Exhibit No.___(MTW-8T)
Docket Nos. UE-061546/UE-060817
Witness: Mark T. Widmer

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,<br><br>Complainant,<br><br>vs.<br><br>PACIFICORP dba Pacific Power & Light Company,<br><br>Respondent. | Docket No. UE-061546 |
| In the Matter of the Petition of<br><br>PACIFICORP dba Pacific Power & Light Company,<br><br>For an Accounting Order Approving Deferral Of Certain Costs Related to the MidAmerican Energy Holdings Company Transition. | Docket No. UE-060817 |

**PACIFICORP**

**REBUTTAL TESTIMONY**
**OF**
**MARK T. WIDMER**

**March 2007**

**Q. Please state your name?**

A. My name is Mark T. Widmer

**Q. Have you filed direct testimony in this case?**

A. Yes.

**Introduction**

**Q. Please describe the purpose of your rebuttal testimony?**

A. My rebuttal testimony has three primary sections. First, I discuss Staff witness Mr. Buckley's proposed power supply adjustments, and I demonstrate that the Miscellaneous Power Supply adjustments proposed by Mr. Buckley are reasonable and should be adopted. I also describe under what condition the Company would be willing to accept the Eastern Market Modification adjustment even though, in our view, it fails the Commission's tangible and quantifiable benefit test for a determination of used and useful. I also discuss Mr. Buckley's proposed water year adjustment.

The second section of my testimony rebuts the testimony of ICNU/Public Counsel witness Mr. Falkenberg. I demonstrate that Mr. Falkenberg's analyses related to the West Control Area (WCA) model and the "used and useful" requirement are asymmetrical and fail to satisfy the applicable used and useful requirement, and that the related proposed adjustments on Interconnection Benefits, Johnston / Wyodak Part 1, and Johnston / Wyodak Part 2 should be rejected. I also demonstrate that Mr. Falkenberg's proposed adjustments for Short-Term Firm Transactions, SMUD Contract, GP Camas, Hydro Water Year

Modeling, Monthly Outages, Ramping and Regulating Margin are flawed and should be rejected.

The third section of my testimony relates to the proposed power cost adjustment mechanism ("PCAM"). I discuss the Company's tolerance for the totality of PCAM adjustments proposed by Staff, identify proposed adjustments that are acceptable to the Company, demonstrate that the Company's proposed PCAM should be adopted as long as certain modifications to Staff's proposed PCAM are adopted, and demonstrate that the ICNU and Public Counsel recommendations should be rejected.

**Staff Power Cost Adjustments**

**Q. What does this section of your rebuttal testimony cover?**

A. This portion of my rebuttal testimony discusses Mr. Buckley's Miscellaneous Power Supply adjustment, his Eastern Market Modification adjustment, and his water year adjustment.

**Miscellaneous Power Supply**

**Q. Please explain Mr. Buckley's proposed Miscellaneous Power Supply adjustment.**

A. The adjustment consists of several corrections to remove expenses related to PacifiCorp's East Control Area (PACE) that were inadvertently included in the Company's filing. The specific adjustments are for (1) Mead/Phoenix and Sierra Pacific transmission expense, (2) Idaho Power transmission expense associated with moving Wyoming resources to Bridger (Dynamic Overlay), (3) east regulating margin expense, and (4) updates of WCA loads. The proposed adjustments reduce Washington net power costs by $0.48 million.

**Q. Do you agree with the proposed adjustment?**

A. Yes. The Company believes it is appropriate to correct the mistakes and to match loads to GRID inputs and the pro forma test period.

**Eastern Market Modification**

**Q. Please explain the Eastern Market Modification adjustment proposed by Mr. Buckley.**

A. The Eastern Market Modification adjustment captures the benefits of an assumed sale from the WCA to PACE at the Borah / Brady interconnection to account for market prices differences between the Mid-Columbia ("Mid-C") and Four Corners wholesale markets hubs located in each control area. The proposed adjustment reduces Washington net power costs by $1.0 million.

**Q. Please explain how the adjustment is modeled.**

A. The sale was based on a share-the-savings approach whereby the transaction margin is allocated between WCA and PACE because the sale cannot be accomplished without each counter party. The sale occurs at the WCA / PACE point of interconnection at Borah / Brady. The volume of the transaction was based on heavy load hour ("HLH") transfers from Bridger net of the portion of Bridger allocated to PACE and was further reduced by 40 percent to account for competition from other generators that could sell to PACE. The price of the sale is equal to the Mid-C hourly price plus a share of the margin. The margin is equal to the difference between Mid-C and Four Corners wholesale market prices and was split 40 percent to the WCA and 60 percent to PACE to account for the additional transmission expenses and line losses PACE would incur delivering the energy to either load and or Four Corners if transmission were available. Finally, the adjustment is incorporated in a GRID study that was requested by Staff.

**Q. What is your recommendation regarding the Eastern Market Modification adjustment?**

A. I understand Mr. Buckley's desire to include some WCA benefits of making a theoretical sale from the WCA to PACE. However, I do not believe the benefits are tangible and quantifiable, as required under the Commission's "used and useful" standard because the adjustment is in part based on assumptions. However, the Company believes the adjustment is superior to those proposed by Mr. Falkenberg and would be willing to accept the adjustment under the condition that the Monitoring Committee proposed by Mr. Buckley is adopted and this adjustment is reviewed in the future.

**Water Year Adjustment**

**Q. Please explain Mr. Buckley's proposed Water Year Adjustment.**

A. The water year adjustment removes net power costs associated with extreme, or "outlier," water years from the base level net power costs. The adjustment is used to support implementation of the PCAM proposed by the Company with adjustments. The adjustment would reduce Washington net power costs by $1.5 million.

**Q. Do you agree with the Water Year adjustment?**

A. I agree that the adjustment should not be implemented without the adoption of a PCAM. I also acknowledge what Mr. Buckley is attempting to accomplish with his adjustment. However, I note that Puget Sound Energy and Avista do not have a similar adjustment in connection with the PCAMs they currently have in place. Finally, the adjustment as proposed is too extreme and should not be adopted without modifications.

**Q. Is Mr. Buckley's proposed water year adjustment to exclude water years greater than one standard deviation distance from the mean of the Commission-approved forty-year rolling window reasonable?**

A. No. The Commission-approved forty-year rolling window is already a sub-set of the available water year hydrology performance sample. The Commission's adoption of the forty-year window had the express intent of excluding extreme hydrology conditions that occurred during the first half of the 20th century and placing greater emphasis on recent historical trends, which are believed to be more indicative of near-term future conditions (Cause No. U-86-02). Mr. Buckley's adjustment does not comport with the apparent intent of the Commission's rulings in this area.

**Q. Please explain.**

A. Mr. Buckley's adjustment is based on the argument that with a PCAM in place, the variance of the forty-year window provides the Company the opportunity to recover through base rates extreme hydro conditions and a means through the PCAM to recover again if extreme hydro conditions occur. The design of the PCAM and impact of hydro volatility on power costs are related, but separate questions. The purpose of using the greatest amount of hydro data available for estimation of net power costs is to remove uncertainty associated with varying hydro conditions. The removal of data from the forty-year rolling window only serves to increase the uncertainty. The fact that the design of a PCAM may account for the impact of hydro volatility does not mean that customers and shareholders should be exposed to greater uncertainty concerning net power costs.

**Q. Are there any methodological issues with how Mr. Buckley makes his adjustment?**

A. Yes. There are two substantive issues with Mr. Buckley's adjustment. First, Mr. Buckley's use of the mean to define the central tendency assumes that the distribution of total generation by water year is normal. However, the adjustment Mr. Buckley makes departs from his underlying assumption that hydro generation is normally distributed. This analysis is summarized below in Table 1.

Mr. Buckley's adjustment does indeed reduce the variance of the annual hydro generation by excluding the upper and lower tails of the distribution, as is evidenced by the reduction in the standard deviation by 339,741 MWh. However, on an overall hydro performance basis, this adjustment significantly changes the proportion of above-normal to below-normal water years. What was a relatively equal 52.5% / 47.5% ratio of above-normal to below-normal water years swings by 6 percent and thus results in a presumed expectation that approximately 60 percent of the time the Company will experience better-than-normal hydro conditions.

Table 1 – Descriptive Statistics of Water Year Adjustment

| | 40yr | 1SD adj | difference |
|---|---|---|---|
| mean | 6,066,864 | 6,153,198 | 86,334 |
| median | 6,163,787 | 6,175,357 | 11,570 |
| min | 4,742,170 | 5,426,384 | 684,214 |
| max | 7,547,760 | 6,834,029 | (713,731) |
| SD | 783,741 | 444,000 | (339,741) |
| above mean | 21 | 13 | (8) |
| below mean | 19 | 9 | (10) |
| above mean % | 52.5% | 59.1% | |
| below mean % | 47.5% | 41.9% | |

The Company has no reason to believe that future frequency of better-than-average hydro conditions will be anything significantly greater than a random walk.

**Q. What is your second substantive issue with Mr. Buckley's water year adjustment?**

A. The second substantive issue is that given Mr. Buckley's adjustment, the expectation is that the variance of the distribution will be reduced, but that the other characteristics of the distribution are presumed to remain unchanged. That is, removing the extreme effects of the tails is presumed not to alter the statistical properties that define the underlying water year variability. Summarized in Table 2 below is an analysis showing that while Mr. Buckley's assumption about the normality of total generation by water year in the forty-year sample may be defensible, the adjusted sample has an appreciable effect on the statistical characteristics of the underlying data.

Table 2 – Goodness of Fit Tests

| | 40yr | 1SD adj |
|---|---|---|
| Anderson-Darling | | |
| Normal | 1 | 2 |
| Uniform | 2 | 1 |
| Kolmogorov-Smirnov | | |
| Normal | 1 | 2 |
| Uniform | 2 | 1 |

Mr. Buckley's one standard deviation adjustment reduces the variance and transforms the hydro generation data into another probability distribution.

**Q. Does the Company have any recommended changes to Mr. Buckley's water year adjustment?**

A. Yes. The Company believes that questions concerning how the PCAM captures and shares the risk between customers and shareholders arising from extreme power cost volatility are distinct from questions about the appropriateness of making adjustments to the Commission-approved hydro modeling methodology. However, if there were an adjustment to exclude some presumed "extreme" water years from the data set based on an assumption that hydro generation is normally distributed, the Company believes that understanding the data on a percentile rank basis is a superior approach to Mr. Buckley's proposed method. The definition of a normal distribution means that approximately 67 percent of all data points fall within one standard deviation. The Company recommends this approach for a water year adjustment if a PCAM is adopted. Excluding all water years outside the 67$^{th}$ percentile would produce a reduction in WCA net power costs of $2.5 million, or approximately $0.6 million on a Washington allocated basis.

**Mr. Falkenberg's Adjustments**

**Q. What does this section of your rebuttal testimony cover?**

A. This portion of my testimony rebuts Mr. Falkenberg's testimony on the Company's WCA model and the selection of used and useful resources as it pertains to the WCA. My testimony also demonstrates that his associated adjustments for Interconnection Benefits, Johnston / Wyodak (Part 1) and Johnston /Wyodak (Part 2) do not meet the Commission's required showing of "tangible and quantifiable benefits," and therefore should be rejected. I also discuss Mr. Falkenberg's proposed adjustments to net power costs in this portion of my testimony.

**WCA Allocation Model**

**Q. Mr. Falkenberg assumes that there is a problem with the WCA model because it has a higher net power cost than the system total or PACE on a $/MWh basis, when the former PP&L system had a lower average system cost than the former UP&L system. Is this a valid comparison?**

A. No. It is true that WCA has a lower average system cost than PACE, when net power costs are excluded. However, the WCA has a higher variable net power cost due to a higher volume of wholesale market purchases and transmission expense, which more than offset the lower average system cost when net power costs are excluded. As shown on Table 3 below, this results in a slightly higher overall average cost for the WCA as compared to PACE. As shown, the total average system cost for the WCA is only 1.2 percent higher than PACE, hardly a significant difference.

Table 3

**Average System Costs**
--- average system costs, WCA vs PACE

| | WCA | PACE |
|---|---|---|
| Depr & Amort Expenses | 74,163,986 | 156,282,776 |
| NPC | 417,037,230 | 464,340,879 |
| OMAG | 99,302,985 | 290,955,426 |
| Pre-Tax Return on Net Plant | 176,931,580 | 364,584,242 |
| **Revenue Requirement (G&T)** | **$ 767,435,780** | **$ 1,276,163,323** |
| **Net Plant** | **$ 1,679,047,834** | **$ 3,331,431,935** |
| Load at Input (MWh) | 20,268,323 | 34,149,180 |
| Average System Cost ($/MWh) | 37.86 | 37.37 |
| NPC | 20.58 | 13.60 |
| Non-NPC | 17.29 | 23.77 |

Note:
Based on unadjusted data used in Washington GRC (UE-061546), including major adjustments

Mr. Falkenberg's comparison is therefore invalid and misleading, and provides no basis for challenging the WCA allocation method.

**Q. In Exhibit No.___ (RJF-3), Mr. Falkenberg compares the WCA $20.58 average cost per MWh of retail load to the total system $15.53 average cost per MWh of retail load from the Company's recent Oregon general rate case (Docket UE-179) and concludes that the GRID net power cost results are "unreasonable." Do you concur with that conclusion?**

A. No. Mr. Falkenberg selectively includes information that supports his desired conclusion and ignores the major driver that explains a higher cost per MWh for the WCA. In his testimony he describes Exhibit No.___(RJF-3) as "adjusting for all of these known differences" (page 11, line 20). He goes on to state that "by virtue of its much lower cost resources, the WCA should enjoy lower variable power costs than PACE." What he ignores, however, is that the WCA meets a significant amount of its retail load with wholesale market purchases. Similarly, low variable cost PACE resources meet a higher percentage of its retail load requirements, thereby lessening the need for market purchases.

**Q. Is Mr. Falkenberg aware of the above relationship?**

A. Yes, I presume so. The Company provided a similar more detailed analysis in the Company's response to Commission Staff data request 61, a copy of which was provided to ICNU.

**Q. Are there other flaws in Mr. Falkenberg's Exhibit No.___(RJF-3)?**

A. Yes. Mr. Falkenberg mixes time periods and hydro normalization methodology. The net power cost study from UE-179 in Oregon is for the 12-month period ending December 2007 and normalized hydro was calculated using the 25-50-75 exceedence levels. This case test period is for 12-months ended March 2006 normalized through March 2007, and hydro is normalized using the Washington 40 year rolling average method.

**Q. In Exhibit No.___(RJF-4), Mr. Falkenberg calculates a WCA cost from the Company's actual net power cost reports and concludes that GRID consistently overstates power costs. Do you agree with that assessment?**

A. No. This is another example of selectively including information that supports his desired assessment and ignoring factors that disprove his assertions. For example, Mr. Falkenberg uses monthly values, and discards system balancing transactions and the hourly dispatch decisions that are behind the monthly values. In other words, his analysis is asymmetric, and fails to take into consideration the cost of the actual hourly dispatch of the system.

**Q. Please explain.**

A. Mr. Falkenberg notes that there is a favorable load/resource balance in the WCA on a monthly basis. Then he sells this surplus using the projected average price for short-term purchases. The flaw in this approach is that regardless of the favorable monthly average load/resource balance, in the individual hours there are unfavorable balances. These hours tend to be in the peak month during the super peak hours when wholesale market prices are the highest. The hours where there are favorable balances tend to be in the shoulder and off-peak hours where wholesale market prices are lower. So Mr. Falkenberg's average energy approach sells the surplus at unrealistically high prices and ignores the cost of covering hours when the system is short.

**The "Used and Useful" Requirement**

**Q. Mr. Falkenberg states that the Company simply ignored the Commission's direction in Docket UE-050684 ("2005 Rate Case") on the "used and useful" requirement. Is that an accurate representation of the Company's case?**

A. No. The Commission's order in the 2005 Rate Case set forth a requirement that a resource provide "tangible and quantifiable benefits" to the Company's Washington customers in order to be included in the Company's Washington rates. In meeting this standard, the Company relies primarily on a control area perspective because the control area is responsible for balancing loads and resources within the control area, which in the case of Washington is the WCA. The Company then determined whether resources outside the control area could meet the "tangible and quantifiable benefits" standard under the Commission's order in the 2005 Rate Case for inclusion within the WCA for the purpose of setting Washington retail rates. The Company certainly did not ignore the Commission's direction from the 2005 Rate Case order, but rather developed the WCA inter-jurisdictional cost allocation methodology for the sole purpose of meeting the Commission's express requirements. Staff witness Mr. Buckley, for his part, found that the Company's WCA method meets the relevant standard from the 2005 Rate Case order.

**Q. Please explain the term "control area."**

A. A control area is a geographic area with electric systems that control generation to maintain schedules with other control areas and ensure reliable operations. In operating a control area, the Company is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the control area, plus net imported power, match customer loads. From this description, it is rather obvious that resources located within the WCA reliably serve Washington customers and therefore are used and useful to Washington.

**Q. How did the Company determine whether other resources were used and useful for the WCA?**

A. Among other things, the Company looked to the following excerpt from Order 04 in the 2005 Rate Case in making its determination on this issue:

> The evidence in the record demonstrates that resources recently acquired in Utah were purchased or built to serve the increasing Utah load and the Eastern control area and that there are significant transmission constraints impeding the exchange of power between the Western and Eastern control areas. The Company responds to questions regarding the benefits of these

> adjustments for Washington, not with quantitative evidence of benefits, but with unsubstantiated broad statements about the potential to move power through the South Idaho Exchange contract, the opportunity to redispatch power, the availability of the Bonneville peaking contract to serve the Western control area, the possibility of off-system or wholesale sales revenues, the potential to defer resource acquisition for the Western control area, and the enhancement of system reliability.
>
> While Staff concedes that some indirect benefits of integration exist – the Company has simply failed to establish the value of any tangible benefits flowing to Washington ratepayers.

Given this guidance, the Company concluded that no other resources were used and useful for the WCA and Washington, given the inability to demonstrate tangible and quantifiable benefits. Because electrons are not color-coded and it is thus impossible to determine whether the output from resources outside the WCA are delivered to the Company's Washington customer, the Company would be left to resorting to the sort of hypothetical explanation of benefits that was rejected by the Commission in the 2005 Rate Case.

It would be necessary to prepare a net power cost study based on system dispatch in order to correctly establish net power cost benefits of PACE resources for the WCA, additional benefits WCA resources may be able to capture from transactions with PACE, or wholesale sales that WCA could make at wholesale market hubs in PACE. This would be necessary because the operation of PACE must be considered to determine what benefits would be available for the WCA. However, since electrons are not color coded, it would still be impossible to tell which resources generated the benefits and we would be back to the Revised Protocol approach of allocating all resources to Washington. In the end, the

Company has not found a way to demonstrate "tangible and quantifiable benefits" to Washington customers for transactions that involve PACE. For these reasons, Mr. Falkenberg's used and useful arguments and the related proposed adjustments for interconnection benefits, Johnston and Wyodak (Part 1) and Johnston / Wyodak (Part 2) should be rejected. In addition, as discussed below, these adjustments are flawed and fail to meet the required showing of "tangible and quantifiable benefits."

**Q. Should 100 percent of Jim Bridger be allocated to the WCA as Mr. Falkenberg suggests?**

A. No. Bridger has interconnections with both WCA and PACE. Therefore, only the amount of energy that is being transferred to the WCA should be included. The Company specifically set the plant size based on PacifiCorp Merchant reservations on the Midway-Summer Lake transmission path to determine the amount of resources that are used and useful for the WCA. This path was evaluated because it is the only path that can transfer PACE resources to the WCA. Actual information for the 48-month period ending July 2006 shows that 1,030 aMW are being transferred to the WCA over this path. Based on this information, the Company sized the Bridger plant so that an equivalent amount of energy would be transferred to the WCA.

If anything, the Company's approach in this filing was generous because it transfers 1,061 aMW of energy to the WCA. The adjustment is conservative because it assumes that Bridger is supplying all of that generation when a very small portion could be delivered from higher cost PACE resources, which I discuss in my following rebuttal testimony.

**Interconnection Benefits**

**Q. Please explain Mr. Falkenberg's proposed interconnection benefit adjustment.**

A. The proposed interconnection benefit adjustment purports to calculate likely benefits WCA provides to PACE, under the assumption that Dave Johnston and Wyodak are part of the WCA. Mr. Falkenberg believes the adjustment is reasonable because, according to him, the WCA model includes costs without benefits. The proposed adjustment would reduce Washington net power costs by $8.6 million. The $8.6 million adjustment comprises $5.7 million for transfer capability and $2.9 million for dynamic overlay benefits.

**Q. Do you agree with the assumed $5.7 million interconnection portion of the benefit?**

A. No. The adjustment does not meet the required showing of "tangible and quantifiable benefits" as it is based only on loose assumptions about how much energy is available from Dave Johnston and Wyodak, how much transmission is available, where it can be sold and for what price, all without doing an hourly dispatch of the Company's system. Further, there are flaws in his calculation. For these reasons alone the adjustment should be rejected.

**Q. Is it possible to quantify how much energy is available from Dave Johnston and Wyodak after Wyoming load requirements have been met?**

A. No. East Wyoming PACE resources comprise not only Dave Johnston and Wyodak, but include many other resources located in the state. For example, during 2006, other Wyoming resources (including power purchases) accounted for over 1,200,000 MWh. The Company also has 110 MW of transfer rights from Utah North to Wyoming. Since electrons are not color coded, there is no way to identify whether or not Dave Johnston and Wyodak energy is even available for interconnection benefits. For that matter we do not know the cost of the energy that may be available for interconnection benefits, because we do not know if it is energy from a Qualifying Facility ("QF"), market purchases, Dave Johnston, or Wyodak. Therefore, we cannot calculate what the margin would be on such transactions. Further, the Company has signed agreements with the Mountain 1 and Mountain 2 QF projects to provide an additional 400,000+ MWh of generation starting by April 2008 and July 2008, which will cloud the determination even further. In fact, the Company expects substantial load growth in the state of Wyoming beginning in 2008, which will require more of the existing energy to be used within Wyoming. Therefore, it cannot be adequately demonstrated that Dave Johnston and Wyodak (or any other Wyoming resources) are used and useful for Washington customers.

**Q. On page 18 lines 7-9, Mr. Falkenberg states: "...in the WCA model, the Company includes only the costs, while ignoring some of the most important benefits of the PACW-PACE interconnections." Do you agree with this statement?**

A. No. The statement is misleading. The primary interconnection between PACW and PACE is the ability to deliver Bridger generation to Utah under the terms of Idaho Power Revised Transmission Service Agreement (RTSA). As the Company acknowledged in response to ICNU data request 2.9, the Company inadvertently left in that portion of the RTSA cost related to moving Bridger generation into Utah and moving Wyoming generation to WCA. As I previously addressed in my discussion of Mr. Buckley's testimony, the Company agrees that this oversight should be corrected. Mr. Falkenberg's observation is predicated on a perceived disconnect between costs and benefits. With this correction, this potential disconnect does not exist. Also, as I explain later in my rebuttal testimony, his adjustment is overstated.

Q. **On page 18, line 17, Mr. Falkenberg states: "It makes no sense to include COB, while ignoring PACE as a potential market for surplus PACW generation." Do you agree with this conclusion?**

A. No. COB is a liquid market hub to which the WCA is connected; the interconnection between PACW and PACE does not constitute a liquid market hub. The nearest liquid market hub in PACE is Four Corners. In absence of a transmission cost, the price between COB, Mid C and Four Corners should be equal. Any transactions with an independent PACE would have to take into account the transmission cost of reaching the Four Corners market. Therefore, it is reasonable to conclude that COB and Mid-C prices serve as a reasonable surrogate for Four Corners prices adjusted for transmission costs.

Q. **In Exhibit No.___(RJF-5), Mr. Falkenberg calculates an interconnection benefit. Does his analysis provide a reasonable adjustment?**

A. No. Ignoring the fact that Wyoming resources have not been shown to be used and useful to Washington customers, the analysis makes several false assumptions regarding the Company's access to the Southern liquid markets and double counts the access used in Exhibit No.___(RJF-6). The first false assumption the analysis makes is that when PACW wishes to make a sale to PACE with an offsetting purchase at Mid C, transmission from Mid-C to PACW load pockets is available. This is not the case. Generally, the transmission capability between Mid-C and West Main is already heavily used. The second false assumption the analysis makes is that that any sale made at Mid-C can be made in a Southern Market Hub by diverting Bridger generation. In reality, some sales are made at Mid-C because it is the only outlet for a surplus in the Walla Walla area. The third false assumption the analysis makes is that whenever PACW wishes to make a sale, PACE has surplus transmission to a liquid market hub. In reality, it is likely that when PACW has a surplus to sell, PACE also has surplus to sell and is already using the transmission path to a liquid market.

**Q. Please explain the false assumptions regarding access to the Southern liquid markets.**

A. Mr. Falkenberg starts his analysis by referring to the topology diagram on page 9 of his testimony. As noted in the footnote on page 8, the diagram is from the GRID Algorithm Guide. As noted in the guide, the diagram is for illustrating the topology generally, and is unrelated to a particular rate case or period of time. For example, because the Commission disallowed Colstrip 3 for purposes of setting Washington rates, the link from Colstrip to Goshen is not pertinent to the Washington study. As noted on the diagram, the 104 MW link to Bridger is not a physical path; rather, it is a surrogate for a feature of the RTSA agreement. The fourth false assumption his analysis makes is that the terms of the agreement allow the type of purchase transaction proposed by Mr. Falkenberg. The contract specifically precludes the type of purchase transaction he proposes. He also looks at the transmission capability from Bridger to Utah North and concludes there is 415 MWs of access to the Four Corners market. The fifth false assumption that Mr. Falkenberg makes is that he ignores the 280 MW limitation of moving generation from Utah South to Four Corners and assumes that the line is available at all times, which is not the case. In addition, part of that 415 MWs consists of short-term firm transmission from Idaho Power. The sixth false assumption in Mr. Falkenberg's analysis is to deem the transmission rate as only $0.73/MWh in all hours. In contrast, IPC's short-term rate is $2.38/ MWh in heavy load hours and $1.33/MWh in light load hours.

Mr. Falkenberg improperly calculates the highest margin of Mid-C with assumed sales at SP-15, Four Corners or Palo Verde ("PV") which involves two additional false assumptions. First, as shown on the topology diagram, the Company has zero access to SP-15. Of course, transmission may be available at times for a sale to the ISO, but there is an import fee that generally ranges from $4 to $4.5 per MWh depending on the market clearing price. Second, as shown on the topology diagram, the Company's access to PV is via the Arizona Public Service ("APS") transmission contract. The Company uses this transmission contract to serve the APS exchange. Therefore, any access to PV is going to be with Cholla generation in the lower priced hours when there are not deliveries for the APS Exchange. These hours are probably the hours when both PACE and PACW have a surplus so the PACE transmission is already being utilized.

**Q. Are there additional issues with the margin calculation?**

A. Yes. As discussed above, the price spread between markets is the market's view of transmission costs between markets. PACE would exercise a trade with PCAW only if its transmission cost is less than the spread. In other words, if PACE could save on transmission cost, it would make a transaction. This is the concept behind the share-the-savings transaction incorporated in Mr. Buckley's proposed Eastern Market Modification adjustment. Mr. Falkenberg reduces the margin by a fixed $0.73/MWh for transmission cost in all hours. The $0.73 from Exhibit No.___(RJF-3) is Mr. Falkenberg's calculation of the Company's third party transmission cost for PACE. It does not consider PACE's recovery of its investment in owned transmission assets. The Company's posted OASIS rate for transmission is $5.84/MWh and the posted rate for losses is 4.48 percent. Using the $51.11/MWh price from Mr. Falkenberg's Exhibit No.___(RJF-7), the transmission cost plus the market value of the losses is $8.13/MWh. Considering the IPC transmission rates, the Cal ISO import rates previously mentioned and the Company's posted OASIS rates, the $0.73/MWh is unrealistic.

**Q. Please explain the portion of the interconnection benefit adjustment related to the dynamic overlay.**

A. Mr. Falkenberg proposes to allocate to Washington a portion of the dynamic overlay benefits based on an unrelated and outdated study from 2004. The adjustment comprises $2.9 million of the total $8.6 million interconnection adjustment. Of the $2.9 million portion, $1.2 million is related to ready reserves and $1.7 million is related to spinning reserves.

**Q. Please provide the context for the dynamic overlay benefits.**

A. As a result of the RTSA transmission agreement with Idaho Power, the Company has historically been able to meet up to 100 MW of spinning reserve requirements and up to 75 MW of ready reserve requirements from WCA resources in lieu of PACE carrying those reserves on low-cost coal and gas resources.

**Q. Do you agree with the proposed adjustment?**

A. No. The adjustment value used by Mr. Falkenberg is based on stale information from a three-year old data response from the Multi-State Process ("MSP") related to a different allocation method. Further, the adjustment does not consider the fact that the reserves may have little or no value if PACE carried its own reserves (as Utah Power did prior to the merger) or bought them from another entity.

**Q. How have changes on the system impacted the proposed adjustment?**

A. The Company has made significant system changes in the three intervening years. The Company has entered into new operating reserve contracts with its PACE industrial customers. Using the updated semi-annual report from the Company's response to Commission Staff data request 61, it indicates there is little value to the ready reserve dynamic overlay component in the 12-month period ending March 2007. Setting the ready reserve dynamic overlay component to zero and making the corresponding adjustment in Path C capability result in a total system net power cost benefit of $0.17 million. In addition, the 525 MW Currant Creek combined cycle combustion turbine has been added to the system, thereby reducing the value of the spinning reserve dynamic overlay component.

**Q. Have the spinning reserve and regulating margin requirements of the WCA also increased?**

A. Yes. With the addition of the 100 MW Leaning Juniper Wind project in 2006 and the addition of the 140 MW Marengo 1 wind project in 2007, WCA spinning reserve and load following requirements have increased due to the variability of wind resources. While the spinning reserve requirements increase by only 2.5 percent for each MW of wind project that is added, the variability of wind can cause a significant increase in load-following requirements. Since WCA load following would be provided from hydro units that can provide spinning reserves, those same units would not be able to provide spinning reserves to PACE if they are being used to follow ever increasing wind generation. For example, a 100 MW wind facility could operate anywhere between a 0 percent and a 100 percent capacity factor for a given hour. When the wind stops blowing, the regulating margin requirement could be as much as 100 MW for this one project, depending upon the operating level. Of course, on average most wind projects in the Northwest will probably operate at an average capacity factor of 30-35 percent. Nonetheless, the variability of wind resources will reduce the flexibility of WCA to provide spinning reserves to PACE.

**Q. Do you expect those requirements to increase substantially in the future?**

A. Yes. As a result of the renewable portfolio standards ("RPS") in Washington and California and the expectation that Oregon will follow, load following and spinning reserve requirements will increase substantially. At some point there is simply not going to be enough hydro to follow the wind. So the question needs to be asked whether it is better to retain the load-following capability for the WCA or sell it to PACE. I believe it should be retained for the WCA.

**Q. Is it reasonable to assume that the full value of the dynamic overlay spinning reserve benefits would accrue to the WCA in a situation of an independent WCA and PACE?**

A. No. The PACE system has the ability to provide its own reserve requirements or to buy them from another entity. The excess spinning reserves may not have any value unless PACE is willing to buy them or WCA can find another customer. However, finding another customer in the hydro-heavy Northwest may be difficult to do. Prior to the merger with Utah Power, the Company did not sell excess spinning reserves. So, PACE would be willing to acquire those reserves from WCA only if they were cheaper than other alternatives. Therefore, it would not be reasonable to ascribe the full value to the WCA.

**Q. What is your recommendation for Mr. Falkenberg's interconnection benefit adjustment?**

A. Given the large number of errors associated with the portion of his adjustment related to transfer capability from West to East and from East to West, the $5.7 million portion of the adjustment should be rejected entirely. The portion of the adjustment related to dynamic overlay benefits is stale due to resource changes on the system so it also should be rejected. If, however, the Commission finds merit in the adjustment, at a minimum, its value should be lower. First, the $1.2 ready reserve component of the adjustment should be adjusted to the current WCA value of $0.17 million and then reduced by 50 percent to account for sharing. The Washington share of this adjustment is $0.019 million. Second, at a minimum, the value associated with spinning reserves should be reduced by 50 percent from $1.7 million to $0.85 million Washington to account for sharing. In addition, the Commission should decide whether these benefits should be assumed to be sold to PACE or are reserved for the WCA. I believe the current benefits should be retained for the WCA for the future and the entire adjustment should be rejected.

**Johnston/Wyodak (Part 1)**

**Q. Please explain Mr. Falkenberg's proposed adjustment.**

A. The proposed adjustment assumes that generation from Dave Johnston and Wyodak is transferred through Bridger, is sold in the wholesale market, and is therefore used and useful for Washington customers. The adjustment would reduce net power cost by $3.8 million Washington.

**Q. Do you agree with the proposed adjustment?**

A. No. As I previously discussed, I do not believe the necessary showing of "tangible and quantifiable benefits" can be made in the case of Dave Johnston and Wyodak.

**Q. Are there also flaws in his proposed adjustment?**

A. Yes. There are several; I will explain each one separately. First, as I previously discussed, the Company's modeling already captures all generation being delivered from Bridger to the WCA because our modeling transfers more energy to the WCA than has occurred historically. Therefore, the proposed adjustment would be a double count of benefits. Ignoring the double count, the second false assumption that Mr. Falkenberg makes is that the proposed incremental transfer is 391,332 MWh. The figure was extracted from the wrong study; the correct figure is 237,430 MWh of Wyoming generation and with the possibility that some of the generation originated in Utah. The third false assumption that Mr. Falkenberg makes is that he applies an annual wholesale market price to a monthly distribution of energy transfers. This is troubling when approximately 43 percent of the transfers occur during the spring months when the Northwest hydro runoff occurs and when wholesale market prices are low.

**Johnston / Wyodak (Part II)**

**Q. Please explain Mr. Falkenberg's proposed adjustment.**

A. This adjustment reflects the allocation impact of his proposal to include the East Wyoming jurisdiction, including Dave Johnston and Wyodak, in the WCA. The proposed adjustment would reduce Washington net power costs by $8.2 million.

**Q. Do you agree with the proposed adjustment from the perspective of the "used and useful" requirement?**

A. No, for the reasons discussed above. Inclusion of these resources and Wyoming East load amount to nothing more than an obvious case of cherry picking.

**Q. Using Mr. Falkenberg's reasoning, can this same argument be made for several other resources from PACE?**

A. Absolutely. This argument could be made for any resource with a lower embedded cost than WCA. Using the 100 MW Deseret purchase, for example, this purchase is similar to a flat product that is priced well below market at approximately $37 per MWh. For this reason, all of the energy may not be used to serve retail load requirements so a portion of the energy may be resold in the wholesale market at a profit. And, it could be argued that the transaction provides a benefit to WCA if the purchase and the retail load it serves are included as part of the WCA, because its embedded cost is lower than the WCA average imbedded cost. However, the problem with this example is that even though it could ***theoretically*** provide benefits to Washington, it is not possible to demonstrate "tangible and quantifiable benefits" for Washington customers.

**Q. Does your testimony address Mr. Falkenberg's allocation adjustment calculation?**

A. No. Mr. Wrigley is addressing that aspect of the adjustment.

**Net Power Costs**

**Q. What are the net power cost issues addressed in this portion of your rebuttal testimony?**

A. The following sections of my testimony rebut Mr. Falkenberg's testimony on Short-Term Transactions, SMUD, GP Camas, Hydro Water Year Modeling, Monthly Outages, Ramping and Regulation Margin Modeling.

**Short-Term Firm Transactions**

**Q. Please explain Mr. Falkenberg's short-term firm transaction adjustment.**

A. Mr. Falkenberg believes there are some serious problems with short-term firm modeling and, as a result, he proposes that all of the transactions executed for the test period be removed from the Company's filing. He believes the adjustment is reasonable because: 1) the Company included only known and measurable transactions at the time of the Company's filing and he expects additional transactions will be made that are profitable, and 2) the Company has not demonstrated the test period executed transactions are needed to serve Washington customers or produce benefits commensurate with their costs. The proposed adjustment reduces proposed net power costs by $35.2 million on a total WCA basis.

**Q. Do you agree with Mr. Falkenberg's assessment?**

A. Not at all. The adjustment is an ill-conceived attempt to use 20/20 hindsight. Moreover, including anything other than known and measurable transactions would be contrary to Commission practices. Further, as explained below, Mr. Falkenberg's concerns are not well founded or are just wrong and should be rejected.

**Q. Is it true that the GRID model does not include an estimate for additional transactions that may occur during the test year?**

A. No. The GRID balancing and optimizing process estimates additional short-term transactions with a linear program to develop the lowest possible cost. This process includes buying energy when short, selling energy when long, buying energy at a lower market and reselling that energy at a higher priced market if transmission is available and displacing more expensive generation with lower priced market purchases, if available.

**Q. Does GRID produce a lower volume of short-term firm transactions than occurs on an actual basis?**

A. Yes. However, this is not surprising and is to be expected with any hourly production dispatch model. GRID is no different because it balances and optimizes the system with perfect foresight on an hour-by-hour basis. In contrast, the actual process of balancing and optimizing the system is a long-term process that continually evaluates changes in load and resource balances and involves transactions to balance and rebalance the system leading up to actual delivery. Further, due to the liquidity in the market and the timing of the transaction, the Company may be forced to buy a standard product, when it does not need the entire amount of energy, and then resell the portion not needed in the wholesale market. For these reasons, actual volume will always be higher than the volume calculated with GRID's perfect foresight. In the end, the best method to capture the difference between actual and normalized transactions would be through a PCAM.

**Q. Do you agree with Mr. Falkenberg's assumption that the additional transactions the Company has and will enter subsequent to the filing for the proforma test period will always appear economic at time of delivery?**

A. No. While the Company enters sales transactions only if the incremental cost of energy is below the wholesale market price and will purchase energy when it is the most economic alternative at the time of execution, there is no guarantee that they will appear to be economic at the time of delivery. Due to factors beyond the Company's control, transactions that were economic at the time of execution may appear uneconomic at the time of delivery. Those factors include market price movements, resource availability or unavailability, weather conditions, snow pack, forced outages and other factors. For example, if a utility purchased energy to meet the winter peak based on an assumption of normal hydro and temperature conditions, those transactions would likely appear to be uneconomic at time of delivery if market prices dropped because actual winter conditions were much warmer and wetter than expected. Therefore, an assumption that future transactions will always appear economic at the time of delivery is not realistic.

**Q. Does Mr. Falkenberg's GRID run excluding all actual short-term firm transactions demonstrate that the transactions were demonstrably detrimental to Washington customers and justify his recommendation to disallow recovery of these costs?**

A. Not at all. Mr. Falkenberg's GRID run merely demonstrates that if the West Control Area had been balanced on an hour-by hour basis with perfect foresight like GRID with the static market prices included in GRID, it would have been more economic than the actual balancing costs. The run does not demonstrate that the transactions were uneconomic or imprudent.

**Q. Were the transactions prudent at the time of execution?**

A. Yes. The transactions were unquestionably prudent because they were entered at then prevailing market prices to balance and optimize the WCA. Unfortunately, market prices increased after many of the short-term firm sales transactions were executed, making the contracts appear less economic than had the Company executed the transaction at a later date. This does not justify a disallowance of actual incurred system balancing costs. Mr. Falkenberg's proposed Short-Term Firm adjustment should be rejected. If the Company relied only on hourly transactions, customers would be subjected to a much higher level of market price risk due to the volatility in the hourly market.

**SMUD**

**Q. Please explain Mr. Falkenberg's proposed SMUD adjustment.**

A. The SMUD adjustment removes the Sacramento Municipal Utility District contract from the Company's proposed net power costs. He believes the adjustment is appropriate because he does not think revenue imputation at $37 per MWh is compensatory and the Southern California Edison (SCE) wholesale sales contract, on which the in-rates revenue imputation previously has been based, expired in October 2006. Because there is not another contemporaneous transaction to use as a reference point, Mr. Falkenberg recommends that the SMUD contract simply be removed in its entirety from proposed net power costs. The effect of removing the contract is equivalent to imputing revenue at current prices. The adjustment would reduce proposed net power costs by $12.3 million total West Control Area.

**Q. Please explain the SMUD transaction.**

A. As a result of the cancellation of a non-regulated nuclear project, the Company entered into a series of complex transactions that resulted in the Company acquiring the firm rights to power from BPA in the future. Subsequently, the Company sold the non-regulated BPA firm energy rights to SMUD for a $94 million payment and later accepted the firm rights to power back as a concession for a sale to SMUD at a rate that was below the then current rate for power.

**Q. Has Mr. Falkenberg presented any persuasive evidence for his proposed adjustment?**

A. No. Just because the SCE contract had a shorter term than the SMUD contract does not mean that the relevancy of the price imputation should change. The SCE contract was used to determine an appropriate revenue imputation price because it was the only contemporaneous contract. There is no reason the $37 per MWh revenue imputation should not continue. On the other hand, current market prices have no relevance to a contract that was signed over 20 years ago and should not be used to impute revenues. If that were a reasonable adjustment, it may also be reasonable to adjust contracts like the Mid Columbia power purchase contracts, which are substantially below market, to current market prices. The effect of this would be a substantial increase in WCA costs.

**Q. The SCE contract was renegotiated at a higher fixed price in April 2002. Did the revenue imputation change in any of the Company's jurisdictions after the contract was renegotiated?**

A. No, and this supports the relevance of the original SCE contract. The contract was converted to a HLH product priced at $60 per MWh. Revenue imputation continued at $37 per MWh despite the renegotiated SCE contract because the relevance of the original contract did not change and the new renegotiated contract was not considered to provide a reasonable basis for imputation. In other words, the contemporaneous SCE contract ended long before the renegotiated SCE contract expired and the revenue imputation continued at $37 per MWh. Therefore, there is no reason to change the revenue imputation just because the renegotiated SCE contract expired.

**Q. Has Commission Staff raised an issue with the SMUD revenue imputation?**

A. No. The Company imputed revenue at $37 per MWh in the Company's two previous Washington rate proceeding (Docket UE-032065 and the 2005 Rate Case) and in the current case Staff has not raised a concern in any of the cases.

**GP Camas**

**Q. Please explain Mr. Falkenberg's proposed adjustment.**

A. The proposed adjustment reduces the expected level of generation during the test period based on a 48-month historical trend line. He believes the adjustment is appropriate because he expects the decline in generation to continue at the same rate it previously declined. The adjustment would reduce proposed net power costs by $0.03 million total Western Control Area.

**Q. Do you agree with the GP Camas adjustment?**

A. No. The adjustment violates the Commission's known and measurable requirement since it is a forecast based on a trend. Recent history also demonstrates that the decline in generation previously experienced has stabilized. Therefore, the trend line analysis used by Mr. Falkenberg to predict generation during the test period understates the expected level of generation.

**Q. How does the most recent level of actual generation compare with Mr. Falkenberg's proposed generation?**

A. The most recent 12-month period of generation shows that the trended level proposed by Mr. Falkenberg is too low. In fact, actual 2006 calendar generation was 162,750 MWh compared to 164,608 MWh included in the Company's filing. Thus, while the generation has declined in the past, the trend is not continuing. Therefore, the proposed GP Camas adjustment should be rejected.

**Hydro modeling**

**Q. Is Mr. Falkenberg's proposed hydro modeling adjustment the same as the one proposed by Mr. Buckley?**

A. It is the same with the exception that Mr. Falkenberg recommends its adoption even if a PCAM is not approved by the Commission

**Q. Do you agree with the hydro modeling adjustment?**

A. No. The adjustment should be rejected under all circumstances. Under normalized ratemaking without a PCAM, this adjustment would only insure that the Company was systematically denied the opportunity to recover 100 percent of its costs. The use of fewer water years would also be directionally different than the Commission's recent actions where they authorized a 50-year hydro normalization for PSE, a move away from their 40-year traditional approach.

**Q. Would the Company be willing to adopt a modified version of the adjustment?**

A. Since the mechanics of the adjustment are approximately the same as proposed by Mr. Buckley, the Company would be willing to accept the adjustment with the same revisions proposed in my discussion of Mr. Buckley's adjustment, assuming adoption of the Company's proposed PCAM. Otherwise, I would not be willing to accept the adjustment.

**Monthly Outage**

**Q. Please explain Mr. Falkenberg's proposed monthly outage rate modeling adjustment.**

A. The proposed monthly outage adjustment would reverse the Company's monthly modeling of forced outage rates and substitute annual forced outage rates. He believes his adjustment is appropriate because he claims it is not industry practice and outages are random. The adjustment would reduce proposed net power costs by $.6 million total company. Further, it should be noted that the proposed adjustment is being revised by Mr. Falkenberg from a decrease in net power costs to a Washington increase of $0.15 million.

**Q. Do you agree with the concept of the proposed adjustment?**

A. No. One of the major principles of ratemaking is to properly match costs and benefits under normal conditions. While I agree that outages are random, there is a shape to those outages each and every year. In some years the shape may be more or less favorable to the Company. Because the market value of energy varies from month to month and sometimes significantly, it is important to match the timing of the outages with the cost of the outages in order to ensure the Company has a reasonable opportunity to recover its costs and customers are not paying too much. This is not possible with annual outage rate modeling because this modeling always assumes that the outages occur equally every month of the year, and we know that is not the case. On the other hand, the use of the Company's monthly 48-month rolling average outage methodology will ensure that costs and benefits are matched.

**Q. Do you have an example of the forced outage variability?**

A. Yes. As shown on the graph provided as Exhibit No.___(MTW-9), Jim Bridger Unit 1 had major outages during the summer peak season in 2002 and 2003, when market prices are high. It also shows that outages were generally lower during the spring with the exception of 2005. The point here is that the outages and costs do vary by month. The best way to match costs and benefits is through monthly modeling.

Q. **Is the methodology used in this case a significant departure from the previous methodology?**

A. No. The only difference is that we moved from annual outage rates to monthly outage rates. The total level of outages is actually the same. This is consistent with the use of monthly information for other GRID inputs.

Q. **Why is the Company now switching to a monthly 48-month rolling average compared to its prior use of a 48-month rolling annual average?**

A. As market prices have escalated to the levels prevalent in the wholesale market today, it is very important to match costs and benefits. Failure to do so could exacerbate what has been a significant under-recovery of costs for some time for the Company. Historically, with lower market prices, monthly modeling was not as important as it is today because the cost of outages was much less.

Q. **What is your recommendation for the monthly outages adjustment?**

A. Despite the fact that the revised proposed adjustment increases Washington net power costs, the Commission should reject Mr. Falkenberg's proposed annual forced outage rate modeling because it does not provide a proper match between costs and benefits.

**Thermal Ramping**

Q. **Please explain the ramping adjustment proposed by Mr. Falkenberg.**

A. The proposed thermal ramping adjustment reverses the ramping adjustment included in the Company's filing. He believes the Company's adjustment is not warranted because he believes GRID understates actual coal-fired generation and the Company's modeling approach is not standard industry practice. He also believes the Oregon Commission Order in Docket UE-139 for Portland General Electric ("PGE") is supportive of his adjustment. The adjustment would reduce proposed net power costs by $0.07 million Washington. Further, it should be noted that Mr. Falkenberg is revising his proposed adjustment to a $0.26 million increase in Washington net power costs.

**Q. Do you agree with the proposed adjustment?**

A. No. The reasons stated by Mr. Falkenberg in support of his proposed adjustment are either wrong or do not provide a sound basis for the proposed adjustment.

**Q. Is there any substance to the argument that the Company is modeling phantom outages and that the modeling is not standard industry practice?**

A. No. The Company has merely used an alternative modeling approach to capture the cost of thermal ramping because GRID is not currently structured to capture ramping as some models do.

**Q. Please explain.**

A. The availability rates in GRID assume that coal fired units are available at full load when being ramped down for maintenance and when restarted and ramped up after planned maintenance and forced outages. In reality, coal-fired units are not available at full load when ramping down for maintenance and when ramping up from outages due to the physical capabilities of the units. Generation is lost while a unit ramps to the minimum level required for synchronizing with the GRID and when a unit is being shut for maintenance. The Company's ramping methodology simply reduces thermal availability to reflect generation not available due to ramping to match costs and benefits. .

**Q. Do you agree with Mr. Falkenberg's suggestion that the UE-139 Commission decision that rejected PGE's ramping adjustment is on point relative to the Company's thermal ramping adjustment?**

A. No. The circumstances are completely different and therefore the PGE order does not provide a sound basis for disallowing the Company's adjustment. PGE merely speculated that the problem was related to ramping. In the Company's case, there is no speculation. It is a fact that the Company's thermal generation is lower as a result of ramping before and after the thermal plants are down for maintenance and after outages. Customers are not being harmed by the Company's modeling. They are being asked only to pay for costs related to the benefits they already receive. For these reasons and the others explained above, Mr. Falkenberg's proposed adjustment should be rejected.

**Regulating Margin Modeling**

**Q. Please explain Mr. Falkenberg's proposed adjustment for regulating margin modeling.**

A. The regulating margin adjustment would reduce the 225 MW maximum limit regulating margin GRID model input to a 125 MW maximum limit. He believes this is appropriate because he was informed during 2004 that the maximum limit used by the Company was 125 MW. The proposed adjustment would reduce net power costs by $0.19 million Washington.

**Q. Do you agree with the regulating margin adjustment?**

A. No. The proposed adjustment is based on stale information that is not relevant to the current operation of the system and should not be used. The maximum regulating margin limit should be based on the most recent information that is available. The 225 MW maximum limit used in the Company's modeling is the latest information available as it is based on a study prepared in 2005. Exhibit No.___(MTW-10) is a graph of the summary results for that study. As shown on the graph, the maximum regulation margin far exceeds the 125 MW limit proposed by Mr. Falkenberg.

**Q. Has Mr. Falkenberg previously seen the aforementioned study?**

A. Yes. The Company used the same maximum limit value in its last Oregon filing, Docket UE-179. The adjustment was supported by Oregon Commission Staff but was contested by Mr. Falkenberg. He apparently has chosen to completely ignore the study because he fails to make any mention of it in this case.

**Q. Mr. Falkenberg has previously criticized the Company's analysis because he claims it defines regulating margin as the difference between the average 5 minute hourly peak demand and the hourly average demand. Is this a valid criticism?**

A. No. The study defines regulating margin as:

Regulating Margin = Maximum [5-minuteLoad{Hour(n)}] – Average [5-minuteLoad{Hour(n)}]

The study uses this definition to establish an estimate of the actual regulating reserve requirement. In reality, the change in load from one level to another is just one component of system regulation. Another component of system regulation receiving increased attention is the impact of wind resources on the regulation margin. Thus, the Company's regulating margin calculation is conservative because it does not include the impact of wind resources at this time.

**Q. Mr. Falkenberg has also claimed that the regulating reserve requirement is "performance based," and therefore that any measure of the regulating reserve requirement based on the ramp within an hour is invalid. Is this a logical conclusion?**

A. No. The fact that NERC doesn't establish a formula for the regulating reserve requirement doesn't lead to the conclusion that utilities are unable to develop a formulaic estimate of the requirement. The Company needs the ability to follow the load as the load ramps from one level to another in order to meet its performance criteria. Excluding this critical component from an estimate of the reserve component defies logic. The *WSCC Operating Reserve White Paper* (July 16, 1998 version 1.0) describes methods of estimating regulation reserve. Method B clearly uses "variation in ramp." (See www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=125 (page 9)).

**PCAM**

**Q. What does the following portion of your rebuttal testimony cover?**

A. The following sections of my rebuttal testimony discuss what is acceptable to the Company with respect to the design and structure of a PCAM. I also discuss Mr. Buckley's recommended changes to certain aspects of the Company proposed

PCAM. I also rebut the concerns of Mr. Falkenberg and Public Counsel witness Mr. Johnson with respect to the Company's PCAM proposal.

**Q. Did Mr. Buckley propose adoption of the Company proposed PCAM with modifications?**

A. Yes. Mr. Buckley proposed adoption effective as of September 1, 2007, with several modifications. I believe some of the modifications are warranted as proposed, while I recommend some changes to others.

**Q. Which of Mr. Buckley's proposed PCAM changes are acceptable without changes?**

A. The proposed changes that are acceptable to the Company are: the September 1, 2007 effective date of the PCAM, 50/50 sharing on the first sharing band, monthly reporting, and a $6.0 million threshold for returning balances to customers or collecting balances from customers. My following rebuttal testimony will discuss the Company's proposed changes to Mr. Buckley's recommendation.

**Q. Do you agree with Staff's proposal to remove the fixed production cost component of the PCAM?**

A. No. Given the significant investment in renewable resources and related costs that will be required of the Company as a result of recently adopted RPS standards in Washington, it is important to the Company that it be authorized to file a power-cost-only type of mechanism so that both variable and fixed costs production costs can be trued up on an annual basis to provide a proper matching of costs and benefits. If this approval is received the Company would adopt Staff's recommendation to remove the fixed production cost component of the

PCAM.

**Q. Do you agree with Mr. Buckley's recommendation to adjust the dead band from plus or minus $3 million to $4 million to account for the use of pseudo-actual information?**

A. I have some concerns with the justification. First, the use of pseudo-actual results is getting more attention than it deserves because most of the costs would be actual or calculated from actual information. For example, retail loads, hydro generation, thermal outages, market prices, coal fuel prices, gas fuel prices and executed short-term purchases and sales will be based on actual results. Thermal generation would be calculated by GRID based on actual forced outages and planned maintenance, fuel prices, and loads. System balancing transactions would also be calculated by GRID based on actual information plus thermal generation. Long-term purchases and sales would be held constant at the level included in rates except for those contracts that are impacted by the variability of wholesale market prices.

Second, I believe the Commission's rejection in the 2005 Rate Case of a system-wide approach for setting Washington rates requires the use of pseudo-actual results, because the system is, in fact, operated and accounted for on an integrated basis. While a substantial amount of actual costs and resources can be identified that serve Washington and the West Control Area, there is not a complete and separate dispatch of this. Therefore, it is necessary to perform a re-dispatch for just the West Control Area and to use pseudo-actual results. Having said this, the Company realizes that there are some concerns. For purposes of this case, the Company would not reject a Commission authorized PCAM if Staff's dead band recommendation was adopted. The Company would reserve the right to revisit the issue in the future after the Company has gained some experience with the mechanism.

**Q. Do you agree with Mr. Buckley's recommendation to adjust the first sharing band to amounts over plus or minus $4 million to $10 million and to adjust the outer band to amounts over plus or minus $10 million?**

A. The Company is willing to accept these changes as long as the Company's proposed changes to Mr. Buckley's water year adjustment are adopted.

**Q. Is the Company willing to accept the entirety of the PCAM proposed by Staff, if adopted by the Commission?**

A. The cumulative effect of all changes proposed by Staff, including the water year adjustment, the exclusion of the fixed cost portion from the PCAM, and Mr. Elgin's 16-basis point reduction to the Company's overall rate of return, are punitive. The Company therefore reserves the right to reject the implementation of a PCAM if Mr. Elgin's adjustment is accepted by the Commission. In addition, the water year adjustment must be modified and PacifiCorp must be permitted recovery of resource costs through a power-cost-only type mechanism for the PCAM to be acceptable.

**Q. How do you respond to Mr. Falkenberg's recommended rejection of the Company's proposed PCAM?**

A. It is difficult to reconcile the various positions that Mr. Falkenberg has taken with respect to power cost recovery mechanisms. For example, Mr. Falkenberg was the ICNU consultant when ICNU supported adoption of Avista's ERM. ICNU also supported the implementation of a PCAM for PSE. Mr. Falkenberg was the consultant that worked for the Wyoming Industrial Electric Consumers when that customer group supported adoption of a PCAM for the Company in Wyoming PSC Docket No. 20000-230-ER-05. That mechanism is similar in many aspects to the mechanism proposed by the Company in this case.

**Q. Do you agree with Mr. Falkenberg's claim that the Company failed to address the Commission's concerns expressed in the 2005 Rate Case?**

A. No. The proposed mechanism is almost identical to the mechanism approved by the Commission for Avista, with the exception of the fixed cost component which I discuss later in my testimony. I will address each of the issues cited by the Commission in the 2005 Rate Case.

**Q. Does the mechanism focus on short-term costs subject to market volatility or other extraordinary events that are beyond the Company's control?**

A. Yes. The net power cost variances associated by the Company's PCAM will be primarily driven by changes in market prices, retail load, fuel prices, forced outages, hydro generation, thermal maintenance, short-term wholesale sales and purchases, other wholesale sales transactions that meet the exclusion requirements and wheeling revenues.

**Q. Does the mechanism address the Commission's concern about a 90/10 sharing band coupled with the absence of a dead band and the balance of risks and benefits between customers and shareholders?**

A. Yes. As I previously discussed regarding Mr. Buckley's recommendations, the

Company is willing to accept an even larger dead band and sharing bands with lower sharing in the first sharing band than originally proposed. In addition, the Company is willing to accept a form of a water year adjustment, which is unrelated to any Commission requirement for a PCAM. These bands are larger than Avista's so they would seem to address the Commission's concerns about balancing risks between customers and the Company.

**Q. Has the Company presented an acceptable allocation methodology?**

A. Yes. The Company concurs with Mr. Buckley that the Company has proposed an acceptable allocation methodology based on the Company's reading of the Commission order in the 2005 Rate Case.

**Q. Do Mr. Falkenberg and Mr. Johnson have valid concerns about the Company's use of pseudo-actual results?**

A. No. As I explained above, a significant portion of the alleged "pseudo-actual results" will be based on actual information or calculated from actual information. I believe the Commission's rejection of a system-wide approach for setting Washington rates requires the use of a small amount of pseudo-actual results, because the system is in fact operated and accounted for on an integrated basis. While a substantial amount of actual costs and resources can be identified that serve Washington and the West Control Area, there is not a complete and separate dispatch. So, it is necessary to perform a redispatch for just the West Control Area and to use pseudo-actual results.

**Q. How do you respond to Mr. Falkenberg's criticisms of the process for developing pseudo-actual net power costs as being too vague?**

A. Given his purported concerns, it is surprising that he did not take advantage of the data request process so the Company could clarify any claimed ambiguities. While ICNU issued over 100 power cost-related data requests to the Company, these requests did not seek to clarify what Mr. Falkenberg found vague about the PCAM.

**Q. Can you address the specific concerns Mr. Falkenberg identified about actual market prices for natural gas and electricity, forced outages and hydro generation?**

A. Yes. The Company would use actual Dow Jones market prices spread to hourly market prices using its market price scalar that is used in setting base rates. This would not be a major complication as it was in the referenced PGE case. As far as actual gas prices, the Company would use actual contract prices for Hermiston fuel expense and would use actual market prices in the dispatch and commitment logic. For forced outages the Company would use average monthly outages to be consistent with actual occurrence. For hydro generation the Company would use actual hourly generation by plant.

**Q. Does Mr. Falkenberg's reference to a TransAlta contract extension identify a legitimate concern?**

A. No. The example he portrayed is not even a realistic possibility. TransAlta or any other counter party is not going to extend a 400 MW contract that is priced below market at the same below-market prices. The methodology proposed by the

Company was derived from the Commission-approved Avista ERM mechanism.

**Q. Are the Company's proposed dead band and sharing bands smaller than Avista's?**

A. No. Mr. Falkenberg's conclusion is wrong. In fact, they are larger even though Avista has a larger Washington presence than the Company. Moreover, the Company's mechanism, unlike Avista's, would include a form of a water year adjustment.

**Q. Have you reviewed Mr. Falkenberg's Exhibit No.___(RJF-10), which purports to show the sensitivity of the WCA to various factors beyond the Company's control?**

A. Yes. The analysis is misleading and should be disregarded. One significant drawback to Mr. Falkenberg's analysis is that he looked only at individual events in isolation. He failed to look at the cumulative impact of a combination of events such as poor hydro conditions coupled with high market prices and loads. One of the things we learned from the 2000/2001 energy crisis is how much exposure utilities have when multiple events converge. Further, his individual exposure analyses are misleading.

**Q. Please explain.**

A. Mr. Falkenberg portrays the Company's exposure to market prices based on a 10 percent variance in the price of electricity. Based on the $47 per MWh average short-term purchase price in the Company's filing, his 10 percent market price exposure amounts to a variance of $4.7 per MWh. This is misleading because it significantly understates potential market price volatility. For example, during last summer's heat wave, market prices approached $190 per MWh.

**Q. Isn't the Company's exposure reduced because it purchases energy forward to cover shortages?**

A. Purchasing forward helps the Company reduce exposures to known energy deficits, but it does not protect the Company from factors beyond the Company's control like poor hydro conditions, plant outages, extreme temperatures and other events that are not known in advance.

**Q. Is his hydro variability analysis also misleading?**

A. Yes, because he uses one standard deviation as being the range of hydro generation volatility, when there is nothing statistically valid about one standard deviation in terms of measuring hydro generation exposure. The analysis is also faulty because it does not vary market prices with extreme changes in hydro generation.

**Q. Please explain Mr. Falkenberg's alternative PCAM proposal.**

A. In the event the Commission decides to adopt a PCAM, he proposes a hydro hedge PCAM to simulate a hypothetical hedge agreement between the Company and Washington customers.

**Q. Please explain the Hydro Hedge.**

A. The Company would "pay" Washington customers a $1.2 million annual premium for the right to have customers pay the Company for poor hydro conditions and the Company to pay customers for good hydro conditions. All hydro generation within one standard deviation would be within his recommended $8.6 million dead band, which is over twice the size of Avista's $4.0 million dead band, and no payment would be made to either customers or shareholders. Outside the dead band, payments would range between plus or minus $1.1 million to $12.4 million.

**Q. If the Hydro Hedge PCAM were a commercial transaction, would the Company enter such a transaction?**

A. No. When coupled with his proposed water year adjustment and the return on equity reduction, the proposed mechanism would be uneconomic for the Company. As shown on Exhibit No.___(MTW-11), the expected value of the hedge for customers during good water years is $5.5 million. During poor water years the expected value for the Company is a mere $0.5 million. Consequently, the proposed Hydro Hedge PCAM is unacceptable to the Company and would cause a rejection of the PCAM.

**Q. Mr. Johnson also recommends that the Commission reject the Company's requested PCAM. Did he provide reasons that are similar to those already addressed regarding Mr. Falkenberg's testimony?**

A. Yes. The testimony has more or less the same themes that are included in Mr. Falkenberg's testimony, which I addressed above in my rebuttal testimony. My following rebuttal testimony will address only the additional issues raised by Mr. Johnson.

**Q. Do you agree with Mr. Johnson's recommendation that the PCAM decision should be deferred to allow for a PCAM designed to reflect the cost allocation method the Commission adopts in this case?**

A. No. This position is particularly odd, considering that Public Counsel opposed an earlier stipulation in the proceeding that would have provided such a bifurcated process.

**Q. Is Mr. Johnson correct when he states that 17.9 percent of West Control Area load is met by hydro generation and that this is less than half the level of exposure to PSE and Avista?**

A. No. Hydro generation meets 30 percent of the Company's WCA load requirements and is 62 percent of the hydro exposure for Avista and is 71 percent of the hydro exposure for PSE.

**Q. Mr. Johnson implies that there is a hydro reliance threshold that a utility need to pass to have a PCAM approved. Is this the case?**

A. To the best of my knowledge, the Commission has never identified a specific hydro reliance threshold that must be met in order to obtain a PCAM.

**Q. Mr. Johnson indicates that the use of historical hydro generation is not a reasonable basis to establish exposure to hydro conditions. Do you agree?**

A. No. It has been a long standing Commission policy to use historical generation adjusted for current operating capabilities to determine a normalized level that is included in rates.

**Q. Is the historical data used in your direct testimony too stale to provide a realistic analysis of the Company's potential hydro exposure?**

A. No. For the most part actual hydro generation variability is a function of annual precipitation and snow packs, so the variability is still relative.

**Q. Mr. Johnson suggests that it is appropriate to compare the Company's hydro exposure and other net power cost risks on a total Company basis. Do you agree?**

A. No. The analysis infers that the determination should be impacted by the relative risk of the other states. This is an unfounded suggestion and inconsistent with Commission finding in the 2005 rate case. Washington operations are regulated on a stand-alone basis and the relative risk of the Company's Utah jurisdiction is irrelevant to Washington. Further, the Commission rejected developing Washington rates based on total system operations in the 2005 Rate Case. Therefore, the analysis is not valid to the determination of a Washington PCAM.

**Q. Mr. Johnson states that an 18 percent variation in hydro production represents a "once-in-a-decade" event. Does this present an accurate portrayal?**

A. No. The four worst water years occurred in the last 12 years of the 40-year period used in the Company's filing. If the information is updated through 2006, the 6 worst water years of the last 40 occurred in the last 15 years. This indicates that the Company's exposure could be much greater than a once in a decade event.

**Q. Mr. Johnson is critical of the Company's proposal to include new resources with a term longer than 2 years in the PCAM if they are under 50 aMW. Do you have any comments?**

A. Yes. The Company included this PCAM provision as a means to simplify the process. However, if the Company's is authorized to file a power-cost-only type mechanism, the Company would be willing to scale back its proposal to exclude from the PCAM all new resources with a term longer than 2 years.

**Q. Does this conclude your testimony?**

A. Yes.