B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

BP-16 Initial Rate Proposal

Power Rates Study Testimony, Part I

December 2014

BP-16-E-BPA-17

INDEX

TESTIMONY of

PETER B. STIFFLER, EHUD BEN ABADI, LINDSAY A. BLEIFUSS, DANIEL H. FISHER, RANDY B. RUSSELL, EMILY G. TRAETOW, and ANNAMARIE E. WEEKLEY

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Witnesses for Bonneville Power Administration

SUBJECT: POWER RATES STUDY, PART I

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Peter B. Stiffler, and my qualifications are contained in BP-16-Q-BPA-37.

A. My name is Ehud Ben Abadi, and my qualifications are contained in BP-16-Q-BPA-01.

A. My name is Lindsay A. Bleifuss, and my qualifications are contained in BP-16-Q-BPA-04.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-16-Q-BPA-12.

A. My name is Randy B. Russell, and my qualifications are contained in BP-16-Q-BPA-36.

A. My name is Emily G. Traetow, and my qualifications are contained in BP-16-Q-BPA-40.

A. My name is Annamarie E. Weekley, and my qualifications are contained in BP-16-Q-BPA-41.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor BPA's Power Rates Study, BP-16-E-BPA-01, and to explain and support changes to the Study.

Section 2: Rate Design

Section 2.1: Tier 1 Rate Design

Q. Are you proposing any rate design changes to Tier 1 rates?

A. No. We have recomputed rates, but we are proposing no changes to the basic design of the Tier 1 rates. How we collect revenues from customers remains virtually unchanged from BP-14 rates. There are some modifications to how the rates are applied to customers, which are detailed in the Power Rate Schedule testimony, Weekley *et al.*, BP-16-E-BPA-22, and in the Power Rates Study Testimony, Part II, Chalier *et al.*, BP-16-E-BPA-23, as well as in this testimony.

Section 2.2: Demand Rate

Q. Does the BP-16 Initial Proposal use the same methodology to calculate the demand rate as was used in the BP-14 rate proceeding?

A. Yes. The BP-16 Initial Proposal uses the same methodology as the BP-14 Final Proposal.

Q. Did you update any demand rate inputs for BP-16?

A. Yes. As noted in the Power Rates Study, section 3.1.6.3, the PF Tier 1 Demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS100 combustion turbine, as determined by the Northwest Power and Conservation Council's Microfin model 15.0.1. We updated the demand rate model, changing the nominal years from FY 2014 and 2015 to FY 2016 and 2017; the Load Shaping rates; the chained GDP Implicit Price Deflators; the cost of debt percentage; the start year of operation; the vintage heat rate; fixed operation and maintenance costs; and the all-in nominal capital cost of the LMS100 combustion turbine.

Q. Have any of these inputs changed significantly since BP-14?

A. Yes. The Northwest Power and Conservation Council's recent research determined that the all-in nominal capital cost of the LMS100 has decreased. At the same time, the Council's estimates of the LMS100 fixed operation and maintenance costs have increased since BP-14. Incorporating these changes more accurately represents the costs plant operators are facing.

Q. Have these changes significantly altered the demand rate itself?

A. No. The changes to the inputs have largely offset each other, leaving the average monthly demand rate relatively unchanged since BP-14. We are proposing an average monthly rate of $9.34/kW as compared to $9.32/kW in BP-14.

Q. Do you propose to apply a dampening methodology to the shape of the demand rate?

A. No. The monthly shape of the demand rate is not volatile enough to warrant the implementation of any dampening methodology.

Section 2.3: Tier 2 Rates

Q. Did you make any changes to the Tier 2 rates?

A. Yes. In addition to updating the Tier 2 rates for updated costs, we added a new vintage Tier 2 rate (VR1-2016). The PF rate schedule now includes four Tier 2 rates: Short-Term, Load Growth, VR1-2014, and VR1-2016. *See* Power Rate Schedules, BP-16-E-BPA-09, PF-16, § 2.2.

Q. What is the difference between the two Vintage products?

A. VR1-2014 was the first Vintage product provided by BPA. It was a market purchase of a flat block of power with delivery to customers beginning in the BP-14 rate period and continuing in BP-16. VR1-2016 is also a flat annual market purchase, but this Vintage product allows customers to purchase stepped amounts of power (the ability to increase annual amounts during the delivery period) with delivery beginning in FY 2016.

Q. Will BPA need to make a significant amount of additional Tier 2 purchases for the BP-16 rate period beyond the amounts already purchased?

A. No. Due to the slower-than-anticipated return of loads throughout the region, the Tier 2 purchases made in 2012 and 2013 leave BPA with no need for additional Tier 2 purchases during the BP-16 rate period. Since the forecast Above-RHWM obligations used for purchasing purposes was higher than the actual Above-RHWM need for Tier 2 customers during the BP-16 rate period, amounts in excess will be reallocated to other Tier 2 cost pool(s). The allocation will be done on a pro rata basis depending on the need across the cost pools at the Remarketing Value, which is set equal to the forecast cost of augmentation. The remaining excess amounts of Tier 2 purchases above the Tier 2 obligations will effectively be remarketed to BPA at the forecast augmentation price and used by BPA for its augmentation needs during the BP-16 rate period. *See* Power Rate Study Documentation, BP-16-E-BPA-01A, Table 3.14.

Q. What is the Load Growth Rate Billing Adjustment?

A. The Load Growth Rate Billing Adjustment is either a debit or credit on the applicable Load Growth customers' bills and is intended to pass through the applicable Load Growth customers' shares of the net cost/credit resulting from remarketing the portion of BPA's 5 aMW purchase that is not needed by Load Growth customers in FY 2016 and FY 2017. The portion of this 5 aMW purchase in excess of the Load Growth customers' needs is remarketed to other Tier 2 cost pools at the forecast augmentation price for each year of the rate period. The proposed Load Growth Rate Billing Adjustment recovers

$376,693 in FY 2016 and $428,748 in FY 2017. *See* Power Rate Schedules, BP-16-E-BPA-09, PF-16, § 2.2.3 and Appendix B.

Q. Are you proposing any changes to the Load Growth Rate Billing Adjustment in BP-16?

A. Yes. We propose to remove the portion of the methodology that capped the amount a customer paid. Specifically, it capped the amount charged at an amount equal to the second-highest percentage impact when compared to each impacted customer's forecast Tier 1 bill. This cap was included in the BP-14 methodology to mitigate the effect on an outlier in the cost allocation that was caused by an error in the calculation of one customer's Above-RHWM load. This is no longer an issue for the BP-16 rate period.

We also propose a monthly charge that spreads the annual cost equally over 12 months. The current BP-14 Adjustment bills the cost in one month.

Q. Have you looked into the cash implications of billing the Load Growth Rate Billing Adjustment in one month?

A. Yes. Due to the increase in the size of the Load Growth Rate Billing Adjustment, we compared the amount of the charge to customers' October bills. We determined that charging the annual adjustment in a single month could have a significant cash impact on customers, with some customers experiencing a 25 to 30 percent increase in their historical October bills. Given this cash impact, we propose creating a monthly charge that spreads the annual amount equally over the 12 months.

Q. How has the cost to be recovered through the Load Growth Rate Billing Adjustment changed for the BP-16 rate period?

A. The Load Growth Rate Billing Adjustment is projected to be larger than in BP-14. During the BP-14 rate period, the Load Growth Rate Billing Adjustment was applicable only in FY 2015 and totaled $53,698. This cost was spread across the 37 Load Growth customers that had Above-RHWM amounts larger than zero, but less than 1 aMW in FY 2015. During the BP-16 rate period, the amounts of the Load Growth Rate Billing Adjustment are projected to total $376,693 in FY 2016 and $428,748 in FY 2017. Using the same allocation methodology, less the removal of the cap as stated above, will result in this cost being spread across 29 customers in FY 2016 and 34 customers in FY 2017. The increase in the Load Growth Rate Billing Adjustment is largely due to the purchase price being higher in FY 2016 and 2017 and the Remarketing Values (the forecast cost of augmentation in the BP-16 rate period) being lower than the Remarketing Values used in the BP-14 rate period.

Q. *Taking the Load Growth Rate Billing Adjustment into account, what is the impact to the cost of serving Above-RHWM load for these customers?*

A. Customers that are allocated a portion of the Load Growth Rate Billing Adjustment have Above-RHWMs that are forecast to be served at the Load Shaping rates. The Load Growth Rate Billing Adjustment effectively adds a premium to the Load Shaping rates applied to that forecast Above-RHWM load. The premium is roughly equal to $5.10/MWh. See Power Rate Study Documentation, BP-16-E-BPA-01A, Tables 3.18 and 3.19. This translates into a total cost of roughly $33.60/MWh for a Load Growth customer's Above-RHWM Load served at the Load Shaping rates. This cost per megawatthour of serving Above-RHWM Load is slightly lower than the projected cost of serving Above-RHWM Load at the Tier 2 Short-Term rate ($34.05/MWh in FY 2016 and $36.62/MWh in FY 2017). *See* Power Rate Schedules, BP-16-E-BPA-09, PF-16, § 2.2.1.

Q. Will any updates be made to the proposed Tier 2 rates and Load Growth Rate Billing Adjustment for the Final Proposal?

A. Yes. In addition to cost inputs, such as the forecast cost of augmentation, updates will be made to BPA's Tier 2 obligation amounts based on customer elections to serve Above-RHWM Load with non-Federal resources. These elections could reduce, by a small amount, the Above-RHWM Load served at BPA's Tier 2 rates during the FY 2016–2017 rate period.

Q. Is there anything else that will change in the accounting of Tier 2 revenue and costs in the Final Proposal?

A. Yes. We found errors in the output sheet of the Tier 2 model that understated BPA's Tier 2 costs by roughly $2 million per year on average. The output sheet is used to provide Tier 2 cost and revenue information to other rate-setting models. The Tier 2 model and documentation included in the Initial Proposal were corrected, but the errors were identified too late in the development of the Initial Proposal to correct downstream rate-setting models and documentation. This means that the Tier 2 model and documentation will not match the information in RAM, the Revenue Requirement Study, and the revenue forecast. All else being equal, updating RAM for the correct Tier 2 costs will increase the melded PF rate (both Tier 1 and Tier 2), which will cause the IP rate to increase slightly (due to the link between the PF melded rates and the IP rate). We will make the complete correction in the Final Proposal.

Section 2.4: Resource Support Services (RSS)

Q. What changes were made associated with RSS?

A. Three small changes associated with RSS were made, specifically: (1) forecast revenue produced from the energy component of the Diurnal Flattening Service (DFS) was allocated to the Non-Slice cost pool instead of the Composite cost pool; (2) applicability of the Transmission Schedule Service (TSS) monthly cap was limited to Specified resources; and (3) the cost of the Open Access Technology International, Inc. (OATI) registration fee was subsumed into customers' monthly TSS fees.

Section 2.4.1: Allocation of DFS Energy Revenue

Q. Why did you change the cost pool where DFS energy revenue is credited?

A. We identified an implementation inequity between the Slice customers and Non-Slice customers. In both the BP-12 and BP-14 rate cases, the DFS energy revenues were allocated to the Composite cost pool, thereby providing all customers, including the Slice portion of the Slice/Block product, a revenue benefit in exchange for the operational costs of providing DFS. We later realized that the operational impacts related to providing DFS energy were not accounted for in the Slice Computer Application. Unlike the capacity used to provide all RSS (including DFS), which operationally impacts Slice/Block, Block, and Non-Slice products, the operational energy impacts of providing RSS have been implemented to impact Non-Slice products only (including the Block portion of the Slice/Block). We are proposing to change the allocation of the forecast DFS energy revenue to address this inequity.

Q. How are the energy components of other RSS treated?

A. The forecast revenue from the energy components of the Secondary Crediting Service (SCS) and Forced Outage Reserves (FORS) is allocated to the Non-Slice cost pool. Consistently, the Slice Computer Application does not reflect the operational energy impacts associated with SCS or FORS. The proposed change to the allocation of DFS energy revenue now matches the allocation of the energy revenue from both SCS and FORS.

Q. Are there other ways to implement this and still provide equity to Slice and Non-Slice customers?

A. Yes. Another viable, and one day potentially preferred, method would be to operationally impact the Slice portion of the Slice/Block product for the energy impacts caused when providing RSS.

Section 2.4.2: Transmission Schedule Service (TSS) Monthly Cap

Q. What are you proposing for the TSS price cap?

A. TSS is a scheduling service provided by BPA to undertake certain scheduling operations on behalf of the customer that have a qualifying resource. The current BP-14 TSS rate is subject to a cap such that if the TSS charge to the customer exceeds $990/month, then the monthly charge is capped at $990/month. We are proposing to limit the TSS price cap to customers with Specified resources. The current price cap was calculated on a cost to BPA per transaction. However, customers with Unspecified resources can use, and are using, multiple scheduling transactions to meet the single Unspecified resource contractual obligation.

When we originally designed the TSS rate, we had assumed that a single contractual obligation was equal to a single transaction. This assumption is true for Specified resource amounts, but is not necessarily true for Unspecified resource amounts. The intent of the cost cap is to reflect the assumption that BPA's costs do not increase with the size of a transaction. In other words, it is assumed that a single large MWh transaction costs BPA roughly the same amount as a single small MWh transaction. Without knowing, or limiting, the number of transactions a customer plans to use to meet a single Unspecified Exhibit A obligation, we can no longer justify the application of a cap that is based on the assumption that a single transaction is used.

Q. Have you considered calculating a cap based on the actual number of transactions used instead of simply using Exhibit A amounts?

A. Yes, we considered this approach and determined that the costs to implement it—specifically, the staff time used to apply such a design—outweighed the benefits of possible added rate precision.

Q. If the scheduling system is largely automated, are transactions still a reasonable measure to calculate a cap?

A. Yes. While it is true that many components (both BPA- and customer-related) of the scheduling system are automated, not all transactions make it through the automated process. Those transactions that do not make it through the automated process require manual adjustments, taking staff time and thereby increasing the cost of BPA's scheduling department. As the number of transactions increases, it is expected that the number of transactions that require manual adjustment will also increase.

Q. Are there any parallel treatments in other BPA rates?

A. Yes. A parallel treatment was used to set BPA's Tier 2 rates. BPA does not apply a cost cap to its Tier 2 rates because Tier 2 rates, in theory, can be made up of multiple scheduling transactions, and it would be unnecessarily complicated to try to account for multiple transactions and, potentially, multiple caps within a single Tier 2 rate. We believe the treatment used for Tier 2 both demonstrates the original intent of the TSS cost cap and supports equitable treatment between customers that choose to have their Above-RHWM Loads served by BPA and those that choose to serve their Above-RHWM Loads with non-Federal resources, such as Unspecified resources.

Section 2.4.3: Open Access Technology International, Inc. (OATI) Registration Fee

Q. What is your proposal for billing the OATI registration fee?

A. The OATI fee is a cost component of providing TSS. Instead of billing the annual OATI fee separately to each TSS customer as we do under the current BP-14 TSS rate, we are proposing to combine the annual OATI fee with the monthly TSS fee.

Q. Why are you proposing this change?

A. We are proposing to include the OATI registration fee in customers' monthly TSS charges because administratively including this small fee ($150/year) for each customer in the overall monthly TSS charge is less burdensome. *See* Power Rate Schedules, BP-16-E-BPA-09, GRSP II.U.4.

Q. How does this change the calculation of the customer's monthly TSS charge?

A. Overall, the calculation for TSS is very similar to BP-14. Monthly TSS rates are calculated by dividing forecast Operations Scheduling costs for the two years of the rate period by the total megawatthours BPA has scheduled in the two most recent historical years. The BP-14 OATI fee is a direct assignment charge in addition to the TSS rate. In BP-16, we are proposing to include the OATI registration fee in the calculation of each TSS customer's monthly fee. For each customer, BPA would: (1) determine the number of resources receiving TSS; (2) take the annual registration fee of $150 and apply it evenly across the applicable resources; and (3) divide by 12 months of the applicable fiscal years within the rate period. The resulting charge is included in the monthly TSS charge on the customer's bill.

Q. Where will this calculation be done?

A. TSS monthly fees are determined as part of the RSS model. These proposed changes are incorporated in the BP-16 TSS calculations. *See* Power Rate Study Documentation, BP-16-E-BPA-01A, Table 3.21.

Section 2.5: Services Provided under the NR Rate Schedule

Q. Have you made any changes to the NR Rate Schedule?

A. Yes. We made substantial changes to the Energy Shaping Services (ESS) for New Large Single Loads (NLSLs) and added a Resource Flattening Service (NRFS) for Specified resources serving NLSLs. *See* Power Rate Schedules, BP-16-E-BPA-09, NR-16 and GRSP II.G.

Section 2.5.1: Energy Shaping Services (ESS) for New Large Single Loads (NLSLs)

Q. What are the changes you made to the ESS?

A. We are proposing to add a capacity component, change the applicable energy rates, and remove the Energy Shaping Service for the NLSL True-Up Charge. *Id*.

Q. Why did you add a capacity component to ESS?

A. ESS is available only to Load Following customers serving NLSLs with non-Federal resources. The purpose of the ESS is to make it possible for a Load Following customer to serve its own NLSL without requiring hourly load management by that customer. The NR-14 ESS rate design includes energy rates but no demand rates. The lack of a capacity component either: (1) required that the Load Following customer still meet its hourly NLSL capacity requirement, or (2) resulted in BPA not being paid for Federal capacity used to serve the Load Following customer's NLSL. The NR-14 ESS rate reflects the first of the two options, but we believe that the hourly capacity requirement somewhat undermines the purpose of ESS, which was to make it possible for a Load Following customer to serve its own NLSL without the complexity that results when a load is managed hourly. For this reason, we propose to add a capacity component to provide more flexibility to a Load Following customer serving its NLSL with non-Federal resources while at the same time adequately compensating BPA for that added flexibility. *Id.*, GRSP II.G.1.2.

Q. How do you propose to measure the demand (capacity) billing determinant?

A. We propose that customers taking ESS establish, in advance, the amount of capacity they need BPA to stand ready to provide. This amount of capacity would be the monthly billing determinant.

Q. How far in advance do customers need to establish their demand billing determinant?

A. We propose that a customer work with BPA to determine a forecast of the billing determinant for each rate period prior to February of a Rate Case Year. This rate period forecast will allow BPA to plan and account for the forecast capacity obligation and the resulting forecast revenue when setting rates. We also propose that customers be allowed to change this forecast with at least 30 days' notice provided to BPA prior to the applicable billing month.

Q. Why are you proposing that BPA be provided at least 30 days' notice for changes to the monthly capacity obligation?

A. BPA is taking on a capacity obligation which must be planned for ahead of the month. It is not uncommon to set and plan for capacity obligations well ahead of the time when the capacity is needed. This allows for coordination with operational planning as well as providing a window of opportunity to purchase capacity from other suppliers, if needed. Ideally, BPA would know its capacity obligation well in advance of the rate period. This advance notice would provide BPA with both operational and financial certainty. Many of BPA's capacity-related products and services require a rate period commitment, such as BPA's Resource Support Services. Clearly, significant advance notice becomes more important as the size of the obligation increases. That said, even the best-laid plans can change, and BPA has examples of capacity-related products and services that provide some flexibility to adapt to a revised plan; for example, load annexation or resource-installation uncertainty. Taking this all into consideration, we believe 30 days' notice strikes the right balance, at this time, between providing BPA sufficient notification of its obligations and allowing customers to adjust their forecasts based on new information and more accurately match their resources to the loads of their NLSLs.

Q. Why did you caveat your statement that 30 days' notice strikes the right balance "at this time"?

A. As we previously pointed out, the size of the obligation must also be considered. At this time, we do not expect that customers will need to adjust their forecast very frequently or by very much, if at all. We anticipate that any changes made to the forecast demand billing determinant will be less than 10 MW in aggregate and most likely closer to 1 to 3 MW, particularly after the operations at these NLSLs stabilize following construction. In addition to any new information provided that may require us to revisit this topic, to the extent BPA observes frequent monthly changes and/or substantially large changes, we may need to revisit this flexibility and potentially lengthen the notice period, limit the amount of change from the forecast value, or remove the flexibility entirely.

Q. Do you include any forecast ESS demand revenue in the Initial Proposal?

A. No, but contingent on customer interest in ESS and the design adopted in the Final Proposal, we plan to include a forecast of revenue for the Final Proposal. We anticipate any forecast ESS capacity revenue to be less than $350,000 a year (estimated with a 3 MW billing determinant multiplied by the NR demand rate for 12 months).

Q. If the Final Proposal includes a forecast of ESS capacity revenue, where will that revenue be credited for purposes of setting power rates?

A. ESS capacity revenue will be credited to the Non-Slice cost pool. This is consistent with the treatment of the PF demand rate revenue as specified in the Tiered Rate Methodology Table 2 and section 3.4, which states that capacity costs incurred for following customer load will be allocated to the Non-Slice cost pool. *See* Tiered Rate Methodology, BP-12-A-03.

Q. Please briefly describe the ESS energy rate design used in the NR-14 rate period.

A. The NR-14 ESS rate design charges or credits a customer for the difference between the measured NLSL and the customer's non-Federal resources serving that NLSL. These differences reflect net monthly/diurnal amounts and are applied to energy rates equal to BPA's forecast market price—also known as the Load Shaping or Resource Shaping rates. The NR-14 ESS rate design also includes an annual true-up that determines whether any net annual energy was purchased from BPA, to which BPA applies a true-up charge to effectively charge the customer the NR energy rate for that energy. The NR-14 true-up rate equals $48.80/MWh.

Q. *What changes do you propose for the ESS energy rate design?*

A. We propose to increase the granularity of the energy rate design. Specifically, if the customer's dedicated resources serving its NLSLs are greater than the measured NLSLs during a month (net monthly energy provided to BPA); we propose to charge and credit the daily/diurnal deviations (NLSL minus resource) at the Intercontinental Exchange (ICE) Mid-C Day Ahead Price Index (or its replacement). If the customer's dedicated resources serving its NLSLs are less than the measured NLSLs during a month (net monthly energy purchased from BPA), we propose to charge and credit the monthly/diurnal deviations (NLSL minus resource) at the applicable NR energy rates. See Power Rate Study, BP-16-E-BPA-01 section 3.4.3.

Q. *Are you proposing to remove the annual true-up under the proposed ESS rate design?*

A. Yes. The new design effectively provides a true-up monthly by charging a customer for any net energy purchased from BPA during a month at the applicable NR energy rates. Thus, an annual true-up is no longer needed.

Q. *If a customer is energy long in a month (net energy provided to BPA), are you proposing any further adjustments to the credit or charge provided at the daily/diurnal index rates?*

A. Yes. Similar to the treatment used in BPA's Energy Imbalance (EI) and Generation Imbalance (GI) rate schedules, we are proposing that the monthly total credit or charge be increased (a larger charge to the customer) or decreased (a reduced credit to the customer) based on the amount of energy provided in excess of the customer's NLSLs. *See* Power Rate Schedules, GRSP II.G.1.

Q. Please provide an overview of the adjustment calculation.

A. The design uses three thresholds to determine the applicability and size of the adjustment. The first threshold defines a small net monthly energy amount. No adjustments are made for small (Threshold 1) net monthly energy amounts. The second threshold defines a medium net monthly energy amount. An adjustment of either 94 percent (if a credit to the customer) or 106 percent (if a charge to the customer) is made for medium (Threshold 2) net energy amounts. The third threshold defines a large net monthly energy amount. An adjustment of either 84 percent (if a credit to the customer) or 116 percent (if a charge to the customer) is made for large (Threshold 3) net energy amounts. *Id*. We base the thresholds on BPA's Energy Imbalance and Generation Imbalance rate schedules.

Q. How did you determine what would be considered a small net monthly energy amount?

A. We base the definition of small on Deviation Band 1 of BPA's Energy Imbalance and Generation Imbalance rate schedules. Specifically, we propose to use the greater of 1.5 percent multiplied by the Total Retail Load of the customer's NLSL, or 1,488 MWh. We calculated the 1,488 MWh assuming that a customer provided 2 MWh of excess energy each hour of a 744-hour month. We also considered the Persistent Deviation Penalty charge and determined it did not need to be factored into Threshold 1 because the Persistent Deviation Penalty charge does not apply to persistent amounts equal to or less than 2 MW. In other words, a customer could persistently schedule 2 MW off actual and still be subject to EI or GI Band 1 and not incur a Persistent Deviation Penalty charge.

Q. How did you determine what would be considered a medium net monthly energy amount?

A. We base the definition of medium on Deviation Band 2 of BPA's EI and GI rate schedules. Specifically, we propose to use the greater of 7.5 percent multiplied by the

Total Retail Load of the customer's NLSL, or 3,720 MWh. We calculated the 3,720 MWh assuming that a customer provided 5 MWh on average of excess energy each hour of a 744-hour month. Unlike Threshold 1, we determined that an adjustment was needed to the 10 MW amount used for the EI and GI Band 2 to account for the Persistent Deviation Penalty charge. Again, unlike Threshold 1, a customer could not persistently schedule 10 MW off actual and avoid the Persistent Deviation Penalty charge. Given this, we believe it is reasonable to assume a customer could have a scheduling error of 5 MW on average and not be subject to the Persistent Deviation Penalty charge.

Q. How did you determine what would be considered a large net monthly energy amount?

A. Net monthly energy amounts larger than Threshold 2 would be considered large net monthly energy amounts.

Q. Why are the percentage adjustments you propose for each Threshold different from the percentages used for the EI and GI Bands?

A. The threshold percentages are different, but they are calculated using the percentages provided in the EI and GI Bands. The application of the thresholds is slightly different from the EI and GI Bands and thus justified the calculation of different percentages. Specifically, the EI and GI Bands are applied with a bracket-type system, not unlike a tax bracket, where each Band is applied to the MWh applicable to that Band, regardless of the Band applicable to the last MWh. This means a customer may be subject to all EI and GI Bands in any particular hour. ESS thresholds are different in that only one threshold applies to all MWh in a month.

Q. Generally, how are the threshold percentages calculated?

A. The threshold percentages are the effective, or weighted average, percentages that would apply under the EI and GI Bands assuming a certain amount of energy applicable to each Band.

Q. Please describe how the Threshold 2 percentage is calculated.

A. The percentage applicable to Threshold 2 uses an average of two approaches. The first approach uses the Band 1 and Band 2 percentages, 1.5 percent and 7.5 percent, respectively. Under this approach, if a customer was halfway into Band 2, its effective percent would be 93 percent, given that some of the MWh would receive 100 percent and some would receive 90 percent of the applicable rate. The second approach uses the Band 1 MW amount and Band 2 MW amount as adjusted for the ESS rate design as described above, 2 MW and 5 MW, respectively. Under this approach, if a customer were halfway into Band 2 (as adjusted), its effective percent would be 96 percent. The average of these two approaches is 94 percent—the percentage we propose to use for purposes of ESS Threshold 2. *Id*.

Q. Please describe how the Threshold 3 percentage is calculated.

A. The percentage applicable to Threshold 3 uses an average of two approaches. The first approach uses the Band 1 and Band 2 percentages, 1.5 percent and 7.5 percent, respectively, and an assumption for the number of MWh applicable to Band 3. Unlike the calculation used for Threshold 2, which is capped, Band 3 is applied to anything larger than Band 2 and requires an additional assumption. We assumed a total error equal to 15 percent, which equates to 7.5 percent applicable to Band 3. Under this approach, the effective percentage would be 84 percent, given that some of the MWh would receive 100 percent, some would receive 90 percent, and some would receive

75 percent of the applicable rate. The second approach uses the Band 1 MW amount and the Band 2 MW amount as adjusted for the ESS rate design as described above, 2 MW and 5 MW, respectively, and an assumption for the number of MWh applicable to Band 3. Unlike the calculation used for Threshold 2, which is capped, Band 3 is applied to anything larger than Band 2 and requires an additional assumption. We assumed a total error equal to 10 MW, which equates to 5 MW applicable to Band 3. Under this approach, the effective percentage would be 85 percent, given that some of the MWh would receive 100 percent, some would receive 90 percent, and some would receive 75 percent of the applicable rate. The average of these two approaches is 84 percent—the percentage we propose to use for purposes of ESS Threshold 3. *Id*.

Q. *You just described how you calculate the threshold percentages when the customer is provided a credit. How would you calculate the threshold percentages when the customer is issued a charge?*

A. We would use a symmetrical approach centered on 100 percent, which is the same approach used in BPA's EI and GI rate design.

Q. *Why do you propose a different treatment than the bracket-like approach used in the EI and GI rate design?*

A. Simplicity.

Q. *Does your proposal change the applicability of Energy Imbalance and Generation Imbalance for a customer?*

A. No. The applicability of the ACS-16 Energy Imbalance and Generation Imbalance rates is specified in BPA's Transmission rate schedule and is not impacted by BPA's ESS, which is an hour-to-hour service provided in BPA's Power Rate Schedules.

Section 2.5.2: NR Resource Flattening Service (NRFS) Charge

Q. Please describe the Resource Flattening Service provided under the NR rate schedule.

A. Similar to BPA's Resource Support Services offered under the PF rate schedule, the Resource Flattening Service (NRFS) allows a Load Following customer to apply the generation of a Specified resource directly to its NLSL.

Q. How do you propose to calculate the charges for the Resource Flattening Service?

A. With one exception, we propose to use the same methodology used for the Diurnal Flattening Service (DFS). The exception is that, at this time, we propose to apply only an energy component and not a capacity component. The capacity component of the ESS effectively serves the same purpose, and we believe in this particular situation it is simpler to handle all capacity needs of a customer purchasing ESS through one service.

We may want to revisit this approach if customers ever plan to serve NLSLs with a combination of service at NR rates and Specified generating resources, primarily because the NR rate schedule charges for actual capacity used, while the capacity component of DFS charges for capacity that BPA stands ready to provide regardless of whether it is used or not. Given that NR energy rates are significantly higher than the current market, we do not expect customers to have BPA serve any portion of their NLSLs during the BP-16 rate period, and thus we propose to set this nuanced issue aside until it becomes relevant.

Q. How do you propose to treat revenue created by the NR Resource Flattening Service?

A. We propose the same treatment used for BPA's Resource Support Services, specifically, the energy component of the Diurnal Flattening Service and allocation to the Non-Slice cost pool, which is described above in section 2.5.1.

Q. *Do you expect any customers to purchase the NR Resource Flattening Service during the BP-16 rate period?*

A. No.

Section 3: Average System Costs (ASCs) and Exchange Loads

Q. *Compared to the BP-14 proceeding, are there any changes to the method or manner in which BPA is forecasting ASCs or Exchange Loads in this proceeding?*

A. No. As in BP-14, the calculations required to determine ASCs, Exchange Load, and ultimately REP benefits have been implemented in accordance with the terms of the 2012 REP Settlement.

Q. *Could the rate period ASCs for FY 2016–2017 used in RAM2016 be revised for the Final Proposal?*

A. Yes. We anticipate that the FY 2016–2017 ASC Review Processes will be concluded prior to the Final Proposal. Concurrent with the Final Proposal, the Administrator or his designee will issue a Final ASC Report for each utility that participated in the FY 2016–2017 ASC Review Process. Each Final ASC Report will contain a final Base Period ASC (calendar year 2013) and one or more final rate period ASCs for FY 2016–2017. For ratesetting purposes, we will include in the Final Proposal the ASCs from the Final ASC Reports that are applicable on October 1, 2015. Final reports for each utility will be published on *BPA's REP Web site*, which is available at *http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx*.

Q. *Does this conclude your testimony?*

A. Yes.