.80	$5.75	$52.00	4.87%	11.06%	1.02	11.32%	48.70%	51.30%	5.81%	6.13%
11	Southern Co.	$2.25	$3.25	$26.25	5.25%	12.38%	1.03	12.70%	69.23%	30.77%	3.91%	6.47%
12	Vectren Corp.	$1.60	$2.50	$21.00	3.26%	11.90%	1.02	12.10%	64.00%	36.00%	4.35%	5.47%
13	Wisconsin Energy	$1.80	$2.75	$20.25	3.32%	13.58%	1.02	13.80%	65.45%	34.55%	4.77%	4.77%
14	Xcel Energy Inc.	$1.35	$2.25	$21.75	4.52%	10.34%	1.02	10.57%	60.00%	40.00%	4.23%	5.00%
15	**Average**	**$1.90**	**$3.26**	**$32.90**	**4.10%**	**10.11%**	**1.02**	**10.32%**	**59.12%**	**40.88%**	**4.17%**	**4.90%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey, March 23, May 4, and May 25, 2012.*
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/5) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

PacifiCorp

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2011 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2011 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V[5] (9)
1	ALLETE	$40.45	$28.78	1.41	37.50	40.50	1.94%	2.73%	28.84%	0.79%
2	Alliant Energy Co.	$43.53	$27.14	1.60	111.02	116.00	1.10%	1.77%	37.65%	0.67%
3	Avista Corp	$25.51	$20.30	1.26	58.42	62.00	1.50%	1.88%	20.42%	0.38%
4	Black Hills Corp	$32.80	$27.53	1.19	43.92	45.00	0.61%	0.73%	16.08%	0.12%
5	DTE Energy Co.	$55.40	$41.40	1.34	169.25	181.00	1.69%	2.26%	25.27%	0.57%
6	Edison Internat.	$43.26	$30.86	1.40	325.81	325.81	0.00%	0.00%	28.67%	0.00%
7	IDACORP	$39.96	$33.19	1.20	49.95	51.00	0.52%	0.63%	16.95%	0.11%
8	Portland General	$24.93	$22.07	1.13	75.36	76.50	0.38%	0.42%	11.46%	0.05%
9	SCANA Corp.	$45.43	$29.92	1.52	130.00	160.00	5.33%	8.09%	34.14%	2.76%
10	Sempra Energy	$62.19	$41.00	1.52	239.93	246.00	0.63%	0.95%	34.08%	0.32%
11	Southern Co.	$45.14	$20.32	2.22	865.13	940.00	2.10%	4.66%	54.99%	2.56%
12	Vectren Corp.	$28.94	$17.89	1.62	81.90	88.00	1.81%	2.93%	38.19%	1.12%
13	Wisconsin Energy	$35.76	$17.20	2.08	230.49	223.00	-0.82%	-1.71%	51.91%	-0.89%
14	Xcel Energy Inc.	$26.80	$17.44	1.54	486.49	515.00	1.43%	2.20%	34.92%	0.77%
15	**Average**	**$39.29**	**$26.79**	**1.50**	**207.51**	**219.27**	**1.46%**	**2.25%**	**30.97%**	**0.79%**

Sources and Notes:

[1] SNL Financial, downloaded on June 4, 2012.

[2] *The Value Line Investment Survey, March 23, May 4, and May 25, 2012.*

[3] Expected Growth in the Number of Shares, Column (3) * Column (6).

[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

[5] Column (9) Line 15 excludes negative values.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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EXHIBIT ICNU/208

CONSTANT GROWTH DCF MODEL

JUNE 20, 2012

PacifiCorp

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE	$40.45	4.48%	$1.84	4.75%	9.23%
2	Alliant Energy Co.	$43.53	5.07%	$1.80	4.35%	9.41%
3	Avista Corp	$25.51	3.99%	$1.16	4.73%	8.71%
4	Black Hills Corp	$32.80	3.05%	$1.48	4.65%	7.70%
5	DTE Energy Co.	$55.40	4.08%	$2.35	4.42%	8.50%
6	Edison Internat.	$43.26	5.25%	$1.30	3.16%	8.41%
7	IDACORP	$39.96	4.03%	$1.32	3.44%	7.46%
8	Portland General	$24.93	3.89%	$1.06	4.42%	8.31%
9	SCANA Corp.	$45.43	6.93%	$1.98	4.66%	11.59%
10	Sempra Energy	$62.19	6.13%	$2.40	4.10%	10.23%
11	Southern Co.	$45.14	6.47%	$1.96	4.62%	11.09%
12	Vectren Corp.	$28.94	5.47%	$1.40	5.10%	10.58%
13	Wisconsin Energy	$35.76	4.77%	$1.20	3.52%	8.28%
14	Xcel Energy Inc.	$26.80	5.00%	$1.04	4.07%	9.07%
15	**Average**	**$39.29**	**4.90%**	**$1.59**	**4.28%**	**9.18%**
16	**Median**					**8.89%**

Sources:
[1] SNL Financial, downloaded on June 4, 2012.
[2] Exhibit ICNU/207, Gorman/1.
[3] *The Value Line Investment Survey,* March 23, May 4, and May 25, 2012.

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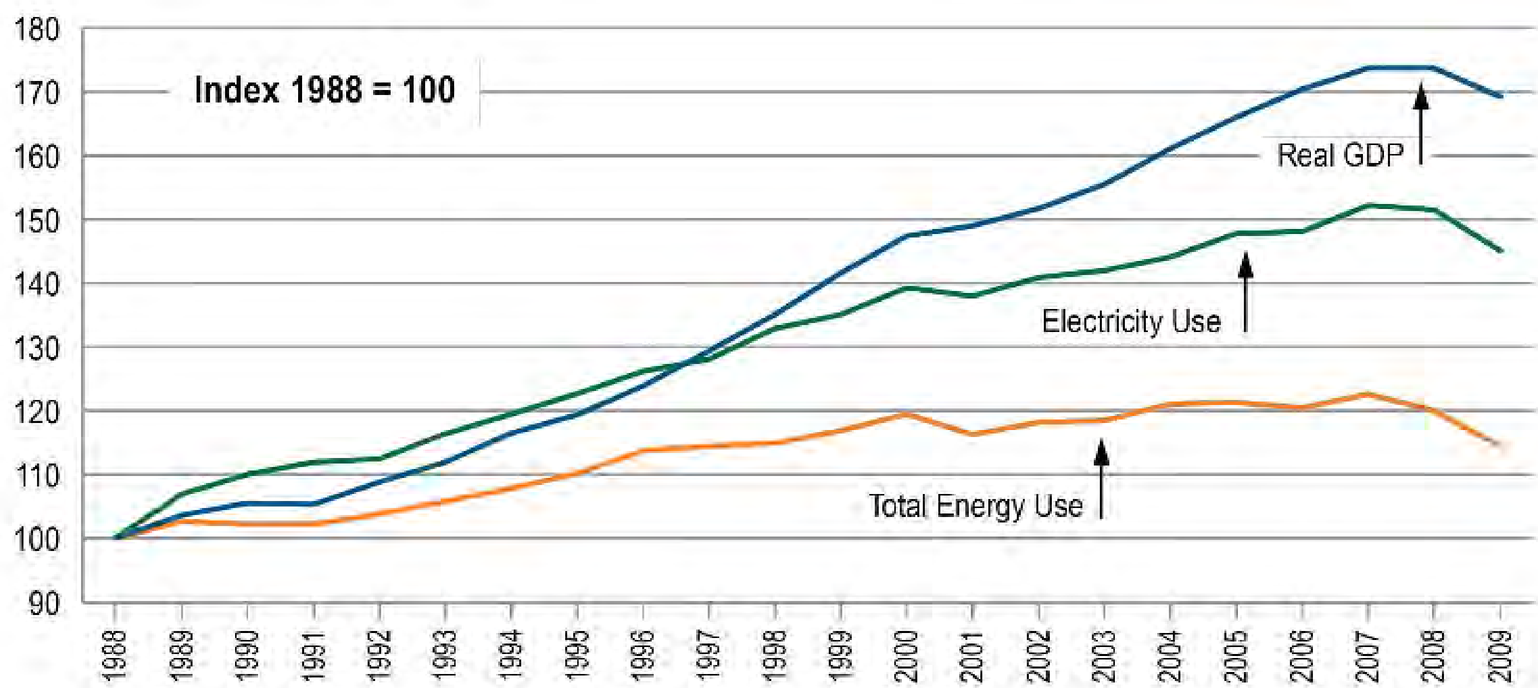
EXHIBIT ICNU/209

ELECTRICITY SALES ARE LINKED TO U.S. ECONOMIC GROWTH

JUNE 20, 2012

PacifiCorp

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Department of Energy, Energy Information Administration.
Edison Electric Institute, http://www.eei.org.

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EXHIBIT ICNU/210

MULTI-STAGE GROWTH DCF MODEL

JUNE 20, 2012

PacifiCorp

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1]	Annualized Dividend[2]	First Stage Growth[3]	Second Stage Growth Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth[4]	Multi-Stage Growth DCF
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	$40.45	$1.84	5.40%	5.32%	5.23%	5.15%	5.07%	4.98%	4.90%	9.82%
2	Alliant Energy Co.	$43.53	$1.80	6.17%	5.96%	5.75%	5.54%	5.32%	5.11%	4.90%	9.59%
3	Avista Corp	$25.51	$1.16	4.72%	4.75%	4.78%	4.81%	4.84%	4.87%	4.90%	9.62%
4	Black Hills Corp	$32.80	$1.48	6.00%	5.82%	5.63%	5.45%	5.27%	5.08%	4.90%	9.96%
5	DTE Energy Co.	$55.40	$2.35	4.19%	4.31%	4.42%	4.54%	4.66%	4.78%	4.90%	9.15%
6	Edison Internat.	$43.26	$1.30	2.26%	2.70%	3.14%	3.58%	4.02%	4.46%	4.90%	7.53%
7	IDACORP	$39.96	$1.32	4.67%	4.71%	4.74%	4.78%	4.82%	4.86%	4.90%	8.31%
8	Portland General	$24.93	$1.06	4.62%	4.67%	4.71%	4.76%	4.81%	4.85%	4.90%	9.28%
9	SCANA Corp.	$45.43	$1.98	4.51%	4.58%	4.64%	4.71%	4.77%	4.84%	4.90%	9.36%
10	Sempra Energy	$62.19	$2.40	6.67%	6.37%	6.08%	5.78%	5.49%	5.19%	4.90%	9.42%
11	Southern Co.	$45.14	$1.96	5.35%	5.27%	5.20%	5.12%	5.05%	4.97%	4.90%	9.58%
12	Vectren Corp.	$28.94	$1.40	4.78%	4.80%	4.82%	4.84%	4.86%	4.88%	4.90%	9.94%
13	Wisconsin Energy	$35.76	$1.20	5.51%	5.41%	5.31%	5.21%	5.10%	5.00%	4.90%	8.56%
14	Xcel Energy Inc.	$26.80	$1.04	5.03%	5.01%	4.98%	4.96%	4.94%	4.92%	4.90%	9.00%
15	**Average**	**$39.29**	**$1.59**	**4.99%**	**4.98%**	**4.96%**	**4.95%**	**4.93%**	**4.92%**	**4.90%**	**9.22%**
16	**Median**										**9.39%**

Sources:
[1] SNL Financial, downloaded on June 4, 2012.
[2] *The Value Line Investment Survey, March 23, May 4, and May 25, 2012.*
[3] Exhibit ICNU/204.
[4] *Blue Chip Financial Forecasts, June 1* , 2012 at 14.

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EXHIBIT ICNU/211

COMMON STOCK MARKET/BOOK RATIO

JUNE 20, 2012

PacifiCorp

Common Stock Market/Book Ratio

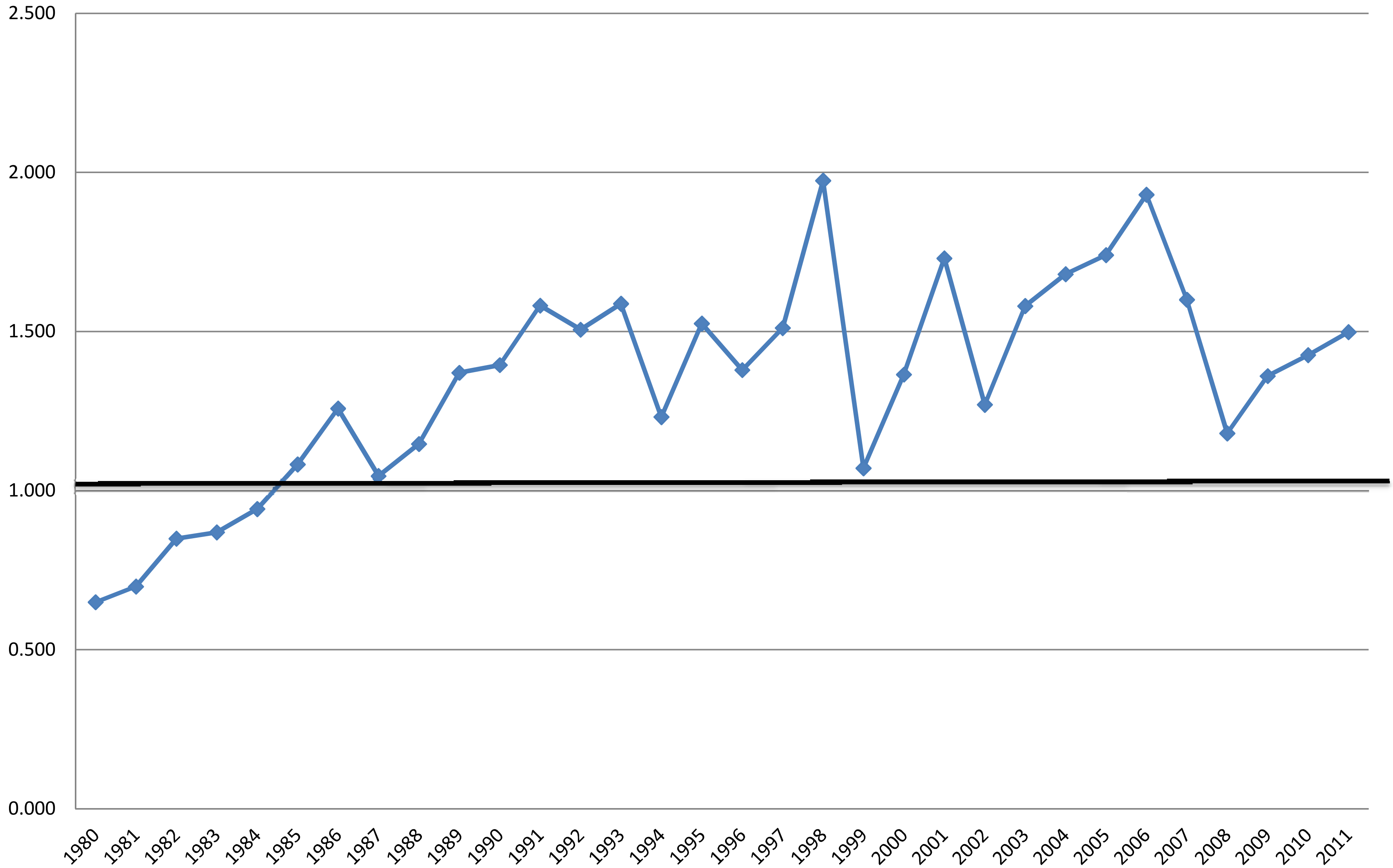

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EXHIBIT ICNU/212

EQUITY RISK PREMIUM – TREASURY BOND

JUNE 20, 2012

PacifiCorp

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)
1	1986	13.93%	7.80%	6.13%
2	1987	12.99%	8.58%	4.41%
3	1988	12.79%	8.96%	3.83%
4	1989	12.97%	8.45%	4.52%
5	1990	12.70%	8.61%	4.09%
6	1991	12.55%	8.14%	4.41%
7	1992	12.09%	7.67%	4.42%
8	1993	11.41%	6.60%	4.81%
9	1994	11.34%	7.37%	3.97%
10	1995	11.55%	6.88%	4.67%
11	1996	11.39%	6.70%	4.69%
12	1997	11.40%	6.61%	4.79%
13	1998	11.66%	5.58%	6.08%
14	1999	10.77%	5.87%	4.90%
15	2000	11.43%	5.94%	5.49%
16	2001	11.09%	5.49%	5.60%
17	2002	11.16%	5.43%	5.73%
18	2003	10.97%	4.96%	6.01%
19	2004	10.75%	5.05%	5.70%
20	2005	10.54%	4.65%	5.89%
21	2006	10.36%	4.99%	5.37%
22	2007	10.36%	4.83%	5.53%
23	2008	10.46%	4.28%	6.18%
24	2009	10.48%	4.07%	6.41%
25	2010	10.34%	4.25%	6.09%
26	2011	10.22%	3.91%	6.31%
27	**Average**	**11.45%**	**6.22%**	**5.23%**

Sources:
[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and January 10, 2012.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

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EXHIBIT ICNU/213

EQUITY RISK PREMIUM – UTILITY BOND

JUNE 20, 2012

PacifiCorp

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)
1	1986	13.93%	9.58%	4.35%
2	1987	12.99%	10.10%	2.89%
3	1988	12.79%	10.49%	2.30%
4	1989	12.97%	9.77%	3.20%
5	1990	12.70%	9.86%	2.84%
6	1991	12.55%	9.36%	3.19%
7	1992	12.09%	8.69%	3.40%
8	1993	11.41%	7.59%	3.82%
9	1994	11.34%	8.31%	3.03%
10	1995	11.55%	7.89%	3.66%
11	1996	11.39%	7.75%	3.64%
12	1997	11.40%	7.60%	3.80%
13	1998	11.66%	7.04%	4.62%
14	1999	10.77%	7.62%	3.15%
15	2000	11.43%	8.24%	3.19%
16	2001	11.09%	7.76%	3.33%
17	2002	11.16%	7.37%	3.79%
18	2003	10.97%	6.58%	4.39%
19	2004	10.75%	6.16%	4.59%
20	2005	10.54%	5.65%	4.89%
21	2006	10.36%	6.07%	4.29%
22	2007	10.36%	6.07%	4.29%
23	2008	10.46%	6.53%	3.93%
24	2009	10.48%	6.04%	4.44%
25	2010	10.34%	5.46%	4.88%
26	2011	10.22%	5.04%	5.18%
27	**Average**	**11.45%**	**7.64%**	**3.81%**

Sources:
[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and January 10, 2012.
[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2011 were obtained from http://credittrends.moodys.com/.

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EXHIBIT ICNU/214

BOND YIELD SPREADS

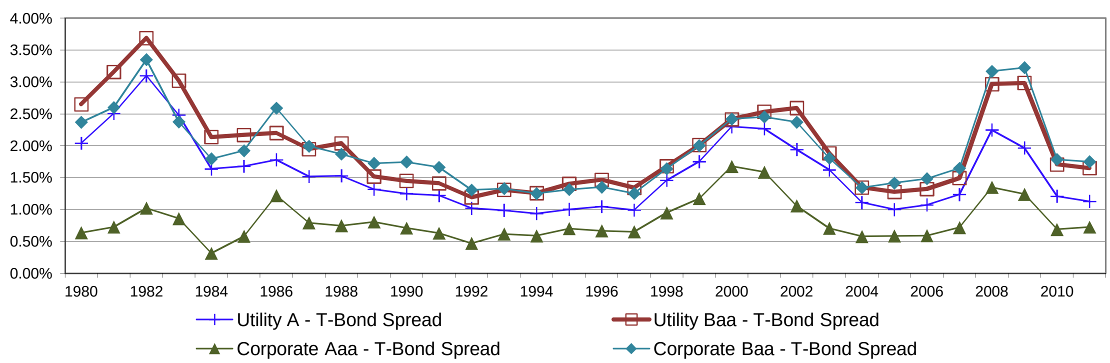
JUNE 20, 2012

PacifiCorp

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[1] (6)	Baa[1] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Utility to Corp. Baa Spread (10)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.29%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%
27	2006	4.99%	6.07%	6.32%	1.08%	1.32%	5.59%	6.48%	0.60%	1.49%	-0.16%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%
31	2010	4.25%	5.46%	5.96%	1.21%	1.71%	4.94%	6.04%	0.69%	1.79%	-0.08%
32	2011	3.91%	5.04%	5.56%	1.13%	1.65%	4.64%	5.66%	0.73%	1.75%	-0.10%
33	**Average**	**7.30%**	**8.87%**	**9.27%**	**1.58%**	**1.98%**	**8.12%**	**9.25%**	**0.83%**	**1.95%**	**0.03%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2011 were obtained from http://credittrends.moodys.com/.

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EXHIBIT ICNU/215

UTILITY AND TREASURY BOND YIELDS

JUNE 20, 2012

PacifiCorp

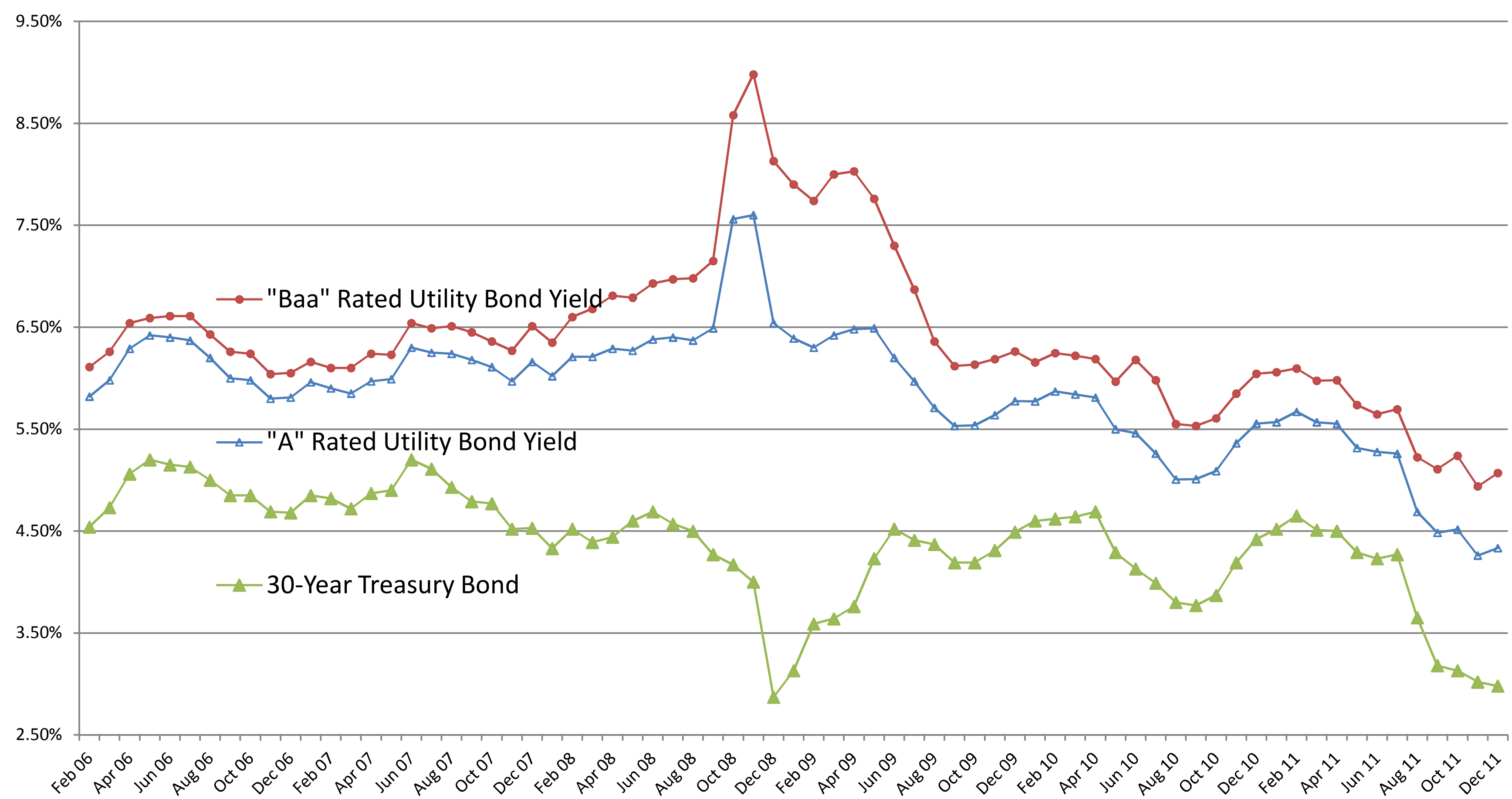
Utility and Treasury Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	06/01/12	2.53%	3.92%	4.75%
2	05/25/12	2.85%	4.20%	5.02%
3	05/18/12	2.80%	4.08%	4.85%
4	05/11/12	3.02%	4.22%	4.96%
5	05/04/12	3.07%	4.29%	5.03%
6	04/27/12	3.12%	4.33%	5.06%
7	04/20/12	3.12%	4.35%	5.07%
8	04/13/12	3.14%	4.37%	5.08%
9	04/06/12	3.21%	4.44%	5.13%
10	03/30/12	3.35%	4.54%	5.20%
11	03/23/12	3.31%	4.51%	5.15%
12	03/16/12	3.41%	4.60%	5.25%
13	03/09/12	3.19%	4.39%	5.04%
14	**Average**	**3.09%**	**4.33%**	**5.05%**
15	**Spread To Treasury**		**1.24%**	**1.96%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2]http://credittrends.moodys.com/.

PacifiCorp

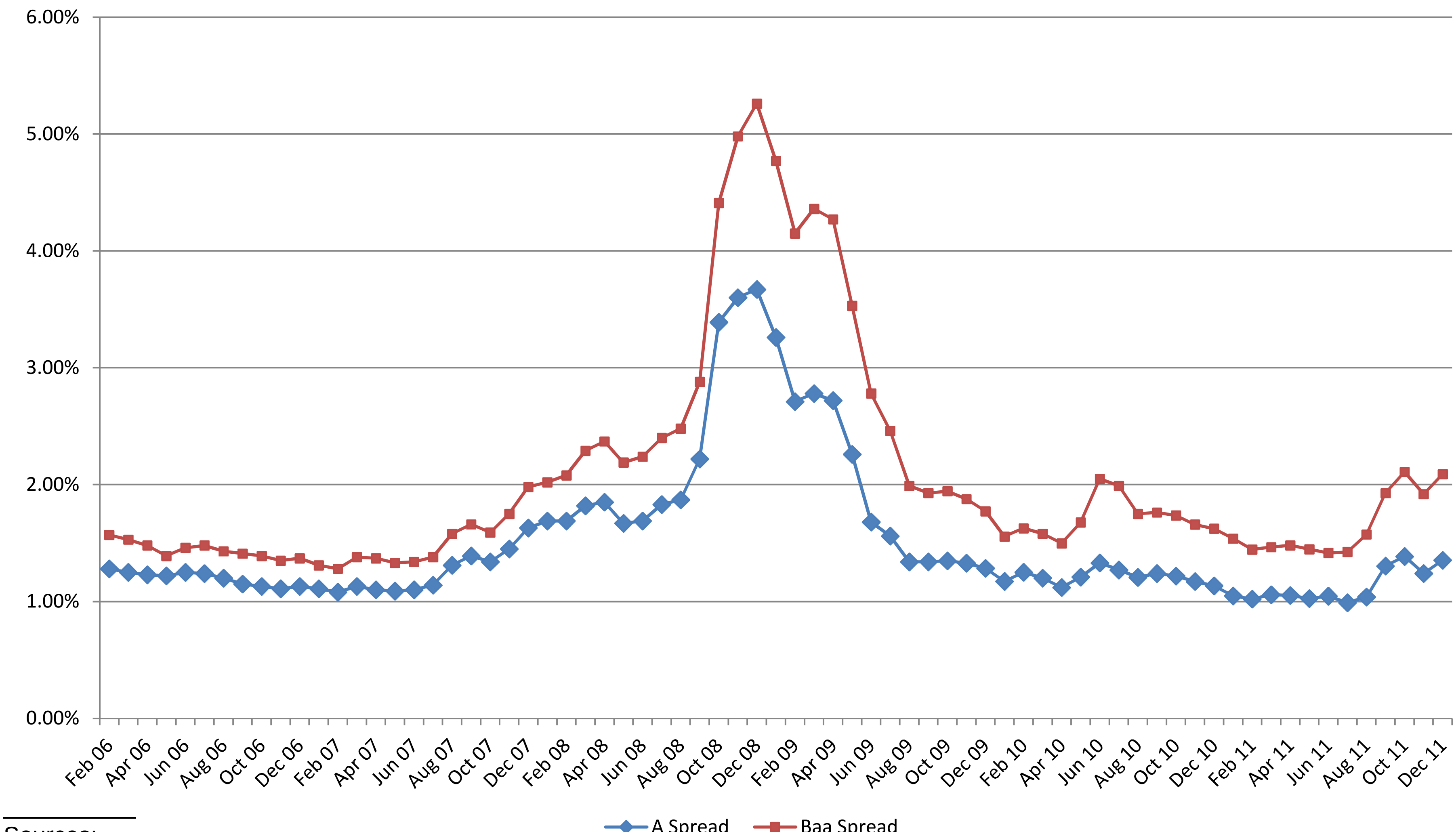
Trends in Utility Bond Yields



Sources:
Merchant Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

PacifiCorp

Spread Between "A" and "Baa" Rated Utility Bond Yield and 30-Year Treasury Bond Yield



Sources:
Merchant Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

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EXHIBIT ICNU/216

VALUE LINE BETA

JUNE 20, 2012

PacifiCorp

Value Line Beta

Line	Company	Beta
1	ALLETE	0.70
2	Alliant Energy Co.	0.75
3	Avista Corp	0.70
4	Black Hills Corp	0.85
5	DTE Energy Co.	0.75
6	Edison Internat.	0.80
7	IDACORP	0.70
8	Portland General	0.75
9	SCANA Corp.	0.70
10	Sempra Energy	0.80
11	Southern Co.	0.55
12	Vectren Corp.	0.70
13	Wisconsin Energy	0.65
14	Xcel Energy Inc.	0.65
15	**Average**	**0.72**

Source:
The Value Line Investment Survey,
March 23, May 4, and May 25, 2012.

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EXHIBIT ICNU/217

CAPM RETURN

JUNE 20, 2012

PacifiCorp

CAPM Return

Line	Description	Market Risk Premium
1	Risk-Free Rate[1]	3.70%
2	Risk Premium[2]	6.60%
3	Beta[3]	0.72
4	**CAPM**	**8.45%**

Sources:

[1] *Blue Chip Financial Forecasts*; June 1, 2012, at 2.

[2] Morningstar, Inc. *Ibbotson SBBI 2012 Classic Yearbook* at 86, and Morningstar, Inc. *Ibbotson SBBI 2012 Valuation Yearbook* at 54 and 66.

[3] Exhibit ICNU/216.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) 2013 Request for a General Rate Revision	))))))))))	Docket No. UE 246

EXHIBIT ICNU/218

STANDARD & POOR'S CREDIT METRICS

June 18, 2012

PacifiCorp

Standard & Poor's Credit Metrics

Line	Description	Retail Cost of Service Amount (1)	S&P Benchmark[1/2] Significant (2)	S&P Benchmark[1/2] Aggressive (3)	Reference (4)
1	Rate Base	$ 3,253,958,859			Exhibit PAC/1102, Page1.0.
2	Weighted Common Return	4.62%			Page 2, Line 3, Col. 4.
3	Pre-Tax Rate of Return	10.34%			Page 2, Line 4, Col. 5.
4	Income to Common	$ 150,335,759			Line 1 x Line 2.
5	EBIT	$ 336,537,243			Line 1 x Line 3.
6	Depreciation & Amortization	$ 192,265,649			Exhibit PAC/1102, Page1.0.
7	Imputed Amortization	$ 7,430,678			Page 4, Line 14, Col 1.
8	Deferred Income Taxes & ITC	$ 71,514,522			Exhibit PAC/1102, Page1.0.
9	Funds from Operations (FFO)	$ 421,546,608			Sum of Line 4 and Lines 6 through 8.
10	Imputed Interest Expense	$ 4,129,156			Page 4, Line 13, Col 1.
11	EBITDA	$ 540,362,726			Sum of Lines 5 through 7 and Line 10.
12	Total Debt Ratio	51%	45% - 50%	50% - 60%	Page 3, Line 3, Col. 2.
13	Debt to EBITDA	3.0x	3.0x - 4.0x	4.0x - 5.0x	(Line 1 x Line 12) / Line 11.
14	FFO to Total Debt	26%	20% - 30%	12% - 20%	Line 9 / (Line 1 x Line 12).

Sources:
[1] Standard & Poor's: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.
[2] *S&P RatingsDirect:* "U.S. Regulated Electric Utilities, Strongest to Weakest," April 20, 2012.

Note:
Based on the April 2012 S&P metrics, PacifiCorp has an "Excellent" business profile and a "Significant" financial profile.

PacifiCorp

Standard & Poor's Credit Metrics
(Pre-Tax Rate of Return)

Line	Description	Weight (1)	Cost (2)	Weighted Cost (3)	Pre-Tax Weighted Cost (4)
1	Long-Term Debt	49.5%	5.37%	2.66%	2.66%
2	Preferred Stock	0.3%	5.43%	0.02%	0.02%
3	Common Equity	50.2%	**9.20%**	4.62%	7.67%
4	**Total**	**100.0%**		**7.29%**	**10.34%**
5	Tax Conversion Factor*				1.6597

Sources:
Exhibit ICNU/202.
* Exhibit PAC/1102, Page 1.5.

PacifiCorp

Standard & Poor's Credit Metrics
(Financial Capital Structure)

Line	Description	Weight (1)
1	Long-Term Debt	48.6%
2	Off Balance Sheet Debt*	1.9%
3	Preferred Stock	0.1%
4	**Total Long-Term Debt**	**50.6%**
5	Preferred Stock	0.1%
6	Common Equity	49.3%
7	**Total**	**100.0%**

Sources:
Exhibit ICNU/218, Gorman/2.
* Exhibit ICNU/218, Gorman/4, Line 6, Col. 1.

PacifiCorp

Standard and Poor's Credit Metrics
(Off-Balance Sheet Debt Equivalents)

Line	Description	Amount (000) (1)	Reference (2)
	PacifiCorp Oregon Allocator[1]		
1	PacifiCorp OR December 2013 Rate Base	$ 3,253,959	
2	Total December 2013 Rate Base	$ 12,592,848	
3	**Jurisdictional Allocator**	**25.84%**	Line 1 / Line 2
	Total Company[2]		
	Off-Balance Sheet Debt		
4	Operating Leases	$ 46,642	
5	Purchased Power Agreements	229,111	
6	**Total Off-Balance Sheet Debt**	$ 275,753	
	Imputed Amortization Expense		
7	Operating Leases	$ 5,992	
8	Purchased Power Agreements	22,765	
9	**Total Imputed Amortization Expense**	$ 28,757	
	Imputed Interest Expense		
10	Operating Leases	$ 2,508	
11	Purchased Power Agreements	13,472	
12	**Total Imputed Interest Expense**	$ 15,980	
	PacifiCorp OR Allocation		
13	Imputed Amortization	$ 7,431	Line 3 x Line 9.
14	Imputed Interest Expense	$ 4,129	Line 3 x Line 12.

Sources:
[1] Exhibit PAC/1102, Page 2.2.
[2] Standard & Poor's Ratings Direct, On-Line.

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EXHIBIT ICNU/219

ADJUSTED HADAWAY DCF

JUNE 20, 2012

PacifiCorp

Summary of Adjusted Hadaway DCF

Line	Description	Hadaway (1)	Hadaway Adjusted* (2)
	Constant Growth DCF		
1	Average	9.6%	9.6%
2	Median	10.0%	10.0%
	Long-Term Constant Growth DCF		
3	Average	10.1%	9.2%
4	Median	10.2%	9.3%
	Multi-Stage Growth DCF		
5	Average	9.9%	9.1%
6	Median	10.0%	9.2%

Sources:
Exhibit ICNU/219, Gorman/2-4
* The adjustment reflects changing the GDP Growth Rate to 4.9%.

PacifiCorp

Adjusted Hadaway Constant Growth DCF Model
(Analysts' Growth Rates)

Line	Company	13-Week Stock Price[1] (1)	Next Year's Dividend (2)	Dividend Yield (3)	EPS Analysts' Growth Rates: Value Line[2] (4)	EPS Analysts' Growth Rates: Zacks[3] (5)	EPS Analysts' Growth Rates: Thomson[4] (6)	Average Growth Rate (7)	Constant Growth DCF (8)
1	ALLETE	$39.13	$1.80	4.60%	6.00%	5.00%	6.50%	5.83%	10.4%
2	Alliant Energy Co.	$41.06	$1.80	4.38%	6.50%	6.00%	4.90%	5.80%	10.2%
3	Avista Corp.	$24.90	$1.18	4.74%	4.50%	4.70%	4.50%	4.57%	9.3%
4	Black Hills Corp	$32.25	$1.48	4.59%	8.50%	5.00%	6.00%	6.50%	11.1%
5	DTE Energy Co.	$51.36	$2.42	4.71%	4.50%	4.20%	3.75%	4.15%	8.9%
6	Edison Internat.	$39.32	$1.31	3.33%	NA	5.00%	3.18%	4.09%	7.4%
7	IDACORP	$40.27	$1.20	2.98%	4.00%	4.70%	4.50%	4.40%	7.4%
8	Portland General	$24.35	$1.08	4.44%	7.50%	5.00%	5.88%	6.13%	10.6%
9	SCANA Corp.	$42.26	$1.98	4.69%	3.00%	4.20%	4.48%	3.89%	8.6%
10	Sempra Energy	$52.63	$2.08	3.95%	3.50%	7.00%	7.33%	5.94%	9.9%
11	Southern Co.	$43.58	$1.94	4.45%	6.00%	5.10%	5.92%	5.67%	10.1%
12	Vectren Corp.	$28.31	$1.41	4.98%	5.50%	4.30%	5.50%	5.10%	10.1%
13	Wisconsin Energy	$32.63	$1.20	3.68%	8.50%	6.30%	7.80%	7.53%	11.2%
14	Xcel Energy Inc.	$25.72	$1.06	4.12%	5.00%	5.10%	5.13%	5.08%	9.2%
15	**Average**	**$36.98**	**$1.57**	**4.26%**	**5.62%**	**5.11%**	**5.38%**	**5.33%**	**9.6%**
16	**Median**			**4.44%**				**5.39%**	**10.0%**

Source:
Exhibit PAC/206, Hadaway/2.

PacifiCorp

Adjusted Hadaway Constant Growth DCF Model
(Long-Term GDP Growth)

Line	Company	Recent Stock Price (1)	Next Year's Dividend (2)	Dividend Yield (3)	GDP Growth* (4)	Long-Term Constant Growth DCF (5)
1	ALLETE	$39.13	$1.80	4.60%	4.90%	9.5%
2	Alliant Energy Co.	$41.06	$1.80	4.38%	4.90%	9.3%
3	Avista Corp.	$24.90	$1.18	4.74%	4.90%	9.6%
4	Black Hills Corp	$32.25	$1.48	4.59%	4.90%	9.5%
5	DTE Energy Co.	$51.36	$2.42	4.71%	4.90%	9.6%
6	Edison Internat.	$39.32	$1.31	3.33%	4.90%	8.2%
7	IDACORP	$40.27	$1.20	2.98%	4.90%	7.9%
8	Portland General	$24.35	$1.08	4.44%	4.90%	9.3%
9	SCANA Corp.	$42.26	$1.98	4.69%	4.90%	9.6%
10	Sempra Energy	$52.63	$2.08	3.95%	4.90%	8.9%
11	Southern Co.	$43.58	$1.94	4.45%	4.90%	9.4%
12	Vectren Corp.	$28.31	$1.41	4.98%	4.90%	9.9%
13	Wisconsin Energy	$32.63	$1.20	3.68%	4.90%	8.6%
14	Xcel Energy Inc.	$25.72	$1.06	4.12%	4.90%	9.0%
15	**Average**	**$36.98**	**$1.57**	**4.26%**	**4.90%**	**9.2%**
16	**Median**			**4.44%**		**9.3%**

Sources:
Exhibit PAC/206, Hadaway/3.
* *Blue Chip Financial Forecasts,* June 1, 2012 at 14.

PacifiCorp

Adjusted Hadaway Low Near-Term Growth
Two-Stage Growth DCF Model

Line	Company	Recent Stock Price (1)	2012 Dividend (2)	2015 Dividend (3)	Annual Change 2015 (4)	Cash Flows 2012 Dividend (5)	Cash Flows 2013 Dividend (6)	Cash Flows 2014 Dividend (7)	Cash Flows 2015 Dividend (8)	Cash Flows 2016 Dividend (9)	GDP Growth* (10)	Two-Stage Growth DCF (11)
1	ALLETE	$39.13	$1.80	$1.95	$0.05	$1.80	$1.85	$1.90	$1.95	$2.05	4.90%	9.2%
2	Alliant Energy Co.	$41.06	$1.80	$2.10	$0.10	$1.80	$1.90	$2.00	$2.10	$2.20	4.90%	9.3%
3	Avista Corp.	$24.90	$1.18	$1.40	$0.07	$1.18	$1.25	$1.33	$1.40	$1.47	4.90%	9.8%
4	Black Hills Corp	$32.25	$1.48	$1.55	$0.02	$1.48	$1.50	$1.53	$1.55	$1.63	4.90%	9.1%
5	DTE Energy Co.	$51.36	$2.42	$2.70	$0.09	$2.42	$2.51	$2.61	$2.70	$2.83	4.90%	9.5%
6	Edison Internat.	$39.32	$1.31	$1.40	$0.03	$1.31	$1.34	$1.37	$1.40	$1.47	4.90%	8.0%
7	IDACORP	$40.27	$1.20	$1.50	$0.10	$1.20	$1.30	$1.40	$1.50	$1.57	4.90%	8.1%
8	Portland General	$24.35	$1.08	$1.20	$0.04	$1.08	$1.12	$1.16	$1.20	$1.26	4.90%	9.2%
9	SCANA Corp.	$42.26	$1.98	$2.10	$0.04	$1.98	$2.02	$2.06	$2.10	$2.20	4.90%	9.2%
10	Sempra Energy	$52.63	$2.08	$2.50	$0.14	$2.08	$2.22	$2.36	$2.50	$2.62	4.90%	9.0%
11	Southern Co.	$43.58	$1.94	$2.20	$0.09	$1.94	$2.03	$2.11	$2.20	$2.31	4.90%	9.3%
12	Vectren Corp.	$28.31	$1.41	$1.60	$0.06	$1.41	$1.47	$1.54	$1.60	$1.68	4.90%	9.8%
13	Wisconsin Energy	$32.63	$1.20	$1.65	$0.15	$1.20	$1.35	$1.50	$1.65	$1.73	4.90%	9.2%
14	Xcel Energy Inc.	$25.72	$1.06	$1.15	$0.03	$1.06	$1.09	$1.12	$1.15	$1.21	4.90%	8.8%
15	**Average**	**$36.98**	**$1.57**	**$1.79**	**$0.07**	**$1.57**	**$1.64**	**$1.71**	**$1.79**	**$1.87**	**4.90%**	**9.1%**
16	**Median**											**9.2%**

Sources:
Exhibit PAC/206, Hadaway/4.
* *Blue Chip Financial Forecasts,* June 1, 2012 at 14.

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EXHIBIT ICNU/220

ACCURACY OF INTEREST RATE FORECASTS

JUNE 20, 2012

PacifiCorp

Accuracy of Interest Rate Forecasts
(Long-Term Treasury Bond Yields - Projected Vs. Actual)

		Publication Data			Actual Yield	Projected Yield
Line	Date	Prior Quarter Actual Yield (1)	Projected Yield (2)	Projected Quarter (3)	in Projected Quarter (4)	Higher (Lower) Than Actual Yield* (5)
1	Dec-00	5.8%	5.8%	1Q, 02	5.6%	0.2%
2	Mar-01	5.7%	5.6%	2Q, 02	5.8%	-0.2%
3	Jun-01	5.4%	5.8%	3Q, 02	5.2%	0.6%
4	Sep-01	5.7%	5.9%	4Q, 02	5.1%	0.8%
5	Dec-01	5.5%	5.7%	1Q, 03	5.0%	0.7%
6	Mar-02	5.3%	5.9%	2Q, 03	4.7%	1.2%
7	Jun-02	5.6%	6.2%	3Q, 03	5.2%	1.0%
8	Sep-02	5.8%	5.9%	4Q, 03	5.2%	0.7%
9	Dec-02	5.2%	5.7%	1Q, 04	4.9%	0.8%
10	Mar-03	5.1%	5.7%	2Q, 04	5.4%	0.3%
11	Jun-03	5.0%	5.4%	3Q, 04	5.1%	0.3%
12	Sep-03	4.7%	5.8%	4Q, 04	4.9%	0.9%
13	Dec-03	5.2%	5.9%	1Q, 05	4.8%	1.1%
14	Mar-04	5.2%	5.9%	2Q, 05	4.6%	1.4%
15	Jun-04	4.9%	6.2%	3Q, 05	4.5%	1.7%
16	Sep-04	5.4%	6.0%	4Q, 05	4.8%	1.2%
17	Dec-04	5.1%	5.8%	1Q, 06	4.6%	1.2%
18	Mar-05	4.9%	5.6%	2Q, 06	5.1%	0.5%
19	Jun-05	4.8%	5.5%	3Q, 06	5.0%	0.5%
20	Sep-05	4.6%	5.2%	4Q, 06	4.7%	0.5%
21	Dec-05	4.5%	5.3%	1Q, 07	4.8%	0.5%
22	Mar-06	4.8%	5.1%	2Q, 07	5.0%	0.1%
23	Jun-06	4.6%	5.3%	3Q, 07	4.9%	0.4%
24	Sep-06	5.1%	5.2%	4Q, 07	4.6%	0.6%
25	Dec-06	5.0%	5.0%	1Q, 08	4.4%	0.6%
26	Mar-07	4.7%	5.1%	2Q, 08	4.6%	0.5%
27	Jun-07	4.8%	5.1%	3Q, 08	4.5%	0.7%
28	Sep-07	5.0%	5.2%	4Q, 08	3.7%	1.5%
29	Dec-07	4.9%	4.8%	1Q, 09	3.5%	1.4%
30	Mar-08	4.6%	4.8%	2Q, 09	4.0%	0.8%
31	Jun-08	4.4%	4.9%	3Q, 09	4.3%	0.6%
32	Sep-08	4.6%	5.1%	4Q, 09	4.3%	0.8%
33	Dec-08	4.5%	4.6%	1Q, 10	4.6%	0.0%
34	Mar-09	3.7%	4.1%	2Q, 10	4.4%	-0.3%
35	Jun-09	3.5%	4.6%	3Q, 10	3.9%	0.8%
36	Sep-09	4.0%	5.0%	4Q, 10	4.2%	0.8%
37	Dec-09	4.3%	5.0%	1Q, 11	4.6%	0.4%
38	Mar-10	4.3%	5.2%	2Q, 11	4.3%	0.9%
39	Jun-10	4.6%	5.2%	3Q, 11	3.7%	1.5%
40	Sep-10	4.4%	4.7%	4Q, 11	3.0%	1.7%
41	Dec-10	3.9%	4.6%	1Q, 12	3.1%	1.5%
42	Jan-11	4.2%	5.0%	2Q, 12		
43	Feb-11	4.2%	5.0%	2Q, 12		
44	Mar-11	4.2%	5.1%	2Q, 12		
45	Apr-11	4.6%	5.2%	3Q, 12		
46	May-11	4.6%	5.2%	3Q, 12		
47	Jun-11	4.6%	5.2%	3Q, 12		
48	Jul-11	4.4%	5.2%	4Q, 12		
49	Aug-11	4.3%	5.0%	4Q, 12		
50	Sep-11	4.3%	4.2%	4Q, 12		
51	Oct-11	3.7%	3.9%	1Q, 13		
52	Nov-11	3.7%	3.8%	1Q, 13		
53	Dec-11	3.7%	3.8%	1Q, 13		
54	Jan-12	3.0%	3.8%	2Q, 13		
55	Feb-12	3.0%	3.8%	2Q, 13		
56	Mar-12	3.0%	3.8%	2Q, 13		
57	Apr-12	3.1%	3.9%	3Q, 13		
58	May-12	3.1%	3.9%	3Q, 13		

Source:
Blue Chip Financial Forecasts , Various Dates.
* Col. 2 - Col. 4.