INDEX

TESTIMONY of

RAYMOND D. BLIVEN and NANCY PARKER

Witnesses for Bonneville Power Administration

SUBJECT: POWER RATES POLICY **Page**

Tables:

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SUBJECT: POWER RATES POLICY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Raymond D. Bliven, and my qualifications are contained in BP-14-Q-BPA-04.

A. My name is Nancy Parker, and my qualifications are contained in BP-14-Q-BPA-51.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide the context and background to the policy objectives for power rates in the BP-14 Initial Proposal. In addition, this testimony highlights certain areas in BPA's direct case for power rates that we would like to point out to rate case parties for their further consideration and input. Generation inputs policy is discussed in the testimony of Fisher *et al.*, BP-14-E-BPA-21.

Section 2: Overview of the BP-14 Initial Power Rate Proposal

Q. Please describe the proposed power rates in the BP-14 Initial Proposal.

A. The BP-14 Initial Proposal is the second power rate proposal under the Tiered Rate Methodology (TRM), BP-12-A-03. The TRM, adopted in November 2008 and twice revised, is a 17-year rate methodology that is intended to ensure a stable long-term rate design structure that coincides with the power sales contracts (Contract High Water Mark (CHWM) contracts) under which service began in October 2011. Under this Initial Proposal, we estimate that the average rate paid by BPA's preference customers for Tier 1 power purchases from BPA will increase by 9.6 percent, and the average rate paid by BPA's industrial customers for power purchases from BPA will increase by 7.4 percent. These rate changes are discussed in section 5 below.

Q. Please discuss briefly the need for the proposed power rate increase.

A. By far, the largest cause of the power rate increase is the expectation of lower revenue from sales of surplus energy. The prices BPA is realizing for wholesale market sales have fallen since the BP-12 rates were put in place and are forecast to remain below BP-12 expectations through at least fiscal year (FY) 2015. In BP-12, the forecast market prices for BPA's net secondary revenues under median revenue conditions were in the $29-33/MWh range; now the forecasts are in $21-23 range. This leads to a reduction of the net secondary revenues reflected in power rates of about $115 million per year. In setting the BP-12 rates, net revenues from secondary sales were expected to pay about 30 percent of the revenue requirement for power; now the net revenues pay for less than 20 percent. The reduction in net secondary revenues and other marketing activities accounts for about 8 percentage points of the proposed 9.6 percent increase.

Other key drivers of the proposed power rate increase include increased operation and maintenance costs to ensure reliability and safe operation of the Columbia Generating Station (CGS) nuclear plant and the dams owned and operated by the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation. Other cost increases include new fish passage requirements and implementation of the Columbia Basin Fish Accords. These increased expenditures account for about 4 percentage points of the 9.6 percent increase.

These rate increases, combined, are greater than 9.6 percent. To offset a portion of these increases, BPA has been able to take advantage of unique opportunities that decrease capital-related costs for the upcoming rate period. BPA was able to reduce the costs of fuel financing for the Columbia Generating Station through the Depleted Uranium Enrichment Program, which reduces costs by $22 million per year. The extension of the CGS operating license through 2043 allows some of the CGS debt coming due during FY 2014-2015 to be extended, reducing the overall cost of borrowing during the rate period. Finally, the CGS relicensing reduced the annual contributions to the plant's decommissioning fund. Overall, debt management actions reduced the rate increase by about 4 percent.

Expenses and capital investments used in development of the Initial Proposal were determined in the Integrated Program Review (IPR) process. See Power Revenue Requirements Study, BP-14-E-BPA-02, section 2.1.

Q. What factors might affect the rate proposal between the Initial Proposal and the Final Proposal?

A. We are concerned that poor net secondary revenues *(i.e.,* secondary revenues minus balancing purchase costs) in the current operating year, FY 2013, due to continued low prices and early forecasts of low water will result in lower than expected starting rate period financial reserves and exert upward pressure on power rates. Expected FY 2013 net revenues could be well below those assumed in the Initial Proposal. The risk mitigation strategy, discussed in section 7, describes how this possibility is addressed in this Initial Proposal.

Q. Are you proposing any changes to the Tiered Rate Methodology?

A. No. The TRM, as revised in the BP-12 rate proceeding, is being implemented in this rate case without any need for further modification. Unlike in the BP-12 rate case, there are no new adjustments between cost pools that were required to implement the TRM in this rate case.

Q. Are there major changes included in this rate proposal?

A. No. While there are a number of changes being proposed in this case, there are none that we consider to be major changes. Section 9 of this testimony further introduces the changes being proposed. In addition, we are highlighting certain issues for which BPA is particularly interested in hearing parties' ideas for possible alternatives. These issues are summarized in section 10.

Section 3: Sources of Policy Guidance for Power Rate Development

Q. Please describe the primary policy decisions and processes that shape the Initial Proposal.

A. The primary policy guidance comes from the statutes that govern BPA and in particular those that address ratesetting. The primary statutes governing BPA ratemaking are the Flood Control Act of 1944, 16 U.S.C. § 825s; the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838; and the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act), 16 U.S.C. § 839. Power Rates Study section 1.2.

In addition to the statutes, the chief policy decisions and public processes that shape the Initial Proposal are expressed in:

(1) Prior wholesale power rate case Records of Decision (ROD);

(2) Bonneville Power Administration Long-Term Regional Dialogue Final Policy and ROD (July 19, 2007);

(3) Columbia Basin Fish Accords RODs (May 2, 2008, November 6, 2008, and July 3, 2012);

(4) Final 2008 Average System Cost (ASC) Methodology ROD (June 30, 2008);

(5) 2008 Financial Plan (July 31, 2008);

(6) Tiered Rate Methodology (September 2, 2009) and ROD (November 10, 2008), TRM Supplemental ROD (September 2, 2009), and TRM changes adopted in the BP-12 ROD (July 25, 2011);

(7) Residential Exchange Program Settlement Agreement Proceeding (REP-12) Administrator's ROD (July 26, 2011);

(8) Administrator’s ROD: Non-Treaty Storage Agreement with BC Hydro (March 23, 2012);

(9) Agency ROD: Amendment No. 1 to Firm Power Sales Agreement with Port Townsend Paper Corporation, Contract No. 11PB-12330 (June 28, 2012);

(10) Letter to the Region: BPA's Proposed Long-Term Power Sales Agreement with Alcoa's Intalco Plant (October 9, 2012); and

(11) Integrated Program Review final report (October 2012).

Together, these documents form the foundation of many of the ratemaking choices incorporated in the Initial Proposal.

Q. What other policy objectives have guided the development of the BP-14 Initial Proposal?

A. Specific financial and policy objectives that guided the development of the BP-14 Initial Proposal are similar to those that have guided past rate proposals but reflect BPA’s and the region’s current economic situation and the fact that this Initial Proposal is implementing the TRM. BPA’s risk mitigation objectives are to:

(1) create a rate design and risk mitigation package that meet BPA financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability;

(2) produce the lowest possible rates, consistent with sound business principles and statutory obligations, including BPA’s long-term responsibility to invest in and maintain the aging infrastructure of the Federal Columbia River Power System (FCRPS);

(3) set lower, but adjustable, effective rates rather than higher, more stable rates;

(4) include in the risk mitigation package only those elements that can be relied upon;

(5) not let financial reserve levels build up to unnecessarily high levels;

(6) allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation; and

(7) rely prudently on liquidity tools, and create means to replenish them when they are used in order to maintain long-term availability.

These objectives are interdependent and require BPA to balance competing objectives against each other when developing its overall rate design strategy. This Initial Proposal reflects BPA Staff's efforts to balance these competing objectives.

Q. Have these objectives changed since the BP-12 rate case?

A. These are the same objectives identified for the BP-12 power rate proposal. BPA is aware of the impact of BPA rates on the Pacific Northwest as well as the need to maintain the FCRPS. And, given that the proposed rate increase is due in large part to low expectations for surplus revenue and that BPA relies to a large extent on the Treasury Facility for power risk mitigation, power rates need to be designed in such a way as to restore the Treasury Facility when it is used, to ensure its future availability.

Section 4: Residential Exchange Program

Q. Please describe recent changes in BPA's Residential Exchange Program (REP).

A. On July 26, 2011, following an eight-month administrative hearing in the REP-12 docket, the Administrator adopted a long-term settlement of REP litigation. The legal, factual, and policy merits of the 2012 REP Settlement are thoroughly addressed in the Administrator's 2012 REP Settlement ROD (REP-12 ROD). The REP-12 ROD and 2012 REP Settlement are currently being reviewed by the Court. The Administrator's decision to adopt the 2012 REP Settlement and his decision to implement the 2012 REP Settlement in this case are not issues within the scope of this proceeding.

Q. How is the 2012 REP Settlement reflected in this rate case?

A. The ratemaking elements of the 2012 REP Settlement are incorporated in this Initial Proposal. The proposed rates and the documentation supporting those rates are based on the Settlement. Because the Administrator has found the Settlement to be consistent with relevant statutes and that the Settlement appropriately provides adequate rate protection pursuant to section 7(b)(2) for the rate period, FY 2014-2015, we have instructed Staff to not perform the section 7(b)(2) rate test in this rate case. In its place, rate protection is provided to preference customers through the limitation of REP benefits to be paid to the region's IOUs below what has been shown would otherwise occur. Consistent with the Settlement, this rate proposal develops Base PF Exchange rates that are compared with Draft ASCs to determine REP participant eligibility. In the Initial Proposal, we find that all six IOUs would be eligible for REP benefits, and one of the two consumer-owned utilities (COU) that filed for an ASC determination would be eligible for REP benefits. The qualifications of each participant will be reexamined in the Final Proposal using the final rates and final ASCs.

Q. What is the level of REP benefits and refund payments BPA is including in rates for the FY 2014-2015 rate period?

A. For IOUs, the amount of REP benefits that are included in the Initial Proposal rates is $274 million for FY 2014-2015. Of this amount, $197.5 million would be paid to the IOUs based on a comparison of each of their ASCs and individual PF Exchange rates. For COUs, the forecast amount of REP benefits is $1.4 million. In addition to REP benefits, $76 million would be withheld from the IOUs and paid to the COUs as refunds in accordance with the terms of the 2012 REP Settlement.

Section 5: Describing the Rate Increase

Q. How much is the PF rate increasing?

A. The adoption of the TRM has complicated the process of describing the nature of the rate increase such that, under the TRM, there is no one single and simple answer to the question. Each of BPA's PF customers is in a different position because of product choices and load characteristics. There also are different methodologies that can be used to measure any increases. Our analysis shows that the rate increases range from 3 to 11 percent for individual customers, but different methodologies can show different results. See Table 2 for our analysis.

One method is used for the individual customer impacts reflected in Table 2. This method compares the application of BP-12 rates and BP-14 rates using billing determinants that are forecast to occur in FY 2014. This method measures how much more a customer would pay if BP-12 rates were extended for another rate period compared to the new BP-14 rates.

Another method, reflected in Table 1, compares posted rates, that is, the BP-12 rate as it was stated in the BP-12 rate case, to the BP-14 rate as it is stated in this case. This method does not account for changes in billing determinants between rate cases but would give a customer an indication of how much more it might pay in FY 2014-2015 compared with FY 2012-2013.

Given the different methods and effects on customers, we have developed a metric that describes the increase in the posted average Tier 1 rates. Sales at Tier 1 rates account for about 95 percent of the power revenues subject to rates that are being adjusted in this rate case. That metric is called the Tier 1 Average Net Cost.

Q. What do you mean by "Tier 1 Average Net Cost"?

A. Tier 1 Average Net Cost was first developed in the BP-12 case as a method to consistently compare Tier 1 rates between rate cases. Previously, we characterized the PF rate increase based on average rates to non-Slice customers. The TRM rate design is much more like the Slice rate structure (although with certain key differences) that existed between FY 2002 and FY 2011, which was a rate design based on percentages of system capabilities.

The TRM rate design puts Slice and non-Slice purchases on a comparable basis by providing a common rate design for all products available to preference customers.

There are significant differences among the available products. Slice purchases include firm requirements power and surplus power, when available, but Slice rates do not include the value of the surplus power. Non-Slice purchases include only firm requirements power, and the value of surplus power is directly reflected through credits to the PF rate for non-Slice power. We developed "Tier 1 Average Net Cost" as a metric that puts Slice and non-Slice purchasers on a common basis by attributing a value to the surplus power that is expected to be sold to Slice purchasers. The imputed value of the surplus power is equivalent to what is included in rates to non-Slice purchasers. Thus, all power sold at PF Public rates to Slice and non-Slice customers can be valued on a common basis, allowing an equitable comparison of the PF Public rates and between rate cases.

Q. How much is the Tier 1 Average Net Cost increasing?

A. In the Initial Proposal, the proposed Tier 1 Average Net Cost of Priority Firm Power purchasers for FY 2014-2015 is 31.68 mills/kWh, 9.6 percent higher than the Tier 1 Average Net Cost of Priority Firm Power determined for the BP-12 Final Proposal for FY 2012-2013. See Table 1. The Tier 1 Average Net Cost for non-Slice purchasers is 9.0 percent higher than for FY 2012-2013. The Tier 1 Average Net Cost for Slice purchasers is 10.3 percent higher than for FY 2012-2013.

Q. Would Slice customers actually pay a BPA rate that is increasing 10.3 percent?

A. No. Slice customers pay the Composite Rate, which is increasing by 1.0 percent. Most of the increase in the average Tier 1 Average Net Cost for Slice purchasers is due to the lower market value of surplus energy, the same factor that drives much of the 9.6 percent increase in the average Tier 1 Average Net Cost for non-Slice purchasers. The actual value of the surplus energy will be experienced directly by Slice purchasers through their market transactions, not through BPA rates.

Q. What level of discount do you propose for eligible irrigation loads?

A. The rate discount for eligible irrigation loads is increasing from 10.26 mills/kWh to 10.52 mills/kWh.

Q. What are the proposed Industrial Firm Power and New Resources rates?

A. The Initial Proposal average Industrial Firm Power (IP) rate is 38.98 mills/kWh, 7.4 percent higher than the FY 2012-2013 IP rate. The Initial Proposal New Resource Firm Power (NR) rate is 73.63 mills/kWh, which is 5.9 percent higher than the FY 2012-2013 NR rate.

Section 6: Assumptions About Service to Direct Service Industries

Q. Are there any changes in assumptions regarding service to the DSIs?

A. Other than the forecast sales level, no.

Q. Please describe the guidance you provided for DSI rate development for the upcoming rate period.

A. Currently, BPA has DSI power sales contracts with Port Townsend Paper and Alcoa for an aggregate 320 aMW of service. Pursuant to a contract amendment with Port Townsend Paper, portions of Port Townsend's load will transfer to Jefferson County PUD when Jefferson begins taking service from BPA, currently expected to begin next July. BPA is reviewing public comments regarding an extension to Port Townsend's contract to purchase 12 aMW of power through September 2022. BPA is currently reviewing public comments regarding a proposed contract to sell 300 aMW of power to Alcoa through September 2022. In this rate proceeding, we have directed Staff to assume that these levels of service are an appropriate forecast for service levels during the FY 2014-2015 rate period. The Administrator has excluded from the rate case BPA's decisions regarding service to the DSIs, including BPA's decision to offer contracts. The total DSI load assumed for this rate proposal is 312 aMW. The Administrator's decisions may differ from this assumption; if so, the Final Proposal will be updated.

Section 7: Initial Proposal Power Rates Risk Mitigation Package

Q. Given the financial and policy objectives described in section 3, what direction did you give Staff regarding the use of liquidity tools?

A. The front line for risk mitigation continues to be financial reserves attributed to Power Services. Power Risk and Market Price Study section 3.2.1.1. We also continue to rely on the availability of the Treasury Facility. *Id.* section 3.2.1.2. Combined, we refer to these tools as liquidity tools, and our policy guidance is to rely prudently on liquidity tools and create means to replenish them when they are used to maintain their long-term availability.

Q. What guidance did you give regarding the development of the Cost Recovery Adjustment Clause (CRAC)?

A. We believe the CRAC mechanism continues to be a useful tool to help ensure that rates are low but adjustable, rather than higher but more stable, consistent with policy guidance. To be consistent with the guidance related to replenishing the liquidity tools, we asked Staff to structure the CRAC to ensure that any of the liquidity Power Services uses will be restored in a timely, responsible manner. The timely replenishment of the liquidity tools needs to be balanced with the fact that trying to collect too much too fast could create difficulties for our customers.

Q. Please describe briefly the power risk mitigation proposal.

A. The CRAC would trigger if Accumulated Net Revenue drops to the equivalent of $0 in Power Services financial reserves, even if the 95 percent TPP standard could be met using a lower threshold for the CRAC than that. Power Risk and Market Price Study section 3.2.4.1. That is the same proposal made for the BP-12 rates. Also, the amount the CRAC will recover in the following year is 100 percent of the first $100 million that Accumulated Net Revenue is below the threshold, and then 50 percent of any amount of underrun beyond $100 million, up to the CRAC annual limit ($300 million). *Id.* That, too, is the same proposal we made for the BP-12 rates.

Finally, the CRAC will continue to apply to the capacity reserve-based Ancillary and Control Area Services rates. See the Power General Rate Schedule Provisions (GRSPs), BP-14-E-BPA-09, GRSP II.C, and Transmission GRSPs, BP-14-E-BPA-10, GRSP II.H. *See also* the testimony of Mandell *et al.*, BP-14-E-BPA-15.

Q. What concerns about risk arose in completing the Initial Proposal?

A. In preparing for the hydroregulation studies, there was considerable discussion about what level of spill to assume. Over the past several years, the amount of spill ordered by the court has exceeded the amounts included in the rate case studies. After considering the question with input from many parts of the agency, we directed Staff to assume the amount that is best indicated by the 2008 FCRPS Biological Opinion. We also instructed Staff to ensure that any amounts of spill in excess of this level would be considered in the risk mitigation tools. This decision increases the risk to power customers, but we believe that it also provides a lower beginning rate level and would collect higher costs due to increased spill requirements only if BPA financial conditions required a CRAC to be implemented.

Section 8: DSI Typical Industrial Margin

Q. What policy direction did you give to Staff regarding the development of the IP rate?

A. According to section 7(c) of the Northwest Power Act, the IP rate is to be based on BPA's "applicable wholesale rates" to its consumer-owned utility customers plus the "typical margins" included by those customers in their retail industrial rates. In order to simplify the workload related to the IP rate, we entered into an agreement with representatives of public power and Alcoa to forgo surveying COUs with industrial customers regarding the costs of service to their industrial customers. See Power Rates Study, BP-14-E-BPA-01, Appendix A, Attachment B. Pursuant to this agreement, in lieu of performing a new customer survey, we directed Staff to rely on the survey performed for the BP-12 rate case, which was conducted in 2011. Also, we asked Staff whether it would be appropriate to escalate the BP-12 typical industrial margin to reflect inflation over the two years. After discussing this question, we decided it would be appropriate to propose to include the effects of inflation in the BP-14 typical margin. Inflation increases the margin by 0.02 mills/kWh. Power Rates Study Appendix A.

Section 9: Summary of Changes to Power Rates

Section 9.1: Provisional Contract High Water Marks

Q. What are Provisional Contract High Water Marks (CHWM)?

A. Provisional CHWMs were created in revisions to the TRM in 2009 and included in CHWM contracts. Under the TRM, CHWMs are based on a customer's Measured FY 2010 Load. Customers that lost loads due to the 2008 economic downturn would have received lower CHWMs than they expected at the time the TRM was developed and consequently would face higher power costs if those loads returned. Recognizing this predicament led to the development of Provisional CHWMs. A Provisional CHWM Amount is a conditional increase in a customer's CHWM for FY 2012-2013 to account for qualifying load loss due to the economic downturn, with the potential for the provisional amounts to become permanent if the load returns.

In FY 2014, BPA will determine, for each customer that has a Provisional CHWM, what part of the customer's Provisional CHWM is retained as permanent CHWM. Section 4.1.8 of the TRM sets forth the criteria that BPA will use to make this determination. Two things occur after each determination is completed. First, if a customer does not retain all of its Provisional CHWM, then the customer's CHWM and related billing determinants are revised and applied retroactively to the start of the fiscal year. Second, if a customer retains any of its Provisional CHWM, then the customer's Contract Demand Quantity (CDQ) is revised and applied retroactively to October 1, 2011. No matter the outcome of a Provisional CHWM determination, billing adjustments will occur for all customers that have Provisional CHWMs.

Q. Please describe potential changes that will result from implementing the CHWM Contract provisions related to the Provisional CHWM Amounts.

A. As described in section 4.1.8 of the TRM, "[i]n FY 2014, BPA will determine, for each customer that has a Provisional CHWM Amount, what part of such customer's Provisional CHWM Amount is retained in its CHWM effective as of October 1, 2013." Section 4.1.9 of the TRM describes specific changes that will be made if the Provisional CHWM Amounts are not retained. In FY 2014, the CHWM contracts for customers whose CHMW is reduced pursuant to section 4.1.8 will be amended to reflect the customer's reduced CHWM. In addition, the customer's CDQ, Rate Period High Water Mark (RHWM), and Tier 1 Cost Allocator (TOCA) will be recalculated, as will the System Shaped Load (pursuant to TRM section 5.2.1). Section 4.1.9 also describes the public process that BPA will utilize before finalizing these changes.

Because these changes will occur during this rate period, we have instructed Staff to include language in the GRSPs explaining how the changes will be implemented in rates. This includes the adjustment to amounts previously billed in FY 2012-2014, consistent with the terms described in TRM section 4.1.10. See GRSPs II.D and II.Y. More details are included in the testimony of Chalier *et al.*, BP-14-E-BPA-19, sections 6 and 9.3.

Section 9.2: Other Demand Billing Determinant Adjustments

Q. Other than for Provisional CHWMs, what demand billing adjustments are proposed?

A. There are two other proposed adjustments. One adjustment is proposed to account for recovery peaks. The other adjustment is proposed to account for extreme load shift events. The adjustments are described with more detail in the testimony of Chalier *et al.*, BP-14-E-BPA-19, sections 9.1 and 9.2.

Q. Why are these adjustments being proposed?

A. In calculating the PF demand charge, the customer's actual average Tier 1 load is subtracted from its system peak to determine the demand billing determinant. After observing the first year of operating under the new TRM rate design, we were informed of concerns with an unintended effect on the demand charge resulting from abnormal load conditions. Such a situation is characterized by peak loads occurring without the underlying energy loads that offset the demand charge effect. The first situation that arose was the result of weather-related outages on BPA's transmission system or on a customer's distribution system. When service outages occur for prolonged periods, the restoration of service often results in short, but relatively high, peak loads. We use the term "recovery peaks" to describe these conditions.

The second situation arose when one customer noted the effect that a labor strike at an industrial consumer had on its demand charge. Another customer with one retail consumer noted that the consumer closes for extended maintenance every two years. After considering these situations, we surmised that there may be similar events that could trigger relatively high demand charges that were not contemplated when the demand rate design was being considered.

Q. What is the intent of the demand rate design?

A. The intent of the demand rate design was to send a price signal to customers that reflects the cost of providing capacity to serve peak loads. The effects of extreme peaks due to weather or other regularly occurring events were considered. Events such as transmission outages, labor strikes, or maintenance outages at consumer facilities were not. The purpose of sending a stronger demand rate signal to customers was to promote demand side management as a viable capacity resource. Demand side management is not a viable option during restoration peaks when people have suffered without heat or lighting for a prolonged period. We believe that the proposed demand adjustments will give customers the option to seek relief from excessive demand charges without compromising the intent of the demand rate design.

Section 9.3: Tier 2 Rate Issues

Q. What Tier 2 rate issues have been identified?

A. Staff came to us with two issues. The first issue was how to set Tier 2 rates when the purchases supporting those sales have not yet been finalized. The second issue was what to do about the costs of a Tier 2 purchase that turned out larger than needed after Above-RHWM loads were determined in the summer of 2012.

Q. How did you instruct Staff to set Tier 2 rates when the costs are not yet known?

A. We suggested that Staff include in the rate schedules the formulas that detail how the Tier 2 rate would be calculated if the costs were known. This allows the calculation of the rate to occur after the costs are known, whether or not the rate case has concluded. The formula approach to the Tier 2 rates is described in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.1.

Q. Please explain the second situation, regarding the costs of a purchase that was larger than needed.

A. Earlier this year, BPA offered a vintage Tier 2 rate opportunity to eligible customers. That offering concluded with customers subscribing to 46 aMW of power for five years. As part of BPA's power purchase for the vintage rate subscribers, it acquired an additional 5 aMW for the Load Growth pool, based upon projected needs of customers. At the time, it was expected that the Load Growth pool would have sufficient need for the 5 aMW for all five years. After completing the RHWM Process, we found that the Load Growth pool had a need for only 1.7 aMW for FY 2015. This left 3.3 aMW in excess of need and, as it appears at this time, the price of the power is higher than current market prices. The TRM specifies that the Load Growth pool members are ultimately responsible for the full costs of the purchases that BPA makes for the pool. To the extent that the power has a lower value, or higher, than when the purchase is made, the Load Growth pool members are responsible for what amounts to a stranded cost, or benefit.

After discussing a number of options with Staff, BPA management, and customers, we directed Staff to develop an allocation for the stranded cost that assigned the costs to pool members with an amount of Above-RHWM load between 0 and 1 aMW. We regret that the stranded costs were incurred, but we have hopes that the market will rebound enough to minimize (or reverse) the effect on the affected customers. We also are seeking further input on the proposed allocation of the stranded cost. While we have listened to customers in preparing the Initial Proposal, we are interested in other ideas parties may put forth. The proposed allocation and billing adjustment for the Load Growth pool are described in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.2.1.

Section 9.3: Remarketing

Q. What is remarketing?

A. The term "remarketed" is used in the CHWM contracts and in the TRM. It may arise when a customer has dedicated or committed to purchase more resources than it needs to serve its load that is above its RHWM. Under remarketing, the customer continues to pay the full cost of the resource it committed to purchase but is credited for the value of this additional power at the time that BPA remarkets it. This concept is further explained in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.2.1.

Q. Why is remarketing being introduced now?

A. The situations in the BP-12 rate case were such that remarketing rights were not triggered. Now, customers have exercised their contractual rights and have asked BPA to remarket resources that they committed to purchase that are in excess of their Above-RHWM need. Therefore, we have instructed Staff to develop rate schedule provisions to allow remarketing to occur within the parameters set forth in CHWM contracts and the TRM. GRSP II.R. We also asked Staff to minimize the potential risks associated with remarketing. Remarketing is discussed in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.2.2.

Section 9.4: NR Rate Energy Shaping Service

Q. What is NR rate energy shaping service?

A. Certain Load Following customers are facing the prospect of new large single loads (NLSLs) locating in their service territories and are considering using non-Federal resources to serve those NLSLs rather than taking service from BPA for that load at the NR rate. The CHWM contracts require that each customer's non-Federal resource(s) be matched to its NLSL load on an hourly basis. This new shaping service would satisfy this contractual requirement.

Q. What instructions did you provide for Staff?

A. We asked Staff to develop a rate for a service that would provide flexibility for the customer, protect BPA from as much risk as possible, and provide the proper statutory rate in the event that BPA energy is used for service to NLSLs. The rate and the service that are being proposed are described in more detail in the testimony of Chalier *et al.*, BP-14-E-BPA-19, section 2.

Section 9.5: Unanticipated Load Service Under the FPS Rate

Q. What is Unanticipated Load Service (ULS)?

A. ULS results from circumstances that cause an increase in a customer's load placed on BPA that was not anticipated in the rate case.

Q. What change is proposed for ULS in the FPS rate schedule?

A. The FPS-12 rate narrowly constrained ULS applicability. We have concluded that there could be other unforeseeable circumstances to which the ULS should apply but that may be omitted inadvertently from an exclusive list. We asked Staff to develop rate provisions that would provide BPA more flexibility to serve ULS in appropriate situations. See GRSP II.Z.4 and the testimony of Chalier *et al.*, BP-14-E-BPA-19, section 3.

Section 10: Additional Issues Where BPA Is Requesting Input from Parties

Q. While BPA is open to input on all aspects of the Initial Proposal, are there any specific proposals for which you are seeking particular help from parties?

A. Yes. A number of issues arose during preparation of the Initial Proposal that we believe may be improved with input from parties. Many of these issues have been discussed with workshop participants during the summer. The input received at the workshops significantly improved the Initial Proposal. Further consideration by all interested parties may serve to find even more improvements.

Q. What are the issues you have identified?

A. We have already related several. The treatment of the Load Growth pool stranded cost is one that may be further improved. NR rate energy shaping service is another, as are the demand billing determinant adjustments. In addition to these, we want to highlight two more: (1) the application of risk mitigation to Ancillary and Control Area Service (ACS) rates and (2) risk mitigation choices that we may face in the Final Proposal if FY 2013 conditions deplete Power's financial reserves.

Q. Please discuss the application of risk mitigation to ACS rates.

A. This proposal would assess 8.2 percent of any CRAC recovery amount to ACS rates. Other risk mitigation options were discussed prior to the rate case, but none was advanced in a form that we deemed to be complete and well-established enough to be incorporated into the Initial Proposal. We welcome all interested parties to continue to work together to see if better options are available.

Q. Please discuss the risk mitigation choices for the Final Proposal.

A. Our weather forecasters tell us that there is a good chance that El Niño conditions present in the Pacific Ocean could lead to a drier than normal FY 2013, although the situation appears to be improving lately because the El Niño is weak. Our risk experts tell us that risk will decrease as FY 2013 passes, but only in the sense that we can better forecast end-of-year FY 2013 financial conditions. Power Services started FY 2013 with $217 million in financial reserves available for risk mitigation. Power Risk and Market Price Study section 3.4.4. Ending reserves are projected to be lower than that. *Id.* section 3.5.2. Risk projections for FY 2013 using long-term averages for expectations show a 12 percent chance of a FY 2014 CRAC. *Id.* section 3.5.3. If it turns out to be a drier than normal year, we expect that lower revenues may deplete the available reserves.

If the forecast that will be done next July shows that Power Services net reserves (see the testimony of Lovell *et al.*, BP-14-E-BPA-15, section 3.2.6) are less than zero, a CRAC will be implemented. An alternative to a CRAC might be to include Planned Net Revenues for Risk in final rates. This would provide revenues to BPA and would spread the impact over two years rather than one. A number of factors would need to be considered before making such a choice, but this may provide an alternative that is worthy of consideration.

BPA will continue to keep its customers and rate case parties apprised of its financial conditions and expectations for a 2014 CRAC as FY 2013 progresses. Conditions may warrant a further discussion about risk mitigation choices for the final rates.

Q. Does this conclude your testimony?

A. Yes.

Table 1:
Overview of Initial Proposal Tier 1 Rates

Tiered PF Rate Summary

		Average	% above BP-12
Unbifurcated PF	$	42.16	8.4%
PF Public (Tier 1 + Tier 2)	$	32.97	8.9%
Base PF Exchange (IOU)	$	46.48	7.9%
PF Exchange with 7(b)(3)	$	59.10	8.8%
IP	$	38.99	7.4%
NR	$	73.58	5.8%

Annual Average $ (1000s)..	BP-12	BP-14	Change
Composite Rate Revenues..	$ 2,262,417	$ 2,329,836	3.0%
Non-Slice Rate Revenues..	$ (325,256)	$ (262,189)	19.4%
Slice Rate Revenues..	$ -	$ -	
Load Shaping Rate Revenues.................................	$ (14,083)	$ 16,019	-213.7%
Demand Rate Revenues	$ 60,101	$ 61,250	1.9%
Tier 1 Revenue Requirement..................................	$ 1,983,178	$ 2,144,917	8.2%
Tier 2 Revenue Requirement..................................	$ 16,363	$ 16,402	
Value of Slice Surplus...	$ (162,043)	$ (122,806)	24.2%
Value of CHWM RECs (credit)..............................			
Refund Amounts (credit)..	$ (76,538)	$ (76,538)	
Net Power Cost to All PF..	$ 1,760,961	$ 1,961,975	11.4%
Annual PF Load (w/firm Slice) (GWh)..................	60,702	61,830	1.9%
PF Average Net Cost ($/MWh)..............................	29.01	31.73	9.4%
Tier 1 Average Net Cost ($/MWh).........................	28.90	31.68	9.6%
Average Tier 2 ($/MWh)...	48.11	39.04	-18.8%

Slice Sales..	BP-12	BP-14	Change
Composite+Slice...	$ 629,081	$ 632,900	
Tier 1 Average Cost ($/MWh)................................	37.43	37.81	1.0%
Value of Slice Surplus+Credits................................	$ (183,325)	$ (143,597)	
Net Cost of Slice Power...	$ 445,756	$ 489,302	
Tier 1 Average Net Cost ($/MWh).........................	26.52	29.23	10.2%

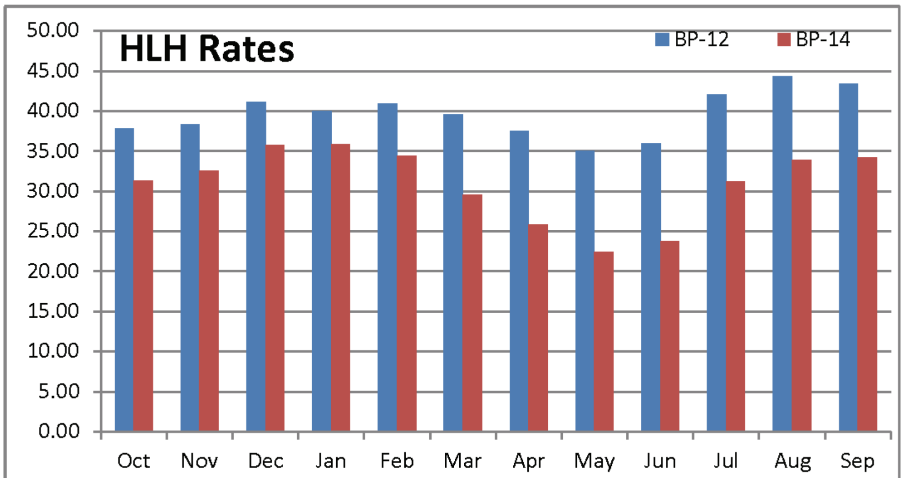
Non-Slice Sales..	BP-12	BP-14	Change
Composite+NonSlice+Shape+Demand....................	$ 1,354,050	$ 1,511,982	
Tier 1 Average Cost ($/MWh)................................	30.98	33.65	8.6%
Credits...	$ (55,256)	$ (55,746)	
Net Cost of Non-Slice Power..................................	$ 1,298,794	$ 1,456,235	
Tier 1 Average Net Cost ($/MWh).........................	29.72	32.41	9.0%

Tiered PF Rate Components....................................	BP-12	BP-14	Change
Composite Rate ($/1 pct/month)..............................	$ 1,952,168	$ 1,967,048	0.8%
Non-Slice Rate ($/1 pct/month)...............................	$ (388,748)	$ (303,923)	21.8%

Table 2:
Comparison of Load Shaping Rates

Load Shaping Rates Comparison
($/MWh)

	BP-12 HLH	BP-12 LLH	BP-14 HLH	BP-14 LLH	HLH Change	LLH Change
Oct	37.86	31.20	31.30	28.06	-17%	-10%
Nov	38.37	31.40	32.51	29.90	-15%	-5%
Dec	41.10	33.39	35.78	31.97	-13%	-4%
Jan	40.03	31.70	35.86	30.24	-10%	-5%
Feb	40.93	33.17	34.39	29.75	-16%	-10%
Mar	39.57	32.33	29.53	25.90	-25%	-20%
Apr	37.53	30.41	25.85	21.20	-31%	-30%
May	35.06	24.40	22.45	15.31	-36%	-37%
Jun	35.97	23.02	23.79	17.42	-34%	-24%
Jul	42.07	29.91	31.17	26.86	-26%	-10%
Aug	44.35	32.15	33.90	28.60	-24%	-11%
Sep	43.45	33.59	34.16	29.37	-21%	-13%
Annual		35.76		28.88		-19%



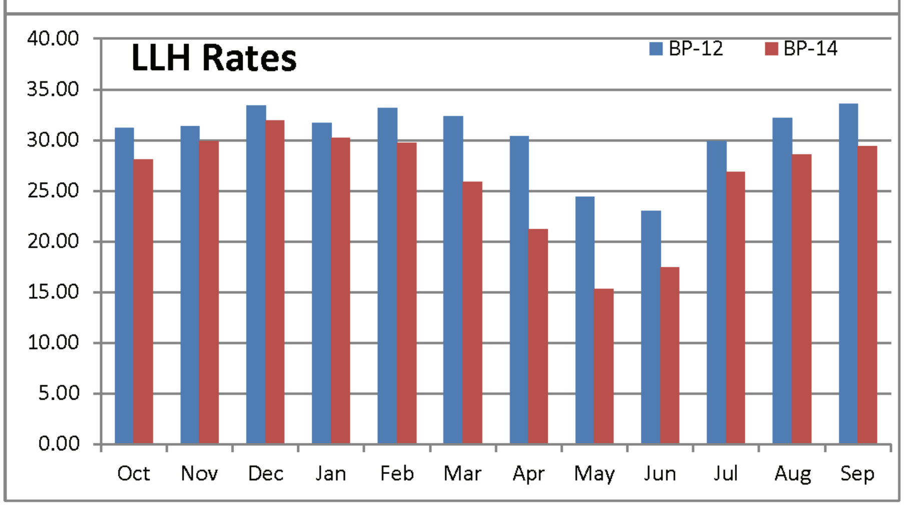
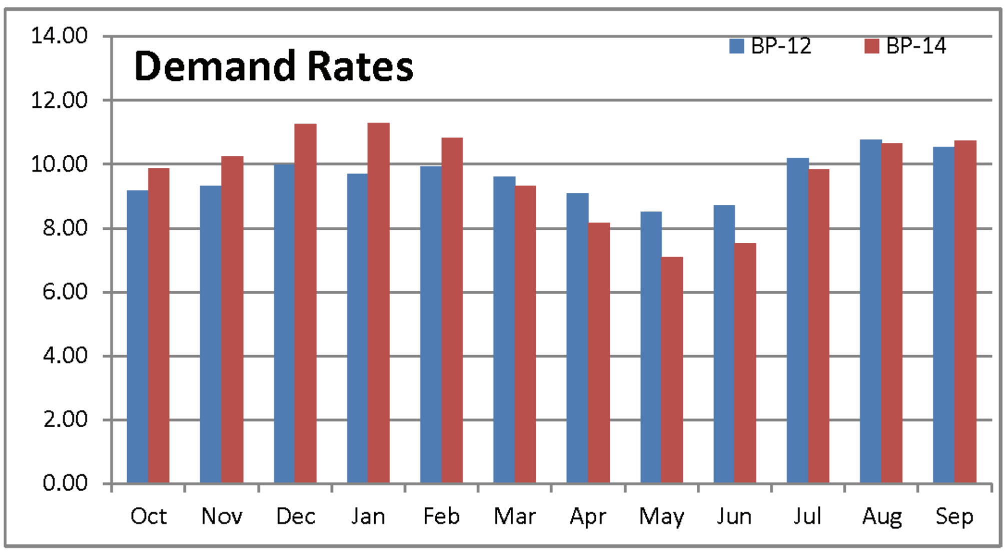


Table 3:
Comparison of Demand Rates

Demand Rates Comparison

($/kW)

	BP-12 Demand	BP-14 Demand	Change
Oct	9.18	9.86	7%
Nov	9.31	10.24	10%
Dec	9.97	11.26	13%
Jan	9.70	11.29	16%
Feb	9.92	10.83	9%
Mar	9.60	9.31	-3%
Apr	9.10	8.16	-10%
May	8.50	7.09	-17%
Jun	8.72	7.52	-14%
Jul	10.20	9.84	-4%
Aug	10.75	10.66	-1%
Sep	10.53	10.74	2%
Annual	9.62	9.73	1%



Irrigation Rate Discount

($/MWh)

	BP-12	BP-14	Change
Rate	-10.26	-10.52	3%
	per MWh of eligible load		

Table 4:
Customer Rate Impacts

Load Following and Block Annual Power Bill

PF Non-Slice Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	Effective Rates PF-14	Percent Change
10055 Albion, City of	3,565	$117,078	$126,266	32.84	35.42	7.8%
10005 Alder Mutual	5,089	156,789	166,216	30.81	32.66	6.0%
10057 Ashland, City of	185,332	6,053,793	6,448,847	32.66	34.80	6.5%
10015 Asotin County PUD #1	5,331	178,029	184,958	33.39	34.69	3.9%
10059 Bandon, City of	68,784	2,214,276	2,359,911	32.19	34.31	6.6%
10024 Benton County PUD #1	872,868	22,534,349	24,488,314	25.82	28.06	8.7%
10025 Benton REA	587,016	16,570,987	17,659,440	28.23	30.08	6.6%
10027 Big Bend Elec Coop	538,292	13,728,221	14,347,480	25.50	26.65	4.5%
10029 Blachly Lane Elec Coop	154,968	4,933,085	5,238,627	31.83	33.80	6.2%
10061 Blaine, City of	79,573	2,601,258	2,758,723	32.69	34.67	6.1%
10062 Bonners Ferry, City of	54,226	1,864,652	1,942,299	34.39	35.82	4.2%
10064 Burley, City of	122,242	3,869,463	4,137,505	31.65	33.85	6.9%
10044 Canby, City of	178,653	5,808,662	6,187,856	32.51	34.64	6.5%
10065 Cascade Locks, City of	19,556	598,848	644,131	30.62	32.94	7.6%
10046 Central Electric Coop	719,995	21,225,060	22,753,482	29.48	31.60	7.2%
10047 Central Lincoln PUD	1,340,463	42,560,146	45,718,279	31.75	34.11	7.4%
10066 Centralia, City of	214,386	7,072,436	7,575,281	32.99	35.33	7.1%
10067 Cheney, City of	139,134	4,484,817	4,798,854	32.23	34.49	7.0%
10068 Chewelah, City of	24,506	780,670	837,901	31.86	34.19	7.3%
10101 Clallam County PUD #1	668,779	20,754,914	22,348,355	31.03	33.42	7.7%
10103 Clark County PUD #1	1,411,470	41,599,084	45,490,910	29.47	32.23	9.4%
10105 Clatskanie PUD	361,069	10,648,902	11,570,365	29.49	32.04	8.7%
10106 Clearwater Power	197,484	5,760,872	6,194,603	29.17	31.37	7.5%
10109 Columbia Basin Elec Coop	111,145	3,127,726	3,278,268	28.14	29.50	4.8%
10111 Columbia Power Coop	28,699	814,766	871,891	28.39	30.38	7.0%
10113 Columbia REA	331,562	8,584,920	8,985,264	25.89	27.10	4.7%
10112 Columbia River PUD	507,798	16,718,016	17,855,472	32.92	35.16	6.8%
10116 Consolidated Irrigation District #19	6,633	267,361	232,020	40.31	34.98	-13.2%
10118 Consumers Power	401,767	12,103,796	12,959,772	30.13	32.26	7.1%
10121 Coos Curry Elec Coop	359,566	10,685,030	11,470,593	29.72	31.90	7.4%
10378 Coulee Dam, City of	19,048	651,252	692,636	34.19	36.36	6.4%
10123 Cowlitz County PUD #1	2,290,183	67,486,427	73,220,191	29.47	31.97	8.5%
10070 Declo, City of	3,249	106,828	114,011	32.88	35.09	6.7%
10136 Douglas Electric Cooperative	161,887	4,550,932	4,893,315	28.11	30.23	7.5%
10071 Drain, City of	17,462	560,955	602,523	32.13	34.51	7.4%
10142 East End Mutual Electric	24,216	712,425	751,148	29.42	31.02	5.4%
10144 Eatonville, City of	31,169	1,051,107	1,113,430	33.72	35.72	5.9%
10072 Ellensburg, City of	214,062	6,873,615	7,331,144	32.11	34.25	6.7%
10156 Elmhurst Mutual P & L	287,415	9,117,178	9,804,352	31.72	34.11	7.5%
10157 Emerald PUD	220,725	6,241,835	6,815,787	28.28	30.88	9.2%
10158 Energy Northwest	24,329	786,960	848,786	32.35	34.89	7.9%
10170 Eugene Water & Electric Board	1,066,301	31,630,163	34,451,579	29.66	32.31	8.9%
10173 Fall River Elec Coop	291,431	8,124,081	8,735,387	27.88	29.97	7.5%
10174 Farmers Elec Coop	4,537	149,944	161,196	33.05	35.53	7.5%
10177 Ferry County PUD #1	105,312	3,182,800	3,406,469	30.22	32.35	7.0%
10179 Flathead Elec Coop	1,467,456	48,515,059	51,887,544	33.06	35.36	7.0%
10074 Forest Grove, City of	229,752	7,539,546	8,058,436	32.82	35.07	6.9%
10183 Franklin County PUD #1	536,046	14,879,418	16,133,160	27.76	30.10	8.4%
10186 Glacier Elec Coop	190,552	5,603,689	5,980,379	29.41	31.38	6.7%
10190 Grant County PUD #2	49,418	1,518,101	1,617,658	30.72	32.73	6.6%
10191 Grays Harbor PUD #1	537,409	15,857,297	17,313,240	29.51	32.22	9.2%
10197 Harney Elec Coop	184,747	4,397,344	4,595,745	23.80	24.88	4.5%
10597 Hermiston, City of	113,206	3,637,331	3,882,151	32.13	34.29	6.7%
10076 Heyburn, City of	42,374	1,343,895	1,438,949	31.72	33.96	7.1%
10202 Hood River Elec Coop	117,560	3,856,812	4,120,778	32.81	35.05	6.8%
10203 Idaho County L & P	54,650	1,697,334	1,819,190	31.06	33.29	7.2%

Table 4, continued

Load Following and Block Annual Power Bill

	PF Non-Slice Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	Effective Rates PF-14	Percent Change
10204	Idaho Falls Power	350,120	10,342,007	11,270,755	29.54	32.19	9.0%
10209	Inland P & L	947,755	28,219,003	30,277,756	29.77	31.95	7.3%
12026	Jefferson County PUD #1	398,939	12,804,366	13,767,699	32.10	34.51	7.5%
10230	Kittitas County PUD #1	89,600	2,747,213	2,914,652	30.66	32.53	6.1%
10231	Klickitat County PUD #1	169,226	4,465,949	4,892,689	26.39	28.91	9.6%
10234	Kootenai Electric Coop	453,523	13,903,271	14,857,938	30.66	32.76	6.9%
10235	Lakeview L & P (WA)	288,519	9,185,051	9,853,036	31.84	34.15	7.3%
10236	Lane County Elec Coop	256,004	7,444,110	8,054,356	29.08	31.46	8.2%
10237	Lewis County PUD #1	388,563	10,823,617	11,851,216	27.86	30.50	9.5%
10239	Lincoln Elec Coop (MT)	123,327	3,454,785	3,744,678	28.01	30.36	8.4%
10242	Lost River Elec Coop	81,400	1,989,665	2,105,557	24.44	25.87	5.8%
10244	Lower Valley Energy	756,826	22,992,075	24,852,687	30.38	32.84	8.1%
10246	Mason County PUD #1	82,340	2,580,518	2,745,638	31.34	33.34	6.4%
10247	Mason County PUD #3	703,094	22,035,957	23,646,977	31.34	33.63	7.3%
10078	McCleary, City of	30,781	1,071,612	1,136,876	34.81	36.93	6.1%
10079	McMinnville, City of	745,539	25,134,933	26,769,454	33.71	35.91	6.5%
10256	Midstate Elec Coop	411,699	11,766,483	12,617,550	28.58	30.65	7.2%
10080	Milton, Town of	65,427	2,094,897	2,248,536	32.02	34.37	7.3%
10081	Milton-Freewater, City of	88,706	2,853,433	3,069,727	32.17	34.61	7.6%
10082	Minidoka, City of	1,141	37,468	39,573	32.84	34.69	5.6%
10258	Mission Valley	333,842	9,984,177	10,760,341	29.91	32.23	7.8%
10259	Missoula Elec Coop	240,083	7,387,257	7,887,757	30.77	32.85	6.8%
10260	Modern Elec Coop	233,700	7,601,552	8,096,134	32.53	34.64	6.5%
10083	Monmouth, City of	75,458	2,534,200	2,693,005	33.58	35.69	6.3%
10273	Nespelem Valley Elec Coop	56,924	1,675,298	1,729,982	29.43	30.39	3.3%
10278	Northern Lights	316,046	9,313,820	10,035,755	29.47	31.75	7.8%
10279	Northern Wasco County PUD	548,134	16,989,738	18,216,224	31.00	33.23	7.2%
10284	Ohop Mutual Light Company	94,339	2,974,017	3,158,802	31.52	33.48	6.2%
10285	Okanogan County Elec Coop	57,433	1,783,306	1,930,233	31.05	33.61	8.2%
10286	Okanogan County PUD #1	200,604	5,416,253	6,012,975	27.00	29.97	11.0%
10288	Orcas P & L	217,568	6,738,800	7,248,127	30.97	33.31	7.6%
10291	Oregon Trail Coop	675,946	20,095,628	21,444,462	29.73	31.73	6.7%
10294	Pacific County PUD #2	140,166	4,143,111	4,544,386	29.56	32.42	9.7%
10304	Parkland L & W	127,354	4,096,680	4,374,708	32.17	34.35	6.8%
10306	Pend Oreille County PUD #1	113,739	3,473,294	3,918,398	30.54	34.45	12.8%
10307	Peninsula Light Company	637,194	20,345,117	21,812,455	31.93	34.23	7.2%
10086	Plummer, City of	36,349	1,212,638	1,283,624	33.36	35.31	5.9%
10087	Port Angeles, City of	747,578	23,006,674	24,863,757	30.77	33.26	8.1%
10706	Port of Seattle - SETAC In'tl. Airport	159,403	5,061,770	5,342,801	31.75	33.52	5.6%
10331	Raft River Elec Coop	303,774	7,232,231	7,607,085	23.81	25.04	5.2%
10333	Ravalli County Elec Coop	164,049	4,985,342	5,331,942	30.39	32.50	7.0%
10089	Richland, City of	889,698	28,923,942	30,906,488	32.51	34.74	6.9%
10338	Riverside Elec Coop	20,619	614,619	654,606	29.81	31.75	6.5%
10091	Rupert, City of	79,395	2,536,991	2,732,385	31.95	34.41	7.7%
10342	Salem Elec Coop	347,516	11,283,633	12,046,734	32.47	34.67	6.8%
10343	Salmon River Elec Coop	283,406	7,955,485	8,483,638	28.07	29.93	6.6%
10349	Seattle City Light	2,294,695	69,651,041	77,690,530	30.35	33.86	11.5%
10352	Skamania County PUD #1	139,237	4,247,286	4,559,224	30.50	32.74	7.3%
10354	Snohomish County PUD #1	3,393,453	100,306,269	109,371,872	29.56	32.23	9.0%
10094	Soda Springs, City of	26,091	838,197	895,528	32.13	34.32	6.8%
10360	Southside Elec Lines	58,914	1,577,595	1,669,866	26.78	28.34	5.8%
10363	Springfield Utility Board	885,865	29,009,366	31,056,248	32.75	35.06	7.1%
10379	Steilacoom, Town of	43,122	1,389,003	1,490,760	32.21	34.57	7.3%
10095	Sumas, Town of	33,125	1,078,568	1,134,421	32.56	34.25	5.2%
10369	Surprise Valley Elec Coop	135,839	3,534,333	3,724,633	26.02	27.42	5.4%
10370	Tacoma Public Utilities	1,651,680	48,802,570	53,136,292	29.55	32.17	8.9%

Table 4, continued

Load Following and Block Annual Power Bill

	PF Non-Slice Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	PF-14	Percent Change
10371	Tanner Elec Coop	105,216	3,265,414	3,428,718	31.04	32.59	5.0%
10376	Tillamook PUD	487,569	15,993,774	17,140,858	32.80	35.16	7.2%
10097	Troy, City of	19,140	637,418	673,553	33.30	35.19	5.7%
10172	U.S. Airforce Base, Fairchild	54,738	1,772,463	1,887,122	32.38	34.48	6.5%
10406	U.S. DOE Albany Research Center	4,565	146,481	154,086	32.08	33.75	5.2%
10426	U.S. DOE Richland Operations Office	249,613	8,046,474	8,678,295	32.24	34.77	7.9%
10326	U.S. Naval Base, Bremerton	251,023	7,936,435	8,473,093	31.62	33.75	6.8%
10408	U.S. Naval Station, Everett (Jim Creek)	12,931	396,825	428,099	30.69	33.11	7.9%
10409	U.S. Naval Submarine Base, Bangor	177,140	5,520,505	5,930,745	31.16	33.48	7.4%
10388	Umatilla Elec Coop	995,971	27,937,897	29,404,807	28.05	29.52	5.3%
10482	Umpqua Indian Utility Cooperative	36,189	1,148,986	1,231,197	31.75	34.02	7.2%
10391	United Electric Coop	263,690	7,393,181	7,897,734	28.04	29.95	6.8%
10434	Vera Irrigation District	238,888	7,702,133	8,250,832	32.24	34.54	7.1%
10436	Vigilante Elec Coop	168,473	4,557,232	4,859,546	27.05	28.84	6.6%
10440	Wahkiakum County PUD #1	47,603	1,486,321	1,572,169	31.22	33.03	5.8%
10442	Wasco Elec Coop	120,562	3,619,790	3,870,329	30.02	32.10	6.9%
11680	Weiser, City of	58,107	1,853,459	1,956,827	31.90	33.68	5.6%
10446	Wells Rural Elec Coop	842,457	24,291,453	26,191,833	28.83	31.09	7.8%
10448	West Oregon Elec Coop	73,905	2,228,611	2,387,219	30.16	32.30	7.1%
10451	Whatcom County PUD #1	240,549	7,417,100	7,911,837	30.83	32.89	6.7%
10502	Yakama Power	87,278	2,673,842	2,828,207	30.64	32.40	5.8%
99999	PNGC Aggregate	4,413,556	127,258,851	135,908,367	28.83	30.79	6.8%
	Aggregate PF Non-Slice Customers	44,627,637	1,345,588,500	1,450,313,495	30.15	32.50	7.8%

Note: Inconsistencies in Consolidated Irrigation District load forecast results in unreliable reporting

Note: Some charges are excluded from this analysis: RSS, TSS, and GTA Delivery, and REP Refund Amounts

Tier 2 Annual Power Bill

	Tier 2 Load Growth Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	PF-14	Percent Change
10288	Orcas P & L	11,502	559,336	407,857	48.63	35.46	-27.1%
	Aggregate Load Growth Customers	11,502	559,336	407,857	48.63	35.46	-27.1%

	Tier 2 Short-Term Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	PF-14	Percent Change
10101	Clallam County PUD #1	11,029	536,994	391,083	48.69	35.46	-27.2%
10076	Heyburn, City of	13,639	664,098	483,650	48.69	35.46	-27.2%
10298	PNGC Aggregate	69,265	3,372,528	2,456,148	48.69	35.46	-27.2%
10089	Richland, City of	38,491	1,874,148	1,364,906	48.69	35.46	-27.2%
	Aggregate Short-Term Customers	132,425	6,447,769	4,695,788	48.69	35.46	-27.2%

DSI Annual Power Bill

	IP Customer	2014 MWh	Payments at IP-12 Rates	Payments at IP-14 Rates	Effective Rates IP-12	IP-14	Percent Change
10007	Alcoa	2,628,000	95,138,880	102,453,629	36.20	38.99	7.7%
10312	Port Townsend Paper	105,120	3,805,555	4,098,145	36.20	38.99	7.7%
	Aggregate IP Customers	2,733,120	98,944,435	106,551,774	36.20	38.99	7.7%

Table 4, continued

Slice Annual Power Bill

	PF Slice Customer	2014 Slice Pctg	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10024	Benton County PUD #1	0.0137030	$32,100,694	$32,341,813	37.58	37.86	0.8%
10103	Clark County PUD #1	0.0218596	51,208,372	51,593,016	37.58	37.86	0.8%
10105	Clatskanie PUD	0.0072661	17,021,590	17,149,445	37.58	37.86	0.8%
10123	Cowlitz County PUD #1	0.0399535	93,595,203	94,298,229	37.58	37.86	0.8%
10157	Emerald PUD	0.0037045	8,678,174	8,743,359	37.58	37.86	0.8%
10170	Eugene Water & Electric Board	0.0179648	42,084,401	42,400,511	37.58	37.86	0.8%
10183	Franklin County PUD #1	0.0078031	18,279,568	18,416,872	37.58	37.86	0.8%
10191	Grays Harbor PUD #1	0.0096995	22,722,081	22,892,755	37.58	37.86	0.8%
10204	Idaho Falls Power	0.0054988	12,881,507	12,978,265	37.58	37.86	0.8%
10231	Klickitat County PUD #1	0.0023654	5,541,194	5,582,816	37.58	37.86	0.8%
10237	Lewis County PUD #1	0.0096216	22,539,592	22,708,895	37.58	37.86	0.8%
10286	Okanogan County PUD #1	0.0036161	8,471,088	8,534,717	37.58	37.86	0.8%
10294	Pacific County PUD #2	0.0028208	6,608,016	6,657,651	37.58	37.86	0.8%
10306	Pend Oreille County PUD #1	0.0018519	4,338,267	4,370,853	37.58	37.86	0.8%
10349	Seattle City Light	0.0362762	84,980,748	85,619,068	37.58	37.86	0.8%
10354	Snohomish County PUD #1	0.0544584	127,574,430	128,532,687	37.58	37.86	0.8%
10370	Tacoma Public Utilities	0.0296627	69,487,940	70,009,889	37.58	37.86	0.8%
	Aggregate PF Slice Customers	0.2681260	628,112,865	632,830,842	37.58	37.86	0.8%

Slice+Block Annual Power Bill under Critical Water (no mkt credit)

	PF Slice+Block Customer	2014 Firm MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10024	Benton County PUD #1	1,727,065	54,635,043	56,830,128	31.63	32.91	4.0%
10103	Clark County PUD #1	2,774,121	92,807,456	97,083,927	33.45	35.00	4.6%
10105	Clatskanie PUD	814,012	27,670,492	28,719,810	33.99	35.28	3.8%
10123	Cowlitz County PUD #1	4,780,745	161,081,629	167,518,420	33.69	35.04	4.0%
10157	Emerald PUD	451,651	14,920,009	15,559,146	33.03	34.45	4.3%
10170	Eugene Water & Electric Board	2,186,163	73,714,563	76,852,091	33.72	35.15	4.3%
10183	Franklin County PUD #1	1,022,464	33,158,986	34,550,033	32.43	33.79	4.2%
10191	Grays Harbor PUD #1	1,142,042	38,579,378	40,205,995	33.78	35.21	4.2%
10204	Idaho Falls Power	692,896	23,223,515	24,249,020	33.52	35.00	4.4%
10231	Klickitat County PUD #1	316,677	10,007,143	10,475,505	31.60	33.08	4.7%
10237	Lewis County PUD #1	988,340	33,363,209	34,560,111	33.76	34.97	3.6%
10286	Okanogan County PUD #1	426,019	13,887,341	14,547,693	32.60	34.15	4.8%
10294	Pacific County PUD #2	316,005	10,751,127	11,202,036	34.02	35.45	4.2%
10306	Pend Oreille County PUD #1	229,180	7,811,561	8,289,251	34.08	36.17	6.1%
10349	Seattle City Light	4,556,027	154,631,789	163,309,598	33.94	35.84	5.6%
10354	Snohomish County PUD #1	6,788,199	227,880,700	237,904,558	33.57	35.05	4.4%
10370	Tacoma Public Utilities	3,500,749	118,290,511	123,146,181	33.79	35.18	4.1%
	Aggregate PF Slice+Block Customers	32,712,355	1,096,414,451	1,145,003,501	33.52	35.00	4.4%

Slice+Block Annual Power Bill under Average Water (net of mkt credit)

	PF Slice+Block Customer	2014 Avg MWh	Net Paymt at PF-12 Rates	Net Paymt at PF-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10024	Benton County PUD #1	2,005,388	46,485,753	50,665,279	23.18	25.26	9.0%
10103	Clark County PUD #1	2,774,121	79,807,367	87,249,501	28.77	31.45	9.3%
10105	Clatskanie PUD	814,012	23,349,281	25,450,861	28.68	31.27	9.0%
10123	Cowlitz County PUD #1	4,780,745	137,320,945	149,543,722	28.72	31.28	8.9%
10157	Emerald PUD	451,651	12,716,912	13,892,527	28.16	30.76	9.2%
10170	Eugene Water & Electric Board	2,186,163	63,030,745	68,769,899	28.83	31.46	9.1%
10183	Franklin County PUD #1	1,022,464	28,518,416	31,039,493	27.89	30.36	8.8%
10191	Grays Harbor PUD #1	1,142,042	32,811,004	35,842,283	28.73	31.38	9.2%
10204	Idaho Falls Power	692,896	19,953,332	21,775,162	28.80	31.43	9.1%
10231	Klickitat County PUD #1	316,677	8,600,419	9,411,334	27.16	29.72	9.4%
10237	Lewis County PUD #1	988,340	27,641,162	30,231,445	27.97	30.59	9.4%
10286	Okanogan County PUD #1	426,019	11,736,816	12,920,844	27.55	30.33	10.1%
10294	Pacific County PUD #2	316,005	9,073,573	9,932,985	28.71	31.43	9.5%
10306	Pend Oreille County PUD #1	229,180	6,710,221	7,456,099	29.28	32.53	11.1%
10349	Seattle City Light	4,556,027	133,058,026	146,989,282	29.20	32.26	10.5%
10354	Snohomish County PUD #1	6,788,199	195,493,829	213,404,244	28.80	31.44	9.2%
10370	Tacoma Public Utilities	3,500,749	100,649,852	109,801,215	28.75	31.37	9.1%
	Aggregate PF Slice+Block Customers	32,990,678	936,957,653	1,024,376,176	28.40	31.05	9.3%

Table 5:
Chart of Non-Slice Customer Rate Impacts

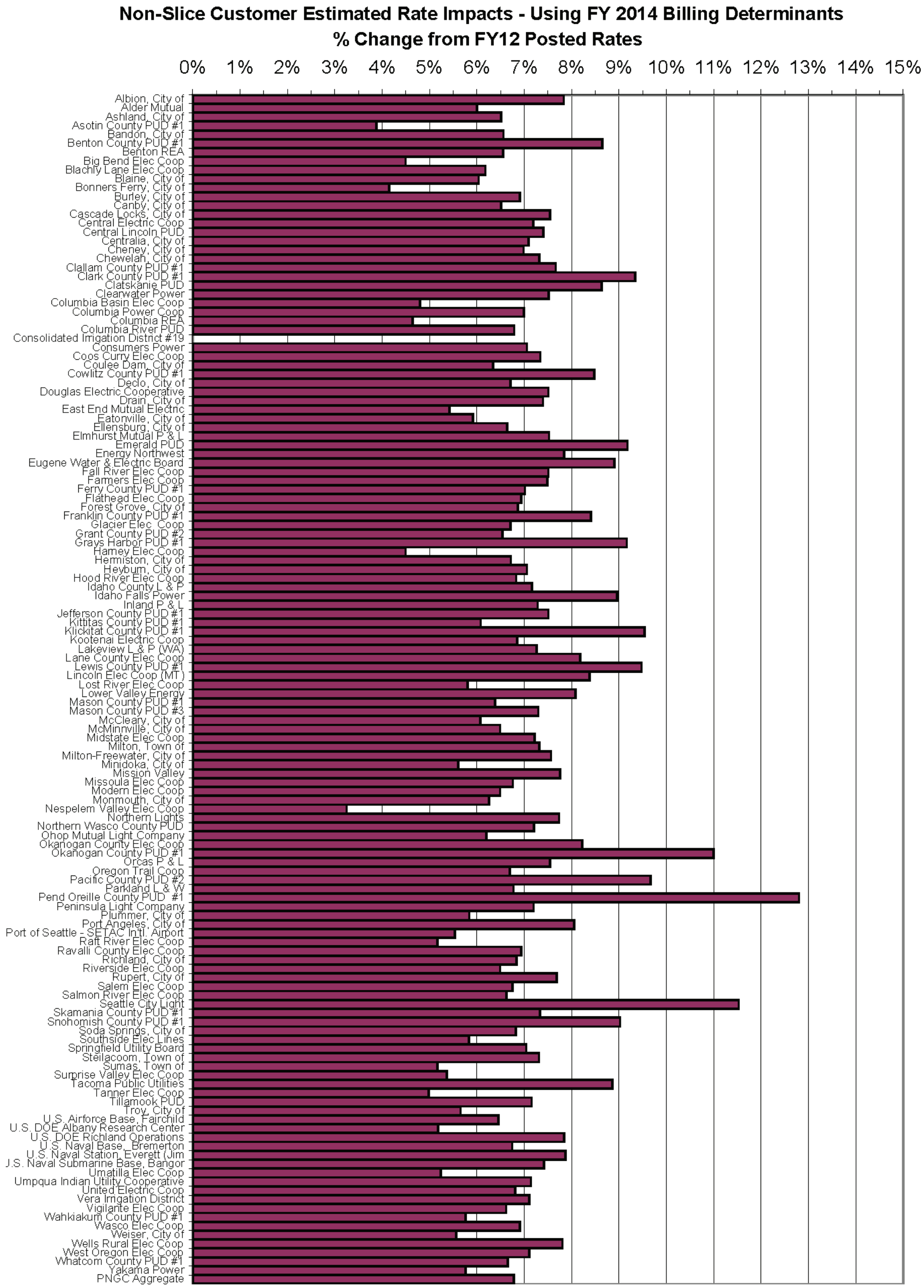


Table 6:
REP Benefits Summary

Residential Exchange Program Benefits

(dollars, in thousands)

	BP-12	*BP-14 REP Benefits*			*Delta*	*Change*
	Errata	*Preliminary*	*Reallocations*	*Planned*	*BP-12 vs BP-14*	
Avista	$11,818	$10,041	($1,907)	$8,134	($3,684)	-31%
Idaho Power	2,024	5,305	(2,652)	2,652	628	31%
Northwestern	2,903	3,857	1,156	5,013	2,110	73%
PacifiCorp	32,167	43,577	(8,017)	35,560	3,393	11%
PGE	58,178	44,331	2,537	46,867	(11,311)	-19%
Puget Sound	75,012	90,390	8,883	99,273	24,261	32%
Clark	14,971	1,424	-	1,424	(13,546)	-90%
Snohomish	4,615	-	-	-	(4,615)	-100%
Total	**201,660**	**198,924**	**-**	**198,924**	**(2,763)**	-1%
IOU Total	**182,102**	**197,500**	**-**	**197,500**	**15,398**	8%
COU Total	**19,586**	**1,424**	**-**	**1,424**	**(18,161)**	-93%

Residential Exchange Program Cost Allocations

(dollars, in thousands)

	FY 2014	**FY 2015**
Unconstrained REP Benefits	$847,864	$847,837
7(b)(2) Rate Protection	621,399	621,729
7(b)(3) PFx Allocation	572,397	572,379
7(b)(3) IP Allocation	20,010	20,021
7(b)(3) NR Allocation	0	0
REP Benefits	198,929	198,920
Refund Amounts	76,538	76,538
Total REP Costs (Benefits + Refunds)	275,467	275,458
REP Benefits paid by PFp	190,488	190,586
REP Benefits paid by IP	8,441	8,334
REP Benefits paid by NR	0	0