BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY

DOCKET NOS. UE-050684 and UE-050412

DIRECT TESTIMONY OF MERTON R. LOTT (MRL-1T)

ON BEHALF OF THE

PUBLIC COUNSEL SECTION

NOVEMBER 3, 2005

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DIRECT TESTIMONY OF MERTON R. LOTT
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I. INTRODUCTION AND SUMMARY

Q. Please state your name and address.

A. My name is Merton R. Lott. My business address is 10809 103rd St. SW, Tacoma, Washington.

Q. By whom are you employed?

A. I am self-employed as a consultant concentrating on utility rate work.

Q. On whose behalf are you appearing?

A. I have been retained by the Public Counsel Section of the Office of the Attorney General of the State of Washington (Public Counsel) to review certain aspects of the recent rate application of PacifiCorp, d/b/a Pacific Power & Light.

Q. What areas will your testimony address?

A. My testimony addresses the following three areas:

1. The history of the development of allocation methodologies to be applied by the Washington Utilities and Transportation Commission (Commission) to this Company from prior to the merger of the Utah and Pacific divisions to the present day;
2. My concerns with the currently proposed allocation methodology, Revised Protocol; and
3. The Company's proposed power cost adjustment mechanism (PCAM).

Q. What are your recommendations with respect to the Company's proposed "Revised Protocol" Interjurisdictional cost allocation methodology?

A. I recommend that the Commission not accept the Revised Protocol for ongoing cost allocations. The Revised Protocol fails to allocate individual costs on a cost causation basis. To date, the allocation procedures proposed by PacifiCorp are approaches that it asserts balance the needs of the various jurisdictions, as new resources are added. But, as the system grows unequally, the future allocation process will again change, thus throwing off the relationship of costs included in each states revenue requirement. No allocation approach to date has been durable and Revised Protocol suffers from the same weakness.

Rather, I recommend that the Commission direct its staff and other interested parties to work with the Company on an allocation system which does not allocate to Washington state resource costs from the Utah Power and Light Company (Utah Power) or resources built to serve Utah loads, as the Revised Protocol and its post-merger predecessor(s) have done and will continue to do if implemented.

There are eight factors which should guide this Commission's consideration of developing a proper allocation methodology for Washington. Because the Revised Protocol fails to meet all of these eight factors, and other consideration in my testimony, I believe the Revised Protocol allocation methodology is not in the public interest and should not be adopted as currently proposed.

Q. Do you have any recommendations on how the Commission should set rates in this proceeding?

A. No, not directly. The Revised Protocol represents an unacceptable allocation methodology as currently proposed. The Commission could set rates that would sunset at a date certain based on the Revised Protocol or a "Hybrid" model unless an agreed upon allocation methodology is approved which supports this rate finding.

Q. What are your recommendations concerning the establishment of a Power Cost Adjustment (PCA) for PacifiCorp?

A. I believe the Company's PCAM proposal is flawed both because a PCA cannot be appropriately initiated without resolution of the allocation question, and because the Company's proposal fails to meet the criteria this Commission has established for PCA mechanisms which I believe are vital to a successful PCA.

In general I do not oppose the establishment of a PCA. However, I believe that any PCA should be driven by actual results being compared to properly allocated results for Washington. Since I do not believe the Revised Protocol is an appropriate or stable allocation approach, determining a proper PCA for PacifiCorp is difficult to impossible.

Q. If the Commission does adopt a specific allocation process in this proceeding and is therefore ready to adopt a PCA for PacifiCorp, what are your recommendations?

A. Generally it is my belief that PacifiCorp should be allowed a PCA that acts in the same fashion as the current PSE Power Cost Adjustment Mechanism (PSE PCA).[1] I cannot recommend a PCA like Avista's emergency Energy Recovery Mechanism (Avista ERM).[2] I will describe in more detail later in my testimony how a PCA could be constructed for PacifiCorp consistent with previous Commission findings.

II. QUALIFICATIONS

Q. Please state your educational background.

A. I graduated from Seattle University with a Bachelor of Arts in Business Administration, with an Accounting Major, in 1973. Subsequent to my graduation I passed the CPA exam and obtained a Certificate of Public Accounting (CPA) in the State of Washington which I maintained for over twenty years. Currently I do not possess a certificate. While employed with the Washington Utilities and Transportation Commission, I attended numerous classes and conferences on regulation, accounting, and finance. These classes met the continuing education

[1] *WUTC v. Puget Sound Energy, Inc.*, Twelfth Supplemental Order Rejecting Tariff Filing; Approving and Adopting Settlement Stipulation Subject to Modifications, Clarifications, and Conditions; Authorizing and requiring Compliance Filing, Docket Nos. UE-011570 & UG-011571, pp. 9-15 (PSE 2001 GRC Order).

[2] *WUTC v. Avista Corporation, d/b/a Avista Utilities,* Fifth Supplemental Order: Rejecting Tariff Filing; Approving and Adopting Settlement Stipulation; Authorizing and Requiring Compliance Filing, Docket No. UE-011595, pp. 14-16 (Avista ERM Order).

requirements for my CPA. Further, as one of the Commission's representatives to the National Association of Regulatory Utility Commissioners (NARUC) subcommittee on accounts from 1991 until my retirement in 2004, I participated in numerous semiannual conferences held by the subcommittee.

Q. Please summarize your professional experience.

A. Subsequent to graduation from Seattle University, I was hired by the Washington Utilities and Transportation Commission as a U&T Accounting Analyst in the Accounting and Finance section of the Utilities and Accounting Division. In 1986, I was promoted to a Revenue Requirement Specialist 5 in the Accounting section, where I was the supervisor of all accountants assigned to the electric industry. During the 1974-1990 period, I performed various phases of accounting and financial analysis of both utility and transportation companies. I served as the lead auditor in rate audits of the major companies in all industries regulated by the Commission, including multiple cases covering all three of the electric firms regulated by the Commission. Included in those proceedings were most of Puget Sound Power & Light's (PSE's predecessor) Energy Cost Adjustment Clause (ECAC) proceedings as well as Washington Water Power's (Avista's predecessor) proposed Power Cost Adjustment petition.

In 1990 I transferred to the Regulatory Affairs Section as the Commission's Accounting Advisor where I was subsequently promoted into a Washington Management Service position. During this period, I advised the Commissioners, Administrative Law Judges, and Review Judges on all formal proceedings that had financial and/or accounting issues. Several major rate proceedings, including those of Washington Natural Gas, Puget Sound Power & Light, US West, and Waste Management, were filed while I held this position. Several merger petitions also were processed during this time frame. Also during this period, Puget Sound Power & Light filed for a Periodic Rate Adjustment Mechanism (PRAM). The PRAM combined a decoupling and a PCA mechanism.

In June 1996, I was promoted to Gas Industry Coordinator where I reported to the Director of Regulatory Services. In this position from 1996 to 2001, I supervised the Regulatory Service Division's staff assigned to the gas industry and coordinated filings in that industry. During this period the gas section processed several tariff filings, rulemakings, and policy development proceedings including several gas general rate cases. During the period I also assisted the Commission as their accounting advisor in several telephone proceedings. In addition, I participated in several electric industry filings, and was the lead analyst in the 1999 PacifiCorp general rate filing.[3]

In January 2001, when the Regulatory Services Division consolidated the gas and electric departments, I became the Energy Industry Coordinator. During this period I worked with the Assistant Director of Energy. Further, I was the lead staff on a series of Puget Sound Energy (PSE) petitions and tariff filings, including the interim and general rate cases in Docket Nos. UE-011570 and UG-011571. That proceeding was resolved with an omnibus all-party settlement involving over 30 parties. That settlement (comprised of a number of sub-agreements) included: the use of an "equity tracker"—a hypothetical capital structure and a tariff mechanism designed to insure that PSE would obtain the desired capital structure over a reasonable time period (settled in the interim rate case); the development of PSE's PCA and "power cost only rate case" (PCORC) mechanism; a fundamental change in PSE's electric line extension policy; consensus agreements on conservation and low income tariffs; a consensus between PSE and the numerous intervening cities

[3] *WUTC v. PacifiCorp, d/b/a Pacific Power & Light*, Docket No. UE-991832 (PacifiCorp 1999 rate case).

regarding line undergrounding tariffs; a service quality index, and settlements on interim and general rate increases for gas and electric.[4] Just prior to my retirement on April 30, 2004, I was the staff lead in PSE's first PCORC filing.

Subsequent to my retirement, I signed a contract with the Commission as an accounting advisor and assisted them on the PSE general rate case in 2004. In 2005 I was retained by Public Counsel to analyze both the Avista and PacifiCorp general rate case filings.

III. THE HISTORY OF INTERJURISDICTIONAL ALLOCATION

Q. Mr. Lott could you now move to the subject of history of allocations with respect to Pacific Power & Light Company (PP&L) and PacifiCorp. Did you participate in PP&L rate proceedings prior to the merger with Utah?

A. Yes.

Q. Were allocations an issue prior to the merger of PP&L with Utah Power?

A. Yes. While it is true that allocations were not directly contested in the rate cases I participated in, the issue of allocations between the jurisdictions was in flux during the 1980's. In 1982 an allocation process was used which had been in place for several years,[5] but by 1986 both the Oregon and Washington Commissions had indicated that the allocators related to production property were inappropriate. During the 1980's Washington Commission Staff participated in a process that resulted in a "fully rolled-in" allocation process for Oregon, Washington, Montana, California, Idaho and Wyoming which allocated production plant on a split between

[4] *PSE 2001 GRC Order.*

[5] *WUTC v. Pacific Power & Light Company,* Fourth Supplemental Order, Docket Nos. U-82-12 and U-82-35.

energy and a 60 month coincident peak (CP) demand allocator.[6] This new allocation process was introduced in Washington in the 1986 proceeding as testified to by Staff witness Mr. Nikula. The general construct of this allocation process is described in the Commission order in Cause No. U-86-02.[7]

Q. Did all jurisdictions agree to the allocation procedure utilized in that proceeding?

A. No. The state of Wyoming did not fully accept the new allocation process. The issue as I understood it at the time was that Wyoming was not in favor of the heavy emphasis on energy in the production plant allocator called "note 1." The Pacific states of Oregon, California, Washington and (I believe) Montana were all winter peaking states with a mix of residential, commercial, and industrial customers. Wyoming's load was dominated by large, flat loaded industrial customers, an energy allocator (like Note 1) resulted in more costs being allocated to Wyoming than would be allocated using a demand allocator.

Q. Why was an energy allocator used?

A. Despite the fact that the Pacific division states had seasonal load patterns, the Pacific division had met this seasonal load with substantial hydro resources and a low-cost peaking contract from the hydro resources of the Bonneville Power Administration. The Company was and is still able to shape this hydro power to meet the load for both seasonal and, more importantly, hourly peaks. These hydro resources removed the demand stress on the Pacific division's capacity requirements. As a result the

[6] "Rolled-in" allocations refers to an allocation method which utilizes system wide operating statistics and system wide account information to determine the allocation of those costs which generally are considered shared costs. A rolled-in allocation process ignores facts such as pre merger endowments, authorizing states with respect to qualifying facilities (QFs), conservation costs, or other such divisional or state oriented cost causation. A few items that are not rolled-in by the "Revised Protocol" include the hydro endowment, the treatment of QFs, and the treatment of conservation expenditures. With respect to power supply, both the system and seasonal allocations generally fit the definition of "rolled-in."

[7] *WUTC v. Pacific Power & Light Company,* Second Supplemental Order, Docket No. U-86-02, pp. 33-34.

"old PP&L" could meet its growing loads' energy and demand requirements by obtaining baseload energy rather than obtaining new peaking resources.

Q. Can you please describe the merger proceeding?

A. PP&L came to the Commission in 1987 asking to merge with Utah Power and Light.[8] PacifiCorp indicated that while the merged companies would operate as a consolidated system, they would maintain a separation between the two operating divisions. In discussions with the Company and in the evidentiary hearing it was suggested that each of the operating divisions would have its own resources and that the power supply synergies would be dealt with through some type of pricing mechanism. Documents that I reviewed from other states in the past indicated that at least for Oregon the same assumptions had been relayed to their Commission. The Commission's orders on the PP&L-Utah Power merger indicate the Commission was concerned that the Pacific States needed to be guaranteed a share of the benefits of the merger, as the Utah states had been promised.[9] Further, the Commission indicated that the integration of the power supply systems of the two Companies should be done consistent with the Company's least cost plan. Please note that the Commission did not state that the addition of new resources had to be consistent with the plan, but that the integration of the two systems had to be consistent with the least cost plan for PP&L.

Q. Did the Oregon Commission take the same position as Washington?

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[8] *In the Matter of the Application of PacifiCorp (Maine) to Merge with PC/UP&L Merging Corp. (PacifiCorp Oregon), and to Issue such Securities and Assume such Obligations as may be Necessary to Effect a Merger with Utah Power & Light Company,* Second Supplemental Order Approving Merger with Requirements, Docket No. U-87-1338-AT (Pacific-Utah Merger Order).

[9] *Pacific-Utah Merger Order*, p. 13; *See also* First Supplemental Order, Docket No. U-87-1338-AT, expressing concerns about the sharing of merger benefits (prompting additional company filings).

A. The Oregon Commission Order was more explicit:

> *"The provisions of the stipulation, together with the various commitments made by the Applicants and the regulatory powers available to the Commission, ensure that Pacific division customers will not absorb any merger-related costs or subsidize the Utah Power division."*[10]

Q. What happened at the initial allocation meeting held in San Diego California?

A. Prior to the San Diego meeting of February 21-23, 1989, PacifiCorp distributed documents indicating its intent to try for a unified allocation process. At the meeting it introduced what it termed the "Bold Course" methodology. Discussions on whether or not to treat the merged systems as one were held. With some reluctance on Washington's part, a decision was made to attempt to go ahead with the process to see if something could be worked out. The reluctance of the Washington Commission Staff to the Bold Course plan stemmed from various concerns, including the fact that the plan did not take into consideration the surplus each division brought to the merger. Washington Commission Staff were also concerned with the assumption in Bold Course that in the foreseeable future the merged system costs would cross below that of PP&L's. We believed there was a high probability that this assumption was not true. One thing staff did like about the proposal was that PacifiCorp intended to share the benefits of the merger between the two divisions.

In addition to the Bold Course proposal by the Company, the Utah agencies presented a proposal which used "rolled-in" allocations. It included a lump sum transfer amount in the form of a liability subtracted from the rate base of each of the Pacific states. The subtracted liability was coupled with corresponding

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[10] *In the Matter of the Application of PacifiCorp and PC/UP&L Merging Corp. for an Order Authorizing the Merger of PacifiCorp and Utah Power & Light Company into PC/UP&L Merging Corp (to be renamed PacifiCorp upon completion of the Merger), and Authorizing the Issuance of Securities, Assumption of Obligations, Adopting of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorizations in Connection Therewith,* Order No. 88-767, p. 23 (Oregon Pacific-Utah Merger Order).

amortization. At the same time, the lump sum was added as an asset to the rate bases of the Utah states with a corresponding amortization. The lump sum transfer was to represent the endowments the two companies brought to the merger, and this plan was termed the "San Diego Plan." As with Bold Course, the Washington Staff was concerned that the plan made an assumption about the difference in costs going away when the Washington Staff was uncertain this would happen.

Q: Were there any statements on the differences in costs of the two systems?

A. Yes. A statement by an Oregon staff member of the allocation group to the Commissioners from all the states indicated that there was a 40% difference in costs per kWh between the two divisions. At the same meeting Dr. Weaver, then a representative from the Utah Division of Public Utilities, indicated that the traditional (rolled-in) allocation approach was unworkable because of the high costs Utah brought to the merger. Washington's Commissioner Casad stated at this meeting that it was his intent to keep the value of the PP&L system for PP&L ratepayers when designing an allocation method.[11]

In June of 1989 the committee came to a tentative agreement to use a version of the Bold Course allocator for a one year period. The allocation process, termed the "Interim" methodology, produced sharing benefits that were approximately equal between the two divisions.

Q. During this allocation process you refer to sharing of benefits between the two divisions and that the sharing was equal as stated above related to the Interim Allocation method, what was the basis for determining the allocation of benefits?

[11] Commissioner Casad was this state's Commissioner representing the Washington Commission in the allocation talks with the various PacifiCorp jurisdictional state Commissioners.

A. PacifiCorp had developed through its least cost planning processes (both PP&L and Utah Power), and through the merger process what it termed stand alone projections of each of the merged companies absent the merger. Based on these projections and a comparison to the projections for the merged Company, PacifiCorp created calculations which were intended to represent the total benefits of the merger. By allocating the results under any particular allocation proposal a calculation of how the merger benefits were being shared was determined. These projections were used for these comparisons despite the fact that regulators from both divisions were concerned that these projections were not entirely accurate. This concern on the part of Commission representatives from both the Pacific and Utah divisions is a significant reason why the Committee settled on sharing benefits 50/50.

Q. Other than the hydro endowment, what were some of the other problems that the Washington Commission Staff noted with respect to the proposed allocation method?

A. The allocation method was the result of substantial give and take. The Interim method gave the Pacific division states the hydro production facilities PP&L owned prior to the merger but did not give them the power from the Mid-Columbia hydro project purchased power arrangements (Mid-C or Mid-C contracts) with Chelan, Grant, and Douglas Public Utility Districts. The allocation process conceded substantial secondary sales to the Pacific division but at the same time substantially increased the total cost of fuel allocated to the Pacific division. The result in the end was the process gave short term results that were satisfactory. But these results were unstable because the allocation was not based on cost causation.

Further, one major controversy was revealed in this process, namely the question of what drives the addition of new resource costs. This was referred to in the Utah Power states as the "stress factor." The Utah states identified the process used for Utah Power which identified the months that placed stress on that system. Interestingly, Pacific Power and Lights Power Supply expert Mr Steinberg and his assistants had a strong reply. They stated that in the Pacific division this simply was not relevant as the Pacific division was not stressed on a demand basis, but rather on an energy basis. The Pacific power supply representatives were extremely adamant that the current allocation process in the Pacific states (which emphasized energy) was correct.

Q. Was there any analysis of whether growth in the two systems would impact the allocations?

A. Yes. In a November 1989 meeting, the Company presented an analysis which indicated that in order to achieve a crossover of PP&L costs with system costs the Pacific division would have to grow at a much higher rate than the Utah division. At the same meeting the Utah agencies were already stating that the only method based on principle was the San Diego method.

Subsequent to that meeting, Mr Lee (the Montana representative) expressed his concern over the continued push to "rolled-in" when the Company had already demonstrated that no crossover was likely to happen. The Utah agencies continued to push for the San Diego approach.

Q. What replaced the Interim method?

A. In early 1990 the states came to agreement on a refinement of the Bold Course approach for the 1990-1992 periods. This approach, named the "Consensus" method, again provided results which shared the benefits of the merger approximately 50/50 during this period.

Q. What did the committee do during the period in which the Consensus method was in effect?

A. During the next two years parties discussed further refinements to the Bold Course or Consensus type of approach. There were numerous different versions including Mercury (a Pacific states' proposal), Gemini (a Utah states' proposal), and Apollo, a compromise of the other two. During this period the issues of endowments and a division's responsibility for what it had brought to the merger dominated the discussions. As a result, an allocation process that was derived from a rolled-in allocation process with two steps added to it became the major focus of compromise and was referred to as "Step Two."

Q. What were the two steps?

A. First each division was held responsible for the production plant owned at the time of the merger. The second step provided for the endowments of each division. The Pacific division's hydro endowment was measured by subtracting the energy and capacity of the hydro systems directly from the Pacific Division's load and demand before calculating the allocation factors for the remaining generation plant. The purchased low-cost hydro from the Mid-C PUDs was still at issue.

Q. What happened to the San Diego approach?

A. As I indicated before, the representatives from Utah had been strongly in favor of moving to this method. They apparently believed that they could take the current year difference in costs, calculate a lump sum amount of money to be added to Utah's revenue requirements and subtracted from Pacific states revenue requirements, and have this amount amortized over some period of time. Their preference was naturally for a relatively short period of time.

Commissioner Casad had been present at many meetings where the PacifiCorp Interjurisdictional Taskforce on Allocations (PITA) leadership group gave progress reports on the different committees' status. At these meetings the Utah staff members had brought up the concept of the San Diego approach as the reasonable method to end this process. Commissioner Casad discussed this plan with me and we determined that the weakness of the San Diego approach was that while the proposal may measure the impact of what each division had at the time of the merger, the proposed static measurement did not measure the impacts of how each of the divisions were growing. We concluded that if the Pacific Division grew slower than the Utah division then the gap in power supply costs would not shrink, but instead grow. Therefore, moving to rolled-in would violate this Commission's order to move to rolled-in through the process of meeting Pacific's least cost plan. As an alternative, we thought a lump sum could be calculated that would take into consideration the difference in growth rates between the divisions. The Washington Commission could then control the treatment of our allocated share and such an approach would be acceptable.

Based on our discussions, Commissioner Casad proposed that the "Lump Sum" method be considered. Despite knowing our ideas would not be acceptable to the Utah agencies and the Company would have severe accounting problems with the proposal to leave portions of the lump sum unamortized on who books we decided to proceed. At following PITA meetings I presented our ideas on how the lump sum could be calculated based on the present value of the differences between Pacific States and rolled-in, including consideration of the growth factors. Further, I discussed the concept that each state should have the ability to control their portion of the lump sum transfer. While Commissioner Casad's Lump Sum proposal died there, it did stop the discussion of the San Diego approach.

Q. What happened at the conclusion of the Consensus method's period of application?

A. The states adopted the Step Two approach, then renamed the "Accord" method.

Q. What was new in the Accord method?

A. The Accord methodology included several changes to the Consensus method. The most notable change for the Pacific division states was the direct allocation of the hydro resources to the Pacific States before the allocation of other resources. Another change involved allocating State Income Taxes and Washington Utility Taxes on a system basis rather than on a situs basis. This element was favorable to Washington, because our Public Utility Excise Tax is a larger share of revenue than the State Income Taxes of the other states.

Q. What changed after that?

A. I did not directly participate after the adoption of the Accord method. It is my understanding from discussions with Washington Commission Staff who continued to attend the meetings (and other sources) that the PITA group continued to meet. As described by Mr. Taylor, apparently there was concern over how the Accord was allocating new resources because of the subtraction of hydro energy and capacity from Pacific states' loads and peaks before calculating the allocator to be applied to new resources (or additions to existing resources). The "Modified Accord" was created and it attempted to rectify this while still maintaining a sharing of benefits. Thereafter Utah decided to abandon the Modified Accord and go to a fully rolled-in approach, largely creating the jurisdictional differences the Company is now attempting to resolve through the Revised Protocol.

Q. Are there themes that you believe are a common thread through the history of the allocation process prior to Utah deciding to abandon the Modified Accord?

A. Yes. I believe there are five common themes that have remained relatively constant throughout the allocation discussions involving PacifiCorp. They are:

1. That the merger was intended to benefit both divisions;

2. That while the actual levels of merger benefits may be debated, the allocation process should attempt to share these benefits equally between the two divisions;
3. The allocation methods that stemmed from PacifiCorp's Bold Course approach could not be sustained due to inherent problems within these models which tried to balance the impacts of costs brought into the merger with costs to provide for growth and replacement;
4. The Pacific division states believed that the merger was appropriate because it reduced total costs and therefore both divisions could be better off with the merger than without the merger, not because the two divisions should be treated as one on a cost basis; and
5. Many of the Utah participants thought the merger would reduce total costs and ultimately move to a single system (rolled-in) where Utah customers could share in the long term benefits of the combined system, including the Pacific division's hydro resources.

Q. Why do you believe the Bold Course allocation process and its successors did not result in a sustainable outcome?

A. Most fundamentally, these approaches did not allocate new resources to the divisions that created the need for the new resources. Under the Modified Accord new resource costs were spread on a system basis while existing resources were allocated on a pre-merger basis. Thus, if one division grows faster than the other the slower growing division ends up paying for expensive new capacity costs the need for which it did not cause. It should be noted that growth is not the only situation that causes this problem. If a major pre-merger power plant assigned to a division is retired its replacement is allocated across the system, thus increasing one division's capacity allocations without a used and useful justification while decreasing the allocation to the division with the retired resource. Further, all modifications to an existing plant were allocated to the system while the existing plant remained a divisionally allocated resource.

Q. Is the Revised Protocol an allocation method that stems from the Bold Course?

A. Generally, yes. While the Revised Protocol eliminates some of the balancing problems contained in the Modified Accord (which is itself a derivative of the Bold Course) it does not deal with growth directly. Thus, allocating new resources to the divisions is not based on the need for the new resource but rather based on the size of each division. Further, the Revised Protocol allocates more capacity to Oregon and Washington than is used in Oregon and Washington. The problem with the Revised Protocol from this standpoint is the same as the Modified Accord. They both violate this Commission's original directive, which was not to roll-in costs except through the least cost plan. In none of the allocation processes, starting with the Bold Course through the currently proposed Revised Protocol, has this directive been considered. Instead there have been multiple attempts to simply dance around the issue by attempting to validate the allocation processes during the PITA period by calculating equal sharing of benefits; and now by making comparisons to allocation processes previously used by different states. These allocation processes previously used, namely "rolled-in" in Utah and Modified Accord in other jurisdictions are themselves flawed systems from this state's perspective in the first place. To use them as the basis for a determination of reasonableness makes little sense.

IV. PROPER ALLOCATION

A. Summary of Proper Determinants for An Allocation Methodology

Q. Would you please describe what factors are important in the creation of a sustainable allocation process for PacifiCorp?

A. There are eight factors that I believe should be considered by the Commission when determining the proper allocation method for PacifiCorp.

First, the allocation methodology should meet this Commission's requirement that the rolling in of resource costs from the Utah division should be accomplished consistent with Pacific's least cost plan. As discussed above in the history portion of my testimony, the original anticipation of the Washington Commission was that the two divisions would remain separate on a power supply basis and the only question with regard to power supply costs would be the determination of how to treat transfers of power from one division to the other. However, at the first allocation meeting PacifiCorp attempted to lead the states down a different allocation path, the Bold Course. Now some 15 years latter and several attempts at making this Bold Course approach work, it is at best difficult to determine whether the allocation methodologies have anything to do with the cost caused by the Pacific and Utah divisions. In my opinion the Revised Protocol is the latest version of the "Bold Course," it is fatally flawed and it should be permanently rejected. A corollary of this first factor is that on a power supply basis the allocation method this Commission adopts should protect the Pacific Division's endowments (including hydro resources) and any other factors that would exist on a Pacific division, stand alone basis. The Company still plans for the two divisions separately. This is discussed in the testimony of Public Counsel witness Charlie Black.

Second, the allocation process the Commission adopts should take a cost causative approach that is sustainable. This factor should be viewed in conjunction with the first factor, noting that cost causation can be interpreted in several different ways by various jurisdictions and therefore take several different forms. Thus, even though some may view the "rolled-in" method as a cost causation method that approach fails this test in my view.

Third, the Pacific division states had a consensus on a heavily energy-weighted allocation method prior to the merger. This consensus for an energy-weighted allocation method was a consensus based on the multiple factors that affected jurisdictions at that time. Any allocation method adopted by the Commission should consider this pre-merger consensus for a heavily energy-weighted allocation. The 75% demand-weighted rolled-in approach proposed here by the Company fails this test.

Fourth, the Eastern control area (as defined by the Company) includes the PP&L portion of Wyoming. Wyoming was part of the Pacific division prior to the merger and any division of costs based on the concept of Pacific division's endowments should allocate to Wyoming a fair treatment of those Pacific division endowments.

Fifth, while Wyoming was part of the Pacific division, some consideration should be given to Wyoming's objections to the allocation methodology agreed to at the time of the merger. Wyoming did not agree to the old Pacific state allocation as adopted by the Washington Commission in the U-86-02 order.[12]

Sixth, the Pacific-Utah merger was entered into to create synergies for the benefit of customers. The merger was a coupling of two companies, and from a regulatory standpoint, eight jurisdictions. Each of those jurisdictions allowed the merger because of the promise that the merger would reduce rates for customers in that state. Thus it is appropriate to establish allocations which result in benefits for all.

Seventh, the PITA allocation processes resulted in allocation procedures that at the time (1992-1997) produced allocation results with approximately equal benefits to both divisions.

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[12] *WUTC v. Pacific Power & Light,* Second Supplemental Order, Docket No. U-86-02, p. 33.

Eighth, in addition to the divisional growth factors, some jurisdictions may reasonably argue that growth rates between the states within a division should impact which resources are the responsibility within that division. The rolled-in approach and Revised Protocol proposed here by the Company fails this test.

I believe these eight factors should guide the Commission's consideration of what allocation methodology would be in the public interest for Washington ratepayers. The Revised Protocol allocation methodology proposed by PacifiCorp in this docket fails to meet all of these eight factors and should be rejected.

Q. Based on the above factors can you identify an allocation process which achieves fairness under each of the factors?

A. Not at this time. It takes many iterations and fine tuning of an allocation methodology to accomplish these goals. While I recommend a general process to be considered, it is only a process.

Q. What is the procedure you recommend?

A. The Commission needs to direct the Staff, Company, and interested parties to create a portfolio approach on a Pacific division, control area, or Washington basis. My preference is to establish an approach which starts with the divisional resources of (the former) PP&L and establish a portfolio for either the division or the Western Control Area. A Washington State portfolio may be acceptable as long as it is based on the same divisional principals. Additional resources should be based on those resources acquired since the merger to serve the Pacific division, which provide the required energy and capacity and can be physically delivered. Neither resources of the Utah division nor new resources acquired in the eastern control area should be allocated to Washington except when the inclusion of those resources can be shown to be consistent with the least cost plan to serve the Pacific load and are deliverable to the Pacific states.

The allocation process needs to achieve results that meet the goals related to fairness and should not simply give Washington the best of everything. As testified to by Mr. Duval, there are risks associated with the increased hydro resource percentage.[13] These risks need to be accepted, and if necessary, certain protections for PacifiCorp should be considered. For example, Washington will have to accept the risks of hydro relicensing and share in other state Commission's adoption of contracts under PURPA. Conversely, because it is less coal-dependent, Washington will have less exposure to environmental control costs associated with coal-fired generating plants.

Q. Do the risks identified by Mr. Duval and the consequences of various events surprise you with respect to the hybrid method compared to the Revised Protocol?

A. No. In fact they only highlight the differences in the two divisions. The divisions have different stress factors and allocations should reflect this. The surplus Mr. Duval discusses in the Pacific control area results in higher costs when market prices are low, but energy surpluses create benefits when market prices are high and in the future. No one should be surprised by these results.

Q. Why doesn't the Revised Protocol meet your requirements for a stable and fair mechanism?

A. The Revised Protocol fails to allocate individual costs on a cost causation basis, using any reasonable definition of cost causation. It fails to meet the "rolled-in" or mechanical allocation factor method, because many of the allocation techniques are simply conventions intended to achieve certain results and are unrelated to this definition of cost causation. Under the definition which starts with what the divisions brought to the merger, the Revised Protocol, in its Bold Course style, fails

[13] *Direct Testimony of Gregory N. Duvall*, GND-1T, pp.14-15.

to start at the foundation of the separate divisions and fails to add new resources to the division based on the least cost needs of a division.

Q. Mr. Duval begins his testimony with the statement that "most MSP participants expressed the view that cost allocations should reflect principles of cost causation."[14] Would you agree that the various state parties have always wanted an allocation process that reflects cost causation?

A. Yes. But, cost causation means different things to different people. Above I described how it has always been the intent of the various jurisdictions to allocate costs in a way that matches the causation of those costs.

To those who have favored and pushed for a fully "rolled-in" allocation method, cost causation is a simple matter of looking where the demand, energy consumption and customers are and then simply allocating costs based on some type of allocation process that utilizes the jurisdictional relationships of these factors. Again, for many of those who have pushed for rolled-in allocations no differences in how the two divisions currently operate or how they could operate is representative of cost causation. They do not recognize that the divisions are a merger of two diverse companies which had substantially different cost drivers. Nor do they recognize that most (if not all) of the state jurisdictions on the Pacific side of the merger entered the merger not because the combined companies would produce average costs that would benefit their customers, but rather because the merger appeared to offer substantial synergies that should reduce cost for all customers in both divisions.

Q. Do the allocation proposals in this proceeding (Revised Protocol) measure cost causation any more accurately than the allocation methods that were previously

[14] *Duval Direct*, GND-1T, p 3.

agreed to by the PITA group, namely the Consensus, Accord, or Modified Accord?

A. No. Each of the older allocation models as well as the Revised Protocol attempt to do the same thing. Namely, each method tries to find a solution that will satisfy (at that moment in time) the various jurisdictions that regulate PacifiCorp.[15] In my opinion none of them attempt to look at the root causation of cost as perceived from this state's concept of cost causation, as expressed in the Commission order in the merger proceeding[16] and as verified to me by Commissioner Casad and the other Commissioners for whom I worked at the time. I am also certain that the same can be said by Utah representatives with respect to their Commission's perspective on the merger.

Q. Please describe some of the problems with Revised Protocol.

A. The Revised Protocol makes adjustments to its rolled-in allocations for Company owned hydro and for MID C contracts. These adjustments are made by comparing the average cost of energy on the system to the average cost of energy from the Company owned hydro and then for the average cost of energy from the Mid C contracts. The Revised Protocol states that it provides the Pacific jurisdictions with the hydro endowment that belonged to the Pacific division states before the merger. But not all of the Mid C contracts are assigned to the Pacific states.

Q Does this hydro endowment give the Pacific states the full advantage the hydro resources in the allocation process?

A. No. Unlike the Accord method, the Revised Protocol's hydro endowment only deals with the cost of energy and appears to fully ignore the value of peaking and other

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[15] It should be mentioned that the Hybrid model may be an acceptable allocation approach if it meets the eight factor test I set forth.

[16] *Pacific-Utah Merger Order*, p. 14.

benefits from the ability to use hydropower resources to shape output by time of day and season. As a result, Pacific division states pay for more capacity then is necessary to meet their demand.

Q. Is there a problem with the allocation of new resources in the Revised Protocol?

A. Yes. Rather than allocating new resources to the division that is experiencing the load growth that requires the new resource, the Revised Protocol allocates the new resources to all states based on their share of overall demand and load. This problem stems from the Revised Protocol's failure to comply with this Commission's order in the merger, which stated that rolling in of resources between the Utah and Pacific divisions would be accomplished only through meeting Pacific Power and Light's least cost plan.

Q. Is there a problem with how fixed costs are allocated by the Revised Protocol?

A. Yes. The Revised Protocol allocates the fixed costs of resources in both divisions and in both control areas utilizing the same allocation factor, 75% demand and 25% energy with a 12 month coincident peak used for determining demand. This allocation method (as described by Mr. Taylor) is in fact the same convention utilized in the Modified Accord, but has little to do with the different stresses within the two divisions. In the PITA process, different issues were "traded" in the allocation process in order to achieve a certain level of merger benefits in both divisions and in each of the state jurisdictions. In the PITA discussions surrounding what type of allocator was appropriate for production plant, the Utah states argued for demand factors based on what they termed "stress factors." This approach is discussed by Mr. Taylor.[17] It attempts to discover which months are responsible for the stress on the system with respect to the need for new plant. This approach was

[17] *Direct Testimony of David L. Taylor*, DLT-1T, p. 18.

probably necessary for Utah Power and for the planning of resources for the Eastern control area.

As I discussed above, the former Pacific Power and Light power supply staff argued quite vehemently that their system was not stressed by demand, but rather the stress was almost purely energy. This was the basis of the 50/50 energy/demand classification method used in the Pacific division states prior to the merger and the reason a 60 month CP (5 years of monthly demands) was used as the demand allocator. The Commission should note that in the Accord method, power plants were allocated by first identifying revised loads and demands for the Pacific division and then by subtracting the hydro endowment from both the loads and peaks. Because the hydro system could meet much of the peak demand, this left a relatively flat load to be served by thermal generating facilities, unlike the eastern control area, where little hydro was available to meet daily variations in load.

Q. Is there a problem with how the Revised Protocol allocates taxes?

A. Yes. It appears that under the Revised Protocol state income taxes are allocated to all states based on income, while the Washington state revenue tax is allocated situs. Income taxes are mainly charged for the operations that are carried out within a state.[18]

In Oregon a majority of the income apportioned to the Oregon income tax is due to retail services provided in Oregon. Thus, to allocate state income taxes as the Revised Protocol does is simply a convention and not a principled resolution of a cost causation question. The Commission should note that prior to the Accord method income taxes were largely allocated situs. In the Accord and Modified

[18] For example, Montana's income tax should be partially allocated to Washington because the basis of Montana apportioning PacifiCorp income to Montana is related to the Colstrip generating plant. Washington ratepayer's use of that resource creates a responsibility toward payment of those taxes.

Accord methodologies state income taxes were allocated across the jurisdictions, but so too was the Washington utility tax.

Q. Does the Revised Protocol allocate fuel costs and non-firm purchases on a principled, cost-causation basis?

A. No. The Revised Protocol allocates fuel and market non-firm purchases on an energy basis. If usage was generally seasonally consistent across the Company, fuel costs and market purchases might well be distributed equally based on energy. However, in PacifiCorp's case the Commission should have several concerns. For example, if we look only at the loads that exist today (ignoring pre-merger differences), the usage of energy is seasonal in the two divisions, and those seasons are in opposition to each other (summer vs. winter). The mix of use of power plants is different from winter to summer with respect to serving PacifiCorp's native load and resources. Further, markets for purchased power are different both regionally and seasonally (winter vs. summer). As such, it is quite probable that the fuel costs are different in the two seasons particularly considering the fact that Pacific division's generating plants have average lower fuel costs than the Utah division's plants. Further, market prices vary substantial between seasons. Thus the allocation of these two variable costs based on *annual* energy consumption is merely a convention and not based on actual cost causation.

Q. Is the proposed treatment of existing Qualified Facilities (QF's) in the Revised Protocol a cost causation allocation?

A. No. While it is true that specific QF's were approved by each state, these resources were in general taken by the Company under PURPA. Different states have had different ways of implementing PURPA. In general, it seems unfair to assume that because Oregon (or some other state) was required to deal with a QF purchase when avoided costs were at their peaks, that now the Washington Commission should require that state to absorb the entire excess costs. This is not cost causation but instead "luck of the draw." While Washington is a benefactor of this convention in the Revised Protocol,[19] it in fact had avoided costs similar to those found in Oregon during the relevant time periods.

Q. Are you concerned with how off system sales are treated under the Revised Protocol?

A. Yes. Off system sales are allocated on energy when non-firm, and are allocated on system generation when firm. These allocations do not match the cost causation of these items. In general, secondary sales by a utility are intended to be a means of selling off excess power at a profit over the incremental costs of producing that power. Regulated utilities are not in the business of acquiring generation for the sole purpose of profiting in the market as would an Independent Power Producer (IPP) such as Calpine. The margin the utility earns on its off system sales should reduce the impact of fixed costs for which the Company is already burdened.[20] Thus it would appear that the proper allocation of off system sales should be to (1) offset the incremental variable costs associated with the sales and (2) allocate the net benefit of the sales to offset the fixed costs that were incurred to enable the benefit in the first place.

Q. What about the Revised Protocol's use of seasonal resources?

A. While it seems appropriate to consider seasonal resources in the fashion the Company proposes, allocating the fixed costs of them to the usage during the seasonal period in which they are used should to be consistent with the total allocation process. Further, the allocations should be consistent with the intended

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[19] *Taylor Direct*, DLT-1T, p. 39.

[20] Please note that I am not implying that in some instances a utility is not capable of selling power for above its fully embedded costs, but only that those profits should not be the moving force behind making such an acquisition.

and actual use of the facilities. For example, a seasonal resource should be fully deliverable to the loads it is allocated to.

The Revised Protocol allocates system generation based heavily on a peak allocator. These peak allocation factors include the monthly demands throughout the year, but the monthly demand is also served by seasonal resources. It appears that to include this seasonal load in both the system allocator and then to assign property directly based on those loads may create inappropriate redundancy.

An example of this second point is Unit 4 of the Cholla Power Plant near Holbrook, Arizona which PacifiCorp owns. A review of the resources allocated seasonally reveals that Cholla is allocated seasonally, and that it is allocated to the winter months.[21] This allocation of Cholla places the greatest burden of this Southern resource on the Pacific States. Interestingly, Mr. Duval's Exhibit No. ___ (GND-8)[22] indicates that one half of the available capacity would be sold off system. These off system sales are not allocated on a seasonal basis consistent with the allocation of Cholla but instead are allocated either on an energy basis (non-firm) or on a system generation basis (firm).[23] This report also identifies Cholla as a resource required for growth and the staff analysis in the report compares Cholla to other base load resources.[24] The inconsistent treatment of Cholla is one example of how the Revised Protocol does not appropriately treat seasonal resources.

Q. Is it you testimony that the Revised Protocol's proposed allocation conventions fail to result in a fair allocation process?

A. Not exactly. My concern with the Revised Protocol is the same as my prior concern with the Modified Accord. It would appear to me that the Revised Protocol does not

[21] *Taylor Direct*, GND-1T, p. 25.
[22] *Duvall*, GND-8, p. 21.
[23] *Taylor Direct*, DLT-1T, p. 25.
[24] *Duvall*, GND-8, pp. 20-27.

have staying power and will not be sustainable. Even if approved today, this allocation method will need to be modified, and probably soon. Those modifications will again go through a consensus building mode with compromises. Utah will again push for rolled-in while the Pacific and slower growing states will seek to protect themselves from losing their endowments or having to pay for the growth in other states.

Q. Are the compromises you list above comprehensive of all of the non-cost causative items included in the Revised Protocol?

A. I do not believe so. If one looks at cost causation starting with the stand alone endowments brought to the merger, an entire additional group of non cost causative problems exist. With respect to the physical cost causative problems within the model I have not attempted to identify any more, but I am sure a comprehensive review of all the allocation techniques within the Revised Protocol would yield additional problematic conventions that contradict cost causation.

B. Growth Impact Analysis

Q. Have you considered the impact of growth in one region or state vs the impact of growth in other regions or states?

A. Yes. The issue can be viewed from a purely theoretical basis, from a historical perspective, or from modeling changes in the allocations based on various proposed scenarios. PacifiCorp claims to have done the third, running its models to determine the impact of various events on individual states revenue requirements.

Q. How would you analyze growth from a theoretical perspective?

A. In a situation where one division or state grows at a rate in excess of the system average, the Company will need to acquire new firm generating resources for this faster growing division. Costs can be broken down into the following four groups:

- State variable and fixed costs;

- Generation;
- Transmission; and
- Allocated overhead.[25]

Directly allocated state costs (such as distribution) should have no impact on rates in other states. For the purpose of this discussion, those costs such as distribution costs, can be ignored because each state would create rates to cover there own distribution costs. In this example, the addition of a new resource adds total costs to the Company. This increases total Company revenue requirement, but this increase in total revenue requirement does not necessarily increase rates.

Q. How can total revenue requirement increase but not rates?

A. Rates are the function of total revenue requirement and the units of service (most often kWh). If the increase in kWhs is greater than the increase in revenue requirement then average rates per kWh actually go down.

Q. If a company experiences an increase in total net production costs on a kWh basis, does this mean that total rates will go up?

A. Not necessarily. As identified above, there are three pieces of allocated costs (transmission, generation and overhead costs). The allocated portion of the total rate is the combination of all three pieces. It is possible that if one cost goes up on a per unit basis that the other two may decline on a per unit basis. That is, an increase in the unit of generation may be offset by a decrease in the unit costs of transmission or overhead.

From a cost accounting standpoint, no group of costs is truly fixed no matter what the level of sales. Instead, they show variability over a range in a "lumpy" or step type of movement. However, even though one would expect some level of variability in all costs associated with growth, it is also possible and likely that for

[25] Note that three of the four groups represent allocated costs.

some portions of costs, the growth would result in synergies, or perceived productivity. As a result it is usually the case, but not always, that companies can increase their profits by growing the level of sales.

Q. Would you please give an example of how an increase in generation costs would not increase the overall average rate or total cost per kWh.

A For purposes of this discussion, I will assume that generation represents approximately 70% of the allocated costs. I will also assume an increase in load of 10% with a cost for the new net generation costs at 10% above the embedded costs. Further, just to add numbers to the example I will assume total generation costs of $7,000,000, a total load of 1,000,000 MWH before the load increase, and that the incremental transmission and overhead costs will be 50% of the previously embedded costs for these items, a 50% synergy.

Table A

Current Load	1,000,000 MWHs	
Revised Load	1,100,000 MWHs	
Current generation cost	$7.00 / MWH	$7,000,000
Added load 10% of original load	100,000 MWH	
Cost of incremental generation	$7.70 / MWH	770,000
Total generation costs	$7.0636 / MWH	$7,770.000
Other Costs current	$3.00 / MWH	$3,000.000
Added Costs for new load	$1.50 / MWH	$150,000
Total other costs per MWH	$2.8636 / MWH	$3,150.000
Total costs current	$10.00 / MWH	$10,000,000
Total costs with new load	**$ 9.93 / MWH**	**$10,920,000**

As can be seen from the above example even though incremental power supply costs increase $7.00 to $7.06 per MWH, the revenue requirement per MWH decreases $10 to $9.93 because of the decline in unit costs of the other allocated cost factors.

Q. Isn't this an abnormal situation with respect to the addition of new load in the electric industry?

A. In general I would think this is abnormal. However, this is exactly the type of situation reflected in Mr. Duval's Exhibit No. ___ (GND-6) which I will discuss later in my testimony.

Q Why do you believe this is abnormal?

A. This is abnormal for several reasons. First, incremental resources tend to be more expensive than the embedded costs by more than the 10% I used in this hypothetical. Second, while some of the other allocated costs are increasing at a slower rate (and show substantial synergies or productivity), others such as transmission are increasing cost components. Within certain ranges of load growth these costs may not increase much, but they will ultimately increase.

Q. What would it take to push the overall costs to an increase as compared to the decrease shown in your example?

A. As implied from the above hypothetical, that could result from any number of factors in combination. For instance, simply moving the incremental generation costs to 30% above the average embedded generation costs would result in increasing total costs. Another possibility would be to reduce the synergies in the other cost factors, thus increasing these other incremental cost components at a rate closer to the increase in load would also result in an overall increase.

Q. How do these changes in average cost flow into a rolled-in allocation process?

A. Ignoring direct state costs, each state may have slightly different impacts depending on how certain costs are allocated. Assuming all allocated costs are spread with similar allocation ratios, then each of the jurisdictions should face equivalent average increases or decreases depending on the overall impact. But in reality this is not always the case. There are substantially different allocation methods for different type of costs. For example, Avista Utilities' Idaho allocation ratios may vary from around 36% for some cost components to 30% for other cost components. This is a 20% difference in cost components for Idaho. This is caused by the differences in load, demand, customers, and direct plant or expenses. Many factors can impact these differences such as large industrial load verse small industrial load, density of customers, temperature, income levels, and other factors that may impact the average statistical relationship.

Load growth does not increase all costs groups by the same ratio and those different cost groups are allocated differently. It may be the case that one state with high loads may have rates that are 75% power supply costs and 25% delivery costs while another state with small average customers spread over a wide rural area may have rates that are only 65% power supply and 35% delivery. It is the combination of how the rates are composed (power, transmission, and other allocated factors), coupled with the increase experienced in each of these costs groups that will dictate a jurisdictions average percentage rate increase.

Q. When looking specifically at the power portion of the rates in various states, are the increases or decreases in average total power costs equal?

A. No. While the average percentage increase should be more uniform than the overall rate impact, it must be realized that the allocation formulas vary within the production arena of the Revised Protocol. 100% of fuel and non firm purchases and sales are based on an energy allocator while firm purchased power, firm secondary sales, and net generating plant costs are allocated on a 75% demand basis. While the increases and/or decreases are not necessarily equal, the fact is that for each component the increases or decreases would be equal.

Q. Is the state that is the cause of the added power plant the state that experiences the greatest rate impact?

A. Under PacifiCorp's Revised Protocol, this is not how costs are allocated. Excluding the impacts of a state's direct costs (which are handled differently in each state), the rate impact is not a function of what state causes the need for the new resource. Instead the rate impact is a function of the percentage increase or decrease in each of the allocated cost groups, as discussed above, times the percentage of revenue requirement from each of those cost groups within the individual state. It is possible that the state with the growth will experience the lowest rate increase.

Further, the level of increase for any state would also depend on the resource(s) used to meet the new load. Assume for a moment two resource additions are possible to meet new load. One is a gas plant and the other is a nuclear plant. They both have equal estimated total costs per kWh and equal production levels but the nuclear plant's fixed costs are three times that of the gas plants. Conversely the nuclear plant has cheaper fuel costs. A state with a lower load factor (thus a higher demand factor compared to its energy factor) would benefit from building a gas plant. In contrast, a state which had a very high load factor (thus a lower demand factor compared to its energy factor) would be worse off with the gas plant. In my opinion, this fact demonstrates the inconsistent nature of the Company's proposal: different states should not have different resource preferences based on the allocation method. All states should prefer that the Company acquire least-cost resources, and each state should bear a fair share of incremental costs incurred to serve the incremental growth occurring in that state.

Q. Don't your statements contradict Mr. Duval's statement that the state with the growth pays for a majority of revenue requirement?

A. No. Mr. Duval discusses revenue requirement and not rates. Remember that the addition of the new plant increases total revenue requirement. This is because the new plant adds to total costs. But the addition of new costs does not mean that average costs go up. Rather, as shown in my hypothetical example above, while revenue requirement went up from $10,000,000 to $10,920,000 rates went down from $10 per MWH to $9.93 per MWH. Thus when one looks at revenue requirement the state with the growth will incur most of the additional revenue requirement but that state will not necessarily incur the most of the rate increase. I will demonstrate this with respect to Mr. Duval's example in his Exhibit No. ___ (GND-6) later in my testimony.

Q. Please discuss Mr. Duval's evaluations of the impact of fast growing states on the slower growing states.

A Starting on page 18 of his testimony, Exhibit No. ___ (GND-1T), Mr. Duval discusses various studies the company conducted to demonstrate that the "Dynamic Proposal" did not have a material impact on other states. The only study he actually presents in his testimony in this docket is discussed on this page and the study results are displayed in his Exhibit No. ___ (GND-6).

Q. What does Mr. Duval claim with respect to this study?

A. Mr. Duval states that based on the assumption that Utah's load increased by an additional 200 megawatts and the addition of a concurrent 200 megawatt gas fired plant, (as shown in his Exhibit No. ___ (GND-6), Utah picks up 93% of the revenue requirement for the increased costs related to that growth. Further, he states that all states pick up some of the revenue requirement impact of serving Utah load addition.

Q When you look at rates does Mr. Duval's statement that Utah picks up a vast majority of the increase hold true?

A. No.

Q. Please explain.

A. In Public Counsel Data Request No. No. 68, I asked:

Refer to Mr. Duval's Exhibit No. ___ (GND-6), provide the annual load in MWh for each state in the two scenarios represented in this table: Extra East Load (MSP Study 1.4), and West resource (MSP Study 1.4). Provide the unit cost per MWh of the 200 MW combined cycle gas plant that was added to meet the additional load, identifying the MWh produced in 2010. Break this production cost between fixed and variable.

The following table was provided with respect to the loads portion of the Data request.

Table B

MWh Loads by State 2010 (System Input)				
State	Extra East Load Resource	West Resource Sensitivity	Difference	Percent Increase
California	992,226	992,226	0	0.00%
Idaho	3,517,182	3,517,182	0	0.00%
Oregon	15,897,364	15,897,364	0	0.00%
Utah	28,779,985	27,696,891	1,083,094	3.91%
Washington	4,872,753	4,872,753	0	0.00%
Wyoming	8,344,363	8,344,363	0	0.00%
Totals	**62,403,872**	**61,320,778**	**1,083,094**	**1.77%**

Comparing the load numbers in the table above to the revenue requirements included in Mr. Duval's Exhibit No. __ (GND-6) result in the following facts:

1. The overall result is a decrease in rates per MWH. The decrease is small, about 0.23%.
2. Production plant increases on a per unit basis.
3. Production expenses increase on a per unit basis although not at the level of production plant.
4. Only Utah (the state that caused the increase in production costs) gets a rate decrease. This decrease is about 0.71%.
5. All other states receive rate increases, with Wyoming getting the largest percent percentage increase at 0.24%. This appears to be a relatively small increase, but in my opinion, considering the impact on overall rates, it should instead go down because there is a decrease in overall average system costs.

Q. Does the results of this rate analysis fit the situation you described above where an increase in revenue requirement can result in a decrease in rates?

A. Yes, even though Mr. Duval's study shows an increase in revenue requirement the study anticipates an overall decrease in rates. This is caused by the increase in power supply costs being offset by decreases in unit costs in other areas. As I described above, the changes in rates (increases) for each of the other states has nothing to do with those states' contribution to the increased costs, but rather that the mix of cost groups allocated to each state is different. For example, Wyoming is the state with probably the highest load factor and what is likely the largest average customer and it sees the highest rate increase. The Commission should note that I cannot fully describe every difference in rate increases because I am unable to view each state's specific cost pools and measure the cost changes based on the information provided in the study and its support.

Q. Do you have other concerns with the study Mr. Duval presents in Exhibit No. ___ (GND-6)?

A Yes. As revealed in Exhibit No. ___(GND-6), for an increase of 200,000 MW that is accompanied by a 1,083,094 MWh increase in load it is possible that an additional 45,000 customers may exist. His model does not appear to assume much if any additional costs in other allocated costs groups. That is; other than the addition of the power plant and associated costs, coupled with an increase in net power supply costs (which probably include variable transmission or wheeling expenses) I see few other cost increases in his model.

Q. You have indicated Mr. Duval's studies appear to offset power supply increases with decreasing per unit costs in transmission and overheads. Should these decreasing costs (on a unit basis) be offset against power supply to determine that costs are not increasing in one state due to growth in another?

A. No. At least not to the degree that Mr. Duval assumes. One issue is whether or not it is appropriate to consider synergies in other allocated costs as an offset to increased power costs in the first place. The issue of whether this is appropriate has more than one concern. First, the allocation of overhead across the two divisions is consistent with the original intent of the merger and the benefits identified during the merger and in reports subsequent to the merger. I do not have the reports available to me now but I do recall that many benefits related to overheads had to do with Pacific or Utah having contracts or systems that when applied to the other utility reduced overall costs. Many other savings apparently had to do with consolidation of several functions performed by both divisions. As a result the new average costs are a result of what exists now including the growth in one division or the other. To say that these cost reductions should offset the cost increases in power supply would not be appropriate.

Second, and even more questionable, is the level of these offsets in Mr. Duval's study. While the Company may not project that these costs will increase in the future related to the load and customer growth, I believe this is an unrealistic assumption. For example, I am very skeptical that transmission costs will actually decline on a unit basis over the long run. It appears to me that rate increases related to transmission continue to occur. New transmission facilities cost more to construct than the existing facilities which are also substantially depreciated. These increases are on a unit basis, either on demand or on non-firm energy. The recent BPA transmission rate increase is one example of this. Another can be found in Avista's current general rate case which reveals that increases in transmission rate base and other related transmission income items are a large driver of Avista's requests for higher rates.[26] Transmission costs tend to be one of those items that increases both on a continuous curve (continuous plant upgrades) and with large step increases, as Avista is experiencing.

With respect to overhead costs, I believe it is extremely naive to believe that large changes in customers, customer load, and customer demand do not increase allocated overhead costs. This is not to say that there are no synergies or productivity gains related to increased loads, but only that increases at some level are probable. Further, from my experience of auditing all the electric companies in this state, along with the 100s of audits in the other industries regulated by this state, it is my opinion that a substantial portion of overhead costs have to do with planning for growth in all areas of the Company, financial, least cost planning, transmission, etc.

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[26] *WUTC v. Avista Utilities,* Docket Nos. UE-050482 and UG-050483, exhibits 114 to 116 (Falkner workpapers).

Thus a state with large growth would be the cost causer of many of these overhead costs.

Q Mr. Duval identified other similar studies at the bottom of page 20 of his testimony, Exhibit No. ___ (GND-1T). Do you have any comment on these?

A. My comments are limited. In Public Counsel Data Request No. 69 I asked for these studies with complete electronic documentation. The response to this request directed me to the look at the Company's response to Public Counsel Data Request No. 60. I reviewed the responses to Public Counsel Data Request No. and I could find no studies, supporting workpapers, or electronic backup for any studies which attempted to measure the impact of growth. However from the descriptions in his testimony I have the following two impressions:

First, it would appear that the studies were based on a similar analysis to that provided in GND-6. I believe it is questionable whether the study fully measures all cost increases caused by growth over that period of time.

Second, the study indicates that over the 14 year study period the present value of the subsidy is $22 million, or less than 1%; an amount that could easily be understated as discussed above. As the higher growth rate is spread over a period of time, it would be only logical that the impact of these subsidies grows over time as the load in the high growth state accumulates. Therefore, assuming linear growth in the subsidy over the 14 years and using an 8% discount rate, the subsidy in the 14th year would be nearly $6 million.

Q. Has this concern over growth been an issue for PacifiCorp in Washington?

A. Yes. As described in the historical discussion above, load growth has been a continuing theme of concern identified by this Commission's participants and other Pacific division states' participants in allocation discussions. This is true when looking at the questions of whether rolled-in should ever be adopted or to the Pacific division states' claim to the hydro endowment. In one of the presentations I made to the PITA group several years ago (related to lump sum transfer); one of the themes was the idea that *if* the Pacific division was the slower growing division then the cost differential would grow not shrink. Under the Revised Protocol the slower growing Pacific division doesn't see its costs grow slower with the addition of system resources. This is because under the Revised Protocol all states and divisions are allocated a share of all resources, new and old equally without consideration of the growth which required the addition of the new resources. This is directly in conflict with the Commission Orders approving the merger.

Q. The study Mr. Duval refers to shifts revenue requirement to Washington resulting in the present value of $22 million over the next 14 years. If it does this to Washington what does it do to other states?

A As I indicated, the study and results were not provided in response to my requests. Based on the fact that Washington is not the slowest growing state it would be my guess that other states with even lower growth rates would have to face an even larger share of the shift. As shown in Exhibit No. ___ (GND-6), Wyoming received the greatest revenue increase, yet Wyoming has the lowest (even negative) growth rate.

Q. What has the difference in growth rates been between the two divisions over the last 10 years?

A. Page 2 of Mr. Duval's Exhibit No. ___(GND-5) gives us a partial answer. The amounts in this exhibit are limited to the state jurisdictions still served by PacifiCorp. In Public Counsel Data Request No. 67, I asked for the levels of this information from all jurisdictions served since the merger, including those jurisdiction no longer served by PacifiCorp. Based on the Company's response I have calculated the following growth rates:

Table C

Totals in MWH				
Growth to 2002	1992 load	2002 load	Growth	% Increase
Total Co. with all Jurisdictions	45,724,505	51,546,989	5,822,484	12.73%
Totals without ID and MT (PPL)	44,729,329	51,546,989	6,817,660	15.24%
Pacific Power & Light Division	27,009,873	26,549,591	-460,282	-1.70%
PP&L without Id and Mt	26,014,697	26,549,591	534,894	2.06%
Utah Division	18,589,104	24,814,241	6,225,137	33.49%
GROWTH to 2004	1992 load	2004 load	Growth	% Increase
Total Co. with all Jurisdictions	45,724,505	53,321,311	7,596,806	16.61%
Totals without ID and MT (PPL)	44,729,329	53,321,311	8,591,982	19.21%
Pacific Power & Light Division	27,009,873	27,094,282	84,409	0.31%
PP&L without ID and MT	26,014,697	27,094,282	1,079,585	4.15%
Utah Division	18,589,104	26,227,029	7,637,925	41.09%
GROWTH since 1989 to 2004	1989 load	2004 load	Growth	% Increase
Total Co. with all Jurisdictions	45,300,548	53,321,311	8,020,763	17.71%
Totals without ID and MT (PPL)	44,318,367	53,321,311	9,002,944	20.31%
Pacific Power & Light Division	26,321,785	27,094,282	772,497	2.93%
PP&L without ID and MT	25,339,604	27,094,282	1,754,678	6.92%
Utah Division[27]	18,978,763	26,227,029	7,248,266	38.19%

[27] Please note that the Utah division amounts do not necessarily comport with Mr. Duval's Exhibit No. __(GND-5) because the FERC jurisdiction is included in all of the Utah Division numbers above. In Mr. Duval's exhibit the Utah FERC numbers are included in some of the Utah numbers, but not all.

Q. What can be seen with respect to growth over the last 10-14 years?

A. Over the last 14 years the Utah division has grown over 7 million MWH compared to the Pacific divisions increase of less than 1 million MWH. Even excluding Idaho and Montana (lost loads) the Pacific division grew less than 2 million MWH. The difference between these two growths is a minimum of 5.4 million MWH. Examining the 12 years from 1992 to 2004 the difference in growth is a minimum of 6.5 million MWH more for the Utah division than the Pacific division.

Q How does this compare to the study provided in Exhibit No. ___(GND-6)?

A. In that study Mr. Duval increased the load by 200 MW, resulting in an increase of just over 1 million MWH. In my opinion the excess increases in the Utah division over the Pacific Division (excluding the lost loads of Idaho and Montana) were approximately 6.5 million, or over 6 times as much as reflected by Mr. Duvall in his study in Exhibit No. ___ (GND-6).

Q. Can we measure what that means with respect to the current status of the Revised Protocol's impact on the slower growing states?

A. One may summarize that it may have a similar impact as does the growth into the future, meaning that nominal values in 2004 may be as great as $6 million. Unfortunately it is extremely hard to tell. The impact of growth on the system is the weighted average impact of the various components of each state's revenue requirement. The period we are talking about represented a time of tremendous upheaval in PacifiCorp's overall productivity, particularly if the reports provided by PacifiCorp were correct with respect to the overall benefits of the merger.

V. POWER COST ADJUSTMENT MECHANISM

A. Summary

Q. Please summarize your testimony with regard to PacifiCorp's proposed Power Cost Adjustment Mechanism (PCA or PCAM).

A. First, the Commission will find it very difficult or impossible to craft a reasonable PCA without having resolved the allocation method. Second, I do not believe the Company's proposed PCA is in the public interest. I believe that the following four areas provide the proper "roadmap" for creating a PCA that meets the public interest test:

- The Commission's prior guidance concerning power cost adjustment mechanisms and recommendations on what a PCA should provide;
- The criteria found in prior Commission findings;
- How these criteria should be applied and how they are being applied in Washington State; and
- The treatment of fixed power supply costs in existing Washington PCAs.

B. Prior Commission Guidance Regarding Power Cost Adjustment Mechanisms

Q. What three broad policy goals has the Commission stated with respect to PCA mechanisms?

A. The Commission has stated that,

1. a power cost adjustment clause should be linked to factors that are weather related;
2. "a power cost adjustment should be a *short-run* accounting procedure that reflects the *short-run* cost changes affected by unusual weather," (whereas the prudency of long run resources is the proper subject for a general rate case); and

3. where a PCA is established, ratepayers should receive the benefit of a cost of capital reduction.[28]

Q. What other guidance has this Commission provided regarding the structure of a PCA?

A. Over the years, the Commission has enunciated guidelines for designing an acceptable PCA. The Commission has stated that,

1. a PCA should be an improvement over the status quo;[29]
2. surcharges should be understandable to the rate payers;[30]
3. a PCA should not mechanically measure cost changes in certain accounts without considering offsetting expense reductions;[31] and
4. a PCA should not provide incentives to do the wrong things, such as discouraging a company from conservation when this is the cheapest resource.[32]

C. Description of Criteria Based on Commission Findings

Q. Please describe what these statements imply about a proper PCA.

A. These statements by the Commission establish six important criteria for PCAs.

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[28] *WUTC v. Avista Corporation,* Third Supplemental Order, Docket Nos. UE-991606 and UG-991607, pp. 49-52. *See also, e.g., WUTC v. Puget Sound Power & Light,* Third Supplemental Order, Docket Nos. U-89-2688-T and U-89-2955-P, pp. 13-15; *WUTC v. Washington Water Power*, First Supplemental Order, Docket No. U - 89-2363-P, p. 8.

[29] *WUTC v. Puget Sound Power & Light Company,* Eleventh Supplemental Order, Docket Nos. UE-920433, UE-920499 and UE-921262, p. 8.

[30] *WUTC v. Puget Sound Power & Light,* Sixth Supplemental Order, Docket No. U-81-41, p. 21.

[31] *WUTC v. Puget Sound Power & Light*, Sixth Supplemental Order, Docket No. U-81-41; and *WUTC v. Puget Sound Power & Light Company,* Eleventh Supplemental Order, Docket Nos. UE-920433, UE-920499 and UE-921262, pp. 10-12.

[32] *WUTC v. Puget Sound Power & Light*, Sixth Supplemental Order, Docket No. U-81-41, p. 23; and *WUTC v. Puget Sound Power & Light*, Final Order, Docket No. UE-901183-T and UE-901184-P, p. 7.

First, the impact of a PCA needs to be logical and understandable to the ratepayer in its application. In other words, ratepayers need to be able to understand why a surcharge or credit is being applied to their bills. Customers need to be able to see the drought or other uncontrollable event as connected with the increased rates that result from the PCA. PCAs that include long deferral cycles that leave ratepayers without a natural understanding of why the surcharge is necessary fail to meet this standard. Rate increases and decreases associated with the PCA should coincide to a reasonable degree with the events causing the deferrals.

Second, a PCA mechanism should allow deferrals only in situations where the total cost of providing service has increased. Thus, if the mechanism fails to measure some portion of the cost of power to the system, the mechanism may unfairly defer costs when costs are not actually increasing in the aggregate.

Third, the cost increases should be for items related to weather (stream flow or temperature) or other items that are truly out of the control of the company. It is worth noting that, in a certain sense; nothing is fully out of control of the company. While it cannot control weather or other external events, a company has the ability to anticipate and respond to situations and limit the impact of various "uncontrollable" events. Some of these tools include the shape of the utility's portfolio, fuel procurement plans, and risk management. By responding properly in many situations a utility can reduce these types of impacts. Many utilities have successfully managed their businesses for decades without relying on PCAs or other risk shifting mechanisms. Ratemaking has always taken into account the fact that weather related factors are variable. Of the three major investor-owned electric utilities in Washington, only PSE at this time has a comprehensive PCA mechanism.

Fourth, ratepayers need to be specifically compensated for the transfer of risk from the stockholder to the ratepayer. This is best accomplished by a reduction in the cost of capital. Absent a reduction in the cost of capital, a substantial portion of the risk should be left with the utility rather than transferring it to the ratepayers. Fifth, the mechanism needs to keep the utility "in the game." That is, the utility needs to be at risk at all times so that deferrals to ratepayers are accompanied at all times with some level of impact on the stockholders. In this way, the utility's incentive to minimize costs remains at all cost levels.

Sixth, the mechanism should not be designed so as to defer costs that are long range in nature. Increases related to general inflation for single items and new resources are more appropriately dealt with in a general rate case. For this reason, the Commission has stated that cost increases associated with new power contracts should be excluded from PCA mechanisms.[33] The Commission has stated that a PCA should be a short run accounting procedure to measure short run cost changes. Long range costs such as new contracts need to be reviewed in the context of changes in the complete cost of providing service during a general rate case.

Q. Why is it only possible to design a PCA after the adoption of a cost allocation method?

A. Washington's jurisdictional responsibility for power costs is ultimately determined by the cost allocation method. Without an interjurisdictional allocation methodology the Washington Commission cannot determine the actual costs attributable to Washington ratepayers from a PCA mechanism. For example, variable gas fuel costs for a CCCT found in FERC account 547 may well be included in a PCA. But without knowing which CCCT plants (or how much output of which plants) are allocated to Washington (if any) it is not possible to determine the actual costs from account 547 that Washington ratepayers will pay under a PCA.

[33] *Avista ERM Order* at pp. 14-16; and *WUTC v. Puget Sound Power & Light*, Third Supplemental Order, Docket No. U-89-2688-T, p. 14.

D. Application of Commission Standards

Q. Would you please describe what feature should exist in a PCA to achieve each of these criteria, starting with the first?

A. This criteria simply states that the deferrals need to be recovered promptly after some type of event happens so that the ratepayer can understand the reasoning behind the surcharges, and that long delays in the recover of substantial amounts is inappropriate.

Q. Please describe what would satisfy the second criteria?

A. The second criteria states that deferrals should only happen when total costs are increased by the event. When a mechanism does not include all costs items in either the variable or fixed portion of the PCA mechanism then it is impossible to measure whether costs actually increased. The PSE PCA mechanism measures <u>all</u> costs of moving the resources to the system, including fixed costs, variable costs, and transmission costs. By contrast, the Avista ERM fails to include any transmission expense or revenues. Because of this PSE's PCA more properly measures whether an increase actually happens. In Mr. Widmer's testimony it is suggested that variable wheeling expense be included, as the case in PSE's PCA. I would agree with such inclusion and would also strongly suggest that system transmission be included in the fixed costs whether through a retail revenue credit or as done with fixed cost in the PSE PCA. Either accomplishes the exact same result. Transmission revenue should also be included in the variable portion of the mechanism.

The second criteria also refers to situations where temporarily closing or permanently terminating major fixed cost resources increases the variable costs recognized through the mechanism. At the same time, because of the duration or permanence of the outage other fixed costs are reduced as an offset to the increased variable costs. Absent a mechanism such as the Colstrip adjustment in PSE's PCA mechanism a utility may be over-rewarded for the cost increases related to these outages. It was this sort of problem related to Colstrip that first identified problems with Puget Sound Power and Light's former energy cost adjustment mechanism deferrals.

Please note that while PSE's PCA includes an adjustment to protect ratepayers from poor reliability at Colstrip, Avista's ERM includes no such provision for any of its resources. It should also be noted that PacifiCorp has many more large generating facilities that may experience such outages than either PSE or Avista. The purpose of such an adjustment would not be to disallow prudently incurred cost, but rather to guarantee that these costs are actually incurred.

Q. Please explain how to meet the third criteria.

A. Existing long term contracts may have cost increases embedded within them. These cost increases are more properly measured in a general rate case in combination with the rate base portion of production costs, which in many cases declines during the deferral periods. These long term contract increases are not out of the company's control and should not be treated as such in a PCA. PSE's PCA eliminates contract increases from consideration in the deferrals while Avista's hastily designed deferral mechanism does not. Admittedly, Avista does not have nearly PSE's level of long term contract purchases, and the issue is far less material.

Q. Please explain what is needed for the forth criteria.

A Excluding the establishment of the Avista ERM (when Avista was in severe financial difficulty) the Commission has stated that it is incumbent on the Company to provide a specific compensation for the shift in risk.[34] In order to establish a PCA that shifts a substantial risk to the ratepayer (such as the no deadband proposed by PacifiCorp here), the Company should be required to identify specific compensating benefits for

[34] See, e.g. *WUTC v. Avista Corporation,* Fourth Supplemental Order, Docket No. UE-991606, pp. 49-52.

the rate payers. Substantial risk affecting the companies' rates of return in excess of 1.5% is included in both PSE's current PCA and Avista's current ERM. This level of risk must be left with the Company to avoid violating this criterion. Alternatively, an adjustment to the allowed rate of return and/or the common equity ratio is required to compensate ratepayers for the shift of risk. Rating agencies have consistently cited power cost adjustment mechanisms as "positives" affecting a company's credit rating; the quid-pro-quo for this is a reduction in the rate of return. PacifiCorp has not proposed a lower rate of return in Washington in conjunction with its proposed PCA.

Q. What is needed to achieve the fifth criteria?

A. Any proposal that requires the utility to share excess costs or achieved benefits in the range of 10%, as proposed by PacifiCorp, achieves this criteria. The need to keep the utility "in the game" rather than getting full recovery for variances achieves this goal. The sharing bands in both the PSE PCA and Avista ERM achieve this goal.

Q. Please identify the importance of the sixth criteria.

A. As noted above, new contracts are not properly included in the cost deferrals of a PCA because they are not unanticipated by the company. Like newly owned resources they have the potential to change the relationships between revenue, expenses, and rate base. The Company has a significant ability to control the timing and terms of these contracts, which are typically of a longer term duration. This is the type of resource properly addressed in a general rate case. PSE's PCA properly eliminates increases caused by the initiation of new long term contracts, while Avista's ERM (improperly in my view) simply flows all new contracts 100% into the deferral account.

E. Treatment of Fixed Costs in Washington PCA Mechanisms

Q. Please provide an explanation of how both the PSE PCA and the Avista ERM deal with fixed power costs.

A. The Avista ERM adjusts this comparison for over-recovery or under-recovery of power costs due to load changes from the so-called authorized load. This is accomplished by means of the "retail revenue credit adjustment." The retail revenue credit is calculated by taking the total of fixed and variable costs and multiplying it times the change in load. Since power cost changes (absent the retail revenue credit) are measured on a nominal basis for variable costs only this adjustment corrects the nominal basis to the authorized costs on a unit basis. In this way fixed costs are limited to the nominal levels in the test period.

In the PSE PCA this same result is accomplished by measuring total deferral year costs by first taking the actual variable costs and then adding the fixed costs determined in the last general rate case or PCORC to that total. A unit cost is calculated in the deferral year and compared to the unit power costs in the test year from the general rate case or PCORC, and represents the total cost of bringing power to the system – fixed costs, variable costs, and transmission costs. Thus in both cases the fixed costs are held constant on a nominal basis and actual variable costs are allowed to flow into the mechanism.

Q. Does this conclude your testimony?

A. Yes, it does.