BP-14 Initial Rate Proposal

Direct Testimony
Volume 2

November 2012

BPA Exhibit No.	Topic	Witnesses
BP-14-E-BPA-21	Generation Inputs Policy	Fisher *et al.*
BP-14-E-BPA-22	Balancing Reserve Capacity Quantity Forecast	Puyleart *et al.*
BP-14-E-BPA-23	Provision of Balancing Reserve Capacity from the Federal Columbia River Power System	Kerns *et al.*
BP-14-E-BPA-24	Balancing Reserve Capacity Cost Allocation Methodology	Klippstein *et al.*
BP-14-E-BPA-25	Operating Reserve Cost Allocation	Messinger *et al.*
BP-14-E-BPA-26	Generation Inputs for Other Services	Wellschlager *et al.*
BP-14-E-BPA-27	Other Inter-Business Line Allocations	Salazar *et al.*
BP-14-E-BPA-28	Ancillary and Control Area Services Rate Design	Jackson *et al.*

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BP-14-E-BPA-22	Balancing Reserve Capacity Quantity Forecast	Francis R. Puyleart Jergen M. Bermejo Stephen H. Enyeart Kevlyn D. Mathews
BP-14-E-BPA-23	Provision of Balancing Reserve Capacity from the Federal Columbia River Power System	Steven Kerns Katherine L. Beale Jergen M. Bermejo Kieran P. Connolly
BP-14-E-BPA-24	Balancing Reserve Capacity Cost Allocation Methodology	Janet Ross Klippstein Jergen M. Bermejo Daniel H. Fisher Mark A. Jackson Eric V. King Paul T. Koski Timothy C. Misley
BP-14-E-BPA-25	Operating Reserve Cost Allocation	Ronald E. Messinger Danny L. Chen Janet Ross Klippstein
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MARK A. JACKSON, LAWRENCE E. KITCHEN, and BARTHOLOMEW A. McMANUS

Witnesses for Bonneville Power Administration

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TESTIMONY of

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Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS POLICY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is Katherine L. Beale, and my qualifications are contained in BP-14-Q-BPA-03.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is Mark A. Jackson, and my qualifications are contained in BP-14-Q-BPA-28.

A. My name is Lawrence E. Kitchen, and my qualifications are contained in BP-14-Q-BPA-36.

A. My name is Bartholomew A. McManus, and my qualifications are contained in BP-14-Q-BPA-45.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide an overview of Bonneville Power Administration's (BPA) use of generation inputs, how BPA allocates costs to generation inputs, and how BPA is addressing particular policy issues associated with the proposed cost allocation and rates for BPA's Ancillary and Control Area Services.

Section 2: Background for Ancillary and Control Area Services in the BPA Balancing Authority Area

Q. Please briefly describe the trend of wind development in recent years in the BPA balancing authority area.

A. The amount of wind generation in the BPA balancing authority area has increased from 500 MW in 2005 to over 4,700 MW today. Most of those facilities are located in a relatively small area near the Columbia River Gorge. More than 50 percent of the wind generation in the Pacific Northwest is being located in the BPA balancing authority area, and developers are continuing to build new wind generators in BPA's balancing authority area.

By the end of FY 2015, BPA forecasts approximately 5,200 MW of wind generation will be integrated into the BPA balancing authority area. Generation Inputs Study, BP-14-E-BPA-05 (Study), section 2.2; Generation Inputs Study Documentation (Documentation) Table 2.1. Although the majority of new wind generation is locating within the BPA balancing authority area, most of that wind generation is exported out of the balancing authority area to other utilities for their load service.

Q. What impacts does the significant increase in wind generation interconnected to the BPA system have on the operations of the FCRPS?

A. The increase of wind generation within the BPA balancing authority area creates additional operational uncertainty and risk for BPA. Major hydro projects on the FCRPS are connected to BPA's Automatic Generation Control System (AGC). AGC signals these major plants to respond continuously by increasing or decreasing their generation output to balance loads and resources. This balancing is necessary to keep the electric system stable. As variable generation in BPA's balancing authority area has increased, the AGC demands on the FCRPS have increased as well, due to both increased physical generation variability and generation forecast error. This requires BPA to dedicate

increasing amounts of generation capacity to respond to these deviations and operate more conservatively to ensure that non-power requirements, such as those for the Endangered Species Act, flood control, navigation, and recreation, are honored. BPA refers to this generation capacity as "balancing reserve capacity." See section 3 below. BPA adjusts its operating plans to ensure that system flexibility is available to provide balancing reserve capacity to either increase or decrease generation as necessary. Maintaining balancing reserve capacity that may or may not be deployed creates operational uncertainty and also causes BPA to have to buy or sell energy to maintain operational balance as BPA responds to deviations from expected operations.

Q. What are Ancillary and Control Area Services?

A. Ancillary Services are services needed with transmission service to maintain reliability within and among the balancing authority areas affected by the transmission service. Under BPA's Open Access Transmission Tariff, BPA is required to provide, and transmission customers are required to purchase, certain Ancillary Services. BPA is also required to offer other Ancillary Services that the transmission customer must either purchase from BPA or a third party or self-supply.

Control Area Services are balancing services charged to customers that do not have a transmission service arrangement with BPA and BPA has identified the service as necessary to meet reliability obligations that are not met by the equivalent Ancillary Service or some other arrangement. See Jackson *et al.*, BP-14-E-BPA-28, section 2, for further discussion on Ancillary and Control Area Services.

Q. What are generation inputs?

A. Generation inputs are the various uses of generation resources that are needed by the BPA transmission operator in order to provide the Ancillary Services, Control Area

Services, and other services that are necessary to support reliable operation of the transmission system.

Q. What is balancing reserve capacity, and how is it used as a generation input?

A. The balancing authority determines the generation capacity that it needs to have available to balance generation and load. As mentioned above, BPA refers to that generation capacity as "balancing reserve capacity," which BPA reserves or stands ready to provide so that it is available if needed. The balance between generation and load may change because of more or less load than expected, more or less generation than expected, or the loss of the expected ability to move planned generation to load. The balancing authority has strict parameters that it is expected to operate within based on the composition of the generation and load in the balancing authority area and the reliability of its transmission system. Based on these parameters, the balancing authority is required to have balancing reserve capacity that it can call upon to either increase or decrease generation within specific time windows. These time windows range from seconds up to 10 minutes. The time windows and the conditions under which the balancing reserve capacity may be called on define the types of generation inputs the balancing authority requires.

Q. Please summarize how the balancing authority uses generation inputs to provide Ancillary and Control Area Services to maintain reliability of the system.

A. The electrical grid in North America is divided into various balancing authority areas. Each balancing authority is responsible for ensuring that, in its area, electrical generation (power production) equals electrical load (power consumption). This is known as balancing generation with load or maintaining load-resource balance. Usually, a transmission provider is also the balancing authority in its area.

The BPA balancing authority utilizes generation inputs to provide Ancillary and Control Area Services to maintain load-resource balance at all times and to respond to the

many variables that affect transmission system reliability. All balancing authorities must maintain reliability within their balancing authority area in accordance with applicable regional reliability standards. It is difficult to predict exactly how much power the load will need at any given moment in time; therefore, each balancing authority must plan its system to ensure system flexibility to respond to system changes that can jeopardize reliable electrical service.

Q. Please explain how this applies to BPA.

A. BPA is divided functionally into two organizations, known as Transmission Services (TS) and Power Services (PS). BPA is a balancing authority pursuant to standards issued by the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). TS is responsible for ensuring that all balancing authority area responsibilities are met. As such, TS has the crucial responsibility of maintaining reliability for BPA's balancing authority area by keeping electrical generation in balance with electrical load. To maintain balance, TS must have access to balancing reserve capacity; that is, generators that are standing by ready to increase or decrease output when called on. When load or other generators increase or decrease relative to a pre-arranged schedule, TS must be able to call on generators to produce either more or less power, depending on whether the load or other generation has increased or decreased. Historically, TS has obtained balancing reserve capacity from PS with the exception of a small decremental balancing reserve capacity purchase pilot from a third-party provider.

Q. What happens if BPA does not maintain load-resource balance?

A. When generation and load are out of balance, the frequency of the electrical grid will move away from its nominal value of 60 hz (cycles/second). In extreme cases, the grid may become unstable, which could cause a number of problems, including variations in

electrical frequency that can damage electronic equipment or cause generators to trip offline. Due to the hazards posed by this type of imbalance, NERC and WECC have developed reliability standards that apply to balancing authorities, including BPA. For example, BPA is required under NERC and WECC reliability standards to maintain load-resource balance and to keep Area Control Error within acceptable limits for Control Performance Standard 1. The generating facilities that provide generation inputs for Ancillary and Control Area Services are operated on AGC to maintain performance within the NERC and WECC standards. If BPA violates these standards, it runs the risk of causing damage to the grid and equipment connected to it and, if the standard violated is Control Performance Standard 1, incurring sanctions from NERC and WECC.

Q. Please describe the distinction between energy and capacity in the context of generation inputs.

A. Energy is the actual use of electricity to do work and is commonly measured in megawatthours (MWh) (the amount of power delivered multiplied by the amount of time that the amount of power is delivered). In the context of generation inputs, energy is the difference in MWh between an entity's actual generation or load and the hourly schedule for that generator or load.

Capacity is the maximum amount of power output, commonly expressed in megawatts (MW), that generating equipment can supply to system load. In the context of generation inputs, capacity is the maximum amount of power output that generation may be required to increase or decrease during any given period.

For example, the difference between energy and capacity is reflected in the provision of generation imbalance. The energy component is recovered through the difference between scheduled and the actual generation of energy through the Generation Imbalance Service charge. This energy charge does not, however, account for the cost of

the balancing reserve capacity that must be maintained each hour in order for BPA to supply this energy, whether this energy is actually supplied or not. Jackson *et al.*, BP-14-E-BPA-28, section 4.

Q. Please describe the various types of balancing reserve capacity used to balance generation and load.

A. The generation inputs for Ancillary and Control Area Services used to balance between generation and load are provided through balancing reserve capacity. The balancing reserve capacity is either incremental (*inc*) or decremental (*dec*) reserves. *Inc* reserves are provided from generators that can increase generation (or loads that can reduce consumption) when loads increase or other generation decreases. *Dec* reserves are provided from generators that can reduce generation when loads decrease or other generators increase.

Q. Please explain spinning and supplemental reserves.

A. Spinning reserves are defined as unloaded generating capacity that is synchronized to the power system and can be increased on very short notice. Supplemental reserves are defined as generating capacity that is not spinning but that can be brought online, synchronized, and capable of serving load on a sustained basis within 10 minutes, or loads that can reduce consumption, when directed, on a sustained basis within 10 minutes. *Inc* reserve capacity is either spinning or supplemental reserve capacity. *Dec* reserve capacity is spinning reserve capacity, because generation can be reduced only on units that are already producing energy.

Q. Please describe the Ancillary and Control Area Services that use balancing reserve capacity.

A. Balancing reserve capacity is used to provide the generation inputs for several Ancillary and Control Area Services. Regulation and Frequency Response Service utilizes

balancing reserve capacity to meet the moment-to-moment variations in loads in the BPA balancing authority area. Variable Energy Resource Balancing Service (VERBS) utilizes balancing reserve capacity for wind and solar resources to meet (1) the moment-to-moment variations in generation (regulation), (2) the longer timeframe variations over 10 minutes (following), and (3) the total hourly deviation between actual and scheduled output (imbalance). Dispatchable Energy Resource Balancing Service (DERBS) utilizes balancing reserve capacity to enable non-Federal thermal generators to meet their regulation, following, and imbalance reserve requirements. Operating Reserves (spinning and supplemental) Service utilizes balancing reserve capacity to provide contingency energy for events that qualify under NERC, WECC, or Northwest Power Pool (NWPP) rules for calling on the contingency energy. Study section 10.

Q. How are Operating Reserves different from the balancing reserve capacity products?

A. Operating Reserves provide capacity for contingency events, such as the failure of a generator or the loss of transmission components within an hour. Operating Reserves do not provide balancing reserve capacity to meet the within-hour differences between actual and scheduled energy during normal operating conditions. There are WECC and NERC standards related to the Operating Reserve obligation for the balancing authority area, and the NWPP has specific rules for the events that qualify for deployment of Operating Reserves by the generator source balancing area or the generator sink balancing area. The "source" balancing area refers to where the energy is generated, and the "sink" balancing area refers to where the load served by the energy resides. For more detail on Operating Reserves see Study section 4 and Messenger *et al.*, BPA-14-E-BPA-25.

Q. Does PS provide other balancing reserve capacity to TS for use by the BPA balancing authority?

A. Yes. PS provides within-hour balancing reserve capacity to TS to follow changes in Federal loads during the hour. These reserves are called Load Following. The costs associated with Load Following Reserve are accounted for in BPA's rate methodology and are recovered in BPA's power rates rather than in transmission rates. Study section 3.1.1. Load following is sometimes referred to in a broader sense to describe all following reserve capacity, including the following reserve capacity needed to support generation. For purposes of understanding the various generation inputs described in this Initial Proposal, "Load Following Reserve" is the following reserve capacity needed to follow changes in Federal loads, and "following reserve" is used to refer to the component of balancing reserve capacity that is used to follow changes in both loads and generators.

Q. What is DSO 216?

A. Through the rate case process, and in consultation with customers, BPA establishes an amount of *inc* and *dec* balancing reserve capacity that it stands ready to provide. Dispatcher Standing Order (DSO) 216 is a tool used to help BPA keep the amount of in-hour balancing reserve capacity deployed within the bounds established in the rate proceeding. When 85 percent of the balancing reserve capacity that is standing ready (either *inc* or *dec*) has been deployed, a warning alarm is issued to BPA dispatch and the wind generating facility operators. Once 90 percent of *dec* reserve capacity has been deployed, BPA automatically limits wind generation for each wind generator or each set of netted wind generation to the wind schedule plus the reserve capacity allocation for the wind generators. If, in the same hour, 100 percent of *dec* reserve capacity is deployed, the wind output is limited to the schedule. Once 90 percent of *inc* reserve capacity has

been deployed, BPA curtails wind e-Tags to the actual wind output plus the wind reserve capacity allocation. If, in the same hour, 100 percent of *inc* reserve capacity has been deployed, BPA curtails wind e-Tags to the actual output of the wind.

Q. *Why is DSO 216 a necessary reliability tool for BPA?*

A. BPA has a finite amount of balancing reserve capacity available to deploy for load and generation changes in the BPA balancing authority area. For *inc* reserve capacity, once that reserve capacity has been deployed, BPA would have to encroach on other reserve capacity commitments (such as Operating Reserve) if BPA did not have a reliability tool such as DSO 216 to limit the use of balancing reserve capacity to the planning assumptions adopted in the rate proceeding. If BPA was not able to limit the output of wind generation and deployed all *dec* reserve capacity on the system, BPA could fail NERC compliance standards and create a large Area Control Error by pushing excess energy onto the system. This also has the possibility of adversely affecting the frequency of the interconnection.

Q. *How is DSO 216 an economic choice for wind generators?*

A. Wind generators can elect to purchase from BPA balancing service that is subject to DSO 216 curtailments when the total amount of balancing reserve capacity in the BPA balancing authority area for wind, load, and thermal generation is exhausted. Alternatively, they can elect a higher cost VERBS "Full Service," which is expected to be subject only to reliability-based curtailments that apply to all types of generation whose schedules exceed actual generation. Wind generators may also purchase VERBS Supplemental Service to mitigate their exposure to DSO 216 curtailments. See section 5 for an explanation of these services. If wind generator customers do not purchase VERBS Full Service or Supplemental Service, however, they receive the economic benefit of a lower rate but must accept the risk of curtailment associated with having a

lower quality level of service. Hence, there is an economic choice made by the wind generators in their service elections. From BPA's standpoint, the use of DSO 216 is necessary to protect system reliability by ensuring that the use of balancing reserve capacity on the system is consistent with, and kept within the parameters of, the customers' service elections and the planning assumptions adopted in the rate case.

Q. *Could there be modifications made to DSO 216?*

A. Yes. The Full Service election alone will likely require changes to DSO 216. There may also need to be changes made for changes in self-supply. BPA will discuss potential changes with stakeholders outside of this rate proceeding.

Q. *By paying for VERBS or DERBS, is the customer acquiring the right to use a specific quantity of balancing reserve capacity?*

A. No. VERBS and DERBS are not a sale of access to balancing reserve capacity for any purpose determined by the user. They are not comparable with a purchase of a put or call option. VERBS and DERBS are services in which BPA commits to making a specific amount of balancing reserve capacity available for specific uses, given specific assumptions about the nature of that use and the ability of the FCRPS to provide that balancing reserve capacity. These amounts are calculated assuming multiple uses of a pool of balancing reserve capacity. The diversity of the multiple uses lowers the total amount of balancing reserve capacity BPA needs to make available based on each individual use and lowers the cost for all users.

Specifically, VERBS is designed to provide an amount of flexibility to cover unavoidable schedule errors associated with the short-term unpredictability of variable energy resource output. VERBS is a Control Area Service, and like other transmission services there are times when the service may be limited or may not be available. For wind resources, VERBS provides an amount of flexibility assuming that schedule errors

(the difference between the scheduled amount and actual generation) are generally consistent with each service election; 30/30 or 30/60 committed scheduling Base Service and with assumed 45-minute persistence-based scheduling for uncommitted scheduling Base Service.

Likewise, DERBS provides a limited amount of balancing reserve capacity to meet the imbalances during ramp periods and during the remainder of the scheduling period that result from unintentional variations in thermal generation output relative to the scheduled output. DERBS is not intended to provide balancing reserve capacity to meet imbalances that result from a failure to adjust plant output in response to submitted schedules, beginning or ending plant changes outside of ramp periods, or other imbalances that are within the control of plant schedulers and operators.

Q. Why is the distinction between a service and a firm capacity commitment important?

A. The key distinction is that VERBS and DERBS are for limited use and are not general put and call options. The increased risks associated with the additional uncertainty and potential for energy accumulation associated with a put or call would reduce the capability of the FCRPS to provide balancing reserve capacity and increase the frequency of balancing reserve capacity reductions. If these services are used for purposes other than to balance unavoidable schedule errors, it would become difficult to determine the quantity of service required. BPA would have to plan operations to allow for full deployment of *inc*s or *dec*s at any time, for long periods of time, and would have to assume that market-driven motivations would lead to increased correlation in use of the service. Currently, BPA plans operations based on an expected distribution of deployments associated with unpredictable schedule errors, which are expected to be random, unbiased, and net to near zero over relatively short periods of time. Under a set of planning parameters that offered a firm capacity commitment, the FCRPS would have

much less available capacity, and the amounts of balancing reserve capacity needed for any individual use would need to be increased.

Section 3: Non-Rate Terms and Conditions for Transmission Service

Q. BPA recently conducted a series of public workshops, known as "Bonneville Open Access Transmission Tariff" or "BOATT" workshops. What was the purpose of the BOATT?

A. The intent of the BOATT was to have regional discussions about BPA's reciprocity safe-harbor OATT in general, specific discussions about provisions of the tariff where BPA was seeking a deviation from *pro forma* tariff language, and discussions of BPA's intent regarding a reciprocity safe-harbor tariff filing with the Federal Energy Regulatory Commission. After filing the tariff, BPA continued public discussions in the BOATT forum with customers and other interested parties about the provision of Generator Imbalance Service under OATT Schedule 9 and the determination of the amount of balancing reserve capacity available for generator imbalance service under BPA's proposed OATT Schedule 10. The intent of these discussions was to develop consensus around services that could fit into the tariff construct and to help inform BPA's Initial Proposal for FY 2014–2015 rates.

Q. What is the current status of the BOATT?

A. Participants in the BOATT developed a preliminary joint proposal that has informed the proposed "Full Service" option rate for VERBS. BOATT participants, including BPA, would like to continue discussions about a variety of processes and practices that are related to implementation of Generator Imbalance Service and the VERBS Full Service option.

Q. Does BPA expect to have additional BOATT meetings during this rate proceeding?

A. Yes. However, BPA expects to address only issues that fall within the reciprocity tariff under the BOATT framework. For issues that do not fall within the reciprocity tariff, but may be related to the implementation of Ancillary and Control Area Service rates, BPA expects to conduct discussions with customers in noticed public meetings coincident with the rate proceeding timeline. BPA refers to this forum as the "ACS Practices Forum." In the ACS Practices Forum, BPA will address business practices related to the provision of Ancillary and Control Area Services under the tariff and the rates.

Q. Which issues does BPA expect to address in the ACS Practices Forum?

A. BPA expects to discuss and develop the requirements that are necessary to provide variable energy resources and purchasing entities with sufficient information to enable wind energy to be e-tagged as "firm" energy. These discussions will also address whether the schedules under VERBS Base Service can and should be broken out into firm and non-firm components (VERBS Base Service is described in more detail below). Accordingly, energy product e-Tag protocols and verification practices for wind generation sourced in BPA's balancing authority area will also be discussed.

Additionally, BPA will discuss its purchase strategy for resources to provide balancing reserve capacity to meet the reserve requirements of Full Service. These discussions will address quantity of balancing reserve capacity needed, the timing of the purchase, the duration of the purchase, and how an inability to purchase sufficient balancing reserve capacity to fulfill the reserve requirement fits into the firm energy e-Tag protocols for those taking the Full Service option.

Q. Why is BPA addressing these issues in a different forum from this rate proceeding?

A. The issues described above are not rate case issues of cost allocation or cost recovery, but are closely related. For example, to offer Full Service and establish a formula rate to

recover the costs of providing that service, we do not need to have a predetermined fixed reserve requirement or a regionally accepted upper limit on the number of curtailments for wind energy to be considered as "firm." However, to make the Full Service product useful to purchasers, we acknowledge the need to develop practices to implement the product in a way that works for BPA and its customers.

It is important to note that we have had success in addressing non-rate issues in separate but parallel forums to rate proceedings in the past. For example, BPA developed DSO 216 and several wind integration initiatives in the Wind Integration Team forum concurrent with the WP-10 rate proceeding. BPA developed the requirements for its committed intra-hour scheduling pilot in a separate forum while establishing a rate discount and persistent deviation penalty charge exemption for participants in the committed intra-hour scheduling pilot in the BP-12 rate proceeding. BPA also developed the requirements for VERBS Supplemental Service in its business practice forums while establishing the rate for that service in the BP-12 rate proceeding.

Q. When does BPA expect to make decisions regarding those issues?

A. We expect BPA to resolve these issues prior to April 1, 2013, when customers' VERBS elections are due. However, we realize that some related issues are outside of BPA's control, such as Northwest Power Pool rules on acceptable energy product codes for e-Tags. If needed, BPA will continue regional discussions past the date customers' VERBS elections are due and work with the region to refine the implementation of Ancillary and Control Area Services.

Q. How does BPA expect to memorialize the decisions that are based on the BOATT and the ACS Practices Forum discussions?

A. BPA plans to discuss how it proposes to memorialize the outcome of the ACS Practices Forum early on in that process. After having those discussions, BPA may decide to

develop a final Record of Decision on the issues. At a minimum, we expect that one or more Business Practices will be developed or modified to describe how BPA will determine the amount of purchases of balancing reserve capacity for Full Service and to describe e-Tag energy product codes and any associated tag validation rules or after-the-fact assessment of compliance with BPA's Business Practices.

Q. Is it critical for these non-rate case issues to be addressed before the final decision in this rate case?

A. No. As explained above, our Initial Proposal is designed to establish rates that ensure that BPA will obtain cost recovery for the services that it provides to its customers, while preserving BPA's flexibility to accommodate changes related to regional e-tagging requirements and implementation of balancing reserve capacity-based services. Nevertheless, although it is not critical or necessary to resolve these non-rate issues before the Administrator's final decision in this rate proceeding, BPA is aiming to resolve these issues by April 1, 2013.

Section 4: Federal Energy Regulatory Commission Policy Regarding Ancillary and Control Area Services

Q. The Commission recently issued Order No. 764 on the integration of variable energy resources. Integration of Variable Energy Resources, Order No. 764, 139 FERC ¶ 61,246 (2012). How does this order apply to BPA?

A. BPA has voluntarily committed to file a reciprocity safe-harbor tariff with the Commission. Compliance with Order No. 764 is an aspect of the Commission's reciprocity requirements. The Commission allows non-jurisdictional transmitting utilities such as BPA to propose changes to their reciprocity tariffs if those changes "substantially conform to or are superior to" the *pro forma* tariff. As described further below, BPA is

still evaluating whether it will propose any modifications to its reciprocity Tariff in response to the Commission's new requirements in Order No. 764. The Commission requires public utility transmission providers to file compliance filings with respect to Order No. 764 by September 11, 2013. We are aware that some industry participants have filed a motion for extension of this deadline, but that the Commission has not yet responded to that motion. Based on the best information available at this time, BPA expects to make a reciprocity safe-harbor tariff filing with the Commission with regard to those requirements sometime in the fall of 2013.

Q. *Has the Commission adopted a specific rate design to recover costs associated with balancing reserve capacity that is necessary to provide Ancillary and Control Area Services?*

A. No. In Order No. 764, the Commission specifically declined to adopt a generic rate design to recover the costs for reserve capacity that is needed to provide balancing services for generators. Order No. 764, P 267. Although the Commission provided some guidance for public (jurisdictional) utilities that may seek to propose a future generator regulation rate, the Commission did not prescribe a specific methodology for transmission providers to inform their determination of balancing reserve requirements or rates to recover the costs of providing those balancing reserves for balancing services. *Id.* P 315.

Q. *Order No. 764 requires public (jurisdictional) utilities to offer the option for 15-minute scheduling or to propose enhancements that result in equivalent or superior benefits. Is BPA planning to offer the option for 15-minute scheduling?*

A. BPA has not yet decided whether it will offer 15-minute scheduling or whether it will file a reciprocity tariff deviation regarding intra-hour scheduling with the Commission. We are currently evaluating the costs associated with automating our systems to

accommodate 15-minute schedules. In addition, BPA is participating with Northwest Power Pool members in regional assessments of a number of enhancements, such as moving toward an Energy Imbalance Market and a Regulation Sharing Program, which may form the basis for an alternative that is superior to the Commission's 15-minute scheduling requirement. The regional assessment of costs and benefits of these enhancements is due to be completed in early 2013.

Q. When does BPA expect to make a decision on whether to offer 15-minute scheduling?

A. BPA expects to make a decision on 15-minute scheduling in early 2013. Although our Initial Proposal does not include a VERBS rate based on 15-minute scheduling, we have included information pertaining to a 15-minute scheduling rate option in the Documentation in Tables 2.27 and 2.28.

Section 5: Initial Proposal for VERBS

Section 5.1: Customer options for VERBS Base Service

Q. Are you proposing to offer customers options to fulfill their VERBS obligations?

A. Yes.

Q. Please describe your proposed options for VERBS.

A. We are proposing to offer all VERBS customers "Base Service," which will provide a level of quality of service at 99.5 percent. Puyleart *et al.*, BP-14-E-BPA-22 (describing the 99.5 percent quality level of service). Base Service customers will be required to elect the type of scheduling that they intend to use for the rate period: (1) 30/60 committed scheduling; (2) 30/30 committed scheduling; or (3) uncommitted scheduling. Jackson *et al.*, BP-14-E-BPA-28, section 6 (discussing the rates for 30/60, 30/30, and uncommitted scheduling Base Service). VERBS customers that fail to elect a specific Base Service scheduling option will be provided uncommitted scheduling Base Service.

In this rate proceeding, BPA refers to committed intra-hour scheduling as 30/30 scheduling and committed hourly scheduling as 30/60 scheduling, where the first number refers to how far ahead of delivery time the schedule value is established, and the second number refers to the duration of the schedule. Uncommitted scheduling gives customers the flexibility to schedule on an hourly or intra-hourly basis or a combination of hourly and intra-hour schedule periods. In addition, we propose to offer customers a "Full Service" option under VERBS. We describe our conceptual framework for these services in more detail below.

In addition, we note that parties may choose to self-supply the imbalance portion of their reserve capacity requirement or to have BPA provide the reserve capacity. Parties may also elect to supplement the level of service they purchase from BPA with supplemental reserve capacity that they acquire or request BPA to purchase under Supplemental Service.

Q. What does "committed scheduling" mean?

A. Under both committed 30/30 and 30/60 scheduling options, VERBS customers would commit to "meet or beat" the schedule accuracy of a signal that BPA will send to the customer at half past each hour and at the top of each hour. This is the approach that BPA currently utilizes in its Committed Intra-Hour Scheduling pilot for FY 2012–2013. Consistent with that approach, schedules must be submitted to BPA by 40 minutes past the top of the hour (hr:40) for both hourly and half hour schedules, and those schedules would start to ramp at hr:50 and complete their ramp to the next scheduling interval at hr:10. Customers that elected 30/30 scheduling would submit a schedule again by hr:15 to start ramping at hr:25 and complete the ramp to the second half hour schedule level at hr:35.

We expect that BPA will check the VERBS customer's schedule accuracy after the fact to ensure that it is achieving the level of accuracy it committed to. VERBS customers may decide to directly use the signal BPA sends or to use another mechanism, but the performance metrics, which will be described in the business practice, remain the same whether they use the BPA signal or their own forecast. VERBS customers would bear any risk of signal inaccuracy or loss and are expected to independently track their plant's actual output to ensure that the signal appears correct. In addition, we expect that a customer that has elected hourly scheduling may occasionally decide to establish a corrected schedule for the second half of the hour if it wishes to reduce its generation imbalance. Its accuracy would then be measured against the half-hourly performance metric for those half-hour schedule increments.

Q. *In what forum is BPA planning to develop the terms and conditions for committed scheduling services?*

A. Consistent with BPA's approach in the FY 2012–2013 rate period, BPA will develop with its customers the terms and conditions for committed intra-hour scheduling service and committed hourly scheduling service in the ACS Practices Forum.

Q. *How will BPA determine the signal that is provided for committed scheduling?*

A. Currently the signal BPA provides for Committed Intra-Hour Scheduling pilot participants is based on a persistence schedule. At the start of the FY 2014–2015 rate period, BPA expects to provide a persistence-based signal for both committed intra-hour schedules and committed hourly schedules. BPA will identify the actual generation for each plant at the minute between hr:29 and hr:30 and the minute between hr:59 and hr:60 and send that information to the wind plants. BPA is currently working with wind generators to obtain more accurate, plant-specific information to improve forecast performance. BPA expects to provide wind forecasts for at least 24 hours ahead to wind

plants that provide plant-specific data. Over time, if BPA and the VERBS customer agree that the forecast performs consistently better than persistence scheduling, we expect BPA will use the forecast instead of a persistence signal for the accuracy metric for committed hourly scheduling. To develop the best possible forecast, BPA purchases forecasts from two forecast vendors and also develops an in-house forecast. On an ongoing basis, BPA looks back at the recent performance of these wind forecasts and assesses which has performed best over the past few hours. It then computes a weighted average "super forecast" that selects from the best-performing forecast at that time.

Q. Are all VERBS customers required to participate in committed scheduling?

A. No. VERBS customers may elect to take the uncommitted scheduling Base Service option and establish their schedule for hourly or half hourly scheduling, based on their own forecasts. We propose to use a 45/60 scheduling assumption to establish the quantity of balancing reserve capacity required to support the uncommitted scheduling Base Service option, and customers electing this option must accept any DSO 216 curtailment risk that may occur depending on their actual scheduling accuracy.

Under our proposal, customers that take Full Service will be required to commit to either committed 30/60 scheduling or committed 30/30 scheduling. We explain the rationale for this requirement below in section 5.2.

Q. Why are you using a 45/60 scheduling accuracy assumption (that is, scheduling accuracy that is consistent with 45-minute persistence for hourly schedules) for uncommitted scheduling Base Service?

A. We expect that the customers that elect uncommitted scheduling will have a balancing reserve capacity requirement that exceeds the requirements associated with 30/60 committed scheduling. We expect this because current scheduling practices, with most schedules being "uncommitted" to a particular scheduling accuracy, have indicated that

schedules are closer to 45/60 scheduling accuracy than 30/60 scheduling accuracy. It is unclear how many (or which) customers may elect to take uncommitted scheduling Base Service at this time. We must make an assumption in order to provide an indication of the additional premium that would be charged for uncommitted scheduling. We will revisit the balancing reserve capacity requirements for uncommitted scheduling Base Service in future rate periods.

Q. What benefits will customers receive from participating in committed scheduling?

A. Customers that elect 30/60 committed scheduling will be exempt from Persistent Deviation penalty charges and will pay a lower Base Service rate than uncommitted scheduling Base Service. Such customers are also expected to accumulate less energy imbalance over time and therefore will lower their generation imbalance costs.

Similarly, customers that elect to participate in 30/30 committed scheduling will benefit, because intra-hour schedules require less balancing reserve capacity, and the VERBS customer that commits to using them will pay a lower Base Service rate than 30/60 or uncommitted Base Service. 30/30 committed scheduling customers are also expected to accumulate less energy imbalance over time, and therefore will lower their generation imbalance costs. We are also proposing to exempt 30/30 committed scheduling participants from the Persistent Deviation Penalty charge. Finally, we are proposing to exempt VERBS customers that participate in the best available scheduling practice (currently 30/30 committed scheduling) from Deviation Band 2 charges under Generation Imbalance Service. See Jackson *et al.*, BP-14-E-BPA-28, section 4 (discussing the proposed changes to the rate design for Generation Imbalance Service).

Q. Why is it necessary for a customer to "commit" to schedule on either an intra-hour or hourly basis to receive a lower rate for VERBS?

A. BPA cannot predict the actual level of capacity use for uncommitted schedules, and there is no certainty that such schedules would meet a specific level of scheduling accuracy over time. With committed scheduling, BPA and the customers are agreeing on a specific scheduling practice, and BPA is tracking the accuracy of the schedules to ensure that the expected scheduling accuracy is achieved. The lower rates for customers that participate in committed scheduling are a direct consequence of their predictable use of balancing reserve capacity under VERBS. It would be inequitable to apply a lower or discounted rate to customers that do not commit to achieve a specific level of scheduling accuracy, because there would be no predictable or consistent reduction in balancing reserve capacity under VERBS.

Q. When must customers elect to participate in a committed scheduling option?

A. Consistent with BPA's approach in during the FY 2012–2013 rate proceeding, VERBS customers must submit their scheduling and service elections by April 1, 2013, to enable BPA to complete the final rate studies.

Q. Are you proposing to allow customers to change their committed scheduling election mid-rate period?

A. Yes; however, VERBS customers may only request a scheduling option that has a longer scheduling period than their April 1st election. For example, a 30/30 committed scheduling customer may request to move to 30/60 committed scheduling. Customers must provide 90 days' advance notice of the change, which would be implemented at the start of the quarter. Jackson *et al.*, BP-14-E-BPA-28, section 6.1 (discussing the rate treatment for mid-rate period changes to the Base Service election).

Our primary concern with allowing customers to change their initial Base Service scheduling election to a shorter committed scheduling period mid-rate period is cost recovery. We expect that customers that changed to the shorter committed scheduling period mid-rate period would want the benefits of the lower rates associated with that election. This can create cost recovery risk, since BPA may not recover its costs for balancing reserve capacity that was already committed, or purchased, to support the customer's initial Base Service scheduling election. Nevertheless, we encourage interested rate case parties to discuss in their direct cases whether customers should have the option to make a mid-rate period change to their initial Base Service election to commit to a shorter scheduling period and, if so, provide possible solutions to our cost recovery concerns.

Q. Why are you not proposing a committed scheduling option for 15-minute scheduling?

A. As mentioned in section 4 above, it is unclear at this time whether the region will adopt 15-minute scheduling or propose an alternative to the Commission. However, if the region unequivocally adopts 15-minute scheduling and the rate case parties support a 15-minute committed scheduling option in this rate proceeding, we may consider a committed 15-minute scheduling option in the Final Proposal. As noted above, we have included information pertaining to a 15-minute committed scheduling option in Documentation in Tables 2.27 and 2.28.

Q. What level of quality of service are you proposing for VERBS Base Service?

A. After calculating the net (pooled) imbalance requirements of wind, load, and dispatchable resources, we propose to establish a capacity requirement for Base Service that covers 99.5 percent of the total *inc* and *dec* requirements of all hours included in the study. Puyleart *et al.*, BP-14-E-BPA-22 (discussing the study for 99.5 percent quality level of service).

Q. Why are you proposing Base Service at a 99.5 percent quality level of service?

A. BPA pools its balancing reserve capacity for use by load, variable energy resources, and dispatchable energy resources within the BPA balancing authority area. BPA's method utilizes a common standard for holding reserves that applies to all uses. BPA has used the 99.5 percent level of service since the WP-10 rate case as the common standard to measure the necessary quantity of reserves.

Since adopting the 99.5 percent level of service, BPA has consistently met NERC and WECC balancing standards. Thus, we are proposing to maintain the 99.5 percent quality level of service for VERBS Base Service for the FY 2014–2015 rate period. It would be inconsistent with good utility practice for BPA to hold less than the 99.5 percent level of service without an adequate substitute reserve capacity (*e.g.*, additional curtailments) because of the risk of non-compliance. We encourage the rate case parties to address our proposed quality level of service in their direct cases.

Q. Has BPA made exceptions to the 99.5 percent level of service requirement?

A. Yes. BPA does not plan to purchase *dec* reserve capacity to maintain the 99.5 percent level of service for Base Service when the FCRPS is unavailable due to hydro system conditions or when BPA determines that the FCRPS capability to provide balancing reserve capacity on a planned basis is insufficient to provide 99.5 percent of the *dec* reserve capacity requirement.

Q. Why does BPA not plan to purchase dec *balancing reserve capacity to maintain Base Service of 99.5 percent during those times when* dec *balancing reserve capacity is unavailable from the FCRPS?*

A. Most parties in the region have not expressed great concern about DSO 216 limits that require feathering of the output of wind plants to scheduled amounts during overgeneration events that exhaust the total *dec* balancing reserve capacity made

available in the BPA balancing authority area for wind, load, and other generation. DSO 216 implementation for overgeneration events effectively causes the wind plant to self-supply decremental reserve capacity. As a result, for the BP-14 rate period, we are proposing not to purchase non-Federal decremental balancing reserve capacity, in addition to any amounts of *dec* balancing reserve capacity that can be provided by the FCRPS, to provide Base Service.

Q. Please explain how the quality level of service for VERBS relates to the concerns regarding the ability of the FCRPS to provide enough balancing reserve capacity to support the balancing needs of the wind fleet in BPA's balancing authority area.

A. The scheduling options selected by VERBS customers will affect the percent of total balancing reserve capacity that can be provided from the forecast availability of FCRPS reserves. BPA is establishing formula purchases charges, as described in Jackson *et al.*, BP-14-E-BPA-28, to ensure that it is able to recover the costs of purchasing generation inputs to cover the remaining reserve capacity requirement for Base Service and any balancing reserve capacity requirements for Supplemental Service or Full Service. If more VERBS customers elect committed scheduling Base Service (*e.g.*, committed 30/30 scheduling or 30/60 scheduling), the FCRPS will cover a higher percentage of the total VERBS capacity requirement. Conversely, if VERBS customers elect uncommitted scheduling, the available FCRPS supply will cover a smaller portion of the total need.

Q. How does the decision regarding the quality level of service impact the VERBS rate?

A. The combination of VERBS customer choices regarding quality of service and type of service (committed or uncommitted scheduling) will affect the percentage of the total VERBS service need that can be provided from the FCRPS. The VERBS rate will be higher or lower depending on whether the average cost of balancing reserve capacity that

BPA must purchase is higher or lower than the cost of the planned FCRPS-sourced balancing reserve capacity.

Q. How does the decision regarding the quality level of service impact the operation of DSO 216?

A. Under our concept for Full Service, if we are successful at purchasing the necessary reserves for the service, we expect VERBS Full Service customers to be unaffected by wind-only curtailments under DSO 216.

Q. Why is DSO 216 a necessary reliability tool to manage Base Service?

A. BPA must limit actual balancing reserve capacity usage to the amounts of reserve capacity provided by the FCRPS and any non-Federal generation input providers. It would be unreasonable to expect a transmission provider to provide unlimited service. The FCRPS is subject to various operating and statutory constraints that accomplish many public purposes, and BPA needs to be able to plan operations of the complex interconnected system of dams and reservoirs that make up the FCRPS. Hence, BPA must have the ability to maintain system reliability when demands on the services it provides are inconsistent with the forecast quantities and uses of balancing reserve capacity made available.

Q. What options will customers that choose to take Base Service have to mitigate their exposure to DSO 216?

A. Customers that take Base Service can mitigate their exposure to DSO 216 by maintaining awareness of their schedule error at all times and correcting schedule errors as quickly as possible. In addition, customers may purchase Supplemental Service to reduce their exposure to DSO 216 curtailments or take Full Service. Jackson *et al.*, BP-14-E-BPA-28, section 6.2.

Q. Are you proposing any rate flexibility to increase the quality level of service from 99.5 percent mid-rate period? Please explain.

A. Yes. VERBS customers may decide at any time during the rate period to purchase Supplemental Service. *Id.* In addition, if because of a legal challenge to DSO 216 BPA is prevented from implementing DSO 216 or is required to amend it materially, we propose to require that VERBS Base Service customers take Full Service and pay the total Full Service charge. Jackson *et al.*, BP-14-E-BPA-28, section 6.

Q. How do you apply the principle of cost causation to price Base Service?

A. We apply the principle of cost causation to price VERBS by (1) identifying the uses of the FCRPS to provide the service and (2) assigning the service its proportionate share of the embedded costs of the FCRPS and the estimated variable costs associated with provision of balancing reserve capacity. In addition, we propose formula purchases charges (described in Jackson *et al.*, BP-14-E-BPA-28, and Study section 10) to assign the cost of purchasing non-Federal generation inputs for balancing reserve capacity-based service.

Q. How is the price for Base Service related to the quality level of service that a customer will receive from BPA?

A. The cost of VERBS is directly related to the amount of balancing reserve capacity required, so small increases in the level of service at the tails of the distribution have an associated ever-increasing and non-linear effect on the costs of the service. If customers request a higher quality of service, incremental amounts of balancing reserve capacity will be necessary to meet the customers' requests. Any addition of balancing reserve capacity will increase the price of VERBS for any customer requesting it. For the BP-14 rates, we are proposing two options for customers to obtain a higher quality level of

service: Full Service or Supplemental Service (see below for more detailed descriptions of these alternatives). Jackson *et al.*, BP-14-E-BPA-28.

Q. Why is the tradeoff between quality of service and price important for the continued integration of variable energy resources?

A. VERBS customers have unique needs regarding the quality of service they receive and the amount of cost they can bear. As each customer makes a choice among the levels of service BPA offers, it is better able to optimize its costs and benefits. In both the WP-10 and BP-12 rate cases, BPA gave customers a choice between a lower quality of service at a lower price (that is, a lower rate but a higher exposure to DSO 216 feathering and curtailment events), or a higher quality of service at a higher cost (that is, a higher rate and a lower exposure to DSO 216 feathering and curtailment events). In this rate proceeding, we are proposing to give customers the option to increase their quality level of service above the 99.5 percent confidence interval (through either Full Service or Supplemental Service), as well as the ability to lower their overall cost exposure for VERBS through participation in committed scheduling.

With the continued increase of variable energy resources in the BPA balancing authority area, it is essential that BPA and its customers develop a number of different alternatives for the provision of balancing reserve capacity services. BPA remains committed to exploring choices it can offer customers in the provision of balancing reserve capacity services consistent with its statutory obligations and preserving the reliability of the FCRPS.

Section 5.2: VERBS Full Service

Q. Please describe your conceptual framework for VERBS "Full Service."

A. We expect VERBS Full Service to be a service option that provides a quality of service designed to eliminate the use of DSO 216 wind-only curtailments of transmission schedules when BPA has successfully purchased sufficient balancing reserve capacity to meet the expected reserve requirement. Under Full Service, we expect that BPA will attempt to purchase sufficient balancing reserve capacity to balance statistically infrequent schedule errors, where actual generation of a wind plant that purchases Full Service is less than its scheduled generation.

Q. Why are you proposing a VERBS "Full Service" rate option in addition to the Base Service rate options?

A. Some VERBS customers have expressed concern that other balancing authorities are unwilling to purchase the output of their wind projects because they are subject to DSO 216 curtailments of their transmission schedules. Other market participants have suggested that the output of wind plants subject to DSO 216 should have an energy tag other than a "firm" energy tag. The owners of wind output have also expressed the concern that an "other than firm" energy tag will lower the value of their energy in the wholesale market. As a result, we are proposing a Full Service option to meet the needs of customers that want to manage their statistically infrequent schedule errors (*i.e.*, low probability differences between actual generation and scheduled generation) by having BPA attempt to purchase additional balancing reserve capacity to support the deliverability of their schedules. In contrast, customers that do not take Full Service (or purchase Supplemental Service) will likely pay a lower rate for balancing service, but must accept the possibility of transmission e-Tag curtailments when significant wind schedule errors from the wind fleet exhaust the total balancing reserve capacity available

to balance load and other resources. See also Jackson *et al.*, BP-14-E-BPA-28, section 6 (discussing the exceptions to Base Service rates and the applicability of the total Full Service rate).

Q. Why is it necessary for Full Service customers to participate in committed scheduling?

A. Under committed scheduling, customers agree to schedule their wind plants to either meet or beat a known scheduling signal provided by BPA to the customer each hour. Use of a known scheduling signal allows BPA to use power production forecasts to estimate the potential variation of the actual output of wind generation from its scheduled output. We expect that BPA will use the forecasts of wind energy and volatility to determine, on a short-term basis, whether to purchase additional resources to provide the capacity difference between Base Service and Full Service. Absent a commitment to a known schedule, however, BPA would have limited information, before the close of each hour of the scheduling window, to determine the appropriate amount of balancing reserve capacity it must purchase to eliminate the customer's total schedule error. Without committed scheduling for Full Service, BPA would not be able to base its purchases of balancing reserve capacity on a power production forecast. Instead, before the close of the scheduling window, BPA would need to purchase enough balancing reserve capacity to provide energy for the estimated error, which in extreme circumstances could be up to the customer's total installed capacity. BPA would not know ahead of time whether the customer will schedule up to its nameplate capacity during a schedule period. Given the geographical concentration of wind plants in the BPA balancing authority area, if individual plants submit generation schedules in anticipation of a wind ramp that does not actually occur until an hour or two later, the cumulative schedule error for multiple plants would exacerbate the total schedule error in the BPA balancing authority area and increase demand on the total balancing reserve capacity available in BPA's balancing

authority area. Conversely, use of a committed scheduling paradigm gives BPA and the customer greater certainty with respect to schedule accuracy and the customer's balancing reserve capacity need.

Q. What is your conceptual framework for the scheduling signal for committed scheduling?

A. As noted above, the details for committed scheduling will be developed in the ACS Practices Forum. However, conceptually, we expect the signal will be based on a persistence value set 30 minutes ahead of the scheduling interval. We also expect that BPA will acquire vendor forecasts and will use an algorithm to select, for each hour and each plant, the best-performing forecast (the "Super forecast"). BPA would then provide those forecasts to wind plants that have provided plant-specific data, to help them predict their generation for several hours into the future. BPA will compare the results of that forecasting method to the accuracy of persistence scheduling. When BPA finds that the combined forecast performs better than persistence for scheduling accuracy, BPA would consult with the wind generator and consider basing the signal on the forecast rather than persistence. We expect that BPA will use persistence scheduling until the forecast developed for that individual plant is producing more accurate predictions of actual plant output.

Q. Will a customer be able to elect into or out of Full Service within the rate period?

A. Yes. We propose that BPA would establish business practices to allow customers to request Full Service for a specified minimum three-month period with notice to begin Full Service and notice to leave Full Service. We expect Full Service would begin on the first day of the month. The notice periods will define the maximum length of a purchase that BPA would attempt to make to provide the service and provide BPA with certainty in planning for purchases made on a shorter term.

Q. What are the differences between Base Service and Full Service?

A. Base Service (under 30/30 committed scheduling, 30/60 committed scheduling, and uncommitted scheduling elections) limits the cost of providing VERBS by providing service that meets the total balancing reserve capacity needs of the BPA balancing authority area during 99.5 percent of the forecast hourly operations. Under Base Service, DSO 216 limitations will be implemented as a transmission curtailment to manage wind events where actual generation is less than scheduled amounts of generation and the total amount of balancing reserve capacity available for load, wind, and other resources in the BPA balancing authority area is exhausted. BPA will also require wind plants to feather their generation output in hours of operation in which actual wind generation exceeds scheduled wind generation and the total amount of balancing reserve capacity is exhausted. The frequency of these transmission curtailments is expected to be about 0.25 percent each on a forecast basis and slightly more for feathering events when the forecasted need for *dec* balancing reserve capacity at 99.5 percent exceeds 1100 MW. The actual number of events will vary based on how consistent the distribution of wind schedule error is with the historical distribution that was studied. Under our concept for Full Service, BPA would attempt to purchase additional balancing reserve capacity to eliminate BPA's application of wind-only transmission curtailments to the Full Service customer. Under Full Service, BPA also would continue to require wind plants to feather their generation output during hours of operation in which their actual wind generation significantly exceeds scheduled wind generation (again, the expected frequency is slightly more than 0.25 percent of the time).

Q. What benefit will the customer receive by taking Full Service?

A. Under our concept for Full Service, we expect Full Service customers not to be subject to wind-only transmission curtailments under DSO 216 when BPA has successfully

purchased sufficient balancing reserve capacity to meet the expected reserve requirement. We expect this higher standard of service would help address concerns of other balancing authorities regarding transmission curtailments of wind output sourced from the BPA balancing authority area and the concerns of wind owners that their hourly amounts of energy receive a lower price in the market. We acknowledge that there may be market transparency differences between the Base Service and Full Service.

Q. *Will BPA decide the e-Tag or other market transparency difference between the Full Service and the Base Service in this rate case?*

A. No. The market transparency and e-Tag requirements that apply to wind generation are not rate case issues.

Q. *If not in the rate proceeding, what forum or process does BPA expect to use to address this issue?*

A. BPA expects to discuss the requirements for using G-F (firm) product codes in the ACS Practices Forum. We recognize that use of product codes is also a broader regional issue, but we expect that BPA will ultimately need to decide whether and how to differentiate G-F from other-than-G-F energy products.

Q. *How much additional balancing reserve capacity will be needed for BPA to provide Full Service?*

A. Based on customer feedback in rate case workshops, we expect some customers will not elect to take Full Service for the entire rate period. As a result, the amount of balancing reserve capacity that BPA may need to purchase during the rate period will likely be lower at the start of the rate period, but will ultimately depend on how many customers elect to take Full Service instead of Base Service and the capacity requirements that are associated with those customers. The amount of balancing reserve capacity needed to support Full Service will also depend on regional expectations for the quality level of

service provided by Full Service. We expect that BPA will address this issue in the ACS Practices Forum.

Q. How do you propose to allocate costs associated with incremental purchases of balancing reserve capacity to provide Full Service?

A. As discussed further in Klippstein *et al.*, BP-14-E-BPA-24, and Jackson *et al.*, BP-14-E-BPA-28, we propose to allocate the costs associated with incremental purchases of balancing reserve capacity to provide Full Service to the customers requesting that service under a formula purchases charge.

Q. Based on your proposal, what would happen to a customer's transmission schedule for Full Service if, despite reasonable efforts, BPA is unable to purchase additional amounts of balancing reserve capacity from third parties to meet the balancing reserve capacity needs of Full Service customers based on a power production forecast?

A. BPA expects to establish business practices for establishing e-Tag and transparency requirements for wind generation based on the purchase of Base Service and Full Service. Such business practices will also establish the tagging and transparency requirements for Full Service when BPA is unable to purchase all of the additional amounts of balancing reserve capacity to avoid wind-only transmission curtailments. Depending on how much of the Full Service level of capacity BPA is able to purchase, we would expect that a portion of the output of a wind project purchasing Full Service would need to be tagged similar to Base Service and be subject to curtailment during hours when BPA is unable to purchase all of the additional amounts of balancing reserve capacity. These important and timely issues are subject to further review and dialogue with customers.

Q. Based on the conceptual framework for a Full Service product, what do you expect to happen to a Full Service customer's transmission schedule if within a scheduling period BPA has insufficient balancing reserve capacity to meet the balancing needs of the BPA balancing authority area?

A. Conceptually, if BPA exhausts its balancing reserve capacity so actual generation is less than the loads of the balancing authority and the scheduled amount of exports from the balancing authority and BPA has curtailed the transmission schedules subject to wind-only curtailments under DSO 216 to their actual generation output, we would expect BPA to request all parties exporting generation from the balancing authority area to curtail their schedules to match their actual generation.

Q. Why would it be appropriate for BPA to curtail all generator transmission schedules to mitigate a balancing reserve capacity insufficiency for Full Service customers that occurs within a scheduling period?

A. BPA would have to curtail all generator schedules for underperforming generators (that is, the generator's actual output is less than the scheduled output) in order to prevent over-deploying balancing reserve capacity. When a generator is not meeting its schedule, BPA has a responsibility to the rest of the entities in the balancing authority area as well as the Western Interconnection to take action on the generators not meeting their obligation before taking action on other entities.

Q. Why are you sharing a conceptual framework for Full Service in this rate proceeding if the terms for Full Service are not rate case issues?

A. We are sharing our conceptual framework for Full Service to help expedite the development of a Full Service product in the ACS Practices Forum. Moreover, we have identified the critical non-rate elements of Full Service in an attempt to help separate these issues from those concerning cost recovery and rates in this rate proceeding. We

intend to work with BPA's customers to evaluate our concept for Full Service and to obtain feedback in the ACS Practice Forum.

Section 5.3: VERBS Supplemental Service

Q. What is Supplemental Service?

A. Supplemental Service is an optional service under the VERBS rate. Customers taking VERBS Supplemental Service would purchase balancing reserve capacity, or have BPA purchase on their behalf, to decrease the number of curtailments a particular variable energy resource would face under DSO 216. See Jackson *et al.*, BP-14-E-BPA-28, section 6.2.

Q. What is your proposal for Supplemental Service?

A. We propose the following:

- BPA will offer VERBS Supplemental Service during the FY 2014–2015 rate period to allow customers to purchase or self-supply *inc* or *dec* balancing reserve capacity to limit DSO 216 curtailments for a variable energy resource designated by the customer.
- BPA will establish a formula rate in the rate proceeding that collects the full cost of any purchases of supplemental balancing reserve capacity that BPA makes for participating customers.
- Outside of the rate proceeding, BPA will develop a business practice that will outline the implementation details for customer self-supply of supplemental reserves and BPA purchase of supplemental reserves.

Q. Why are you proposing to offer Supplemental Service?

A. Some customers have indicated a desire for an option to elect a higher level of service than what is available under the proposed Base Service, and on a shorter notice time-

frame than available under our concept for Full Service. Some customers have also indicated a concern regarding the impacts of curtailments for wind being exported from the BPA balancing authority area when BPA has exhausted all of the balancing reserve capacity it is holding for an hour. These customers have indicated that they are interested in the option of purchasing a higher quality of service, but they are concerned that purchasing Full Service may be too expensive or not provide the certainty they need. VERBS Supplemental Service allows customers purchasing this service to reduce or eliminate the potential for DSO 216 curtailments of transmission schedules from their variable energy resources on the time frames of their choosing.

Q. Will all of the details of the proposed VERBS Supplemental Service, including the requirements and operating protocols, be addressed in the BP-14 rate case?

A. No. The primary issue to resolve in the rate proceeding is recovery of the costs associated with Supplemental Service. Issues that are commercial or operational in nature will be addressed outside of the rate case. BPA is currently working on an internal project called Enhanced Supplemental Service to address many of the concerns expressed by customers about BPA's initial Supplemental Service business practice. BPA will modify its business practice in the ACS Practices Forum. This business practice will outline the requirements for resources to be used for supplemental reserves, a mechanism for BPA to secure products and to define how they will be dispatched by BPA, a mechanism for customers to self-supply supplemental reserves, and other implementation details. As with all business practices, this will be posted for public comment in order to solicit the best ideas in the region for purchasing and supplying supplemental reserves.

Section 5.4: Impact of Self-Supply

Q. Please describe the current Customer-Supplied Generation Imbalance (CSGI) Pilot.

A. The current CSGI pilot is a business practice that allows VERBS wind customers to self-supply the imbalance component of their VERBS balancing reserve capacity requirement. As part of this pilot, CSGI participants purchase only the regulating and following components of VERBS from BPA.

Q. When and how will BPA evaluate the success of the CSGI Pilot?

A. BPA is currently evaluating the success of the pilot and expects to complete the evaluation by January 1, 2013. As part of the evaluation, BPA will assess CSGI performance relative to the parameters established in the CSGI Pilot business practice. BPA may propose some modification of the performance requirements if the evaluation suggests changes are needed.

Q. Is BPA anticipating that some variable energy resources will self-supply a portion of their balancing reserve capacity during the rate period?

A. Yes.

Q. What assumptions regarding self-supply are reflected in the Initial Proposal?

A. We forecast that 1,428 MW nameplate of wind will self-supply the imbalance component at the start of the rate period and that 1,538 MW will self-supply by the end of the rate period. The average self-supply nameplate quantity for the rate period is forecast at 1,505 MW. Study section 2.7.4; Documentation Table 2.17.

Q. What is the basis for this assumption?

A. The CSGI pilot has been in effect for more than two years, and BPA has not received indication from the current CSGI participant that it does not plan to continue as a participant. We have not received any indication from other VERBS customers that they intend to self-supply for the FY 2014–2015 rate period.

Q. How will you determine the amount of self-supply for the forecast in the Final Proposal studies?

A. We will base our assumption for Final Proposal studies on customers' VERBS Balancing Service elections for the rate period. These elections are due on April 1, 2013.

Q. What will variable energy resources indicate when they file balancing service elections on April 1, 2013?

A. Variable energy resources will indicate whether they will self-supply one or more components of VERBS Base Service. Customers that elect to take all VERBS components from BPA will indicate their preferred VERBS scheduling performance option. As described in section 5.1 above, the choices for scheduling performance are 30/30 committed intra-hour scheduling, 30/60 committed hourly scheduling, or uncommitted hourly scheduling.

Q. What service options will customers have after April 1st?

A. Customers that advance an expected post-FY 2015 interconnection into the rate period will need to elect a scheduling option for Base Service (for example, 30/30 committed scheduling, 30/60 committed scheduling, or uncommitted scheduling). Customers may also elect Full Service for specified periods if they have also elected either 30/30 committed scheduling or 30/60 committed scheduling. See also Jackson *et al.*, BP-14-E-BPA-28, section 6 (discussing the Full Service exception under Base Service rates). Although we do not expect any customer will discontinue its effort to self-supply during the rate period, customers that can no longer self-supply during the rate period will need to elect a Base Service scheduling option. See also *id.* section 6.1 (discussing Formula Purchases Charges that may apply to a customer).

We are not proposing to allow customers to change their base service election to a shorter scheduling period than the customer's initial April 1st election. This is because of

the potential cost-shift risk that results from the reduced balancing reserve capacity requirement for the shorter scheduling period relative to BPA's planned balancing reserve capacity commitment for the initially elected service. As noted earlier, however, we encourage interested parties to address this issue in their direct cases.

Section 6: Cost Allocation for Balancing Reserve Capacity-Based Ancillary and Control Area Services

Q. What is BPA's pricing principle for setting power and transmission rates?

A. BPA sets rates based on cost causation and equitable allocation of costs.

Q. Why is the principle of cost causation important for equitable rates?

A. Setting rates consistent with cost causation means that BPA's rate design takes into account the cause of a particular cost so that revenue recovery of that cost comes from the product, service, or customer(s) that caused that cost to be incurred. This principle supports equitable allocation of costs, and thus equitable rates, since the amount a customer pays BPA accurately reflects BPA's cost of providing the service. Applying the principle of cost causation to BPA's rate design also results in equitable rates when the principle is applied consistently to comparable products, services, or customers.

Q. How do you apply the principle of cost causation to price VERBS?

A. We have applied the principle of cost causation to the rate design of balancing services in two primary ways. The first is to set different balancing service rates based on operational characteristics and elected scheduling practices, which have an impact on the amount of balancing reserve capacity BPA must hold to balance the system. Second, we created a methodology to determine the balancing services that cause the need, and thus the cost, to purchase balancing reserve capacity. This cost causation methodology is

applied consistently across BPA's three categories of balancing users: load, dispatchable energy resources, and variable energy resources.

Q. How much balancing reserve capacity from the FCRPS are you proposing that BPA supply for balancing reserve capacity-based Ancillary and Control Area Services and Load Following Reserve over the FY 2014–2015 rate period?

A. We propose that BPA supply up to 900 MW of *inc* and up to 1100 MW of *dec* balancing reserve capacity for balancing reserve capacity-based Ancillary and Control Area Services and Load Following Reserve on average over the rate period. Kerns *et al.*, BP-14-E-BPA-23, section 4. Depending on customers' service elections, BPA will purchase additional balancing reserve capacity up to the total *inc* reserves required to meet their service needs. We do not propose that BPA purchase additional *dec* reserves beyond what the FCRPS can provide.

Q. Did you consider such limitations when forecasting the balancing reserve capacity requirement for VERBS?

A. Yes. Based on input from customers in rate case workshops and the results of a BPA pilot project that sought to purchase *dec* balancing reserve capacity, we are proposing that BPA not purchase non-Federal *dec* balancing reserve capacity when BPA's forecast need for *dec* balancing reserve capacity exceeds the 1100 MW of *dec* balancing reserve capacity that can be supplied by the FCRPS. We expect that the need for *dec* balancing reserve capacity to maintain a 99.5 percent quality of service will exceed FCRPS capability in December 2014. This date can change depending on when additional wind plants interconnect in the BPA balancing authority area and on the megawatt amount of wind plants that elect to participate in the committed intra-hour scheduling product.

Q. Why did BPA choose not to purchase non-Federal dec *balancing capacity in the* dec *acquisition pilot?*

A. BPA issued a Request for Proposal (RFP) to purchase up to 300 MW of non-Federal *dec* balancing reserve capacity. The responses BPA received under the RFP offered non-Federal *dec* balancing reserve capacity at roughly five to six times the cost of *dec* balancing reserve capacity supplied by the Federal system. BPA asked customers if they thought the value of reducing the number of instances where BPA was required to limit the overgeneration of wind plants through use of DSO 216 justified the additional expense. Our understanding is that most customers did not believe the additional expense would be justified.

Q. Did you consider the interests of customers that thought the expense of additional dec *balancing reserve capacity is justified?*

A. Yes. As described above, we propose a modification of its Supplemental Service to include the purchase of *dec* balancing reserve capacity. Any customer that wishes to reduce the instances when its overgeneration is reduced under DSO 216 can purchase on its own or request BPA to purchase *dec* balancing reserve capacity through Supplemental Service.

Q. If BPA is capable of providing additional (more than the planned amount) balancing reserve capacity from the FCRPS within the rate period, will BPA first utilize Federal balancing reserve capacity before making purchases of non-Federal balancing reserve capacity?

A. Not necessarily. BPA maintains discretion as to how much (if any) additional FCRPS balancing reserve capacity to offer on a short-term basis. This is not a rate case issue. BPA's business practice for selecting and prioritizing offers will be discussed in the ACS

Practices Forum. Any offer from the FCRPS will be evaluated at the same time and on the same basis as other offers.

Q. If BPA is unable to provide inc *balancing reserve capacity from the FCRPS to balance variable energy resources, does BPA expect to contract for non-Federal sources of* inc *balancing reserve capacity to provide balancing services?*

A. Yes. BPA plans to purchase amounts of non-Federal *inc* balancing reserve capacity to maintain the 99.5 percent level of service on a planning basis. Study section 10. We are proposing four different types of balancing reserve capacity purchases. Study sections 3 and 10.

Q. If BPA is unable to provide the forecast quantity of Federal balancing reserve capacity to provide VERBS during the rate period, do you propose to provide a credit to VERBS customers?

A. Yes. As explained in Jackson *et al.*, BP-14-E-BPA-28, section 6.4, the rate credit will be calculated monthly and is equal to the ratio of hourly unavailable *inc* and *dec* balancing capacity from the FCRPS due to reductions caused by hydro system limitations to the planned hourly average capacity that was expected to be available from the FCRPS. For example, if the monthly planned average *inc* and *dec* balancing reserve capacity is reduced by 25 percent from planned levels for each hour of the month, the credit for the month would be 25 percent of the VERBS charge. The credit is for hydro system-related reductions in available capacity. The credit applies to VERBS customers taking all three components of VERBS from BPA, so CSGI Participants and VERBS Solar would not see a credit. Those customers do not see a real reduction in the Regulation and Following that BPA provides when overall reserves are reduced. Power customers will see a reduction in VERBS revenues from the rate credit.

Q. Why are you proposing to provide a credit for the VERBS rate only for hydro-related reductions in Federal balancing reserve capacity?

A. We believe our proposal to provide a credit for hydro-related reductions in Federal balancing reserve capacity is consistent with the Commission's guidance regarding the impact of weather-related events on balancing reserve capacity-based services. In Order No. 764, the Commission states that weather-related events "should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations." Order No. 764, P 321. Our proposal ensures that VERBS customers do not bear the costs associated with Federal balancing reserve capacity that BPA cannot provide because of hydro system limitations. Commission policy and industry practice do not support the provision of rate credits for interruptions to any other service. On rare occasions there may be transmission-related reasons for limiting balancing reserve capacity, and if such an event were to occur it would not be reasonable to have power customers pay the credit back on the VERBS rate.

Q. Why does the rate credit not apply to the DERBS rate?

A. The rate design used for DERBS is different from that used for VERBS. Specifically, the billing factor for DERBS is measured on actual use, while the billing factor for VERBS is measured on nameplate. Study section 10.

Q. Do you propose that BPA attempt to make non-Federal purchases during the times when BPA is unable to provide the forecast quantity of Federal balancing reserve?

A. Yes. We are proposing that BPA attempt to maintain the 99.5 percent level of service through the purchase of non-Federal balancing reserve capacity. These purchases would replace the planned-for but unavailable FCRPS-sourced balancing reserve capacity. These purchases are defined as Type 2 purchases and are discussed in greater detail in Study section 3.5.4.

While this is our proposal, we acknowledge that more discussion is needed with customers to determine if they want BPA to attempt to make these purchases to maintain the 99.5 percent level of service. We are aware that some customers may prefer that BPA not attempt to make these purchases and instead temporarily lower the quality level of Base Service until the FCRPS can provide the rate case forecast amount of balancing reserve capacity. We encourage interested rate case parties to discuss this issue in their direct cases.

Q. *How do you propose to address the timing, quantity, and cost of balancing reserve capacity purchases?*

A. We will have discussions in the ACS Practices Forum about these topics and will develop business practices where needed.

Section 7: Definition of Incremental Cost for Imbalance Energy

Q. *Are you proposing any changes to the rates for Generator or Energy Imbalance Services?*

A. Yes. We are proposing to change the calculation of BPA's incremental cost for both Energy and Generator Imbalance Services from an hourly market index to a weighted average cost of energy deployed.

Q. *Why are you proposing to change the calculation of its incremental cost for Energy and Generation Imbalance Services from an hourly market index to a weighted average cost of energy deployed?*

A. There are times when the hourly market index price may be lower than the expected operating costs of a non-Federal resource. As a result, some resources may be reluctant to sell a balancing reserve capacity product to BPA because they may be compensated for capacity but not fully compensated for any energy that is deployed. To increase the

likelihood that non-Federal generators will offer to sell to BPA reserve capacity for imbalance services, we are proposing to compensate those generators for energy that is deployed from those resources, in addition to their costs of the reserve capacity. We propose to pay the non-Federal generator's offer price of generation deployed for imbalance energy, and then average that cost with the hourly index price for energy deployed from Federal resources to calculate BPA's incremental cost of imbalance energy.

Q. Are you proposed definition of incremental cost consistent with your cost allocation methodology for non-Federal purchases of balancing reserve capacity? Please explain.

A. Yes. First, the cost allocation methodology is a rate construct and does not change how BPA operates the system. The cost allocation methodology identifies which users of balancing reserve capacity caused the need to purchase balancing reserve capacity and allocates the costs to those users. The methodology is not used to identify operational access to a particular source of balancing reserve capacity; nor does it require that operators deploy available balancing reserve capacity in a particular order or that they match available balancing reserve capacity to a particular schedule error. Second, the cost allocation methodology determines cost causation associated with the need to purchase and hold capacity; it does not determine cost causation associated with the deployment of that capacity in a particular hour.

Q. How is the proposed definition consistent with the principle of cost causation?

A. The cost of deployment during an operational hour is caused by customers with schedule error during that hour. Our proposal is to allocate the deployment costs incurred during an hour proportionally to a customer's error in the same hour.

Q. How will the proposed definition of incremental cost for Energy and Generation Imbalance Service apply to negative deviations (actual generation greater than scheduled) where acquisitions of dec capacity from non-Federal resources are deployed?

A. BPA does not plan on purchasing *dec* capacity to replace unavailable Federal resources, but it is possible that customers taking supplemental service could purchase *dec* capacity for deployment by BPA. Deploying *dec* capacity for a resource directly offsets a like amount of positive deviation (overgeneration relative to the schedule) for the resource that purchased the *dec* capacity. We assume that there will be no incremental costs relative to the hourly market index for non-Federal deployment of *dec* capacity, so we are proposing not to adjust the incremental costs for negative deviations for deployment of those resources.

Q. How would BPA ensure that the cost of non-Federal energy that is included in BPA's proposed calculation of incremental cost is reasonable?

A. In the ACS Practices Forum, we expect BPA to explore the possibility of requiring independent audits, price caps, or any other parameters that will help to ensure that the costs of non-Federal energy that is deployed for imbalance energy are reasonable.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

FRANCIS R. PUYLEART, JUERGEN M. BERMEJO,

STEPHEN H. ENYEART, and KEVLYN D. MATHEWS

Witnesses for the Bonneville Power Administration

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TESTIMONY of

FRANCIS R. PUYLEART, JUERGEN M. BERMEJO,

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Witnesses for the Bonneville Power Administration

SUBJECT: BALANCING RESERVE CAPACITY QUANTITY FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Francis R. Puyleart, and my qualifications are contained in BP-14-Q-BPA-52.

A. My name is Juergen M. Bermejo, and my qualifications are contained in BP-14-Q-BPA-05.

A. My name is Stephen H. Enyeart, and my qualifications are contained in BP-14-Q-BPA-17.

A. My name is Kevlyn D. Mathews, and my qualifications are contained in BP-14-Q-BPA-44.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Balancing Reserve Capacity Quantity Forecast in the Generation Inputs Study, BP-14-E-BPA-05, section 2 (Study), and Generation Inputs Documentation, BP-14-E-BPA-05A (Documentation). Our testimony describes the development of the forecast of the balancing reserve capacity necessary to provide within-hour balancing services during the rate period. In addition, we describe the key components of the analysis and assumptions underlying the forecast methodology. Finally, we describe the results of our analysis using data sets that reflect 99.5 percent of the balancing reserve capacity requirement values, the impacts of

assuming that some generators may self-supply imbalance reserves during the rate period, the impacts of assuming that variable generators (wind and solar generation) schedule on the half-hour and quarter-hour scheduling intervals, and the impacts of 30-minute and 45-minute persistence scheduling accuracy for wind generation.

Section 2: BPA's Balancing Reserve Capacity Requirements

Q. Why must BPA maintain balancing reserve capacity to provide within-hour balancing services within its balancing authority area?

A. BPA must maintain load-resource balance within its balancing authority area at all times. Study section 2.1.2. Load-resource balance means that the amount of energy being consumed inside the BPA balancing authority area (load) plus the amount of energy that is being scheduled out to other balancing authority areas equals the amount of energy being generated inside the BPA balancing authority area plus the amount of energy being scheduled in from other balancing authority areas. On a broad level, BPA must provide within-hour balancing in order not to burden the rest of the interconnection with changes to load or generation inside the BPA balancing authority area boundaries.

More specifically, BPA must comply with multiple North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards. The primary standards that relate to within-hour balancing services are BAL-001-0a, Real Power Balancing Control Performance, and BAL-005-0b, Automatic Generation Control (AGC). The purpose of BAL-001-0a is to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real time. The requirements in BAL-001-0a limit how far out of load-resource balance a balancing authority can be before it violates the standard.

BAL-005-0b establishes requirements for balancing authority AGC necessary to deploy regulating reserve to maintain load-resource balance.

Q. What components make up the balancing reserve capacity requirements?

A. BPA separates its balancing reserve capacity requirements into regulating, following, and imbalance components. *Id.* The following reserve component is sometimes referred to as "load following" reserve. Our testimony and the Study use "following" and "load following" interchangeably.

Q. Please describe these components and how they interrelate.

A. Regulating reserve is the amount of balancing reserve capacity needed to balance the changes in load or generation on a moment-to-moment basis. Following reserve is the amount of balancing reserve capacity needed to balance the changes in average load and average generation every ten minutes over the course of an hour. The imbalance reserve component is the additional amount of following reserve caused by a difference between the actual hourly average load or generation and the hourly amount estimated (scheduled) for the load or generation. The summation of these components determines the total balancing reserve capacity requirement. *Id.*

Q. How is the imbalance component different from Generation or Energy Imbalance?

A. Generation and Energy Imbalance are used to settle the energy difference between schedules and actuals after the fact, while the imbalance component in the forecast is used to determine the amount of balancing reserve capacity needed to meet the balancing authority area balancing reserve capacity requirement. In addition, Generation Imbalance is based on the difference between the one-hour average actual generation and the generation estimated (scheduled) for the hour. Energy Imbalance is based on the difference between the one-hour average actual load and the load estimated (scheduled) for the hour.

Q. How does BPA use the balancing reserve capacity requirement and the various components determined in the Balancing Reserve Capacity Quantity Forecast?

A. The component quantities determined in the Balancing Reserve Capacity Quantity Forecast are used in the cost allocation methodology to forecast the revenues BPA will receive from providing balancing reserve capacity. *Id.* section 2.1.1. They are also used to assign costs to the Ancillary and Control Area Services rates, which use the component quantities to establish rates for these services. *Id.*

Q. Please explain how the balancing reserve capacity requirements are used to set the deployment limits for DSO 216.

A. Balancing reserve capacity requirements are used to establish the trigger setpoint levels for deployment of DSO 216. Warnings are sent to the wind projects when 85 percent of the balancing reserve capacity requirements are deployed for incremental (*inc*) or decremental (*dec*) reserves. When 90 percent of the *inc* balancing reserve capacity is deployed, schedules for all wind projects are reduced to the wind projects' current generation level plus their allocated amount of the *inc* balancing reserve capacity requirement, if less than their schedule. If in the same operating hour the *inc* balancing reserves deployed reaches 100 percent, schedules for all wind projects are reduced to their current generation level, if less than their schedule. At the point when 90 percent of the *dec* balancing reserve capacity is deployed, all wind projects are instructed to reduce generation to their schedule plus their allocated amount of the *dec* balancing reserve capacity requirement. If in the same operating hour the *dec* balancing reserves deployed reaches 100 percent, all wind projects are instructed to reduce generation to their schedule.

Q. What resources does BPA use to provide generation for the overall balancing reserve capacity requirement to maintain balance within the hour?

A. BPA designates Federal Columbia River Power System (FCRPS) generating resources under AGC to provide the generation inputs necessary to maintain within-hour load-resource balance. BPA's AGC system adjusts plant generation of these designated FCRPS resources based on the differences between scheduled and actual load and generation. The cumulative *inc* and *dec* generation required to maintain load-resource balance within the hour forms the basis for the balancing reserve capacity requirement. As the balancing reserve capacity requirement exceeds the amount of within-hour balancing reserves the FCRPS can provide, BPA will need to procure within-hour balancing reserves from non-FCRPS generators. AGC will deploy non-FCRPS within-hour balancing reserves in a similar manner to those provided by the FCRPS.

Section 3: Background of the Balancing Reserve Capacity Quantity Forecast Methodology

Q. How does the Balancing Reserve Capacity Quantity Forecast methodology used for this Initial Proposal differ from the methodology used for the FY 2012–2013 rate period?

A. The base methodology is similar to the one that was used to forecast balancing reserve capacity requirements for the FY 2012–2013 rate period, but we have continued to improve the methodology and have made certain modifications for the FY 2014–2015 rate period. We are using larger data sets to forecast the balancing reserve capacity requirement in this proceeding, and we have updated the data sets to include more recent information. The forecast for the FY 2012–2013 rate period was based on data sets for a 24-month study period from October 1, 2007, to September 30, 2009. The study period

for the Balancing Reserve Capacity Quantity Forecast in this Initial Proposal is the 48-month period from October 1, 2007, to September 30, 2011. *Id.* section 2.1.2.

In addition to wind generation data retrieved from BPA's Plant Information system (PI) for the 48-month period listed above, we requested supplemental data from the wind project owners and operators in the BPA balancing authority area for the FY 2014–2015 rate period to use in instances where the PI wind generation data was not the most accurate data. The supplemental data is estimated generation data from the wind project, which is the theoretical output of the wind turbines online as calculated from the wind speed readings at each turbine and the power versus wind speed curve for that turbine. See Study section 2.3.1 for more details on these data.

For the FY 2012–2013 rate period, BPA used a generalized approach for assigning balancing reserve needs to solar generators of one-half of the balancing reserve requirements of wind generation's regulation and load following. For the FY 2014–2015 rate period, BPA has acquired actual solar photovoltaic generation data from Sacramento Municipal Utility District (SMUD). We use this data to run a full analysis, similar to wind and load, of the balancing reserve capacity needs for solar generation. See Study section 2.4.3 for more details on these data.

We have refined the data set used to "scale in" the generation of wind projects expected to be online during the rate period. *Id.* section 2.3. We now have more actual wind generation data available to use in the Balancing Reserve Capacity Quantity Forecast than was available in the FY 2012–2013 rate proceeding, and we have incorporated more actual generation data into our analysis. In addition, we have expanded the methodology used to "scale in" generation to fill all missing data points in the wind generation. Section 2.3.2 of our testimony describes the changes in detail.

Section 4: Assumptions in the Balancing Reserve Capacity Quantity Forecast Methodology

Q. Have you prepared a detailed description of the Balancing Reserve Capacity Quantity Forecast methodology and the assumptions in your analysis?

A. Yes. Study section 2.7 describes our methodology in detail. The following sections of our testimony summarize key components of the methodology and certain assumptions.

Section 4.1: Installed Generation Capacity Assumption

Q. Please describe how you estimate the amount of generation capacity that will be online in BPA's balancing authority area during the rate period for purposes of the Balancing Reserve Capacity Quantity Forecast.

A. BPA manages a generator interconnection "queue" that currently has over 80 requests pending, including small generation, representing almost 15,000 MW to interconnect to BPA's transmission system. Many of those requests originally sought to interconnect by 2013. Because the majority of the interconnection requests in BPA's queue at this point are for new wind generators, most of the discussion below reflects how we estimate the wind generation that will be online in BPA's balancing authority area in the future. The Study includes all non-AGC-controlled generation types coming online during the rate case, such as hydroelectric, thermal, and solar photovoltaic generation as well as wind.

Prior to BPA offering an interconnection agreement and allowing the project to interconnect, each interconnection request must go through a series of studies called for under the interconnection procedures in BPA's Open Access Transmission Tariff and environmental studies required under the National Environmental Policy Act (NEPA) and other Federal laws. Projects vary widely in terms of their siting process, the time it takes to complete the environmental studies, and the time required for BPA to construct the

required interconnection and network projects. We have used this internal forecast to forecast the installed generation capacity during the rate period. *See* Documentation Tables 2.1, 2.2, and 2.3.

Q. What factors and information do you consider in developing its assumptions about the number of projects that will come online in the future and the timing of the interconnection and energization of those projects?

A. We consider a variety of factors and information. One of the primary sources that we consider is information that developers provide during the interconnection process. Each request in the queue must go through a study process under BPA's interconnection procedures before BPA can offer an interconnection agreement and allow the project to interconnect. Under this study process, we completed a series of studies regarding the interconnection and conducts meetings with the customer to review the study results at each phase. Those meetings include discussions with the customer regarding its project's plan of service, including the schedule for the interconnection.

The developer submits a proposed project schedule with the interconnection request. We typically assume that the project will not interconnect earlier than the date in the proposed project schedule, but most often the date is determined as the plan of service is developed. During the meetings with us, the customer provides information such as its siting process and timing, project scheduling, financing commitments, and turbine orders. This information provides some general indicators of when the project is likely to interconnect. We update the internal forecast of the study request at each study phase based on customer-provided information and BPA's schedule requirements. If the developer has not demonstrated a desire to interconnect (for example, obtained financing commitments or ordered turbines), we take that lack of readiness into account when forecasting interconnection of that particular project.

The information provided by the developer in the interconnection process typically does not provide a complete picture of the circumstances surrounding a particular request. Based on our experience, we also evaluate the project schedules based on certain other criteria. For example, as described previously, BPA must conduct an environmental review before deciding whether to interconnect a particular generator. This review can take substantial time to complete, and BPA typically coordinates the review with the timing of the state or county environmental permitting process. As a result, the status of the environmental review process and interconnection customer permitting process for a request plays a significant role in our assumptions regarding interconnection and energization schedules. We also consider the specific interconnection and system projects that will be required to interconnect a particular project. Larger, more complex interconnection projects and network additions typically require more time to complete and are a factor for any particular project. As BPA and the customer establish a more well-defined plan of service in the interconnection process, we refine the forecast of the interconnection based on the particular network additions and interconnection plan of service required to interconnect the generator. Other projects in the queue, especially those with earlier request dates, also may affect the plan of service and related forecast for the later queued requests.

A customer may execute an engineering and procurement agreement to determine the project schedule once the studies have been completed, prior to completion of the environmental review. An engineering and procurement agreement typically commits the customer to provide funds for BPA to begin work on the design of the necessary interconnection projects or acquisition of equipment with a long lead time. When a customer executes an engineering and procurement agreement, we will incorporate the

project into its construction program schedule, which provides more certainty as to the schedule for that particular project.

The last major factor is the customer's commitment to a schedule to execute and fund an interconnection agreement. Finally, once a customer agrees to fund the interconnection projects and signs an interconnection agreement, we can establish a firm construction schedule to be included in the forecast.

Q. When did you estimate which future projects would be online for purposes of the Balancing Reserve Capacity Quantity Forecast used in the Initial Proposal?

A. For purposes of the Balancing Reserve Capacity Quantity Forecast prepared for the Initial Proposal, we used a June 2012 forecast of generation interconnection dates. There are several study stages that need to be completed to provide the balancing reserve capacity and associated costs for the Initial Proposal, including the balancing reserve capacity calculations and the cost determination of the reserve requirements. The installed generation forecast is the first building block needed for the Balancing Reserve Capacity Quantity Forecast. We finalized the forecast of projects in June to allow that data to be used for the other studies and documentation that must be completed for the Initial Proposal.

Q. What is your overall estimate for the amount of installed capacity for the different types of generators that you expect to be online during the rate period?

A. Study Table 2.1 identifies the amount of installed capacity that we estimate will be online during the FY 2014–2015 rate period for each type of generation in the Balancing Reserve Capacity Quantity Forecast. The forecast of installed wind capacity is an average of 4,871 MW; installed solar capacity is an average of 15 MW; non-AGC-controlled hydroelectric capacity is an average of 2,527 MW; non-Federal thermal capacity is an average of 5,192 MW; and Federal thermal capacity is 1,276 MW.

Q. Will you update your assessment of the amount of installed capacity that will be online during the FY 2014–2015 rate period for the Final Proposal based on the most recent information available at that time?

A. Yes. BPA periodically updates its projections regarding the amount of generation that will come online in the future, and we intend to update our assessment for the Final Proposal based on BPA's most current update.

Q. How does your assessment account for economic factors such as recession, natural gas prices, or changing tax incentives?

A. We rely on the customer meetings and conversations as to their project scheduling, and the information on the progress of their site permitting process and expected completion. This information provides some general indicators of when the project is likely to interconnect, taking into account external economic factors. Indirectly, we also note the utility industry direction and appetite for new generation, as discussed at public meetings with BPA and others. More recently, we are now considering the overall goals of the region for renewable portfolio standards as a more general indicator for the installed capacity forecast over the next several years.

Section 4.2: Assumptions for Wind Generation: Scaling in Wind Generation

Q. What is meant by "scaling in" wind generation?

A. Scaling in wind projects refers to the process of estimating the output of future wind projects or gaps in the data of existing wind projects based on the output of existing wind projects. The term "scaling" in this case refers to applying a percentage to the existing wind projects' output (with associated lead or lag, explained below) to estimate the future wind projects' output.

Q. Why is scaling necessary for developing the Balancing Reserve Capacity Quantity Forecast?

A. The generation variability of all existing and future wind projects, and their associated schedules, affects the amount of balancing reserve capacity required in BPA's balancing authority area. Without the scaled-in future wind projects in the Study, we risk forecasting less balancing reserve capacity than BPA would need to carry to meet the within-hour balancing requirements through the FY 2014–2015 rate period.

Q. Did you make any changes to your scaling methodology from that used for the FY 2012–2013 rate period? If so, what were the changes?

A. Yes. The scaling methodology was improved to allow for the methodology to fill in all missing data points. The FY 2012–2013 methodology was unable to fill in several large sections of missing data because of the way it used existing projects to scale in new projects and to fill missing data. There were several large sections of missing data for all projects that resulted in the scaling methodology attempting to use missing data to fill missing data. For example, if data from five minutes in the future is being used to fill in missing data for now and the data is also missing for five minutes into the future, then the scaling methodology cannot fill in the missing data point for now. The improvements made to the scaling methodology allow the code to rank and select other groups of existing plants to scale in the missing sections left by the FY 2012–2013 scaling methodology. Study section 2.3 describes the new scaling methodology in detail.

Q. Please summarize your analysis with respect to scaling in the generation for wind projects.

A. We use a 48-month data set (October 1, 2007, through September 30, 2011) with one-minute average actual wind generation data as a starting point. Study section 2.3.1. With that data set, we forecast the wind generation output for the rate period. We use the

installed capacity of the wind projects that BPA forecasts to be online during the rate period and calculate the future output using the prevalent direction of weather pattern changes and time delays between existing and future projects within the BPA balancing authority area. We use three existing projects to scale in the generation of a particular future project. The result is an estimate of the generation for the different amounts of installed wind capacity during the rate period. *Id.*

Q. *Why do you use wind generation data from the study period October 1, 2007, to September 30, 2011, as the basis for your analysis regarding the generation of future wind projects?*

A. As part of BPA's ongoing efforts to reflect actual system behaviors in its rates, we expanded the data set used for the study to include the most up-to-date full-year data. For the FY 2014–2015 rate proceeding, we use the same data set as the FY 2012–2013 rate proceeding, with the following two years of data added, for a total of four years of data. For the FY 2012–2013 rate proceeding, BPA selected the two-year period prior to October 1, 2009, in order to avoid using data that would reflect operator interventions associated with the implementation of reliability and operating protocols by BPA. In order to address the potential issues that operator interventions cause in the data for the two additional years, BPA used a combination of expected generation output supplied by the existing wind projects in the BPA balancing authority area and the wind scaling methodology.

Q. *What are the BPA reliability and operating protocols that could result in operator interventions, and how would those affect the data?*

A. The reliability and operating protocols implemented by BPA are DSO 216, the CSGI pilot program, and BPA's Oversupply Mitigation procedures. On October 1, 2009, BPA implemented DSO 216 to maintain reliability during severe and extremely low-

probability ("tail") events. The implementation of DSO 216 may result in limiting the output of projects to maintain reliability during tail events when those projects might have otherwise been generating. *See* Fisher *et al.*, BP-14-E-BPA-21, sections 2, 5. Data from a period when DSO 216 was in effect might not fully reflect the variability in generation that BPA could face during the rate period.

In August 2010, BPA initiated the CSGI pilot program, in which participants supply the generation imbalance portion of their within-hour balancing reserves (there is currently only one participant in CSGI). The CSGI participant must meet performance metrics for the station control error of its wind projects netted with its balancing resources. While the participant may use a variety of means to meet the performance metrics, at times it must use operator limitation of its wind projects' output to meet the metrics. Data from a period when the CSGI participant was modifying the output of its projects might not fully reflect the variability in generation that BPA could face during the rate period.

In the spring of 2011, BPA first adopted Oversupply Mitigation protocols to address times of concurrent high water flow and high wind generation that could affect Biological Opinion obligations. During the periods of Oversupply Mitigation, wind project operators were required to limit the output of their facilities to allow BPA to increase generation from the FCRPS. Fredrickson *et al.*, OS-14-E-BPA-1, section 3. Data from a period when the Oversupply Mitigation protocol was in use might not fully reflect the variability in generation that BPA could face during the rate period.

Q. What was the expected generation output used in your analysis?

A. Prior to beginning the studies for the FY 2014–2015 rate proceeding, BPA requested the expected generation output of every wind project online during the period of October 1, 2009, to September 30, 2011. While some wind project owners have tuned the

calculation of expected generation beyond a basic approach, expected generation is fundamentally a calculation of the predicted output for every online turbine based on the wind speed reading from each turbine's anemometer and the power versus wind speed curve for that turbine. BPA received the expected generation data for approximately 75 percent of the wind projects in the BPA balancing authority area. The remaining plants were filled through the scaling methodology laid out above.

Q. What is the basis for your assumption that you can predict generation for future wind projects by using leading or lagging generation values from existing projects?

A. Weather data typically reflect a west-to-east wind pattern across the area from Hood River east along the Columbia River, which is where most of the future wind projects are planned. Documentation Table 2.2. 3TIER, a renewable energy forecasting and assessment company, provided data to BPA in 2008 that showed the leads and lags between the locations of certain existing and future projects in the balancing authority area. That data reflected the west-to-east wind pattern, as well. The amount of time it takes for a weather pattern to move across the area was calculated by BPA from numerical weather model data provided by National Renewable Energy Laboratory for calendar year 2004–2006. Study section 2.3.1. In addition, BPA used actual minute-by-minute wind plant generation data and a mathematical modeling tool, MATLAB, to analyze correlations between existing wind plants at various time offsets. The highest correlated time offsets found between different existing wind plants reflected the west-to-east wind pattern. Based on all this information, we forecast the future project generation using the leads and lags from other projects. *Id.* Study section 2.3.1 explains the development of the correlation and lead and lag data.

Q. How do you decide which existing projects to use to scale in a particular project?

A. Correlations, distances, and time delays are calculated for every project to every other project. For each future project, trios of existing projects are created and ranked by correlation, distance, and time delays. The highest ranked trio is used to scale in the new project. *Id.* section 2.3.2.

Q. Why did you use more than one existing project to scale in a future project?

A. The diversity of the output of the existing wind projects is an important factor when scaling in a future wind project. By using three existing wind projects, we are able to ensure that some of the diversity in wind output is reflected in the future wind projects. In other words, use of multiple projects at multiple time delays provides a means to reflect diversity in the analysis. If a single project were used, the estimated output of the future project would have the same pattern as the existing project, merely moved forward or backward in time.

Q. Please explain the adjustments that you made to the generation data to develop generation estimates for a particular wind project.

A. We time-shift generation of the existing project and develop ratios of the existing project capacity to the future project capacity. *Id.* Time-shifting means that the output of an existing project is moved forward in time if the weather pattern normally would reach the existing project before the future project or backward in time if the weather pattern normally would reach the existing project after the future project. We base the number of minutes the project output is shifted on the prevalent pattern seen in the area for existing projects and the lead and lag data.

As three projects are always used to create a scaled-in project, each of the three projects must be adjusted to reflect the scaled-in project's installed capacity and the correlation of the three projects to the scaled-in project. To adjust for the installed

capacity of the scaled-in project, the existing project's output is multiplied by the proposed installed capacity of the future project over the installed capacity of the existing project. *Id.* To adjust for the correlation of each existing project to the scaled-in project, the existing project's output is multiplied by the existing project's correlation to the scaled-in project over the sum of all three existing projects' correlations to the scaled-in project. *Id.*

Section 4.3: Assumptions for Thermal Generation

Q. Please summarize your analysis regarding the balancing reserve capacity requirement associated with thermal generators.

A. We examined the historical balancing reserve capacity requirements of thermal generators in the BPA balancing authority area by analyzing the actual thermal generation and schedules for the same time period used for wind generation (October 1, 2007, to September 30, 2011). We assumed that future thermal projects would have the same balancing reserve capacity requirement as an existing thermal project per megawatt of installed capacity. Using 48 months of actual minute-by-minute data, we integrated thermal generation into balancing reserve capacity calculations similarly to wind, that is, as a reduction from load to account for coincidental balancing reserve capacity usage. We analyzed load, wind projects (existing and future), future solar projects, existing thermal projects, and existing hydro projects simultaneously for their contribution to the balancing reserve capacity requirements. As seen during the last rate proceeding, we found the use of balancing reserve capacity to be due primarily to the station control error (generation minus schedule) of thermal generators during startup, station control error during shutdown, and periods of excessive movement during the operating hour. *Id.* section 2.4.

Q. Is your method of analysis regarding the balancing reserve capacity requirement associated with thermal generators different from that used for the FY 2012–2013 rate period? If so, what has changed?

A. Yes. The primary analysis is identical to the FY 2012–2013 rate proceeding, but we reduce the non-Federal thermal projects' within-hour balancing reserve requirement based on their improved performance between FY 2010 and FY 2011. This is consistent with the method used in the FY 2012–2013 rate proceeding and reflects the change in behavior seen after notification to the non-Federal thermal generators of the pending rate. The improvement seen from FY 2010 to FY 2011 was 7.8 percent in *inc* reserves and 5.1 percent in *dec* reserves. Any improvement seen during FY 2012 will be reflected in the Final Study.

Section 4.4: Assumptions for Hydroelectric Generation

Q. Please summarize your analysis regarding the balancing reserve capacity requirement associated with hydroelectric (hydro) generators.

A. We examined the historical balancing reserve capacity requirements of hydro generators in the BPA balancing authority area by analyzing the actual hydro generation and schedules for the same time period used for wind generation (October 1, 2007, to September 30, 2011). We assumed that future hydro projects would have the same balancing reserve capacity requirement as an existing hydro project per megawatt of installed capacity. We analyzed only non-AGC-controlled hydro generation because AGC-controlled hydro generation is used to supply BPA's balancing reserve capacity requirement. Using 48 months of actual minute-by-minute data, we integrated hydro generation into balancing reserve capacity calculations similarly to wind, that is, as a reduction from load to account for coincidental balancing reserve capacity usage. Load,

wind projects (existing and future), future solar projects, existing thermal projects, and existing hydro projects were analyzed simultaneously for their contribution to the balancing reserve capacity requirements. Study section 2.4. Our analysis shows that hydro's use of balancing reserve capacity was minimal. Documentation Table 2.16. Thus, hydro generators are not assessed balancing reserve capacity requirements for the FY 2014–2015 rate proceeding. We propose to incorporate the balancing reserve capacity requirements into the load-balancing reserve capacity requirements.

Q. Is your method of analysis regarding the balancing reserve capacity requirement associated with hydro generators different from that used for the FY 2012–2013 rate period? If so, what has changed?

A. We are using the same method of analysis for hydro for the BP-14 rate case as we used for the BP-12 case.

Section 4.5: Assumptions for Solar Generation

Q. Please summarize your analysis with respect to scaling in the generation for solar projects.

A. The forecast of installed capacity for the rate period includes an average of 15 MW of solar generation. Because BPA has no utility-grade solar projects in its balancing authority area at this time, BPA contacted other regional utilities with solar generation and received one-minute solar photovoltaic generation data for an unscheduled 1.655 MW Sacramento Municipal Utility District (SMUD) project for the 48-month period of study. The SMUD data is scaled to a 15 MW solar project, as forecast to be online for the entire FY 2014–2015 rate period, by multiplying the generation data by 15 MW and dividing by the 1.655 MW installed capacity. Schedules were synthesized from the data provided. Using the 48 months of actual minute-by-minute data, we

integrated solar generation into balancing reserve capacity calculations similarly to wind; that is, as a reduction from load to account for coincidental balancing reserve capacity usage. Load, wind projects (existing and future), future solar projects, existing thermal projects, and existing hydro projects were analyzed simultaneously for their contribution to the reserve requirements. *Id.* section 2.4.3.

Q. How is this scaling method different from the method you used for scaling solar generation for the FY 2012–2013 rate period?

A. During the FY 2012–2013 rate case, no actual solar data was available to integrate into the study, so we made assumptions regarding the variability of solar resources for the FY 2012–2013 rate period. The FY 2014–2015 Initial Proposal uses real solar generation data in a manner similar to that used for wind and load.

Q. Please describe how you synthesized schedules for the solar generation data?

A. From conversations with SMUD and other utilities with solar generation, we determined that a reasonable proxy for solar generation schedules is the hour of day average generation by month. All of the solar generation data was separated into bins by hour of day and month and then averaged, resulting in a value to be used for the schedule for that hour of the day in that month. For example, all of the one-minute data for the hour ending 12 (11:00 AM to 11:59 AM) for all four of the Julys in the data set were averaged, and that average was used as the schedule for every hour ending 12 in all four Julys in the data set. *Id.*

Section 4.6: Load Assumptions

Q. Please summarize how you derived the actual balancing authority area load and balancing authority area load forecasts in your analysis.

A. Similar to the generation data, we used a 48-month data set (October 1, 2007, to September 30, 2011) with one-minute average actual load data as a starting point. With that data set, we forecast the load through the rate period using load growth projections. We used hourly archived data for the load forecasts and adjusted that data using load growth factors for the forecasts for future years. *Id.* section 2.5.

Q. Has your method of deriving balancing authority area load and load forecasts changed from that used for the FY 2012–2013 rate period? If so, how has it changed?

A. We are using the same method of analysis for hydro for the BP-14 rate case as we used for the BP-12 case.

Q. Why is it necessary to take load estimates and forecasts into account in forecasting BPA's balancing reserve capacity requirements?

A. Load variations affect the within-hour balance similarly to the impact of variation in generation. To accurately calculate the amount of balancing reserve capacity needed, the methodology needs to account for all factors that contribute to the balancing reserve capacity requirements forecast for the same time period as the generation in the Study.

Section 5: Forecasting the Total Balancing Reserve Capacity Requirement

Q. Please summarize your methods for forecasting the incs *and* decs *associated with each reserve component.*

A. With the generation and load data described previously, we created load net generation actual and load net generation schedule data sets for the forecast. The load net generation actual data set is the total actual load minus the total wind generation minus the total

actual thermal generation minus the total actual hydro generation. The load net generation schedule data set is the total load forecast minus the total wind schedule minus the total thermal schedule minus the total hydro schedule ramped in over 20 minutes. We calculate the load net generation numbers for every one-minute clock period in the Study. *Id.* section 2.7.1.

We used the load net generation numbers to create the ten-minute averages, one-hour averages, and total schedules that are used to forecast the overall balancing reserve capacity requirements for the BPA balancing authority area. To calculate the total balancing reserve capacity components (regulation, following, and imbalance), we determined the difference between the one-minute average of load net generation actual and the ramped-in load net generation schedule for each minute of the 48-month study period. *Id.*

To calculate the regulating reserve component, we determined the difference between the one-minute average of load net generation actual and the ten-minute average of the load net generation actual for each minute of the study period. *Id.* To calculate the following reserve component, we determined the difference between the ten-minute average of load net generation actual and the ramped-in one-hour average of the load net generation actual for each minute of the study period. *Id.* To calculate the imbalance component, we determined the difference between the ramped-in one-hour average of the load net generation actual and the ramped-in load net generation schedule for each minute of the study period. *Id.*

We calculated those values for each hour of the study period, resulting in 24 data sets representing each hour of the day throughout the study period for each balancing reserve capacity component. For example, all data that we downloaded or created for regulating reserve for hour 1:00 to 2:00 for each day of the study period are combined

into one regulating reserve data set for hour 1:00 to 2:00. To develop our base forecast, we removed the highest 0.25 percent of the numbers from the *inc* side and the lowest (largest negative) 0.25 percent of the numbers from the *dec* side from the data set for each hour of the day. *Id.* section 2.7.2.

The resulting numbers contain 99.5 percent of values for each of the regulation, load following, and imbalance forecasts by hour of day for the FY 2014–2015 rate period. We used the maximum of the remaining numbers in each data set as the total *inc* and *dec* needed for each respective hour of the day and balancing reserve capacity component. The maximum of the 24 hours of the day is taken as the requirement for each balancing reserve capacity component. This entire process is repeated for the increasing levels of forecast installed wind to determine the balancing reserve capacity requirement for each month throughout the rate period. *Id.* section 2.7.3.

Q. Has your method of forecasting the inc*s and* dec*s associated with each reserve component changed from that used for the FY 2012–2013 rate period? If so, how has it changed?*

A. Our method of forecasting *inc*s and *dec*s has not changed from FY 2012–2013.

Q. Why do you discard a percentage of the highest numbers from the inc *side and the lowest numbers from the* dec *side?*

A. BPA has historically used 99.7 percent (three standard deviations) of the values resulting from the studies when calculating the amount of reserve needed for within-hour balancing reserve. This methodology was modified for the FY 2010-2011 rate period to 99.5 percent—in conjunction with the development of DSO 216—as a way to provide reliable service without the expense of providing balancing reserve capacity for every possible situation. Removing the additional 0.2 percent of variation slightly decreases the overall balancing reserve capacity requirement but, with existing reliability and

operational protocols BPA has in place, this 0.2 percent variation has not created reliability issues or risk of violating the NERC or WECC standards or criteria.

Q. Why do you use the maximum values out of the hour-of-day data as the basis for the total balancing reserve capacity requirements?

A. BPA must set aside enough resources to meet almost all of the extreme contingencies on its system; so, for purposes of forecasting the amount of balancing reserve capacity required, it is reasonable to use the maximum hour out of the day after removing the most extreme events. In addition, this method more accurately distributes the total balancing reserve capacity requirement among the different components. While wind in the BPA balancing authority area is relatively independent of daily patterns, load, thermal generation, and hydro generation can be highly correlated to time-of-day patterns, which are more accurately captured using the maximum values out of the hour of day data.

Section 6: Allocation of the Total Balancing Reserve Capacity Requirement

Q. Please describe your method of allocating the total balancing reserve capacity requirement between generation resources and load.

A. Using the maximum numbers out of the 99.5 percent of the total *inc* and *dec* values described above, we determined the contribution of wind, solar, thermal, hydro, and load to the regulating reserve, following reserve, and imbalance reserve components for each hour of day using incremental standard deviation (ISD). Study section 2.7.3. The ISD measures how much the load and generation types contribute to the total load net generation reserve requirement, based on the sensitivity of the total balancing reserve capacity to variation in the individual components. *Id.*

We used the observed maximum allocation of reserve by component to calculate the relative contribution of each component to the total load net generation requirement.

Finding each component's maximum allocated contribution to the reserve need regardless of the hour of day is done because the total load net generation requirement did not necessarily occur during the same hour of day as the maximum generation or load component. In order to ensure that we take into account the full variation, and therefore balancing reserve capacity requirements caused by load and the generation types, we used the maximum number from load, thermal, hydro, solar, and wind components irrespective of the hour of day in which those occurred. *Id.*

For each component, its percent allocation is calculated as the individual component's requirement divided by the total requirement. For example, the wind percentage is calculated as the wind requirement divided by the load requirement plus wind requirement plus solar requirement plus thermal requirement plus hydro requirement. *Id.*

Q. Has your method of allocating the total balancing reserve capacity requirement between generation resources and load changed from that used for the FY 2012–2013 rate period? If so, how has it changed?

A. Our method of allocating the total requirement between generation and load has not changed.

Q. Please explain your basis for using the maximum wind, solar, thermal, hydro, and load components that you mention above.

A. We used the maximum components to depict most accurately the use of balancing reserve capacity in the BPA balancing authority area by the respective component (wind, solar, thermal, hydro, or load). *Id.* Because the maximum usage by wind, solar, thermal, hydro, and load does not occur on the same hour of the day, we propose to fairly distribute the total balancing reserve capacity requirement by using the maximum

requirement for each when calculating the percentage of the total requirement assigned to each.

Q. Why do you propose to use ISD to allocate the total reserve requirement to wind, solar, thermal, hydro, and load as opposed to other allocation methods?

A. ISD allocates the balancing reserve capacity need based on how each component contributes to the total balancing reserve capacity need. This approach takes into account any diversity benefits that may exist between the regulation signals for load, wind, solar, thermal, and hydro; the following signals for load, wind, solar, thermal, and hydro; and the imbalance signals for load, wind, solar, thermal, and hydro. *Id.* The result is an allocation of the 99.75 percent and 0.25 percent load net generation balancing reserve capacity requirements, where the individual load, thermal, hydro, solar, and wind reserve requirements linearly sum to the load net generation balancing reserve capacity requirement. *Id.*

Because the BPA balancing authority area is effectively a portfolio of megawatts, we use a calculation rooted in financial portfolio analysis. The result is a method identifying the relative drivers behind the BPA balancing authority area's need for balancing reserve capacity and a reasonable methodology for assigning balancing reserve capacity to the various uses of the system for the purposes of allocating costs and establishing different rates for different types of service.

The expansion of ISD for the Initial Proposal allows us to allocate the reserve requirements among more components than the previous calculation used in the FY 2010–2011 rate case, which allocated reserve requirements between wind and load. This facilitates accounting for multiple sources identified as contributing to the balancing reserve capacity requirement. *Id.*

Section 7: Potential Impacts of Customer-Supplied Generation Imbalance and Intra-Hour Scheduling on the Generation Reserve Forecast

Q. What impact does CSGI have on balancing reserve capacity requirements during the rate period?

A. CSGI reduces the balancing reserve capacity requirements for the FY 2014–2015 rate period. We developed a forecast of the impact of CSGI that may result from customers supplying their own imbalance reserves. The results for 99.5 percent balancing reserve capacity levels with the CSGI assumptions are presented in Documentation Tables 2.17 through 2.24. The results for the 99.5 percent balancing reserve capacity levels without any CSGI assumptions are presented in Documentation Tables 2.10 through 2.16.

Q. What did you assume about the amount of installed wind capacity that will be partially balanced as a result of CSGI for purposes of your estimate?

A. We assumed that customers would self-supply imbalance reserves for approximately 1,438 MW of installed wind capacity as of October 2013 and that this amount would increase to approximately 1,538 MW by the end of the rate period. Documentation Table 2.17.

Q. What information did you rely on to make that assumption?

A. Our assumption is based on the most recent information about the CSGI pilot program and the extent of participation at this point. The current business practices related to CSGI establish processes and requirements for customers that want to participate in the CSGI pilot program. The process starts with a customer applying to participate in the CSGI pilot program and fulfilling the requirements of the CSGI business practice. Our assumption about CSGI reflects the most up-to-date information available, which is based on current CSGI participation data including the amount of installed wind capacity for

existing CSGI pilot program participants that have satisfied the requirements of BPA's CSGI-related business practices.

Q. What impact would committed 30/30 or committed 30/15 scheduling have on the balancing reserve capacity requirement?

A. Committed 30/30 or committed 30/15 scheduling reduces the balancing reserve capacity requirements for the FY 2014–2015 rate period. We developed a forecast of the impact of committed scheduling that may result from all wind generation scheduling on a 30-minute basis at 30-minute persistence forecasting accuracy and on a 15-minute basis at 30-minute persistence forecasting accuracy. The savings that would result from all wind generation in the BPA balancing authority area scheduling with 30-minute persistence on a 30-minute basis are presented in Documentation Tables 2.25 and 2.26. The savings that would result from all wind generation in the BPA balancing authority area scheduling with 30-minute persistence on a 15-minute basis are presented in Documentation Tables 2.27 and 2.28.

Q. Do you intend to update the estimates based on CSGI election estimates for the Final Proposal?

A. Yes. We intend to update the estimate based on the most up-to-date information available prior to the Final Proposal.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

STEVEN R. KERNS, KATHERINE L. BEALE,

JUERGEN M. BERMEJO, and KIERAN P. CONNOLLY

Witnesses for Bonneville Power Administration

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Witnesses for Bonneville Power Administration

SUBJECT: PROVISION OF BALANCING RESERVE CAPACITY FROM THE FEDERAL COLUMBIA RIVER POWER SYSTEM

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Steven R. Kerns, and my qualifications are contained in BP-14-Q-BPA-34.

A. My name is Katherine L. Beale, and my qualifications are contained in BP-14-Q-BPA-03

A. My name is Juergen M. Bermejo, and my qualifications are contained in BP-14-Q-BPA-05.

A. My name is Kieran P. Connolly, and my qualifications are contained in BP-14-Q-BPA-13.

Q: What is the purpose of your testimony?

A. The purpose of our testimony is to describe the amount of *inc* and *dec* balancing reserve capacity that BPA proposes to provide from the Federal Columbia River Power System (FCRPS) for the provision of balancing reserve capacity for the FY 2014–2015 rate period. As more fully explained in Puyleart *et al.*, BP-14-E-BPA-22, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) have established reliability standards that require BPA to maintain a sufficient amount of balancing reserve capacity to ensure a reliable balancing authority area. In order to meet these reliability standards, BPA must set aside or acquire an amount of capacity necessary to support the balancing reserve capacity needs of BPA's various transmission users. The amount, or quantity, of balancing reserve capacity that is needed

for system reliability for all users is described in Puyleart *et al.*, BP-14-E-BPA-22, and the accompanying studies. In this testimony, we explain how much of this total need for balancing reserve capacity can be supplied from the FCRPS.

Section 2: Overview

Q. Why are you assessing how much balancing reserve capacity can be supplied from the FCRPS in this rate proceeding?

A. We are assessing how much balancing reserve capacity can be supplied from the FCRPS because such an assessment is needed for both ratemaking and operational planning purposes. For ratemaking purposes, such an assessment informs other components of the Initial Proposal, such as the cost allocation of embedded and variable costs to the various uses of balancing reserve capacity. *See* Power Rates Study, BP-14-E-BPA-01, section 4.3. For planning purposes, our assessment informs whether and to what extent BPA must attempt to acquire *inc* and *dec* balancing reserve capacity from sources other than the FCRPS to meet balancing authority area reliability needs.

Q. Please explain what you mean by inc *and* dec *balancing reserve capacity.*

A: *Inc* is short for incremental and refers to the ability to increase generation as needed. *Dec* is short for decremental and refers to the ability to reduce generation as needed. Balancing reserve capacity is used to respond to changes in generation and load in response to a signal from the balancing authority area, within scheduling periods. In general, BPA supplies both *inc* and *dec* balancing reserve capacity from flexible capacity of the FCRPS.

Q. Please briefly describe what you mean by flexible capacity.

A. Flexible capacity describes an estimate of the flexibility that may be available from the FCRPS to respond to within scheduling period differences between actual generation and

load and scheduled generation and load, assuming limited energy content, and assuming that BPA manages its surplus power marketing to shape less water from light load hours to heavy load hours to ensure that the planned amount of such flexibility is available.

Q. What do you mean by "flexibility" of the FCRPS?

A. By "flexibility" we mean the amount of operational changes the hydro projects that comprise the FCRPS can accommodate without risking operational objectives. While "flexibility" can refer to changes in any of the parameters associated with a hydroelectric project (*e.g.*, forebay, tailwater, discharge, generation), this testimony will limit the use of the term "flexibility" to refer to changes in generation that the FCRPS can accommodate.

Q. Why are you measuring FCRPS flexibility to determine how much flexible capacity the FCRPS can provide for balancing reserve capacity?

A. After other obligations and needs are accounted for, the remaining ability of the FCRPS to increase or decrease generation within a scheduling period defines the available amount of balancing reserve capacity.

Q. In general, how do you assess the amount of FCRPS flexibility that will be set aside as capacity for balancing reserve capacity?

A. We assessed how much flexible capacity to provide from the FCRPS for balancing reserve capacity by considering the many constraints and limitations that may affect FCRPS hydro operations during different times of the year. Those constraints and limitations arise from Endangered Species Act (ESA) fish requirements, reliability concerns, flood control issues, and other operational objectives.

In addition, BPA is obligated by contract to commit a significant portion of its power production capacity and operational flexibility for long-term energy sales to preference power customers. After BPA ensures that its long-term firm power sales obligations are met, the remaining power production capacity and operational flexibility

on the system must be allocated between two types of uses. These two types of uses are surplus power marketing and provision of operating and balancing reserve capacity. Surplus sales move water with relative certainty, allowing BPA to ensure that high priority FCRPS operational objectives are met. Providing reserve capacity moves water in uncertain ways, using flexibility that may remain after other water management constraints and firm load obligations are met. BPA cannot allocate all available flexibility to provision of balancing reserve capacity because of the uncertainty about whether the balancing reserve capacity will be deployed and because of the uncertainty associated with moving water through the system.

We also considered the actual operations of the FCRPS. That is, we looked at past specific events that led to changes in the amount of balancing reserve capacity the FCRPS was able to carry.

All of these factors and limitations, as well as real-time operations, taken together, helped inform our assessment of the amount of balancing reserve capacity available from the FCRPS.

Section 3: Physical and Operational Characteristics of the FCRPS

Q. Why are you describing the physical and operational characteristics of the FCRPS?

A. The amount of flexible capacity the FCRPS may have during the rate period depends in large part on the operational objectives placed upon the operations of the dams and the uncertainties resulting from the physical characteristics of the FCRPS.

Q. Please describe the physical characteristics of the FCRPS.

A. The FCRPS is a complex system of 31 interconnected dams on the Columbia, Snake, and Willamette rivers. The dams were authorized for many purposes besides the production of power; in fact, power production in many instances is an incidental purpose of the

FCRPS when faced with certain operational conditions. The primary purposes of the FCRPS include navigation, recreation, fish mitigation, irrigation, and flood control. The Army Corps of Engineers (COE) and the Bureau of Reclamation (Reclamation), which own and operate the dams, direct BPA in their operation to ensure that the flow of water through the dams is managed to achieve their various purposes.

The need to use water for multiple purposes means that the Federal agencies cannot simply operate the dams to provide capacity whenever needed. For example, the large upriver dams are storage dams, meaning they have reservoirs behind them that can store water for later use. Every winter, however, BPA must lower the reservoir behind Grand Coulee Dam (its largest power producer) to leave room for the spring runoff that refills it. Water in the reservoirs must be held at levels low enough to ensure that the runoff does not cause overfilling and flooding, but high enough to ensure there is enough water to meet irrigation, navigation, and fish mitigation requirements. Similarly, the amount of water released to the lower river projects must be enough to ensure sufficient flows for fish migration and barge passage, but not so much as to flood downstream communities.

Q. How is capacity produced on the FCRPS?

A. Capacity is the instantaneous potential of a generator to produce power. The FCRPS has about 22,000 MWs of installed capacity, but only enough fuel (water) under dry conditions to produce about 6,000 aMW of energy annually. This means that the FCRPS is an energy-limited system, and the operators of the FCRPS must constantly make choices of how to allocate and use that limited amount of water to produce power to meet firm power obligations. In addition to being energy-limited, the FCRPS is storage limited and can only store about 30 percent to 40 percent of its annual average run-off. This means that the timing of when the limited amounts of fuel are available is often

dictated by precipitation patterns. Finally, the availability of water to produce power is frequently dictated by other non-power requirements of the multi-purpose FCRPS such as flood risk management, fisheries mitigation, recreation, navigation and irrigation operations. Taken all together, these factors mean that the ability for BPA to make determinations of when there is fuel available to place behind turbines to create the flexible ability to produce capacity on any hour, is extremely limited by other factors.

Q. *Flexible capacity is largely produced by the "Big 10" dams. If that is true, why are you considering the operational characteristics of the entire FCRPS?*

A. The FCRPS is a large, interconnected system. The 21 dams that are not part of the "Big 10" either produce small amounts of generation or are non-dispatchable, meaning that their generation schedules are set a day in advance and that changes to their generation schedule during the day require manual intervention, and, in some cases, declaration of a system emergency. Some of these dams, such as Libby, Hungry Horse, Albeni Falls, and Dworshak, are storage reservoirs that can affect the operational flexibility available at the downstream "Big 10" projects.

Q. *How do the operational objectives of the FCRPS inform your assessment of the amount of flexible capacity the FCRPS will have available during the rate period?*

A. Because the FCRPS is used for multiple purposes, we have to take into account how certain high-priority operational objectives may affect the amount of flexibility the FCRPS will have at any given time. These higher-priority operational objectives include safety, reliability, flood control, navigation, and operations for fish listed under the Endangered Species Act.

Q. *Please describe what you mean by the operational objective of "safety."*

A. In general, rapid changes in operations can create waves or turbulence in the water that can create safety issues. A specific example is when there are divers in the water at

various times for equipment maintenance; other examples include rescue operations and minimizing turbulence or wave impacts in reservoirs for recreational boating. Flood control also relates to public health and safety.

Q. Please describe what you mean by the operational objective of "reliability."

A. In simplest terms, reliability means dependable service to load to avoid load shedding and blackouts. A myriad of factors interact to ensure system reliability. In an electrical system, generation must equal loads at all times and voltage stability must be maintained, or the system risks blackouts. Most interconnected generators in an electrical system are required to contribute to system stability by providing voltage control and by responding to automatic or manual signals from dispatchers. Operating reserve capacity contributes to reliability by providing a planned amount of capacity to respond to unexpected events in the system.

Q. Please describe what you mean by the operational objective of "flood control."

A. The COE and Reclamation establish specific operational targets at certain times of year to ensure that there is sufficient storage space in reservoirs to use to prevent flooding during spring runoff. As the winter snows melt, river operations are carefully coordinated to avoid causing floods.

Q. Please describe what you mean by the operational objective of "navigation."

A. The Columbia River is a major transportation corridor of high economic value. Barge movement through the river is facilitated by operation of locks which affect the movement of water downstream. Operational constraints are placed on the FCRPS to ensure proper channel depth or current conditions are maintained to allow upstream and downstream barge movement.

Q. Please describe what you mean by the operational objective of "operations for fish listed under the ESA."

A. In considering the ecological objectives of the ESA and the Clean Water Act (CWA), operations are planned to comply with the ESA Biological Opinions ("BiOps") and applicable state and tribal water quality standards, to the extent practicable. Spring and summer spill and water quality constraints have also been adopted by court order. There are a number of operational requirements associated with endangered fish species as required by court order from the US District Court:

- Spill during juvenile migration season to aid in fish passage, which diverts fish from passing through turbines to passing through spillways or other passage routes.
- Limit on the total dissolved gas in the river water; dissolved gas causes nitrogen to form bubbles in the fishes' bloodstream and can cause the fish to die of gas bubble disease, which is like "the bends" that affects divers.
- Reservoir elevation targets designed to store water in the winter to augment flows in the spring and summer with the goal of providing adequate volume and velocity to assist juvenile migration downstream.
- Reservoir draft timed to provide water temperature control during hot weather.
- Limits on generating unit operations, which narrow the operating range in order to improve survival for fish that pass through the turbines.
- Restricted forebay ranges to provide steady velocity conditions.

Q. How do these high-priority operational objectives affect the amount of flexibility you project the FCRPS will have to provide flexible capacity?

A. In general, operational requirements limit the flexibility of the FCRPS. In some cases, generally in very high and very low flow conditions, it is not possible to meet all of the high-priority objectives simultaneously. BPA coordinates with the COE and

Reclamation to operate the FCRPS to meet as many of the high-priority operational objectives as possible. Any remaining operational flexibility that exists after meeting these high-priority objectives can be used for other purposes, such as providing balancing reserve capacity.

Q: What uncertainties can affect the operational flexibility of the FCRPS?

A. Although there are a variety of events that can cause the FCRPS to lose operational flexibility, we identify here four uncertainties that commonly restrict flexibility. First, there is uncertainty in streamflow. The drainage basin of the Columbia River system is massive and encompasses an area slightly larger than France. The result of unpredictable weather patterns that build snowpack across the basin is a large amount of uncertainty in runoff volume and location. As the snow pack melts, it is not uncommon to see localized impacts and spikes in the runoff as weather systems pass through the basin. During high-flow conditions, operational flexibility is very limited.

Q. What is the second uncertainty?

A. There is uncertainty in flood control objectives and operations for fish listed under the Endangered Species Act, especially during the spring. Coordinating these operations of the FCRPS with the COE and Reclamation is a day-to-day activity in the spring that can result in quick changes to operational objectives that may result in the FCRPS having very limited operational flexibility.

Q. And the third uncertainty?

A. Non-Federal projects interconnected to the FCRPS can change operations unexpectedly. While BPA plans for and coordinates with non-Federal hydro operations (with BC Hydro and the mid-Columbia projects being particularly important to the FCRPS), there can be unexpected flow from non-Federal projects. Like the FCRPS, non-Federal projects have their own operational objectives and load obligations to meet. Unexpected flows from

these projects can lead to higher or lower flows than necessary to maximize FCRPS flexibility and result in a loss of the operational flexibility necessary for balancing reserve capacity.

Q. What is the fourth uncertainty that commonly restricts flexibility?

A. There is uncertainty in the amount of real-time load that the FCRPS may be called upon to serve to ensure reliable load service. Loads are generally a function of temperature. Deviations in actual temperatures from forecast temperatures can result in actual loads being very different from the planned load. BPA also has contractual obligations that grant preference power customers the ability to change their schedules 30 minutes prior to the hour of delivery. To address all of these variables, BPA's hydro schedulers and short-term planners cover hour-to-hour load uncertainty and schedule change rights by creating an "operational buffer" that "stands ready" to provide power production capacity in the event conditions change. The more that BPA experiences these uncertainties during the rate period, the larger the buffer BPA hydro-schedulers generally hold out to maintain system reliability and to meet FCRPS operational objectives, and the less flexibility BPA has to provide other services, such as balancing reserve capacity.

Section 4: Assessing the Amount of Flexible Capacity Available from the FCRPS

Q. In light of the limitations and complexities you have noted, how do you determine the amount of flexible capacity available from the FCRPS during the FY 2014–2015 rate period?

A. Our assessment of the amount of reserve capacity the FCRPS can reasonably and reliably provide is based on our experience with and observations of the FCRPS's historical capability under the limitations and operational objectives described above. We also

considered as part of our assessment the operational ability of the FCRPS to provide balancing reserve capacity under various flow conditions.

Q. What do you mean by "experience with and observations of the FCRPS's historical capability under the limitations and operational objectives described above"?

A. We identified specific times in the past when BPA has experienced problems maintaining flexible capacity at planned levels, and we considered how those events, if they were to reoccur during the rate period, or under different flow conditions, would affect the ability of the FCRPS to provide balancing reserve capacity.

Q. What do you mean by "flow conditions"?

A. The term "flow condition" is used to qualitatively describe the volume and rate of water flow on the Columbia and Snake rivers. A high flow condition describes some period where the rate of flow is above average. Conversely, a low flow condition generally describes some period where the rate of flow is below average.

Q. Why did you consider flow conditions as part of your assessment?

A. Flow condition directly combines with both machine and operational constraints to either limit or free up FCRPS flexibility.

Q. Please describe the flow conditions you considered.

A. We looked at a high-flow scenario that considered the joint conditions of meeting non-power objectives while carrying and deploying balancing reserve capacity.

Q: Was operational flexibility limited in the high flow conditions you considered?

A. Yes.

Q. Why is there limited operational flexibility in high flow conditions?

A. First, the FCRPS is a storage-limited system, which means that the ability to store water from a high water year into a future year is very limited. Federal storage is about 30 million acre-feet (Maf), which is a fraction of the annual runoff. Other river systems

in the United States, such as the Colorado and Missouri river systems, can store two to three times the annual runoff. In addition, operations for fish listed under the ESA require the FCRPS reservoirs to refill annually.

Second, as discussed above, excess spill can be harmful to fish listed under the ESA by increasing the concentration of nitrogen gas in the river. High Total Dissolved Gas (TDG) levels can result in gas bubble trauma in fish. The states of Oregon and Washington have enacted even more stringent specifications. Operations for fish listed under the ESA require that all practicable steps be taken to reduce the amount of spill when these TDG limits are being exceeded. Therefore, attempts are made to minimize TDG on a system-wide basis at and beyond the spill and water quality constraints to minimize saturation throughout the system. Reducing the amount of balancing reserve capacity frees up generating capacity that can be used to pass additional water through turbines rather than spilling.

This is why, in high flow conditions, there is limited ability to make operational changes at FCRPS hydro projects without risking operational objectives.

Q. Has the FCRPS experienced high flow conditions in the recent past?

A. Yes. We have experienced these conditions in actual operations in the springs of 2011 and 2012, which were both above-average water years.

Q. How did these flow conditions operationally affect the ability of the FCRPS to provide balancing reserve capacity?

A. In 2011, balancing reserve capacity was periodically limited between May 10th and July 13th. In 2012, balancing reserve capacity was periodically limited between April 8th and July 31st. In June 2010, which was a below-average water year that had a delayed runoff, BPA also experienced a period of high flow conditions during the runoff. In 2010, balancing reserve capacity was periodically limited from June 5th to June 12th.

In each of these events, balancing reserve capacity carried by the FCRPS was reduced to a minimal level necessary to maintain reliability for load service.

Q. Have there been other times in the past three years when there has been a need to limit balancing reserve capacity due to limited flexibility on the FCRPS?

A. Yes. On May 19 and 20, 2010, *inc* balancing reserve capacity was reduced due to transmission congestion. On April 24, 2012, BPA observed *inc* balancing reserve capacity was limited due to a transmission emergency that occurred at the same time a barge broke free on the Columbia River. On April 25, 2012, BPA reduced *inc* balancing reserve capacity due to the combination of above-average uncertainty on contracts with hourly change rights combined with higher than expected loads and the need to maintain Operating Reserve.

Q. Given the complexity of operating the FCRPS to meet high-priority objectives while dealing with a significant amount of uncertainty, what minimum amount of balancing reserve capacity do you project can be sourced from the FCRPS during the rate period?

A. The FCRPS must be planned to meet the high-priority operational objectives discussed above. In light of these limitations, the minimum amount of balancing reserve capacity we project would be physically available on a planning basis from the FCRPS 365 days of the year is 400 MW of *inc* balancing reserve capacity and 300 MW of *dec* balancing reserve capacity. These amounts of balancing reserve capacity are the current estimate of the amount necessary to ensure load service is not interrupted and voltage stability is maintained. Variable energy resources can use this flexibility if such use does not interfere with reliability for load service. This amount of balancing reserve capacity also reflects the minimum amount of balancing reserve capacity we have seen held out by the FCRPS in situations where operational flexibility has been reduced because of weather, fish, or other operational constraints.

Q. Does the 400/300 MW limit represent the minimum amount BPA expects to provide from the FCRPS on a forecast basis or on a real-time basis?

A. The 400/300 MW limit is the minimum amount BPA can provide on a forecast basis to maintain system reliability for load. At times, unpredictable events may cause less balancing reserve capacity to be available from the FCRPS. At times, more flexibility may be available, but BPA sells its system capability in various product forms, over various time horizons, to various customers in various markets. In order to provide a larger amount of flexibility from the FCRPS for balancing service, BPA must determine the amount to set aside well in advance.

Q. What amount of flexible capacity from the FCRPS are you proposing to provide for the FY 2014–2015 rate period?

A. Our answer above (400/300 MW) reflects our assessment of the amount of flexible capacity that could be sourced from the FCRPS at all times during the rate period. However, we recognize that most of the time operational conditions do not limit balancing reserve capacity to these minimal levels. Providing balancing reserve capacity beyond the minimal levels depends in large part on how much additional operational and forced marketing risk BPA wishes to take. Based on our assessment of the expected operational flexibility of the FCRPS, our assessment of BPA's other committed or planned uses of the FCRPS, and assuming BPA retains certain risk mitigation features, we estimate that BPA can offer up to 900 MW in *inc* balancing reserve capacity and up to 1100 MW in *dec* balancing reserve capacity from the FCRPS, most of the time during the rate period.

Q. Please explain why the inc *limit is lower than the* dec *limit.*

A. In addition to providing balancing reserve capacity, BPA must also supply Operating Reserve. Operating Reserve is an additional *inc* obligation meant to cover contingencies

such as power plant equipment and transmission equipment failures. Operating Reserve must be held above and beyond balancing reserve capacity so BPA can supply these reserves even if fully deploying *inc* balancing reserve capacity for balancing purposes. In terms of priority, Operating Reserve takes precedence over balancing reserve capacity.

Q. In concluding that BPA could offer 900 MW in inc *balancing reserve capacity and 1100 MW in* dec *balancing reserve capacity, what "risk mitigation features" do you assume would be in place during the FY 2014–2015 rate period?*

A. The ability of the FCRPS to provide these amounts of balancing reserve capacity is dependent on maintaining certain risk mitigation tools that allow BPA to limit balancing reserve capacity to levels necessary for reliable load service when there is insufficient operational flexibility to meet high-priority operational objectives. This includes DSO 216 and other tools that ensure the FCRPS is not deployed beyond the amounts BPA has agreed to commit. Assuming these tools are in place, offering more flexible capacity than the long-term planning limit can be accommodated most of the time during the rate period.

Q. If the risk mitigation tools you identified were not available, would your assessment change?

A. Yes. If BPA is unable to ensure, through DSO 216 and other operational risk mitigation tools, that the amount of balancing reserve capacity deployed is consistent with the amount we have made available and accounted for in operational planning, then we would offer the amount available to ensure reliability of load service, and we would reassess whether any amount beyond the base level of 400/300 MW in balancing reserve capacity could be made available.

Q. Why are you proposing to provide 900 MW of inc *and 1100 MW of* dec *balancing reserve capacity?*

A. Provision of additional balancing reserve capacity supports the integration of variable energy resources, which is an important agency policy. Moreover, operationally, BPA has been able to manage the risk of carrying an amount of balancing reserve capacity larger than what was needed for reliability for load service in the past. For example, in October 2012, BPA is offering 773 MW of *inc* balancing reserve capacity and 991 MW of *dec* balancing reserve capacity. After assessing past experience with providing significant amounts of balancing reserve capacity and the operational constraints and flexibility of the FCRPS, as well as BPA's existing obligations for energy sales, we project BPA can offer for this rate period 900 MW of *inc* balancing reserve capacity and 1100 MW of *dec* balancing reserve capacity, which is more than the minimum amount necessary for load service reliability, and more than the limited amount that is feasible to offer continuously with 100 percent certainty.

Q. How was the 900 MW inc *and 1100 MW* dec *limit determined?*

A. As noted above, there are many operational objectives that BPA, the COE, and Reclamation must meet when operating the system. In assessing the amount of balancing reserve capacity to source from the FCRPS beyond what is necessary to maintain reliability for load, we consider BPA's historical performance in carrying large amounts of balancing reserve capacity, and we consider how well BPA's risk limitation tools are working.

Q. Please give examples.

A. During calendar year 2010, BPA provided an average allocation of 800 MW *inc* and 990 MW *dec* and was able to make the balancing reserve capacity required available over 99 percent of the time. During 2011, the average allocation was 759 MW *inc* and

933 MW *dec*, and BPA was able to make the *inc* balancing reserve capacity available about 92 percent of the time and the *dec* balancing reserve capacity available about 88 percent of the time. In 2012, BPA has provided less balancing reserve capacity and has also encountered more instances of needing to limit balancing reserve capacity. During this entire time, BPA was able to effectively limit balancing reserve capacity to lower levels when necessary. We have also established policies and procedures to encourage wind generators to improve their scheduling accuracy.

Q. What have you concluded from these examples?

A. Qualitatively, we considered BPA's history with carrying balancing reserve capacity, BPA's ability to manage risk of overdeployment, and the ongoing improvement in scheduling accuracy, and concluded that BPA could offer most of the time for this rate period somewhat higher levels of balancing reserve capacity than it provided in the past. BPA's ability to offer the higher levels is contingent on having the ability to limit below these levels when operational constraints make that necessary.

Q. In your answers above, you state in several places that your assessment is that BPA could provide 900 MW of inc *and 1100 MW of* dec *in balancing reserve capacity "most of the time." What do you mean by "most of the time"?*

A. Provided BPA has the ability to occasionally limit the amount of balancing reserve capacity to the 400/300 MW minimum we noted above when operational constraints affect the ability of the FCRPS to source balancing reserve capacity, we believe BPA can provide additional amounts of balancing reserve capacity at a high probability for the remaining hours of the year. While we cannot predict exactly how conditions may play out in any particular year, our general assessment, which accounts for both time and quantity of availability, is that BPA can make up to 900 MW *inc* and 1100 MW *dec*

balancing reserve capacity available approximately 98 percent of the time on an annual average basis.

Q. Please explain how you determined the 98 percent.

A. As mentioned above, at times during the last three years BPA had to reduce the balancing reserves. The limit amount can vary greatly depending on the hydro conditions and operational objectives at the time. During the last three years, the annual average percent of reserves supplied by the FCRPS ranged between 90-99 percent of the rate case amounts. Since two of the three previous years were above average water years, and because we are assuming average water for this rate period, we recommend assuming 98 percent of the rate case planned amounts can be supplied from the FCRPS on an annual average basis. Because this is a rough approximation based on limited data and experience, we expect to refine the expectation for future rate periods. The actual limit amount and duration in any year will vary.

Q. Will the 900/1100 MW amount be revisited in future rate cases?

A. Yes. In future rate cases, we expect that BPA will revise its assessment of the amount of balancing reserve capacity available from the FCRPS based on the operational and policy objectives relevant at that time.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

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Witnesses for Bonneville Power Administration

SUBJECT: BALANCING RESERVE CAPACITY COST ALLOCATION METHODOLOGY

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SUBJECT: BALANCING RESERVE CAPACITY COST ALLOCATION METHODOLOGY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Janet Ross Klippstein, and my qualifications are contained in BP-14-Q-BPA-37.

A. My name is Juergen M. Bermejo, and my qualifications are contained in BP-14-Q-BPA-05.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is Mark A. Jackson, and my qualifications are contained in BP-14-Q-BPA-28.

A. My name is Eric V. King, and my qualifications are contained in BP-14-Q-BPA-35.

A. My name is Paul T. Koski, and my qualifications are contained in BP-14-Q-BPA-38.

A. My name is Timothy C. Misley, and my qualifications are contained in BP-14-Q-BPA-49.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor section 3 of the Generation Inputs Study, BP-14-E-BPA-05 (Study) and Generation Inputs Study Documentation, BP-14-E-BPA-05A (Documentation), to explain the cost allocation methodology for Regulating Reserve, Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Variable Energy Resource Balancing Service (VERBS) Reserve.

Section 2: Overview

Q. What is the overarching principle of BPA's cost allocation methodology for generation inputs?

A. BPA's cost allocation methodology is based on the principle of cost causation. Those entities that are causing the costs should bear the responsibility for paying those costs. This principle avoids cost shifts between customer classes.

Q. Please explain how costs that are allocated to the various generation inputs are recovered and how these costs affect power rates.

A. Costs allocated to generation inputs are assigned to Transmission Services (TS) and recovered through transmission rates. The revenue received from providing generation inputs is a revenue credit to BPA power rates and thus reduces power rates by lowering the revenue requirement.

Q. Why are balancing reserve capacity costs assigned to TS?

A. TS uses balancing reserve capacity to provide Ancillary and Control Area Services to transmission customers. These services are required pursuant to reliability standards issued by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). When Power Services (PS) supplies balancing reserve capacity to TS, PS no longer has such capacity available for other purposes.

Q. To which transmission rates are these costs assigned?

A. The costs for balancing reserve capacity are allocated to the proposed ACS-14 Regulation and Frequency Response, VERBS, and DERBS rates (balancing services). *See* Jackson *et al.*, BP-14-E-BPA-28. The other generation inputs that PS provides to TS for recovery in transmission rates are discussed in other testimonies. Messinger *et al.*, BP-14-E-BPA-25; Wellschlager *et al.*, BP-14-E-BPA-26; Salazar *et al.*, BP-12-E-BPA-27. The

variable cost portion of the cost allocation methodology addressed in this testimony also pertains to the spinning portion of Operating Reserve.

Q. What are the methods for allocating costs described in your testimony?

A. The three methods for allocating costs described in this testimony are embedded cost, direct assignment, and variable cost. Each method is explained in detail in section 3 of the Study and summarized below in this testimony.

Q. How are you proposing to allocate costs to the balancing services?

A. We are using a similar methodology to the methodology used in BP-12, with updated inputs, for the embedded cost component of the generation inputs rates. The direct assignment and variable cost components have changed slightly from BP-12, since BPA is no longer forecasting costs associated with the decremental balancing reserve capacity acquisition pilot. The direct assignment component includes the full direct assignment amount and not an amount reduced by revenue received from BPA's Green Energy Premium.

Q. Are there any new features you are addressing in this case regarding the allocation of costs associated with these balancing services?

A. Yes. In this rate case we are forecasting for the first time that the Federal Columbia River Power System (FCRPS) will not be the sole source for meeting the balancing reserve capacity needs for BPA's balancing authority area. Instead, BPA will be purchasing balancing reserve capacity from third parties when FCRPS capacity is either insufficient (on a forecast basis) or unavailable (on a real-time basis). In section 6 of this testimony, we describe BPA's proposed methodology for assigning these purchase costs to the customer groups that will be using these types of balancing reserve capacity.

Q. Why are you proposing to allocate an embedded cost component and a variable cost component to the balancing services?

A. We propose to allocate a share of the embedded cost of the FCRPS to the generation inputs that support VERBS, Regulation and Frequency Response Service, DERBS, and Operating Reserve because providing these services requires use of FCRPS capability. Study section 3.2. Users of the capability of the FCRPS should share in paying for a portion of the embedded costs of the FCRPS. Such an allocation ensures that the embedded costs of the FCRPS are allocated among those that benefit from the use of the FCRPS and avoids cost shifts among BPA's customers. If VERBS, Regulation and Frequency Response Service, DERBS, and Operating Reserve were not provided from the capability of the FCRPS, then the balancing reserve capacity of the FCRPS could be used for other system purposes. Moreover, if no embedded costs of the FCRPS were allocated to these services, BPA's other customers (primarily PF power customers) would bear the full costs of paying for the embedded cost of the FCRPS, even though a portion of the capability of the FCRPS was being used by transmission customers.

We also propose to allocate to the generation inputs that support VERBS, Regulation and Frequency Response Service, DERBS, and Operating Reserve certain variable energy costs that the system incurs by operating the FCRPS to provide balancing reserve capacity. Providing balancing reserve capacity requires Power Services to change the operation of the FCRPS from an efficient power operation to an operation that: (1) is less efficient in converting water to electricity (less efficiency); and (2) produces electricity at times in which it is less valuable than during efficient power operation (energy shift). Study section 3.4. Allocating these costs to the users that are creating the need to make these changes to the FCRPS is consistent with the ratemaking principle of cost causation.

Q. If BPA was not proposing to provide balancing reserve capacity, how would these variable costs be recovered?

A. If BPA provided less balancing reserve capacity, BPA would not incur the variable costs associated with the additional amounts of these generation inputs. Rather, power production would be more efficient, and BPA's revenues could be assumed to be increased by BPA selling additional amounts of power into the market. In addition, if less balancing reserve capacity were required, BPA could make additional power sales at higher prices because BPA would not be required to shift power production from Heavy Load Hours (HLH) (when power is more valuable) to Light Load Hours (LLH) (when power is less valuable).

Section 3: Embedded Cost Methodology

Q. What is meant by embedded cost?

A. Embedded cost refers to the actual depreciated cost of an electrical system, such as the cost of generation facilities used to provide balancing reserve capacity, operation and maintenance costs, and other associated costs. For purposes of BPA's embedded cost methodology, the embedded cost is a specifically defined portion of BPA's annual revenue requirement associated with the generation projects that are used to provide generation inputs for these balancing reserve capacity services.

Q. What is balancing reserve capacity?

A. Balancing reserve capacity is the generation capability ready to increase or decrease generation to provide load-resource balance in the balancing authority area in order to meet reliability standards. See Fisher *et al.*, BP-14-E-BPA-21, section 2, for further explanation.

Q. Please describe the Regulation and Frequency Response Service.

A. Regulation and Frequency Response Service is an Ancillary Service that provides for the continuous balancing of loads in the BPA balancing authority area to maintain frequency at 60 cycles per second. Study section 10. TS has the obligation to maintain this balance in accordance with NERC control performance criteria. *Id.* In order to provide this service, BPA requires balancing reserve capacity from generation inputs. *Id.* Balancing reserve capacity is provided from the FCRPS through the immediate responsiveness of automatic generation control (AGC) to maintain balance in moment-to-moment changes. *Id.*

Q. Please describe VERBS and explain how balancing reserve capacity from the FCRPS is made available to TS for this service.

A. VERBS is a Control Area Service that provides balancing reserve capacity to integrate wind and solar generation projects into the BPA balancing authority area. Study section 10. It includes three components: regulating reserve for moment-to-moment variation, following reserve to account for within-hour variation, and imbalance reserve to account for the difference between actual generation and schedules within the scheduling period. *Id.* VERBS is provided by increasing or decreasing committed online FCRPS generation through the use of AGC equipment as necessary to follow the moment-by-moment changes, the within-hour variations, and the differences in variable energy resources' actual generation relative to the schedule. *Id.*

Q. Please describe DERBS and explain how balancing reserve capacity from the FCRPS is made available to TS for this service.

A. DERBS is a Control Area Service that applies to all non-Federal thermal generators in the BPA balancing authority area. *Id.* This service is necessary to support the within-hour deviations of thermal generation from the hourly generation estimate *(i.e.,* generation

schedule). DERBS is the same service for non-Federal thermal generators that is provided by VERBS to wind and solar generators. *Id.*

Q. Briefly describe the proposed methodology for allocating embedded costs associated with the provision of FCRPS balancing reserve capacity for Regulation and Frequency Response Service, VERBS, and DERBS.

A. The embedded unit cost of Regulating, DERBS, and VERBS balancing reserve capacity is calculated by taking the costs associated with the hydro projects that are used to provide balancing reserve capacity for these services and dividing these costs by the average annual capacity amount of those same hydro projects (adjusted for other requirements). Study section 3.2. The embedded unit cost is then multiplied by the quantity of balancing reserve capacity forecast for each balancing reserve capacity service to yield the embedded cost allocation for that product. *Id.*

Section 3.1: Specific Aspects and Inputs of the Embedded Cost Methodology

Q. What FCRPS resources are used to provide the balancing reserve capacity for Regulation and Frequency Response Service, VERBS, and DERBS?

A. Of the entire FCRPS, only the "Big 10" hydro projects are capable of providing balancing reserve capacity for Regulation and Frequency Response Service, VERBS, and DERBS. Study section 3.2.1. The Big 10 hydro projects are Bonneville, Chief Joseph, Grand Coulee, Ice Harbor, John Day, Little Goose, Lower Granite, Lower Monumental, McNary, and The Dalles. *Id.*

Q. Why is provision of this balancing reserve capacity limited to these resources?

A. Balancing reserve capacity for those services must be provided by units that are connected to AGC, and the Big 10 projects are the only FCRPS hydro projects BPA connects to AGC. *Id.*

Q. How is the revenue requirement for the embedded cost methodology determined?

A. The embedded cost net revenue requirement associated with the Big 10 hydro projects is composed of (1) power-related costs of the Big 10 hydro projects on a project-specific basis; (2) an allocation of associated fish mitigation costs; (3) an allocation of administrative and general expense; and (4) three specific revenue credits. Study section 3.2.8.1; Documentation Table 3.5.

Q. Please describe the allocation of the fish mitigation and administrative and general costs.

A. The fish mitigation costs and the general and administrative costs are not set on a project-specific basis. Study Section 3.2.8.1. To allocate those costs to the Big 10 hydro projects, we determine the share of the Big 10 projects to total energy of the FCRPS. Using this method, the Big 10 projects are allocated 91 percent of the fish mitigation costs and the general and administrative costs because the Big 10 projects comprise 91 percent of the energy of the FCRPS. Study section 3.2.8.1.

Q. Please describe the revenue credits.

A. The three specific revenue credits are 4(h)(10)(C) (non-operations), Colville payment Treasury credit, and synchronous condensing. *Id.* The 4(h)(10)(C) (non-operations) revenue credit is applied because BPA receives a credit against its annual payments to the U.S. Treasury in recognition of funding the system wide mitigation of BPA's fish and wildlife Direct Program expense and capital costs. *Id.* The credit is based on the non-power portion of the FCRPS projects purposes, for which power ratepayers are not responsible. Power Revenue Requirement Study, BP-14-E-BPA-02, section 1.2.6. BPA makes annual payments under a settlement to the Colville Tribes tied to the generation at Grand Coulee Dam. The Colville payment Treasury credit recognizes that BPA receives a credit against its annual payments to the U.S. Treasury as the Federal government's contribution to the annual payment to the Colville Tribes. *Id*. section 1.2.3.

The 4(h)(10)(C) (non-operations) revenue credit and the Colville payment Treasury credit are part of the net revenue requirement for the Big 10 hydro projects. *Id.* section 2 and Table 2E. The synchronous condensing revenue credit is added to avoid double-counting, because the synchronous condensing costs are allocated to TS in a separate calculation in section 5 of the Study.

Q. How are the balancing reserve capacity amounts associated with each service quantified?

A. The balancing reserve capacity amounts for each service used in the embedded cost calculation are provided by the Balancing Reserve Capacity Quantity Forecast. Study section 2. The Study provides the quantities for Regulating Reserve, VERBS Reserve, and DERBS Reserve. In addition, the Study provides a quantity for Load Following Reserve, which includes the balancing reserve capacity for load, Columbia Generating Station, and non-AGC-controlled hydro generation (Federal and non-Federal hydro generation). Also, the Operating Reserve quantity forecast is an input to the embedded cost calculation. The Operating Reserve quantity is provided by the Operating Reserve Cost Allocation. *Id.* section 4.

Q. How is the amount of balancing reserve capacity that the Big 10 can produce quantified?

A. We forecast the amount of balancing reserve capacity that can be sourced from the FCRPS. *See* Kerns *et al.*, BP-14-E-BPA-23 (explaining the flexibility and operational limitations of the FCRPS). For purposes of allocating embedded costs and determining a unit cost for balancing reserve capacity, the amount of balancing reserve capacity for the Big 10 projects is quantified by determining the 120-hour peaking capacity of these projects. Study section 3.2.7.

Section 3.2: 120-Hour Peaking Capacity

Q. What is the 120-hour peaking capacity?

A. For the FY 2014–2015 rate period, we have identified 120-hour peaking capability as a critical measure to determine resource availability to meet sustained peak loads over an extended period of time and maintain operational reliability. Study section 3.2.6. Generally, the 120-hour hydro peaking capacity is defined as the averaged period of hourly Federal system hydro generation that is calculated from the highest six hours of generation for each of five weekdays of a four-week period. Study section 3.2.5. We propose to use the 120-hour peaking capability as a measure of the system's sustained capacity for allocating costs among all capacity uses of the system.

Q. Why do you propose to use 120-hour peaking capacity?

A. We use a 120-hour capacity estimate to represent the amount of available capacity on the Federal hydro system that is available to reliably serve Federal system load obligations while meeting balancing reserve capacity obligations and power and non-power requirements within any period or water condition. *Id.* BPA planning uses 120-hour capacity to simulate the typical operation of the Federal system to meet normal weather load obligations. The measurement of 120-hour capacity for use in the embedded cost methodology is reasonable because it represents the ability of the FCRPS to meet its capacity obligations while meeting the physical characteristics and limits placed on modeled Columbia River Basin projects, including hard project constraints (*e.g.*, flow limits, elevation limits), project outages (planned and forced outages), balancing reserve capacity requirements, one-percent efficiency restrictions, and non-power constraints (flood control, variable draft limits, fish operations pursuant to the Biological Opinions, and Canadian Treaty operations). Study section 3.2.3. It is not meant to represent a time of system stress to meet large weather deviations, additional reserve obligations, or other

extreme conditions. The 120-hour capacity quantification is the same capacity planning standard used in BPA short-term planning. Therefore, using 120-hour peaking capacity to calculate the unit cost of Regulating, VERBS, and DERBS balancing reserve capacity is an appropriate measure of the system capacity capability.

Q. What modeling tools do you use in the calculation of the 120-hour peaking capacity in this study?

A. We use the combination of HYDSIM and HOSS models to calculate the 120-hour peaking capacity of the FCRPS. HYDSIM is a computer model that simulates monthly energy hydro production under the physical characteristics and limits placed on modeled Columbia River Basin projects. HYDSIM simulates these regional hydro projects to meet system load while continuing to meet Pacific Northwest regional power and non-power requirements for the 80 water years of record (October 1928 through September 2008). HYDSIM provides monthly project flows, initial and ending conditions, and constraints that are used as inputs to the HOSS model. HYDSIM is described in the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.1.

The HOSS model simulates the hourly operation of the Federal system to meet hourly loads for each period of the 80 water years for the study period. Both HOSS and HYDSIM use the same project constraints and reserve requirement estimates listed above; however, HOSS focuses on hourly constraints and HYDSIM focuses on monthly constraints. The HOSS model uses monthly project flows, initial and ending conditions, and constraints supplied by the HYDSIM model in the HOSS hourly simulation. Study section 3.2.4. The outputs of HOSS are not directly used for rate setting purposes. Rather, monthly Federal system regulated hydro generation energy relationships are developed to provide monthly HLH energy, LLH energy, and 120-hour hydro peaking capacity using outputs from HOSS.

Q. Please explain how the HOSS curves are derived and used.

A. The hourly output of HOSS is used to develop relationships between monthly average energy during each of the 14 periods of the year and the associated 120-hour hydro peaking capacity for each of the 80 historical water years. Study section 3.2.4. These relationships are created through curves that define peaking capacity as a function of monthly energy for each of the 80 hydro conditions. The data from HOSS are entered into an Excel spreadsheet, and the curve-fitting function in Excel is used to generate a peaking capacity equation for each month that reflects the 120-hour peaking capacity of the system for any given energy content for that period. Study section 3.2.6.

These equations (curves), one for each of the 14 periods of the year, are applied to the energy output of HYDSIM to produce the 120-hour hydro peaking capacity for each period. Study section 3.2.7. The resulting 120-hour hydro peaking capacity amounts represent the 120-hour peaking capacity of the regulated hydro projects.

Q. Why are curves applied to the energy output of HYDSIM, and how does this represent system capacity?

A. BPA uses the monthly energy output derived from HYDSIM to estimate the amount of regulated hydro energy available for the Federal system by period for each of the 80 water conditions of record. Study section 3.2.3. This HYDSIM analysis provides monthly regulated hydro generation forecasts for energy in average megawatts while incorporating power and non-power operating requirements for the study period. HYDSIM forecasts provide the base data for the energy analysis for the loads and resources studies used in ratemaking and long-range planning and are not intended to simulate hourly Federal system operations. The HOSS model does not provide the regulated hydro energy output; rather, HOSS provides the basis for the Federal system regulated hydro energy to 120-hour peaking capacity relationships. *Id.* section 3.2.4. In

order to provide consistency, the Power Loads and Resources Study, BP-14-E-BPA-03, the Power Risk and Market Price Study, BP-14-E-BPA-04, and the Generation Inputs Study all use the same HYDSIM regulated hydro energy forecasts as the base for the 120-hour peaking capacity curves.

The curves derived from HOSS are only the energy-to-capacity relationships per period. To obtain the capacity values for each period, the curves must be applied to a monthly energy value. The model that produces the energy values by month is HYDSIM. Because the curves take into account the power and non-power constraints on the system, the resulting capacity values after applying the curves to HYDSIM amounts represent the regulated hydro system capacity.

Q. Are you proposing to use average water conditions from 1958 to determine the 120-hour peaking capacity?

A. We propose to use 1958 water conditions to forecast the 120-hour peaking capacity, because it represents the ability of the Federal system to provide peaking capacity under average water and weather conditions. The use of an average water assumption to calculate the unit embedded cost of peaking capacity continues the same assumption that was used to develop the current balancing reserve capacity rates. By using average water BPA has taken into account that secondary sales are a use of the FCRPS. Products and services that include a benefit from secondary sales are also subject to risk mitigation tools. See Mandell *et al.*, BP-14-E-BPA-15, section 3.3, for a more detailed description of the proposal regarding application of risk mitigation tools to Ancillary and Control Area Service rates.

Q. Are the generation input uses of balancing reserve capacity accounted for in the 120-hour peaking capacity forecast?

A. Yes, for all balancing reserve capacity uses except Operating Reserve, the HOSS model incorporates balancing reserve capacity forecasts using both the *inc* and *dec* balancing reserve capacity amounts, which are provided by the Balancing Reserve Capacity Quantity Forecast. Study section 2.11. The balancing reserve capacity includes: (1) *inc* balancing reserve capacity, which is capacity available to ramp up generation to meet increasing within-hour load and/or decreasing within-hour generation: and (2) *dec* balancing reserve capacity, which is generating capacity available to ramp down to meet increasing within-hour generation and/or decreasing within-hour load. *Inc* and *dec* balancing reserve capacity are explained in greater detail in section 5 below. In HOSS, the *inc* requirement is treated as a reduction to available capacity to generate power, and the *dec* requirement is treated as an increase in the minimum generation requirement at Grand Coulee, Chief Joseph, McNary, John Day, and The Dalles. The treatment of Operating Reserve in the HOSS model is described in section 3.3 below.

The HYDSIM model incorporates the *inc* and *dec* balancing reserve capacity by reducing the availability of turbines that can be used to produce power on a monthly basis. The HYDSIM generation estimate of Federal hydro energy therefore reflects power set aside for balancing reserve capacity and Operating Reserve.

Q. Does the 120-hour peaking capacity take into account the impacts associated with providing balancing reserve capacity for the various services?

A. The 120-hour peaking capacity takes into account the generation input uses of balancing reserve capacity, because those products and services diminish the usable capacity of the Federal system and reduce its capability to serve firm load. The 120-hour peaking capacity amount is intended to reflect the capacity of the system for producing energy

after all constraints, limitations, and requirements are taken into account. Study section 3.2.5. Among these requirements is the capacity for balancing reserve capacity and Operating Reserve. In the embedded cost methodology, the net revenue requirement is spread across all system capacity uses. The embedded cost calculation adds the balancing reserve capacity and Operating Reserve requirement to the 120-hour peaking capacity to yield all system capacity uses for purpose of pricing and allocating costs. *Id.* section 3.2.8.

Q. Please explain the adjustments that are made to the 120-hour peaking capacity for the regulated hydro projects to derive the capacity of the Big 10 hydro projects.

A. Two adjustments are made to the 120-hour peaking capacity of regulated hydro projects to calculate the 120-hour peaking capacity of the Big 10 hydro projects. The regulated hydro projects are reduced by 3.35 percent for capacity transmission losses. *Id.* section 3.2.7. Then the transmission loss-adjusted regulated hydro projects are multiplied by 94 percent to reflect the Big 10 hydro projects as a portion of the regulated hydro projects. *Id.*

Q. Why is the adjustment for transmission losses made?

A. The 120-hour peaking capacity is adjusted for transmission losses because the FCRPS has inherent capacity losses to transmit generation to Federal system load obligations. These capacity transmission losses total 3.35 percent of the available 120-hour generating capacity. Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.5.

Q. How is the 94 percent adjustment of regulated hydro to represent the Big 10 derived?

A. The Federal system regulated hydro represents 14 projects whose hydro operations are simulated in HYDSIM and HOSS, and thus the 120-hour peaking capacity produced from the HOSS curves reflects all 14 projects. As described above, only the Big 10 projects are controlled in real time by AGC and provide balancing reserve

capacity. To determine the necessary adjustment to the regulated hydro 120-hour peaking capacity, we take a proportion of the regulated hydro annual average energy amounts. The proportion was determined by taking the total annual average energy production of the regulated hydro projects and dividing by the annual average energy of the Big 10 hydro projects. The proportion calculated on energy was applied to the 120-hour peaking capacity. The portion of the total capacity that is associated with the Big 10 projects is 94 percent of the regulated hydro projects. Documentation Table 3.2. This 94 percent adjustment for the 120-hour peaking capacity of the Big 10 hydro projects is a measure of the Big 10 hydro projects as compared to the 14 regulated hydro projects.

Q. Have you considered using any other measurements for system capacity in the embedded cost methodology, and if so, why is BPA proposing to continue to use the 120-hour peaking capacity?

A. We considered using critical water rather than average water for the 120-hour peak for the embedded cost methodology. We are proposing to continue with the 120-hour peaking capacity under average water as the allocation factor for embedded cost because the 120-hour peaking capacity takes into account non-power constraints and is representative of the available capacity for system planning purposes. It also represents an allocation factor that balances all firm uses of the hydro system.

Section 3.3: Embedded Cost Calculation

Q. Please describe the components of the hydro project system uses that are used to calculate the embedded cost.

A. The hydro project system use is the sum of: (1) the 120-hour peaking capacity of the Big 10 hydro projects; (2) balancing reserve capacity quantities for Regulating Reserve,

Load Following Reserve, DERBS Reserve, and VERBS Reserve; and (3) capacity reserve quantity for Operating Reserve adjusted to account for non-spinning Operating Reserve that may be provided by Federal hydro projects other than the Big 10.

Q. Are the balancing reserve capacity amounts added back to the HYDSIM/HOSS-developed 120-hour peaking capacity the same as the balancing reserve capacity assumptions within HYDSIM and HOSS themselves?

A. The data inputs for HYDSIM and HOSS for Regulating Reserve, Load Following Reserve, DERBS Reserve, and VERBS Reserve are the same as the balancing reserve capacity quantities forecast in section 2 of the Study, Documentation Table 3.4, with two exceptions. The monthly total *inc* and *dec* amounts used as data inputs to the hydro models are between two and five megawatts lower than the amounts forecast in Documentation Table 2.18. These numbers will be revised to match the forecast in section 2 in the Final Study. The other exception is that the monthly total *inc* balancing reserve capacity amount was capped at 900 MW, and the monthly total *dec* balancing reserve capacity amount was capped at 1100 MW. The data inputs for HYDSIM and HOSS include *inc* and *dec* amounts, while the embedded cost methodology only uses the *inc* amount for the calculation.

The Operating Reserve amounts input into HYDSIM and HOSS are calculated in a manner that is consistent with the reserve forecast in the Operating Reserve Cost Allocation in section 4 of the Study (*i.e.*, 3 percent of resources and 3 percent of load). However, instead of using the average Operating Reserve requirements, the Operating Reserve input for HOSS and HYDSIM is based on historical peak balancing authority area generation at the 95th percentile by month.

Q. Why is the Operating Reserve amount used as an input to the HYDSIM and HOSS models different from the amount used in the hydro project system uses?

A. The peak 95th percentile is used instead of the average, because it is at high levels of generation that Operating Reserve constrains the system. If the study were to assume the average Operating Reserve, then during periods of high generation, the HYDSIM and HOSS models would not adequately cover the required Operating Reserve.

Q. Please explain the slight adjustment made to the Operating Reserve to account for Operating Reserve not supplied by the Big 10.

A. The Operating Reserve quantity used is adjusted to account for the fact that Supplemental (non-spinning) Operating Reserve can be carried on projects in addition to the Big 10 hydro projects. Since the Big 10 hydro projects comprise 91 percent of the hydro projects in the BPA balancing authority area capable of providing Operating Reserve (Documentation Table 3.6, line 7 and Table 4.4, line 17), the Supplemental Operating Reserve quantity is reduced by nine percent to account for the portion that may be carried on other projects.

Q. What is the proposed embedded cost allocation for Regulation and Frequency Response Service, VERBS, and DERBS?

A. The proposed embedded unit cost of balancing reserve capacity need for Regulation and Frequency Response Service, VERBS, and DERBS is $6.93 per kilowatt per month of balancing reserve capacity need. Documentation Table 3.6, line 13. The embedded cost allocation is $5,072,760 for Regulation and Frequency Response Service; $43,409,520 for VERBS; and $5,072,760 for DERBS. Study section 3.2.8.3; Documentation Table 3.6, lines 14-16.

Q. How does the embedded cost forecast impact power rates?

A. The embedded cost forecast is included in the Generation Inputs for Ancillary, Control Area and Other Services revenue credit for the power rates. The revenue PS collects through providing generation inputs lowers the revenue requirement for power rates.

Q. How are the embedded costs used to calculate Ancillary and Control Area Services rates?

A. The embedded cost revenue forecast is recovered through the appropriate Ancillary and Control Area Services rates. *See* Study section 10; Jackson *et al.*, BP-14-E-BPA-28.

Section 3.4: Embedded Cost for Different Levels of Service

Q. What is the level of service assumption used in your base case for the Initial Proposal?

A. We assume a 99.5 percent level of service for the base case in the Initial Proposal. Fisher *et al.*, BP-14-E-BPA-21, section 5.1. We also assume an amount of customer self-supply of the imbalance component of VERBS, which affected the balancing reserve capacity quantity. See Study section 2.7.4 for further explanation of this assumption.

Q. What is the reason for providing the embedded cost calculations for a scenario where no customer elects to self-supply the imbalance component in VERBS?

A. We are providing cost calculations for one scenario in addition to the base case in order to inform the parties of the cost impacts. The base case assumes a level of self-supply based on the Customer-Supplied Generation Imbalance Pilot Program, which began in September 2010. Customers must make elections by April 1, 2013, whether or not to self-supply for the FY 2014–2015 rate period. This amount will be used for the self-supply amount for the Final Proposal. There is the possibility that no customers will elect to self-supply for the rate period.

Section 4: Direct Assignment of the Wind Integration Team (WIT) Costs

Q. What costs are proposed to be directly assigned to the VERBS rate?

A. We are proposing to directly assign Wind Integration Team costs to the VERBS rate. Study section 3.3.

Q. Please briefly describe why BPA formed the WIT.

A. As part of the WI-09 Settlement, BPA assembled the internal cross-agency WIT to explore technical solutions to address the challenge of balancing loads and resources to preserve system reliability while accommodating the rapid development of wind energy in the BPA balancing authority area. The mission of the WIT is to clearly define and execute a plan for integrating wind generation in a manner that allows for the continued highly reliable operation of the Federal power and transmission system at the lowest cost consistent with sound business and operations practices.

Q. Please describe the various initiatives the WIT has undertaken since its formation.

A. The WIT has developed and implemented numerous initiatives that have helped allow for a steady increase in the amount of wind interconnected to BPA's balancing authority area. These initiatives will continue in the FY 2014–2015 rate period. These initiatives include:

(1) Dispatcher Standing Order 216 (DSO 216): DSO 216 is BPA's primary reliability tool for managing variable generation. The purpose behind BPA's operating procedure known as DSO 216 is to fix the limits of BPA's balancing reserve capacity obligations and ensure the reliability of the BPA balancing authority. DSO216 has also been deployed as a way to reduce wind integration costs by substituting infrequent wind curtailments for additional balancing reserve capacity. This operating protocol limits the amount of Federal hydro capacity BPA must set aside to back wind while maintaining reliable power service. BPA developed automated tools and communication protocols to

either limit actual wind generation according to the set schedule or curtail e-Tags to actual generation in response to the amount of balancing reserve capacity deployed.

(2) Dynamic transfer capability (DTC): Methodology developed for determining dynamic transfer limits and application of that methodology to nine transmission paths. BPA then developed and implemented a process to allocate and award this DTC to requesting utilities. That process, collaboratively developed with customers, resulted in new DTC offers, awards, and Dynamic Transfer Operating Agreements that are now in effect.

(3) Forecasting, state awareness tools: BPA has created a wind speed and wind generation forecasting system in order to achieve better reserve management through more informed operational decisions and to enhance hydroelectric generation reliability as more wind generation is integrated. BPA will also be making the wind generation forecast for each wind project available to the project owner/operators to improve scheduling accuracy.

(4) Intra-hour power scheduling: The purpose of the Intra-hour Scheduling initiatives is to reduce the error between actual performance and schedules to allow for a more efficient use of the existing electric system without sacrificing reliability and to assist with the integration of variable energy resources.

- ***Committed Intra-Hour Scheduling***

  Committed Intra-Hour Scheduling is designed to reduce the amount of balancing reserve capacity held by BPA by reducing the difference between scheduled and actual output. In exchange for a rate discount, participating parties commit to schedule, with a scheduling accuracy equal to or better than 30-minute persistence for each scheduling period.

- ***California Independent System Operator (CAISO) Intra-Hour Scheduling Pilot***

CAISO Intra-Hour Scheduling Pilot is designed to move a portion of the balancing needed for wind that is serving load in California to the CAISO. This reduces the amount of balancing reserve capacity held by BPA by reducing the difference between scheduled and actual output.

(5) Customer-supplied generation imbalance: The purpose of the Customer-Supplied Generation Imbalance (CSGI) effort is to provide customers a choice of balancing reserve capacity suppliers and to reduce the overall dependence on the FCRPS for balancing capacity and energy.

(6) Supplemental Service: As the amount of wind on the BPA system has continued to increase and approaches the point of exhausting the ability of the FCRPS to provide balancing reserve capacity (*incs* and *decs*), BPA has begun exploring the purchase of balancing reserve capacity from third parties. BPA developed a Supplemental Service program to allow parties, including BPA, to procure additional balancing capacity and energy. BPA is now working on an "Enhanced Supplemental Service" to increase the ability of market participants to make shorter-term purchases of balancing capacity to meet the balancing needs of their variable energy resources.

(7) WebExchange (WebEx): Previously known as Intra-Hour Transaction Accelerator Platform (ITAP). The purpose of the WebEx is to provide a bulletin board market for hourly and intra-hour power products, with functionality to submit transmission service requests (TSRs) and e-Tags for confirmed transactions. This market will speed up the transaction process, making it more feasible to meet the short deadlines for intra-hour schedules.

Q. Please briefly explain how BPA funds the WIT.

A. The WIT is an internal cross-agency team made up of employees from PS and TS, with support from Corporate and Legal. For FY 2012–2013 the WIT was funded with funds that were directly assigned to VERBS as well as from the reinvestment of Green Energy Premium (GEP) revenues. For FY 2014–2015, we propose that the WIT budget be directly assigned to the VERBS rate.

Q. What changes from the BP-12 rate case are you proposing for costs directly assigned to the VERBS rate?

A. In BP-12, BPA assigned the cost of the TS employees' participation in the WIT along with the TS portion of Corporate and Legal employee costs for supporting WIT initiatives. The Power Services' share of WIT costs, including the PS portion of Corporate and Legal employee costs for supporting WIT, were covered by unspent GEP revenues.

In BP-14, we are proposing to directly assign the full WIT costs. It is assumed that the GEP revenues will be fully reinvested prior to the FY 2014–2015 rate period and will not be available to help fund WIT initiatives in that rate period. In addition, Staff is not proposing to include the Dec Acquisition Pilot Project in the direct assignment for this rate case. In place of the Dec Acquisition Pilot Project, Staff proposes to offer enhanced Supplemental Service. Staff proposes that the implementation costs of enhanced Supplemental Service, which will allow BPA to make *inc* and *dec* purchases, will be included in the WIT budget.

Q. What is the policy rationale for directly assigning these WIT costs to the VERBS rate?

A. These costs are for staffing BPA's WIT and associated projects described above that are for the benefit of variable energy resources in the BPA balancing authority area. Directly assigning these costs to the VERBS rate is consistent with BPA's principles of cost

causation and BPA's goal to ensure no cost shifts result from the integration of variable energy resources.

Section 5: Variable Cost Pricing Methodology

Q. Why are you proposing to include a variable cost component in the generation inputs cost allocation?

A. BPA operates an interconnected system of dams and reservoirs. Providing balancing reserve capacity affects the FCRPS output in MW, timing of energy generated, and revenues received. Losses of efficiency and value occur as the system is set up to allow balancing reserve capacity to be deployed, and additional losses occur as the balancing reserve capacity is actually deployed. The inclusion of this variable cost component in the cost allocation study allows BPA to appropriately allocate these losses to the parties who benefit from balancing reserve capacity services.

Q. Generally, how is the variable cost of balancing reserve capacity calculated?

A. The variable cost of balancing reserve capacity is calculated in two general steps. The first step calculates the cost of making the FCRPS capability ready and available should the need to deploy balancing reserve capacity arise. These costs are referred to throughout this testimony as stand-ready costs. The second step calculates the cost of actually deploying balancing reserve capacity as the need arises. These costs are referred to throughout this testimony as deployment costs. The tool used to calculate both of these costs is the Generation and Reserves Dispatch (GARD) Model. Study section 3.4.1.

Q. What is the GARD Model, and what does it do?

A. The GARD Model is an MS Excel 2003-based model developed by BPA. All inputs and outputs are based in Excel spreadsheets. The core of the model is written in Visual Basic

for Applications (VBA). The GARD Model analyzes variable costs in two general categories. The first category is the stand-ready costs, which are the costs associated with making a project capable of providing balancing reserve capacity. The next general cost category is the deployment costs, which are those costs incurred when the system uses its reserve capability to actually deliver in response to a reserve need.

Q *Please describe changes that have been made to the GARD Model inputs as compared to the inputs that were used in the FY 2012–2013 rates.*

A. The model has been changed from a 70-water-year study to an 80-water-year study to match the upgrade made to HYDSIM.

Q. Please describe the inputs for the GARD Model.

A. The GARD Model uses inputs from the HYDSIM model, a hydraulic model of coordinated river operations that calculates monthly average generation values by project for each of the 80 historical water years, and actual system data. The primary inputs into the GARD Model are tables of project-specific generation values calculated by HYDSIM.

Q. What are the tables of project-specific generation values used for?

A. These generation tables are used by the GARD Model to determine the generation request which, in turn, determines the project's unit commitment and dispatch. The generation request is the amount of Heavy Load Hour (HLH) or Light Load Hour (LLH) generation that a specific project is being asked to produce. The project's unit commitment consists of the number and type of units put online. The dispatch is the generation from the committed units, which must equal the generation request while at the same time meeting the balancing reserve capacity obligation.

Q. How do you determine a project's specific HLH and LLH generation request?

A. HYDSIM output tables are input into a pre-processing spreadsheet to calculate each project's HLH and LLH generation request prior to considering balancing reserve capacity needs. Determining a project's specific HLH and LLH generation request begins with monthly energy amounts for each of the 80 historical water years from HYDSIM. Monthly energy amounts are taken for Grand Coulee (GCL), Chief Joseph (CHJ), John Day (JDA), and The Dalles (TDA). These four projects are generally referred to as controller projects in this testimony. Additionally, the pre-processing spreadsheet calculates amounts of pre-existing *dec* capability for each project by month and historical water year based on the calculated LLH generation and the project's minimum flow and/or minimum generation requirements. The purpose of pre-existing *dec* capability input is to ensure that the GARD Model does not unnecessarily move energy out of HLH and into LLH when providing *dec* capability.

Q. Please describe the nature of the generation request in more detail and explain how it is applied to the GARD Model.

A. The generation request is a set of generation values, for each month of each water year for HLH and LLH, for each controller project. Given these generation values, the GARD Model finds the efficiency-maximizing unit commitment and dispatch. This process mimics the basepoint setting process, where the hydro duty scheduler submits requested generation amounts to each project and the project commits and dispatches its units in the most efficient manner possible in order to meet the requested generation.

Q. If the Big 10 projects are all capable of AGC response, why are costs calculated based on only four controller projects?

A. Although all of the Big 10 projects are capable of being, and at various times of the year are, armed for AGC response, GCL, CHJ, JDA, and TDA are the only projects analyzed,

because these four controller projects are most often armed by the hydro duty scheduler for AGC response. Study section 3.4.2.1. The projects used in the GARD Model are representative of the entire Big 10, because the variable costs calculated by the GARD Model are based on recovering the total amount of balancing reserve capacity needed for generation inputs provided to TS, and this cost calculation is unlikely to vary to any significant degree whether it is spread over the four controller projects or over the Big 10 projects. Using the four controller projects that are armed most often made the GARD Model manageable, as compared to trying to factor in all 10 projects that have varying degrees of use depending on the time of year. *Id.*

Q. What is the next step in calculating variable costs?

A. Supervisory Control and Data Acquisition (SCADA) data are used to develop relationships between average energy and HLH generation for each of the respective controller projects. This evaluation is constrained by unit availability, requirements to operate within 1 percent of peak efficient generation, and minimum turbine flow constraints. The results of the evaluation are functional relationships between average energy production and HLH generation.

Q. What time period does the SCADA data span?

A. Data are from the period January 1, 2002, through December 31, 2007.

Q. Why is the 2002–2007 data set used in developing the functional relationship between energy and HLH?

A. The 2002–2007 period is used to balance the need for a robust data set with the desire for operations that are similar to current practice and bound by similar constraints. Going back farther in time would include periods when operations were significantly different from current operations. Additionally, this period serves well as a base case because it predates the large wind fleet buildup.

Q. Please explain what inc *reserves and* dec *reserves are.*

A. *Inc* reserves, a component of balancing reserve capacity, are required to maintain load-resource balance when an undergeneration situation exists within the BPA balancing authority area. In an undergeneration situation, instantaneous loads are higher than planned and/or the instantaneous generation is lower than planned. Under these circumstances, FCRPS generation must automatically *inc* to maintain system balance. The quantity of reserve is set to cover 99.75 percent of all under-generation magnitudes calculated by the Balancing Reserve Capacity Quantity Forecast.

Conversely, *dec* reserves, also a component of balancing reserve capacity, are reserves required to maintain load-resource balance when an over-generation situation exists within the BPA balancing authority area. In an over-generation situation, instantaneous loads are lower than planned and/or the instantaneous generation is higher than planned. Under these circumstances, FCRPS generation must automatically *dec* to maintain system balance. The *dec* reserve is the amount of generation that the FCRPS must be capable of decreasing to maintain load-resource balance. The quantity of reserve is set to cover 99.75 percent of all over-generation magnitudes calculated by the Balancing Reserve Capacity Quantity Forecast.

Q. Please explain how inc *reserves and* dec *reserves are treated in the GARD Model.*

A. Reserves are input into the GARD Model by general reserve type. Specifically, the reserves are input into the model by quantity of *inc* and *dec* regulation, *inc* and *dec* following, *inc* and *dec* imbalance, and total Operating Reserve. Given these reserve classifications, the GARD Model determines the required amounts of spinning and non-spinning reserve to meet *inc* obligations and the amount of generation required to meet *dec* obligations. It is worth noting that all *dec* reserves must by definition be supplied from generation that is spinning.

Q. How are the quantities of spinning and non-spinning reserve determined?

A. The determination of the quantities of spinning reserve versus the quantities of non-spinning reserve is derived from the NERC requirements as well as system operator judgment. NERC requires that at least 50 percent of the balancing authority area Operating Reserve obligation be met with spinning capability responsive to AGC. NERC also requires that 100 percent of the balancing authority area Regulating Reserve must be carried on units with spinning capability responsive to AGC, because Regulating Reserve must respond on a moment-to-moment basis. In contrast, following and imbalance reserve do not have NERC-defined criteria, and therefore it is assumed that at least 50 percent of the *inc* following reserve must be carried as a spinning obligation and up to 50 percent as a non-spinning obligation. For imbalance reserve, up to 100 percent of the *inc* obligation may be met with non-spinning capability. Study section 3.4.2.2.

Q. Why does the GARD Model need to maintain the spinning portion of the Operating Reserve obligation at all times as compared to the balancing spinning obligation?

A. Operating Reserve is not used for balancing purposes and may be deployed only for qualifying contingencies. WECC's currently proposed standard, which is expected to go into effect during the rate period, requires Operating Reserve to be maintained within the balancing authority area equal to three percent of hourly integrated load plus three percent of hourly integrated generation. Because the Operating Reserve requirement is an instantaneously calculated requirement, even momentarily using Operating Reserve capability for balancing purposes is a violation of WECC/NERC disturbance criteria.

Q. What amount of regulation inc *and* dec, *following* inc *and* dec, *imbalance* inc *and* dec, *and Operating Reserve are assumed for purposes of running the GARD Model?*

A. On average, the regulation *inc* and *dec* are 126 MW and -125 MW, the following *inc* and *dec* are 377 MW and -386 MW, and the imbalance *inc* and *dec*, adjusted for self-supply

and committed intra-hour scheduling, are 399 MW and -559 MW. The Operating Reserve obligation is 559 MW. These amounts are derived from the Balancing Reserve Capacity Quantity Forecast, Table 2.18 of the Documentation, and the Operating Reserve Cost Allocation, section 4.3 of the Study.

Section 5.1: Specific Variable Costs Considered by the GARD Model

Q. What are the basic categories of variable costs used in the GARD Model?

A. There are two broad categories: stand-ready costs and deployment costs.

Q. Please describe the stand-ready costs.

A. In order to meet the potential reserve requirements on any given hour, BPA's system must be set up to respond to these reserve needs going into the operational hour. Stand-ready costs are those variable costs associated with making the FCRPS capable of providing the required reserve. In short, they are the costs that arise from making the FCRPS ready to deploy reserves as needed. There are four general subcategories of stand-ready costs: energy shift, efficiency changes, cycling losses, and spill.

Q. What are deployment costs and how do they differ from stand-ready costs?

A. Deployment costs are those variable costs realized when the FCRPS actually deploys the stand-ready reserve to automatically *inc* or *dec* generation in order to meet a within-hour reserve need that changes due to variations in loads and resources. The costs of meeting the within-hour variations in loads and resources are referred to as "deployment costs." There are three general cost subcategories for deployment costs: response losses, cycling loss, and spill.

Q. How does the act of providing balancing reserve capacity result in the type of stand-ready cost quantified as energy shift cost?

A. Energy may shift out of the HLH period in order to make *dec* capability available during the LLH period and/or to make available sufficient non-spinning and/or spinning *inc* capability during the HLH period. In the first instance, fuel normally used to meet peak generation needs is consumed during periods of lowest demand to make sufficient generation capability available on the FCRPS to fully deploy available *dec* reserves without violating minimum generation requirements. The need to shift energy is typically driven by the need to generate during the graveyard period. Depending on water conditions, energy may also be shaped into the shoulder LLH period to make available *dec* capability. In making available non-spinning and spinning *inc* capability, energy shift impacts typically manifest as a reduction first in super-peak generating capability followed by a bleeding into the shoulder HLH period. Should additional *inc* capability be required after completely flattening generation across the HLH period, such as in high flow scenarios, energy is shifted into the shoulder LLH period and, eventually, into the graveyard period.

Q. How are the energy shift costs calculated?

A. Energy shift costs are calculated by determining how much energy is moved into or out of the four blocking periods of super-peak (top eight demand hours of the day), shoulder HLH (this varies, but typically consists of clock hours 07:00 through 12:00 and 21:00 through 22:00), shoulder LLH (clock hours 23:00 through 00:00 and 05:00 through 06:00), and graveyard (clock hours 01:00 through 04:00). Energy shifted into or out of a given time block is multiplied by the price for that time block, resulting in a revenue or expense. If the energy is shifted into a time block with a higher price than the time block BPA would have otherwise sold the energy in, then the net result is a revenue for BPA.

If the energy is shifted into a time block with a lower price than the time block BPA would have otherwise sold the energy in, then the net result is an expense for BPA. Totaling the revenues from energy shifted into a time period and the expenses from energy shifted out of other time periods yields the energy shift cost. The greater the differential in price between time periods, the greater the cost of energy shift. Prices for the time periods are taken from the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

To calculate the energy shift cost associated with a quantity of balancing reserve capacity, the GARD Model compares generation values for the no-reserves case to the test case where balancing reserve capacity must be carried. Study section 3.4.3.1. If energy is moved out of HLH and into LLH due to the need to increase LLH generation and/or graveyard generation and/or to make sufficient super-peak or HLH *inc* capability, the HLH generation is reduced and the LLH generation is increased relative to the base case. Because HLH generation is more valuable than LLH generation, an economic impact is realized as HLH generation is reduced and LLH generation is increased.

Q. Does an energy shift cost always arise as a consequence of providing balancing reserve capacity?

A. No. To the extent the generation request plus the *inc* balancing reserve capacity is less than maximum generation, energy will not be shifted into the LLH period, because there is sufficient generating capability available to meet the generation request as well as the full *inc* balancing reserve capacity.

Additionally, to the extent that the shoulder LLH and graveyard generation is already above minimum generation, there is no need to pull energy out of the HLH period. In these instances, "pre-existing *dec*" capability is said to exist. If the pre-

existing *dec* capability does not fully meet the *dec* requirement, energy is shifted out of the HLH period and into the shoulder LLH and/or graveyard periods.

Q. *Is the energy shift cost dependent on the amount of spinning reserves versus non-spinning reserves?*

A. No. Energy shift costs are the same whether the *inc* reserve is carried as spinning or non-spinning. Energy shift due to *inc* reserve obligations is a function of the difference between maximum generating capability and the requested generation from a controller project. If the difference between the maximum and requested generation is less than the *inc* reserve need, energy must be shifted. Whether the reserve is carried as spinning, non-spinning, or some combination thereof is then a function of the unit commitment and dispatch. The mere need for reserve capability is the cause of energy shift costs, regardless of whether that capability is available as spinning or non-spinning.

Q. *In determining energy shift costs, why are the super-peak and graveyard time periods explicitly taken into account?*

A. The super-peak and graveyard time blocks are explicitly considered for the energy shift calculation because these periods are first impacted by the need to shift energy when making available *inc* and/or *dec* capability. Not considering these periods would understate the energy shift impact. When providing *dec* capability, the first period where energy shift may be required is the relatively low-value graveyard time block. Explicitly calculating how much energy is put into the graveyard period for the *dec* provides greater accuracy in the cost calculation. Likewise, should energy be put into the LLH period to provide *inc* capability, accounting for the quantity of energy going into the graveyard time block versus the shoulder LLH block improves the accuracy of the cost calculation.

Q. Does shifting energy to make incs *available provide an offset to the cost of providing* dec *balancing reserve capacity?*

A. No. The typical scenario where energy is shifted to provide *inc* balancing reserve capability is periods of high river flows. In these instances, sufficient LLH generation exists to provide the required *dec* balancing reserve capacity. Any additional energy shifted into the LLH period due to increasing the HLH *inc* capability results in having *dec* capability greater than required.

Q. Based on the amount of balancing reserve capacity forecast in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast cost for energy shift?

A. The total average energy shift included in the Initial Proposal for the FY 2014–2015 period is 1,845,055 MWh, worth $11,984,612. Documentation Table 3.11, lines 1-3.

Q. Are energy shift costs reflected in any other rates study?

A. Yes. The impact of the energy shift is implicit in the RevSim studies, described in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. What is RevSim, and does RevSim accurately reflect the energy shift cost?

A. RevSim is a revenue simulation model used to calculate the net revenues and net revenue at risk. *Id.* RevSim underestimates the energy shift cost, because it does not consider monthly time periods any more refined than the HLH and LLH blocks. As a result, an adjustment is passed to RevSim based on the GARD super-peak graveyard adjustment in order to fully reflect the cost of the energy shift. The MWh of energy shift sent to RevSim from the GARD Model are incremental amounts above and beyond the hydro generation amounts supplied to RevSim by the Loads and Resources study, BP-14-E-BPA-03. Power Risk and Market Price Study, BP-14-E-BPA-04, sections 2.5 and 2.6.

Q. Besides the adjustment for energy shift, are any of the other results from the Variable Cost Pricing Methodology provided to RevSim?

A. Yes. The full impact of all remaining cost categories are sent to RevSim. These impacts (represented as MWh adjustments) include efficiency changes, cycling costs, spill costs, response losses, deployment cycling costs, and deployment spill costs. *Id.* section 2.5. Each of these cost categories will later be explained in further detail.

Q. How are the MWh amounts taken into account in RevSim?

A. RevSim receives a data table containing the incremental amounts of energy shift. The impacts are characterized as MWh of gains and losses by diurnal time period, month, and water year.

Q. Please describe the subcategory of stand-ready costs known as efficiency change.

A. Efficiency changes are increases or decreases in the controller projects' ability to generate power given a flow of water.

Q. Why does the act of providing balancing reserve capacity change the efficiency of the FCRPS?

A. Efficiency may change when providing reserves because the generation for a given time period may change. For example, providing *dec* capability for the LLH time period may require the shifting of energy from the HLH period into the LLH period. This shifting of energy results in increased LLH generation. Altering the generation dispatch often results in a change in the efficiency of a given controller project, because project efficiency changes with respect to generation. In order to make sufficient reserve capability, the dispatch and resulting efficiency from the controller projects may be altered.

Q. How does the GARD Model use the inputs described above to calculate the efficiency losses?

A. The GARD Model uses the above inputs to calculate the change in efficiency between a base case, where balancing reserve capacity is not required, and the test case requiring defined quantities and components of balancing reserve capacity. For each month of each water year for HLH and LLH, the GARD Model finds the efficiency-maximizing unit commitment and dispatch for GCL, CHJ, JDA, and TDA. The efficiency-maximizing unit commitment and dispatch are found for the base case and the case in which balancing reserve capacity is being carried. Any observed difference in the efficiency between the base case and balancing reserve capacity case is the change in efficiency. More precisely, the GARD Model models efficiency by minimizing the amount of water consumed per MW generated. Efficiency changes may occur when having to change generation patterns for energy shift or when making available additional spinning reserve capacity *(inc)* by maintaining generation at the same level but putting additional units online.

When holding balancing reserve capacity, it is often necessary to shift energy, with the consequence of changing the requested generation from a controller project for a given time period. Changing the generation level typically results in a change in efficiency, because generator units at a given controller project will be dispatched to an alternate loading, and the number and type of unit used to meet the generation request will often differ from the base (no balancing reserve capacity) case.

Similarly, should additional spinning reserve capacity be required, the generation request remains unchanged; however, requiring additional spinning reserve capacity causes changes to the unit commitment and dispatch. Changing the unit commitment and

unit dispatch at a controller project often adversely changes the ability of the controller project to minimize flow per unit of generation.

Q. Is there any interplay between the cost of energy shift and efficiency changes, and if so, how does the GARD Model account for this interaction?

A. Yes, there is an interaction between energy shift and efficiency changes. Any time energy shift occurs, the generation request from a controller project changes. Generation changes due to shifting energy may result in changing the efficiency of the controller project. The GARD Model accounts for the interaction by separately calculating the costs associated with energy shift and the impact associated with efficiency changes. Study sections 3.4.3.1 and 3.4.3.2.

Q. Are efficiency losses always a consequence of providing balancing reserve capacity?

A. Changing a controller project's unit commitment and dispatch may result in an efficiency gain or loss. Gains may be observed if the generation request, inclusive of balancing reserve capacity, decreases the water flow per MW generated. For example, under a high flow condition, carrying *inc* balancing reserve capacity may push units operating beyond peak efficiency back toward peak efficiency. Another example may occur on LLH, during which increased *dec* balancing reserve capacity result in a higher generation level, requiring the commitment of additional online units. The additional online units may allow for an increased ability to fine-tune the optimization of the unit dispatch, with a resultant increase in overall controller project efficiency.

Q. Please explain how efficiency can increase when providing balancing reserve capacity when the baseline measurement is an optimal unit commitment and dispatch.

A. An optimal efficiency exists for any given level of generation. Adding balancing reserve capacity without changing generation almost always reduces efficiency. But adding balancing reserve capacity and changing generation may result in an increase in

efficiency, because the efficiency lost by adding balancing reserve capacity is offset by the efficiency gained by moving the generation to a generation level yielding a more efficient operation from the outset. Without balancing reserve capacity, the achieved efficiency gain from altering the generation level would have been even greater, because a more efficient unit commitment and dispatch could be achieved.

Q. How does a spinning reserve obligation versus a non-spinning reserve obligation affect efficiency losses?

A. For any given *inc* reserve capacity obligation, the greater the proportion of spinning capability required, the greater the efficiency loss. Conversely, the higher the proportion of the balancing reserve capacity carried as non-spinning, the lower the efficiency loss. This is true because the greater the spinning obligation, the greater the impact the obligation has on unit commitment and dispatch. Spinning reserve capacity is defined as unloaded turbine capability, so increasing the spinning obligation requires increasing the unloaded turbine capability. Unloading turbines and increasing the number of online turbines generally results in decreasing the efficiency of the controller project. Conversely, carrying more *inc* reserve capacity as non-spinning provides the controller project with increased flexibility to optimally commit and dispatch units, resulting in improved efficiency. The greater the non-spinning allowance, the more the *inc* obligation can be provided by idle turbines.

Q. How are efficiency losses priced?

A. Efficiency losses are priced using the market price forecast HLH price, as calculated in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

Q. Why is the HLH price used for all periods?

A. The HLH price is used for all periods because no matter whether losses occur during the HLH period or the LLH period, they both result in decreased HLH generation. For the

HLH period, HLH generation is directly lost during that period. For the LLH period, the same is true, because losses realized during the LLH period result in increased consumption of water that would otherwise have been used to generate during the HLH.

Q. Are efficiency gains also priced at the HLH price?

A. Yes.

Q. Are efficiency changes accounted for in any other rate studies?

A. Yes. All efficiency impacts calculated by the GARD Model are sent to RevSim, so the impact to secondary net revenue is correctly reflected. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. Based on the amount of reserves described in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast cost for efficiency losses?

A. The total annual average efficiency change for the FY 2014–2015 period is a gain of 37,631 MWh, worth $929,237. Documentation Table 3.11, lines 4-6.

Q. Please describe the sub category of stand-ready costs known as cycling losses.

A. Cycling losses originate from the additional synchronization and ramping of units in order to have reserve capability standing ready to respond.

Q. How are the cycling losses calculated?

A. Unit cycling losses originate from the additional synchronization and ramping of units. For cycling, the number of units cycled online or offline is calculated by comparing the online units for each unit family at a given controller project in the base, no reserves, case to the online units in the case where the reserve requirement is being met. To the extent that more or fewer units are online, a cycling cost is realized. Study section 3.4.3.3.

Q. How does the GARD Model use the inputs described above to calculate the cycling loss?

A. The loss calculations are controller project-specific and are functions of the individual unit family efficiency curves and the level of generation required from the individual

units to meet the generation request for the amount of reserves required to stand ready. For each unit cycle, synchronization and ramping losses are calculated. During synchronization, water is lost as the unit is spun to synchronize to grid frequency. Water losses during synchronization are equal to 10 percent of full gate flow for three minutes. Ramping losses occur as the unit ramps up to its required generation level. Losses associated with ramping are calculated by evaluating the integral of the specific unit efficiency function from minimum generation to requested generation. The GARD Model fully ramps units to their requested generation level over seven minutes, which is the typical time to fully ramp up to a unit's requested loading.

Q. Why is the cycling loss assumed to occur on each HLH or LLH period?

A. Cycling losses are assumed to occur in each HLH and LLH period for a given month, because the generation level for each HLH and LLH period in a given month is considered an average generation representative of all HLH and LLH periods in the month. That is, in the GARD Model, all HLH periods for a month are considered identical to each other, and all LLH periods for a given month are considered identical to each other. An observed unit cycle during any HLH or LLH period is said to occur for each HLH or LLH period in the month. For example, if one additional unit is online during the HLH period relative to a case without a reserve requirement, that one additional unit is assumed to be needed for each HLH period in the month. That is, for a month with 31 HLH periods, 31 additional unit cycles would occur relative to the case without reserves. These additional unit cycles occur for all time periods, because the balancing reserve capacity must be available at all times.

Q. How are the cycling losses priced?

A. All base cycling losses are priced at the monthly HLH price from the market price forecast, as calculated in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

Q. Why is the HLH price used for all periods?

A. The HLH price is used because the base cycling impact (that is, losses in energy) is taken out of the HLH period. In other words, since BPA seeks to maximize HLH sales, efficiency losses translate to lost HLH generation with resulting lost sales.

Q. Does the GARD Model or the Variable Cost Pricing Methodology include any additional maintenance costs associated with the additional cycling required by standing ready to provide reserves or deploying reserves?

A. The calculation of cycling losses, whether for stand-ready purposes or deployment purposes, does not attempt to account for any additional maintenance costs due to frequent cycling of the units. There are additional maintenance costs associated with the additional cycling of units to provide reserves, but for purposes of this rate proposal we have not attempted to evaluate these additional costs. All maintenance costs are included in the overall reserve requirement that is used in the embedded cost analysis.

Q. Are cycling losses accounted for in any other rate studies?

A. Yes. All cycling losses calculated by the GARD Model are sent to RevSim, so the impact to secondary net revenue is correctly reflected. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. Based on the amount of balancing reserve capacity described in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast for cycling cost?

A. The total annual average cycling loss for the FY 2014–2015 period is 5,482 MWh, worth $170,803. Documentation Table 3.11, lines 7-9.

Q. Please describe the subcategory of stand-ready costs known as spill losses.

A. Spill losses may occur given the combination of a large *inc* reserve obligation and high river flows. In this instance, water may need to be spilled, because it cannot be shifted into LLH and must be moved past the controller project.

Q. How are the spill losses calculated?

A. Spill losses may be incurred when the GARD Model must flatten (that is, set equal) the HLH and LLH generation in order to provide balancing reserve capacity. The flattened generation profile maximizes the combined *inc* and *dec* capability across all hours. Should the GARD Model still fail to carry sufficient *inc* capability, it will begin spilling to achieve the joint objective of meeting the *inc* reserve obligation as well as the controller project flow requirements. Study section 3.4.3.4.

Q. How does the GARD Model use the inputs described above to calculate the spill loss?

A. The loss calculations are controller project-specific and are functions of the amount of response, the total *inc* reserves required, and the total quantity of energy that must pass the project. The GARD model calculates the amount of energy that cannot be passed through the turbines for power production due to the need to stand ready with *inc* capability.

Q. Are the spill losses a result of having to provide balancing reserve capacity, or are these costs a result of having too much water in the FCRPS?

A. The spill losses calculated in the GARD Model are the result of having to provide balancing reserve capacity. Any spill resulting from excess water in the FCRPS is handled by HYDSIM and is not part of the balancing reserve capacity cost. Incremental amounts of spill above and beyond that normally occurring in a high-water scenario may result from providing *inc* reserves. It is these *inc* amounts that are reflected in the GARD Model's spill costs.

Q. How are the spill losses priced?

A. Spill losses are valued in the diurnal period in which they occur. Spill occurring during the HLH period is valued at the HLH price, and spill occurring during the LLH period is valued at the LLH price.

Q. Are spill losses accounted for in any other rate studies?

A. Yes. All spill losses calculated by the GARD Model are sent to RevSim, so the impact to secondary net revenue is correctly reflected. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. Based on the amount of reserves described in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast for spill cost?

A. The total annual average spill loss for the FY 2014–2015 period is 63,951 MWh, worth $1,444,655. Documentation Table 3.11, lines 10-11.

Q. Please describe deployment costs.

A. Deployment costs are those variable costs incurred when the FCRPS automatically increases or decreases generation in order to balance the system. These costs are distinct from the stand-ready costs. The cost subcategories for deployment costs are response losses, cycling loss, and spill loss.

Q. What inputs does the GARD Model use to determine deployment costs?

A. In addition to the same inputs used in calculating the stand-ready cost, the GARD Model uses a SCE file containing *inc* and *dec* signals for each minute of each month being studied. The SCE signal is the sum of the difference between actual and scheduled balancing area generation and the difference between actual and scheduled balancing area load. The SCE file contains the total difference between actual and scheduled for all load and generation on a one-minute time-step, resulting in an amount of *inc* or *dec* that must be provided by the controller projects.

Q. Why is this additional input used?

A. The SCE file is used to model the efficiency changes, unit cycles, and spill during the course of actually deploying reserves.

Q. Are there any overlaps between the deployment and the stand-ready costs?

A. No. Deployment costs are realized only when controller projects respond to a balancing reserve capacity need. Stand-ready costs, on the other hand, are realized when setting up the FCRPS with the capability to respond.

Q. Please describe the sub-category of deployment costs known as response losses.

A. Response losses are a type of efficiency loss experienced when committed units are deploying *inc* or *dec* reserves in response to a balancing need. The GARD Model responds to a balancing need on a minute-to-minute basis, as directed by the SCE file, by dispatching committed units with the objective of maintaining load-resource balance while continuing to minimize the water used to produce power at the requested level of generation. Study section 3.4.4.1.

Q. How are response losses different from efficiency losses?

A. Response losses are incurred when a controller project that is standing ready to respond actually increases or decreases generation in response to a reserve need.

Q. How are response losses calculated in the GARD Model?

A. The GARD Model calculates response losses by continually optimizing the unit dispatch, loading each online unit such that the marginal cost of each unit is identical while at the same time meeting the requested generation level and maintaining the Operating Reserve obligation. The efficiency changes are calculated on a minute-to-minute basis. All efficiency changes occurring during the LLH period are totaled by month and reported as a monthly LLH total. Likewise, all efficiency changes occurring during the HLH period are totaled by month and reported as a monthly HLH total. *Id.*

Q. *Does the energy used in providing the* inc *reserves and* dec *reserves balance over time?*

A. Yes. Over time, BPA assumes that the energy consumed during the deployment of balancing reserves nets to zero. Wellschlager *et al.*, BP-14-E-BPA-26, section 4.

Q. *If, over time, the expected average control error is zero MW, why are response losses not zero on average?*

A. Response losses are not zero because the gains and losses in efficiency incurred during reserve deployment are not symmetrical. That is, the change in efficiency for a 1 MW increase in generation is not equal to the change in efficiency for a 1 MW decrease in generation. The degree of this asymmetry is driven by the particular characteristics of a given unit family, the unit's generation level, the unit commitment, and corresponding efficiency prior to reserve deployment.

Q. *How are response losses priced?*

A. Response losses are priced at the monthly HLH price from the market price forecast, as calculated in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

Q. *Why is the HLH price used for all periods?*

A. The HLH price is used because response impacts, losses and gains in energy, are taken out of or put into the HLH period.

Q. *Are response gains also priced at the HLH price?*

A. Yes.

Q. *Are response losses accounted for in any other rate studies?*

A. Yes. All response losses calculated by the GARD Model are sent to RevSim, so the impact to secondary net revenue is correctly reflected. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. Based on the amount of balancing reserve capacity described in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast cost for response losses?

A. The total annual average response loss for the FY 2014–2015 period is 42,397 MWh, worth $1,372,188. Documentation Table 3.11, lines 12-13.

Q. Please describe the subcategory of deployment cost known as deployment cycling losses.

A. Deployment cycling losses are realized during the course of reserve deployment when committed units responding to a balancing need cannot continue deploying *inc* or *dec* reserves while staying within unit-specific operating constraints, and/or additional units are needed to continually maintain the Operating Reserve obligation. When committed units have reached their limits, additional units are brought online in the event of continued *inc* deployment or taken offline in the event of continued *dec* deployment.

Q. How are deployment cycling losses different from cycling losses?

A. Cycling losses are associated with the additional unit cycles required to meet both a project's generation request and stand-ready reserve requirement. Deployment cycling losses are experienced during actual reserve usage as additional units are brought online or taken offline.

Q. Is there overlap between response losses and deployment cycling losses?

A. No. Response losses apply to only those units that are already committed and online when reserves are deployed. Deployment cycling losses are associated with non-spinning units being brought online to respond to the *inc* signal or units being taken offline to respond to the *dec* signal.

Q. How are deployment cycling losses modeled?

A. The GARD Model determines how many units from each unit family are cycled by re-optimizing the unit commitment and dispatch. As generating units are cycled on or off, water is lost to synchronization and/or ramping. Study section 3.4.4.2.

Q. How does the GARD Model use the inputs described above to calculate the deployment cycling losses?

A. The deployment cycling loss calculations are controller project-specific and are functions of the individual unit efficiency curves as well as the level of generation required from the individual units. For each unit on cycle, synchronization and ramping losses are calculated. For each unit off cycle, only ramp-down losses are calculated. Water lost during synchronization to grid frequency equals 10 percent of full gate flow for three minutes. Losses associated with ramping are determined by calculating the excess water used in ramping a unit from minimum loading up to its requested generation. The amount of this loss varies and is directly related to the characteristics of the unit being ramped. The GARD Model fully ramps units to their requested generation level over seven minutes. As with cycling losses for stand-ready cost, the calculation of cycling losses does not attempt to account for any additional maintenance costs that may be realized due to frequent cycling of the units.

Q. How are deployment cycling losses priced?

A. All deployment cycling losses are priced at the monthly HLH price from the market price forecast, as calculated in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

Q. Why is the HLH price used for all periods?

A. The HLH price is used because energy lost due to cycling is taken out of the HLH period.

Q. Are deployment cycling losses accounted for in any other rate studies?

A. Yes. All deployment cycling losses calculated by the GARD Model are sent to RevSim, so the impact to secondary net revenue is correctly reflected. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. Based on the amount of reserves described in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast cost for deployment cycling losses?

A. The total annual average deployment cycling loss for the FY 2014–2015 period is 4,797 MWh, worth $157,629. Documentation Table 3.11, lines 14-15.

Q. Please describe the subcategory of deployment cost known as deployment spill losses.

A. Deployment spill arises if GCL receives a *dec* reserve deployment request requiring generation changes jeopardizing its dynamic tailwater limitations. GCL's ability to drop generation is limited because of tailwater bank stability concerns, which limits the rate of change in project outflow. More specifically, the limit is on how quickly the outflow may decrease. If GCL's tailwater elevation decreases too quickly, the downstream river banks begin to collapse.

Q. How are deployment spill losses calculated by the GARD Model?

A. Deployment spill losses are calculated using a functional relationship between GCL's generation and its minimum generation. This is a dynamic relationship serving to maintain downstream bank stability. Should violation of tailwater constraints become a risk, GCL will have to spill water during the course of the *dec* deployment to maintain acceptable rates of change in tailwater elevation as the generation is dropping.

Q. How does the GARD Model account for unique characteristics of the GCL project?

A. As stated above, spill may occur if the generation drop exceeds the drop rate allowed by the project. The drop rate constraint is a particular feature of GCL. If the *dec* request exceeds the limit, additional water must be spilled to slow the rate of change in the tailwater elevation. The tailwater constraint is represented in the GARD Model as a function of GCL LLH generation.

Q. How are deployment spill losses priced?

A. All deployment spill losses are priced at the LLH market price from the market price forecast, as calculated in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. This is because the energy cannot be shaped into HLH. In these instances, the system must continue to move the water on LLH even if generation is decreasing during a *dec* reserve deployment. Because the water must continue to move, the opportunity to shape into HLH does not exist, and only LLH generation is forgone.

Q. Is deployment spill accounted for in any other rate studies?

A. Yes. All deployment spill calculated by the GARD Model is sent to RevSim, so the impact to secondary net revenue is correctly reflected. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.5.

Q. Based on the amount of reserves described in the Balancing Reserve Capacity Quantity Forecast, what is the proposed forecast cost for deployment spill?

A. For FY 2014–2015, the total annual average deployment spill loss incurred deploying *decs* is 79 MWh, worth $2,223. Documentation Table 3.11, line 16.

Section 5.2: Variable Cost of Reserves

Q. What is the total forecast variable cost of providing reserves?

A. The total variable cost of providing reserves for the FY 2014–2015 period is $14,202,873 annually, based on the average amount of reserves described in the Study, section 2, and the spinning portion of the Operating Reserve described in the Study, section 4. Documentation Table 3.12, line 6.

Q. What is the purpose of apportioning cost to the different types of reserves?

A. The total variable cost of providing balancing reserve capacity is apportioned according to type of reserve to ensure cost recovery from the appropriate rates. Specifically, the

total cost is apportioned into the cost of load Regulating Reserve, load following and energy imbalance for load, VERBS, DERBS, and Spinning Operating Reserve. The costs we allocate to load Regulating Reserve, VERBS, DERBS, and Operating Reserve are recovered through the Ancillary and Control Area Services rates. The remaining costs, those for load following and energy imbalance reserve, are recovered through the PF rate. Documentation Table 3.12.

Q. How is the balancing reserve capacity cost apportioned to reserve type?

A. The balancing reserve capacity costs are apportioned to reserve type in direct proportion to a given reserve type's composition of spinning (*inc*), non-spinning (*inc*), and *dec* reserves. Study section 3.4.5. From the GARD Model, the total cost for supplying all reserve products is totaled into the general categories of spinning, non-spinning and *dec*. The proportion of spinning reserve required for each of the reserve products is calculated relative to the total reserve. This proportion is used to allocate the total cost to the reserve product. Similarly, the proportion of non-spinning reserve required by each of the reserve products is calculated relative to the total reserve. This proportion is used to allocate the total cost of non-spinning reserve to the specific reserve products. *Dec* reserves are all spinning, and the process for allocating the *dec* cost is performed in the same fashion.

Section 5.3: Alternative Variable Cost Forecast

Q. Were any other variable cost forecasts generated?

A. Yes. In addition to calculating the cost of reserves based on the 99.5 percent level of service in the Balancing Reserve Capacity Quantity Forecast with self-supply of generation imbalance and a reduction for 30/30 committed scheduling, another study was run. The other study calculated the Variable Cost without self-supply of generation

imbalance but does include the reduction for 30/30 committed scheduling. Both studies capped the amount of balancing reserve capacity provided from the FCRPS at 900 MW *inc* and 1100 MW *dec*. *See* Documentation Table 3.16.

Section 5.4: VERBS Credit Adjustment to Generation Inputs Revenue Forecast

Q. Are there times of the year where BPA is not able to provide the full balancing reserve capacity?

A. Yes. As explained in Kerns *et al.*, BP-14-E-BPA-23, there are times at which the flexibility of the FCRPS is limited due to the need to meet non-power, high-priority, hydraulic objectives. During these times the full balancing reserve capacity may not be available. BPA staff (Kerns *et al.*, BP-14-E-BPA-23, section 4) project that the FCRPS will be able to supply the rate case forecast amount of balancing reserve capacity approximately 98 percent of the time on an average annual basis.

Q. How are you proposing to account for these reductions in the balancing reserve capacity of the FCRPS?

A. As described in Fisher *et al.*, BP-14-E-BPA-21, section 6, we are proposing to provide VERBS ratepayers a rate credit so that VERBS customers do not bear the costs of Federal balancing reserve capacity that BPA is unable to provide because of hydro system limitations.

Q. How is the value of the VERBS rate credit determined?

A. We propose to make an adjustment to the generation inputs revenue forecast based on an expected value of the percent of balancing reserve capacity availability from the FCRPS and the VERBS Credit rate. As noted above, BPA estimates balancing reserve capacity availability will be 98 percent on an annual average basis over the FY 2014–2015 rate period. For the estimated 2 percent of balancing reserve capacity unavailability from the

FCRPS, we applied the VERBS Credit *inc* rate of $7.30 per kW per month of balancing reserve capacity plus the VERBS Credit *dec* rate of $0.60 per kW per month of balancing reserve capacity to produce a result of approximately $1.0 million on an annual average basis for the rate period. Documentation Table 3.21.

Q. Was this rate credit reflected in the generation input revenue forecast included in the Initial Proposal?

A. No. The generation inputs revenue forecast was completed for the Initial Proposal before the calculation for the impact of the VERBS Credit was included in the revenue forecast. The VERBS Credit will be included in the generation inputs revenue forecast when the final rate case numbers are run for the Final Study, which will be based on the best information available at that time.

Section 6: Types of Balancing Reserve Capacity Purchases

Q. Have you identified the potential for BPA to purchase balancing reserve capacity during the FY 2014–2015 rate period to support its Balancing Services?

A. Yes. We have identified the potential for four types of balancing reserve capacity purchases during the FY 2014–2015 rate period. Study section 3.5.

Q. What are the four types of balancing reserve capacity acquisitions that you have identified?

A. As described in greater detail in the Study, section 3.5, we have identified four types of balancing reserve capacity purchases. Type 1 purchases are planned purchases needed to make up the shortfall between the planned Federal balancing reserve capability (900 MW) and the rate case planned balancing needs of the Base Service after adjusting for any self-supply of generation imbalance (CSGI or other). Type 2 purchases are needed when BPA is operationally unable to provide the planned Federal balancing

reserve capacity (up to 900 MW). Type 3 purchases are needed to provide the Full Service balancing service option. Type 4 purchases are needed to support an unplanned increase in balancing services needed by the balancing authority area.

Q. Why do you separate balancing reserve capacity acquisitions into four types?

A. Each type is made for a specific purpose and under a specific circumstance. These differences in purpose and circumstance justify a distinction and warrant different methods for allocating their costs.

Q. How do you propose to allocate costs for Type 1 purchases?

A. We propose to allocate Type 1 purchase costs based on a methodology that determines which balancing service use causes the need for BPA to acquire balancing reserve capacity. The methodology is applied equally and consistently across three identified use categories (Categories): load, dispatchable energy resources, and variable energy resources (which includes solar resources). Study section 3.5.3.

Q. Why do you apply the principle of cost causation to purchases to these three Categories?

A. We propose these three Categories because of the significant difference in operational characteristics between load, dispatchable energy resources, and variable energy resources, as demonstrated through the Balancing Reserves Capacity Quantity Forecast Study. *Id.* section 2. That said, we acknowledge that there can be a significant difference in operational characteristics among customers within each of these three use Categories. Given that the forecast need to acquire balancing reserve capacity is new to BP-14, we propose an approach that identifies cost causation at the first level of operational characteristic differentiation.

Q. What do you mean by "operational characteristic differentiation"?

A. We use operational characteristics to mean the amount of reserve requirement needed relative to a Category's size – a percentage that measures the amount of reserve

requirement a Category, a resource type, or a particular resources needs in proportion to its nameplate (or equivalent for load). As identified in the Balancing Reserves Capacity Quantity Forecast Study, this percentage varies significantly among the three Categories, but also within the Categories. For example, on aggregate, dispatchable energy resources have a balancing reserve capacity requirement equal to 1.1 percent of their nameplate while variable energy resources have a balancing reserve capacity requirement equal to 11.2 percent of their nameplate (given certain scheduling elections and self-supply assumptions). Documentation Table 3.19. However, within the variable energy resource Category, there are also significant differences between solar resources (2.0 percent) and wind resources participating in 30/30 committed scheduling (10.5 percent). Documentation Table 3.20.

Q. Explain how a lower level of operational characteristic differentiation could be applied to the methodology (i.e., defining more than three use categories).

A. While not part of our initial proposal, this cost causation methodology could be applied to more use categories (at a more granular level). A more granular approach could be used to identify and distinguish cost causation within the three use categories we propose (load, dispatchable energy resources, and variable energy resources). Subcategories of variable energy resources could be created to distinguish the causation of purchases between different variable energy resources and their elections. For example, a subcategory could be used to distinguish among: (1) a solar resource and a wind resource; (2) a resource with a self-supply commitment that reduces BPA's need to purchase balancing reserve capacity; and (3) a resource that uses scheduling practices that contribute more to (or cause) BPA's need to purchase balancing reserve capacity. While these types of subcategories are not part of our Initial Proposal, the expanded category examples listed above have been included to illustrate how the cost causation

methodology would work with more than our initially proposed three use Categories. Documentation Table 3.20.

Q. How do you propose to allocate costs for Type 2 purchases?

A. We propose to allocate Type 2 purchase costs to all resources (with the exception of AGC-controlled hydro resources) based on their proportional monthly balancing reserve capacity need. AGC-controlled hydro resources are excluded since they are resources providing balancing reserve capacity. Study section 3.5.4.

Q. Why do you use a different approach for Type 2 purchases than is proposed for Type 1 purchases?

A. Type 1 purchases are caused by demand, which means they can be linked to a particular customer or customer category (based on cost causation). In addition, the amount of Type 1 purchases needed during the rate period will be forecast in the final studies. This allows us to use a straightforward method for determining cost causation with regard to Type 1 purchases and set rates accordingly. Type 2 purchases are different. Type 2 purchases are caused by an unplanned reduction in BPA's supply of balancing reserve capacity. Furthermore, the amount of Type 2 purchases will not be known until after rates are set. Essentially, Type 2 purchases are the result of the actual capability of the FCRPS being less than the forecast used in the rate case (*i.e.*, rate case forecast error). This is just one of many actuals that will be different from the forecasts and assumptions used in the rate setting process. For these reasons, we propose that these purchase costs be allocated more broadly than the other three types of purchases and that BPA not reassess purchase responsibility used for Type 1 purchases in the middle of a rate period. Instead, we propose to allocate the costs of Type 2 purchases to all resources (with the exception of AGC-controlled hydro) and reevaluate the forecast planned FCRPS capability in the next rate setting process.

Q. Why does load not share in the cost of Type 2 purchases?

A. All balancing capacity uses are impacted if the FCRPS cannot provide the rate case forecast amount of balancing reserve capacity. While variable energy resources and dispatchable energy resources are exposed to the cost of Type 2 purchases, load is impacted by funding the VERBS Credit. Load is financially impacted in two different ways depending on the customer type – Slice or Non-Slice. Slice customers are affected through upward pressure (increased costs to Slice customers) on the Slice True-Up, since the Slice True-Up accounts for reduced revenue provided from the VERBS. Non-Slice customers are impacted through upward pressure on (or the use of) cash reserves, since the portion of BPA's revenue requirement that was forecast to be recovered from VERBS customers is no longer collected. In order to mitigate this particular source of Power Services' revenue risk, we propose to downward adjust the full generation inputs credit that is included in the Composite Cost Pool revenue credit by the expected value of the VERBS Credit. *See* Study section 3.6. If load were allocated Type 2 purchase costs, it would result in load paying twice for the same event when the FCRPS is unable to provide the rate case planned amount of balancing reserve capacity: once through the VERBS Rate Credit from Power financial reserves, and again through the allocation of Type 2 purchase costs.

Q. How do you propose to allocate Type 3 purchases?

A. Type 3 purchases are made for the Full Service option available to variable energy resources. Consistent with cost causation, we propose these costs be allocated to variable energy resources that take Full Service.

Q. How do you propose to allocate Type 4 purchases?

A. Type 4 purchases are made if BPA has an unplanned increase in balancing services. This can occur for several reasons: (1) a resource has elected to self-supply but is unable to

continue self-supplying one or more components of VERBS or DERBS; (2) a resource has a projected interconnection date after FY 2015 but interconnects during the FY 2014–2015 rate period; (3) a variable energy resource commits to a specific scheduling practice but does not maintain a scheduling performance consistent with or better than that committed scheduling practice; (4) a variable energy resource elected Base Service with a committed scheduling option but chooses to take Base Service with a longer scheduling period; or (5) a non-Federal thermal resource operating in another balancing authority area chooses to dynamically transfer into the BPA balancing authority area during the FY 2014–2015 rate period. We propose that the costs that result from the need for Type 4 purchases be directly assigned to the customer that received the expanded balancing service. This allocation would apply until BPA can reflect the increased balancing need in the rate setting process.

Q. Is your cost allocation proposal consistent with the principle of cost causation?

A. Yes. Our proposal is that demand (or need) caused purchases be allocated to the balancing capacity user that caused that cost. Type 1, Type 3, and Type 4 purchases are demand-caused purchases and can be linked to a particular customer or customer Category. As stated above, Type 2 purchases are different because they are supply-caused and are a result of forecast error. For this reason, we propose to allocate the costs to the users that are affected by the supply.

Q. Why is your proposed Type 1 purchases cost allocation methodology fair and equitable?

A. The methodology is fair and equitable because it is applied consistently across all users of balancing capacity. Simply stated, Type 1 purchase costs are allocated to the Categories with remaining balancing service need after all Categories are first provided equal access to the cost of the planned FCRPS balancing reserve capacity, which is an amount of FCRPS-sourced balancing reserve capacity equal to approximately 3.5 percent of a

Category's nameplate (or nameplate equivalent for load). As described above, the operational characteristics of users of balancing capacity vary considerably, with some users requiring more than 14 percent of their nameplate while others require less than 2 percent. Documentation Tables 3.19 and 3.20. The FCRPS is planned to be able to provide 3.5 percent of the total nameplate (or equivalent for load) of all balancing users. The cost allocation methodology provides equitable treatment among all balancing users by identifying the balancing reserve capacity uses that cause BPA's need to acquire Type 1 purchases and allocating those costs to those uses.

Q. Why is your proposed Type 2 purchases cost allocation methodology fair and equitable?

A. Given the circumstances under which Type 2 purchases occur (an unexpected decrease in the supply of balancing reserves capacity), we believe the proposed allocation is fair and equitable. Under our proposal, costs are allocated proportionally to the users that are affected by Type 2 purchases.

Q. Why is your proposed Type 3 purchases cost allocation methodology fair and equitable?

A. Our proposal for Type 3 purchases is to allocate these costs to the customers that take the service that creates the costs. If no customers take Full Service, BPA will not need to make any Type 3 purchases and will not incur any Type 3 purchase costs. Type 3 purchase costs are a direct result of a customer's use of balancing reserve capacity under the Full Service option and, thus, the customers that take Full Service should be allocated the costs of providing that service.

Q. Why is your proposed Type 4 purchases cost allocation methodology fair and equitable?

A. Our proposal for Type 4 purchases is to directly assign the costs of Type 4 purchases to the customers that cause the need for those purchases. For example, Type 4 purchases can be the result of customers doing something different than what they committed to do.

It would be unfair and inequitable to allocate these purchase costs to customers other than to the customers that were unable to meet their commitments.

Type 4 purchases can also result when a new customer that was not expected requests balancing service in the middle of a rate period. While this particular event is the result of forecast error, it is demand-caused, which justifies a different approach than what was used for Type 2 purchases. BPA has routinely required that unanticipated service be at the marginal cost of that service until BPA can properly account for that service the next time it sets rates. For example, this approach is demonstrated through the BPA's Priority Firm (PF) and New Resources (NR) Unanticipated Load Rate. *See* Power Rate Schedules, BP-14-E-BPA-09.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

RONALD E. MESSINGER, DANNY L. CHEN and JANET ROSS KLIPPSTEIN

Witnesses for Bonneville Power Administration

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TESTIMONY of

RONALD E. MESSINGER, DANNY L. CHEN, and JANET ROSS KLIPPSTEIN

Witnesses for Bonneville Power Administration

SUBJECT: OPERATING RESERVE COST ALLOCATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46.

A. My name is Danny L. Chen, and my qualifications are contained in BP-14-Q-BPA-10.

A. My name is Janet Ross Klippstein, and my qualifications are contained in BP-14-Q-BPA-37.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor section 4 of the Generation Inputs Study, BP-14-E-BPA-05 (Study) and section 4 of the Generation Inputs Study Documentation, BP-14-E-BPA-05A (Documentation). We explain how Operating Reserve amounts are forecast and describe the proposed cost allocation for Operating Reserve.

Section 2: Operating Reserve Forecast

Q. What is Operating Reserve?

A. Operating Reserve constitutes the generating capacity necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment. Within a balancing authority area, adequate generating capacity must be available at all times to maintain scheduled frequency and avoid loss of firm load following generation or transmission contingencies. Operating Reserve is described as "Contingency Reserves" under the Western Electricity Coordinating Council (WECC) reliability

standard. For the purpose of this testimony, BPA refers to this reserve capacity as Operating Reserve, which is consistent with definitions contained in BPA's Open Access Transmission Tariff (OATT).

Q. Please describe BPA's relationship to the Northwest Power Pool (NWPP).

A. BPA is a participating member of the NWPP Reserve Sharing Program for Contingency Reserves. By participating in the Reserve Sharing Program, BPA is better positioned to meet NERC disturbance control standards due to access to a deeper and more diverse pool of shared reserve resources. Participation in this program also increases efficiency in that the shared reserve obligation for the group as a whole is less than the sum of all the individual participants' reserve obligations. By sharing reserves, participants are entitled to use not only their own "internal" reserve resources, but also may call on other participants for assistance if their internal reserve capacity does not fully cover a contingency.

Q. When is Operating Reserve needed?

A. Operating Reserve is needed when forced outages of generation or transmission equipment occur. Within a Reserve Sharing Group, such as the NWPP, adequate generating capacity must be available at all times to maintain scheduled frequency and avoid loss of firm load following generation or transmission contingencies.

Q. What is Spinning Operating Reserve?

A. Spinning Operating Reserve is a portion of the total Operating Reserve. Spinning Operating Reserve is provided by the unloaded generating capacity of the system's firm resources that are synchronized to the power system, responsive to frequency deviations, and ready to serve additional demand. These firm resources must respond immediately to serve load in the event of a system contingency and be capable of providing the full Spinning Operating Reserve obligation within 10 minutes. WECC requires each

balancing authority area to maintain a Spinning Operating Reserve obligation equal to a minimum of 50 percent of its Operating Reserve obligation.

Q. What is Supplemental (Non-Spinning) Operating Reserve?

A. Supplemental (Non-Spinning) Operating Reserve is the portion of the total Operating Reserve obligation that does not meet the definition of Spinning Operating Reserve. Supplemental Operating Reserve is generating capacity that is not necessarily synchronized to the system but is capable of serving demand within 10 minutes, or interruptible load that can be removed from the system within 10 minutes. This reserve capacity must be capable of fully synchronizing to the system and ramping to meet load within 10 minutes of a contingency.

Q. Are transmission customers allowed to obtain Operating Reserve from other suppliers?

A. Yes. The BPA OATT allows transmission customers to obtain Operating Reserve by (1) self-supply; (2) purchase from a third party; or (3) purchase from BPA Transmission Services (TS). Currently, the BPA business practice for Operating Reserve allows transmission customers to either make a two-year election to have TS as their supplier or choose another supplier. The transmission customer has the option to change non-TS suppliers annually. If the customer does not make an affirmative election to self-supply or acquire Operating Reserve from a third party, the customer must purchase Operating Reserve from TS.

Q. Have any transmission service agreement holders elected to obtain Operating Reserve from sources other than BPA?

A. Yes, some transmission customers have elected to obtain Operating Reserve from other suppliers, either by self-supply or third-party supply to meet their reserve obligation within the BPA balancing authority area.

Q. If transmission service agreement holders elect alternative sources of Operating Reserve, what is the impact to BPA generation inputs for Operating Reserve?

A. If transmission customers elect to self-supply or third-party supply their Operating Reserve obligation, the amount of BPA-supplied generation inputs for Operating Reserve is reduced. Study section 4.3; Documentation Table 4.2.

Q. How do you determine the forecast reserve obligation for Operating Reserve?

A. We forecast the requirement based on historical Operating Reserve requirements in the BPA balancing authority area. We first forecast the balancing authority area requirement consistent with the WECC standard based on a statistical regression approach. We then forecast the expected amount of reserve obligation that transmission customers will elect to self-supply or third-party supply Operating Reserve based on the elections as of May 2011, which reduces the BPA Operating Reserve requirement. The remainder is the amount forecast to be supplied by BPA through generation inputs. Study section 4.3.

Q. What is the current WECC Operating Reserve requirement that applies to balancing authority area operators?

A. The current WECC standard for Operating Reserve (BAL-STD-002-0) establishes the minimum amount of spinning and non-spinning (Supplemental) Operating Reserve that BPA must set aside for its balancing authority area. The minimum Operating Reserve is currently the greater of (a) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or (b) the sum of 5 percent of the balancing authority's load responsibility served by hydro and wind generation and 7 percent served by thermal generation. At least 50 percent must be spinning reserve.

Q. Is there a proposal to change the current WECC Operating Reserve requirement that applies to balancing authority area operators? Please explain.

A. Yes. WECC is seeking approval for BAL-002-WECC-1, which states that the minimum Operating Reserve requirement is the greater of the most severe single contingency or the sum of 3 percent of load and 3 percent of generation. The WECC Board approved the proposed BAL-002 standard in June 2012 and is currently awaiting approval from NERC and the Federal Energy Regulatory Commission (Commission).

Q. Are you proposing to change its reserve requirement assumptions for the Operating Reserve forecast during the FY 2014–2015 rate period? Please explain.

A. No. The reserve requirement assumption for the Operating Reserve forecast depends on the timing of BAL-002-WECC-1 approval. This assumption is based on the best available information at the time the forecast is made. BPA made a split assumption in the FY 2010–2011 and FY 2012–2013 rate cases, using the requirements of 5 percent of hydro/wind generation and 7 percent of thermal generation in the first year, and 3 percent of both generation and load in the second year based on WECC approval and assumption of Commission approval during the rate period. However, Commission approval did not occur, and the standard was remanded back to WECC. Currently, however, we believe that it is likely that the Commission will decide to approve the BAL-002-WECC-1 regional reliability standard effective on or before the start of the FY 2014–2015 rate period.

Q. Why are you proposing to forecast Operating Reserve requirements for FY 2014–2015 using only the requirements of the new proposal currently under consideration for NERC approval?

A. Based on the WECC revisions to the standard that address the issues raised by the Commission, and the WECC Board's approval of the standard in June 2012, we anticipates that NERC and Commission approval is likely to occur in FY 2013, allowing

sufficient implementation time for the proposed standard to be effective for the FY 2014–2015 rate period.

Section 3: Allocating Cost for Operating Reserve

Q. Are you proposing any changes to the Operating Reserve cost allocation as compared to the FY 2012–2013 cost allocation for Operating Reserve?

A. No. There are no proposed changes to the embedded cost methodology for Operating Reserve. Study section 4.4.

Q. Please give a general overview of your proposed embedded cost calculation for Operating Reserve.

A. The net revenue requirement associated with the hydro resources capable of providing Operating Reserve is divided by the sum of the regulated and applicable independent hydro projects capacity uses and the total reserve requirement. The result is a unit cost for all uses of capacity, which is multiplied by BPA's Operating Reserve obligation to allocate embedded costs to Operating Reserves.

Q. What was the derivation of the revenue requirement attributable to the subset of resources capable of providing Operating Reserve?

A. The embedded cost Net Revenue Requirement for Operating Reserve is composed of (1) power-related costs of the relevant hydro projects on a project-specific basis; (2) an allocation of associated fish mitigation costs; (3) allocation of the administrative and general expense; and (4) three revenue credits. Study section 4.4.3; Documentation Table 4.5. The revenue requirement associated with the resources capable of providing Operating Reserve is consistent with BPA's Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2, Table 2F.

Q. Please describe the system resources available for providing Operating Reserve.

A. To determine the system resources identified for the Operating Reserve cost allocation, we first identify those Federal resources in the BPA balancing authority area available to provide Operating Reserve. An example of a resource not able to supply Operating Reserve is Columbia Generating Station (CGS), which operates most economically at 100 percent capacity. As such, it has no ability to respond to requests for additional capacity to be dispatched in the event of a disturbance. Some small run-of-river independent resources also are not able to supply Operating Reserve due to operational limitations, and some small independent hydro resources are outside of BPA's balancing authority area. All remaining system resources are available to provide Operating Reserve – Spinning or Operating Reserve – Supplemental. Study section 4.4.2; Documentation Table 4.4.

Q. Please describe how you quantify the size of the system that is used to allocate costs for the Operating Reserve uses of the system.

A. We sum the regulated hydro projects, applicable independent hydro projects that can be counted on for capacity uses, and the total reserve requirement. We use a 120-hour peaking capacity measurement for the regulated hydro resources. For a detailed discussion of the 120-hour peaking capacity, see Study section 3.2. The independent hydro resources' capacity is based on mid-month elevations. The calculation uses the 1958 water year, which represents average water conditions. The total reserve requirement includes Regulating, Load Following, Operating, Dispatchable Energy Resource Balancing Service, and Variable Energy Resource Balancing Service balancing reserve capacity, as determined by the Balancing Reserve Capacity Quantity Forecast. Study section 2; Documentation Tables 2.18–2.22.

Q. Please describe why you add Regulating, Load Following, Operating, Dispatchable Energy Resource Balancing Service, and Variable Energy Resource Balancing Service reserve capacity to the regulated and independent resource capacity value for purposes of determining the total capacity system uses.

A. The two models (a combination of HYDSIM and HOSS models) used to quantify the 120-hour peaking capability of the regulated hydro include a reduction to the system capability for balancing and operating reserve capacity. Therefore, to correctly capture the entire amount of capacity available for system uses, we add the reserve capacity (which is a use of the system) back into the capacity quantities. Study section 4.4.1.

Q. Do you use the same methodology proposed to allocate embedded costs to Operating Reserve for both Spinning Operating Reserve and Supplemental Operating Reserve?

A. Yes, although the Spinning Operating Reserve does have a variable cost component added to its cost allocation. *Id.*

Q. Why did you add a variable cost component to the Spinning portion of the Operating Reserve cost allocation and not the Supplemental portion?

A. Ensuring that sufficient Spinning Operating Reserve exists at all times to respond to a qualifying contingency imposes a measurable variable cost on the system. See Study section 3.4 and Klippstein *et al*., BP-14-E-BPA-24, section 5, for further discussion of these variable costs. Therefore, we assigned a variable cost component to the Spinning portion of the Operating Reserve cost allocation. *Id.*

Q. What is the unit cost and total forecast cost allocation for Operating Reserve?

A. The total forecast cost allocation for Operating Reserve on an annual average basis is $50,939,235. The unit cost for the Supplemental portion is $7.26 per kW per month, comprised of only an embedded cost allocation. The unit cost for the Spinning portion is $7.93 per kW per month, comprised of an embedded cost allocation of $7.26 per kW per

month plus a variable cost allocation of $0.67 per kW per month. Study sections 4.4.3–4.4.5.

Q. How do you propose BPA recover its costs when Operating Reserve is called upon to deliver energy?

A. When Operating Reserve is utilized to provide energy, that energy is priced based on an hourly energy index in the Pacific Northwest, or an alternative index if an adequate hourly index is not available, as determined by BPA. Study sections 10.4.1–10.4.2. We are forecasting no revenue from the energy associated with deployment of reserve capacity, because BPA will be compensated at the current market price at the time of deployment. There is no difference in cost recovery between using the energy for an Operating Reserve deployment and selling the power off the trading floor.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

JOHN D. WELLSCHLAGER, DANNY L. CHEN,

MELIKE B. KAYIM, AND RONALD E. MESSINGER

Witnesses for Bonneville Power Administration

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TESTIMONY of

JOHN D. WELLSCHLAGER, DANNY L. CHEN,

MELIKE B. KAYIM, AND RONALD E. MESSINGER

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS FOR OTHER SERVICES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is John D. Wellschlager, and my qualifications are contained in BP-14-Q-BPA-64. I am a witness for Synchronous Condensing.

A. My name is Danny L. Chen, and my qualifications are contained in BP-14-Q-BPA-10. I am a witness for Generation Dropping and Generation Input to Supply Energy for Imbalance Services.

A. My name is Melike B. Kayim, and my qualifications are contained in BP-14-Q-BPA-32. I am a witness for Synchronous Condensing, Generation Dropping, and Generation Input to Supply Energy for Imbalance Services.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46. I am a witness for Synchronous Condensing.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor sections 5 and 6 of the Generation Inputs Study, BP-14-E-BPA-05 (Study), and its Documentation, BP-14-E-BPA-05A (Documentation). We: (1) describe Synchronous Condensing and the allocation of costs to Transmission Services (TS) for operating Federal Columbia River Power System (FCRPS) hydro units as synchronous condensers; (2) explain the costing methodologies used to allocate generation costs to Generation Dropping; and (3) explain the energy and

generation imbalance services and the proposed cost allocation for the associated generation input.

Section 2: Synchronous Condensing

Q. What is a synchronous condenser?

A. A synchronous condenser is essentially a motor with an exciter system that enables it to dynamically absorb or supply reactive power as necessary to maintain voltage as needed by the transmission system. Study section 5.1. Some FCRPS generating units are capable of operating in synchronous condenser or "condense" mode and are requested to do so at times by TS for voltage control. *Id.* As with any motor, FCRPS generators operating in synchronous condense mode consume real power supplied by the FCRPS. *Id.*

Q. What is the distinction between generators operated for power production and generators operated as synchronous condensers?

A. Generators operated in condense mode perform the same voltage control function as when producing real power. Normally, generating units are operated to produce real power and at the same time provide voltage control. However, at certain times real power production must be curtailed (*e.g.*, for fish-related spill). At such times, having units idle at particular locations may degrade reliability, so the transmission system operator will request that certain units be operated in condense mode. Generators operated in condense mode perform the same voltage control function as generators that are producing real power, but the units are not capable of producing any real power while being operated in condense mode. This is because the generator turbine is "de-watered" by shutting off the water supply (and using air compressors, if necessary, to push water below the blades of the turbine), so that the unit may spin freely.

Q. Why is the operation of certain FCRPS generators in condense mode an important service?

A. At certain locations and under certain conditions, having generating units offline adversely affects transmission reliability. For example, TS monitors and manages reactive margins to support transfers on the Southern Intertie. To the extent a sufficient number of units are not online and generating near the Intertie, TS will request that units be placed in condense mode to ensure adequate voltage support and reactive reserves.

Q. What costs do you propose to assign to TS for synchronous condensing?

A. We propose the following costs be assigned to TS for synchronous condensing:

(1) Energy costs consumed by FCRPS generators while operating in condense mode for voltage control; and

(2) Investment in plant modifications at the John Day and The Dalles projects necessary to provide synchronous condensing. Study section 5.2.

Q. Why do you use the market price forecast to calculate the cost allocation for synchronous condensing?

A. Because the energy consumed to run these units is energy not available to market, it is appropriate to use the market price of this energy rather than the PF rate. This valuation more accurately reflects the alternative use of this energy. The market price forecast for the risk analysis is used to be consistent with other market valued power forecasts in this rate case. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

Q. What is the total cost assigned to TS for synchronous condensing?

A. The proposed cost of generation inputs to provide synchronous condensing is $1,578,953 per year ($1,291,953 per year for energy consumed by synchronous condensing, and an average of $287,000 per year for synchronous condenser plant modifications at John Day and The Dalles). Study section 5.4; Documentation Tables 5.1 and 5.3.

Q. To which Transmission segments are the costs for Synchronous Condensing assigned?

A. Costs associated with John Day and The Dalles projects are assigned to the Southern Intertie Segment. Documentation Table 5.3. Costs for all other projects are assigned to the Network Segment.

Section 3: Generation Dropping

Section 3.1: Generation Dropping Frequency Forecast

Q. What is Generation Dropping?

A. Generation Dropping is a remedial action scheme (RAS) action implemented to maximize transfer capacity on constrained transmission paths and to protect the system against cascading outages or other major system disturbances. Study section 6.2. These paths can be either internal to the BPA system (*e.g.*, the Raver-Paul line) or major interties to other systems, such as the California-Oregon Intertie (COI). For purposes of allocating generation input costs, we focus on the cost of Generation Dropping associated with the COI.

Q. Why does the cost analysis focus on Generation Dropping associated with the COI?

A. There is a contractual allowance in the Pacific Northwest AC Intertie Ownership Agreements that non-Federal participants associated with the AC intertie transmission that do not self-supply the generation dropping for their capacity ownership share of the intertie will be charged for BPA supplying the generation dropping. Currently, five out of six participants are not self-supplying.

Q. Which hydro projects are equipped to provide Generation Dropping for the COI?

A. The RAS associated with Generation Dropping for the COI path is armed to drop the large generating units at Grand Coulee and smaller generation units at Grand Coulee, Chief Joseph, McNary, John Day, and Lower Monumental.

Q. Why does the cost analysis focus on the large generation units at Grand Coulee?

A. The cost of using large units at Grand Coulee for Generation Dropping significantly exceeds the costs associated with wear and tear on smaller units at Grand Coulee and at the other projects that are sometimes used for Generation Dropping. Thus, we excluded the negligible impact of smaller units at Grand Coulee and at other projects in our cost analysis.

Q. How do you forecast the amount of average Generation Dropping per year?

A. Because events that cause generation to be dropped happen on an irregular basis, we determined that analyzing as long a period of time as possible would yield a more representative average historical pattern of generation dropping. Therefore, we considered all the data available since the first identified generation drop, which occurred in 1996. From 1996 through 2012 (a 17-year period), 18 drops have occurred, resulting in one drop per year on average. Study section 6.3.

Section 3.2: Generation Dropping Costs

Q. Did you make any changes to the methodology used to calculate costs for Generation Dropping from that used for the FY 2012–2013 rate period? If so, what were the changes?

A. We are using the same method of analysis for the BP-14 rate case that we used for the BP-12 case.

Q. What costs do you propose to assign to TS for Generation Dropping?

A. We propose the following costs be assigned to TS for generation dropping:

(1) Incremental equipment deterioration, replacement, or overhaul costs;

(2) Incremental routine operation and maintenance costs; and

(3) Incremental lost revenue in the event of replacement or overhaul.

Q. What are the amounts of these costs that you propose to allocate to Generation Dropping?

A. The costs are allocated to reimburse the three cost categories listed above. We calculated "Incremental Equipment Deterioration, Replacement, or Overhaul" costs to be $138,763 annually. We calculated "Incremental Routine Operation and Maintenance" costs to be $4,441 annually. We calculated "Incremental Lost Revenue in the Event of Replacement or Overhaul" costs to be $191,503 annually. Documentation Table 6.1, line 6.

Q. What is the total revenue forecast for Generation Dropping?

A. The cost of Generation Dropping allocated to TS, which becomes revenue to PS, is forecast at $334,707 annually for FY 2014–2015. *Id.*

Section 4: Generation Input to Supply Energy for Imbalance Services

Q. What is energy imbalance?

A. Energy Imbalance is an Ancillary Service that BPA provides to transmission customers with load in the BPA balancing authority area. Energy Imbalance is provided when there is a difference between scheduled and actual energy delivered to a load in the balancing authority area during a schedule hour. Study section 10.7.1.

Q. What is generation imbalance?

A. Generation Imbalance is a Control Area Service that BPA provides to generation resources with generation in the BPA balancing authority area. Generation Imbalance is provided when there is a difference between scheduled and actual energy delivered from a generation resource during a schedule hour. *Id.* section 10.7.2.

Q. What is the generation input to supply energy for imbalance needs?

A. As the Balancing Authority, TS supplies or absorbs energy to maintain load-resource balance within the BPA balancing authority area. When actual deliveries vary from scheduled deliveries, TS must use generation resources to supply imbalance needs to

make up the difference. This energy is supplied by Power Services except where a customer self-supplies its generation imbalance obligation.

Q. How is the generation input for energy and generation imbalance discussed here different from the imbalance component of Variable Energy Resource Balancing Service (VERBS) and Dispatchable Energy Resource Balancing Service (DERBS) reserve capacity described in other testimonies, e.g., BP-14-E-BPA-21 and BP-14-E-BPA-28?

A. The generation energy input for Energy and Generation Imbalance is an amount of energy required to meet the hourly imbalance calculated after the fact. Study sections 10.7.1 and 10.7.2. The imbalance capacity components of VERBS and DERBS are amounts of capacity, part of the total balancing reserve capacity that BPA sets aside and uses to balance the generation and load within the scheduling hour. *See id.* sections 2.1.2, 10.5, 10.6. The capacity provides the capability to provide the required amount of energy to meet the imbalance between scheduled and actual energy.

Q. How do you propose to price energy supplied from the Federal system for imbalance needs?

A. When energy is supplied from the Federal system to meet imbalance needs, such energy would be priced based on an hourly energy index in the Pacific Northwest, as determined by PS, and in accordance with the BPA Open Access Transmission Tariff and rate schedules. PS will determine an energy index based on volume of trade, liquidity, and price transparency that best reflects market value. If an adequate hourly energy index is not available, PS will apply the criteria set forth above to select an appropriate energy index.

Q. Why do you propose to use an hourly index to price energy supplied from the Federal system for imbalance services?

A. Because the energy forgone by these units is not available to market, it is appropriate to use the market price of this energy. This valuation reflects the opportunity cost of

energy. The market price forecast is used to be consistent with other market-valued power forecasts in this Initial Proposal. *See, e.g., id.* section 9.7.

Q. What effect does the use of non-Federal balancing reserves have on your proposal to use an hourly index to price energy for imbalance needs?

A. The use of non-Federal balancing reserves does not affect the cost of supplying energy from the FCRPS. The hourly index price is the cost of energy provided by PS to TS for imbalance needs. The Study describes our proposal to base the Energy Imbalance Service and Generator Imbalance Service rates on an hourly average cost of all energy deployed, Federal and non-Federal, to provide imbalance services. *Id.* section 10.7; *see also* Fisher *et al.*, BP-14-E-BPA-21, section 7.

Q. What is the revenue forecast for generation inputs to meet imbalance needs?

A. The net energy transfer can result in either a revenue or cost. The transfer results in revenue when TS provides energy to the customer to meet the imbalance and results in a cost when TS absorbs energy from the customer to meet the imbalance. The forecast for the FY 2014–2015 rate period is $0 revenue for energy to meet the imbalance needs, for both Energy and Generation Imbalance services. This is consistent with the TS forecast need for this service. Study section 10.7.

Q. Why are you forecasting $0 in revenue for generation inputs to provide imbalance services?

A. Revenues from imbalance services are dependent on variations in market price and each customer's scheduling accuracy. We are not forecasting any revenue from imbalance services because of the uncertainty associated with those variables. In addition, we expect the amount of imbalance on the system to decrease over the rate period. We are proposing to continue its Customer-Supplied Generation Imbalance pilot program and to expand the available committed scheduling options. *See* Fisher *et al.*, BP-14-E-BPA-21. All of these programs are expected to decrease the amount of imbalance. Fisher *et al.*,

BP-14-E-BPA-21, sections 5.1, 5.4. Therefore, we are not projecting any revenue associated with generation inputs for imbalance services.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

TRACEY L. SALAZAR, DANNY L. CHEN, MELIKE B. KAYIM,

JANET ROSS KLIPPSTEIN, KEVLYN D. MATHEWS,

RONALD E. MESSINGER, and GLENN A. RUSSELL

Witnesses for Bonneville Power Administration

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Witnesses for Bonneville Power Administration

SUBJECT: OTHER INTER-BUSINESS LINE ALLOCATIONS

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Tracey L. Salazar, and my qualifications are contained in BP-14-Q-BPA-56. I am a witness for Redispatch.

A. My name is Danny L. Chen, and my qualifications are contained in BP-14-Q-BPA-10. I am a witness for Station Service.

A. My name is Janet Ross Klippstein, and my qualifications are contained in BP-14-Q-BPA-37. I am a witness for Station Service.

A. My name is Kevlyn D. Mathews, and my qualifications are contained in BP-14-Q-BPA-44. I am a witness for Station Service.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46. I am a witness for Segmentation of COE and Reclamation Integrated Network and Delivery Facilities.

A. My name is Glenn A. Russell, and my qualifications are contained in BP-14-Q-BPA-54. I am a witness for Segmentation of COE and Reclamation Integrated Network and Delivery Facilities and Station Service.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor sections 7, 8, and 9 of the Generation Inputs Study, BP-14-E-BPA-05 (Study), and its Documentation, BP-14-E-BPA-05A (Documentation). We describe the forecast of revenues BPA Power Services (PS) will receive from BPA Transmission Services (TS) in the FY 2014–2015 rate period for Redispatch Services provided by PS under Attachment M of BPA's Open Access Transmission Tariff (OATT).

We also describe the segmentation analysis of the U.S. Army Corps of Engineers (COE) and U.S. Bureau of Reclamation (Reclamation) transmission facilities, assigning investment to the various segments of the transmission system, including Generation Integration, Integrated Network, and Utility Delivery. This testimony addresses only those transmission facilities owned by the COE and Reclamation. The segmentation of BPA-owned transmission facilities is addressed in the Transmission Segmentation Study, BP-14-E-BPA-06.

Additionally, we explain the forecast of revenues PS will receive from TS for energy used by BPA for Station Service use at its substations and other facilities located at the Ross Complex and Big Eddy/Celilo Complex, the methodology used to forecast that Station Service energy usage, and the costs that PS will allocate to TS for Station Service energy usage.

Section 2: Redispatch

Q. Please describe the Redispatch Services provided by PS under Attachment M.

A. Under Attachment M, TS requests redispatch of Federal resources as part of congestion management efforts. Generally, redispatch results in decrementing resources that can effectively relieve flowgates that are at or near Operating Transfer Capability limits and

incrementing resources to maintain service to loads. Redispatch essentially shifts generation from one Federal project to another project to alleviate congestion on the Transmission system.

Q. In what situations will TS request redispatch from PS under Attachment M?

A. Under Attachment M of the OATT, there are three types of redispatch that may be called upon by TS from PS: (1) Discretionary Redispatch; (2) Network Transmission (NT) Firm Redispatch; and (3) Emergency Redispatch. Under Discretionary Redispatch, TS requests that Federal generation be shifted from one project to another. PS provides this service at its discretion based on real-time operating objectives and constraints. TS requests Discretionary Redispatch prior to curtailing any transmission schedules.

TS requests NT Firm Redispatch to maintain firm NT schedules. NT Firm Redispatch can be requested only after all non-firm Point-to-Point and secondary NT schedules are curtailed according to North American Electric Reliability Corporation (NERC) curtailment priority. PS fulfills its NT Firm Redispatch obligation by either shifting generation from one Federal project to another or making transmission and/or power purchases or sales to maintain firm NT schedules during planned or unplanned outages. PS is required to provide NT Firm Redispatch when requested by TS to the extent PS can do so without violating non-power constraints.

Emergency Redispatch is requested after TS declares a system emergency as defined by NERC. PS must provide Emergency Redispatch even if non-power constraints are violated. *See* Study section 7.4.

Section 2.1: Redispatch Revenues

Q. How do you calculate PS revenues from Attachment M redispatch events?

A. The actual revenues associated with Attachment M redispatch are calculated based on one of two sources, depending on how the redispatch is provided: either based on market prices for incrementing and decrementing Federal generation at the time the redispatch is provided, for redispatch provided from Federal generation; or based on the actual cost to PS of purchasing and/or selling power or purchasing transmission, for redispatch provided by purchases and/or sales of energy or purchases of transmission.

Q. How do you forecast PS revenues for Attachment M redispatch for the FY 2014–2015 rate period?

A. In order to forecast PS revenues for the FY 2014–2015 rate period, we look at historical actual revenues collected by PS in FY 2010 and FY 2011 for Redispatch services. We compare the actuals to the forecast for those years and then considered whether to adjust the forecast up or down. The forecast may be adjusted upward to reflect potential increases due to increased uncertainty or anticipated increases in market prices. The forecast may be adjusted downward to reflect unusual redispatch events that are not expected to recur, increased constraints on PS's ability to provide redispatch, or anticipated decreases in market prices. *Id.* section 7.1; Documentation Tables 7.1 and 7.2.

Q. Has this methodology changed from the previous rate period?

A. No. This is the same methodology used in the previous rate period. In forecasting PS revenues for the FY 2012–2013 rate period, BPA used prior years' forecast revenues and actual revenues and considered whether any adjustments should be made. We determined that the forecast used in prior years remained an accurate forecast for the FY 2012–2013 rate period and that no adjustments were needed. *See* BP-12 Final Proposal Generation Inputs Study, BP-12-FS-BPA-05, section 7.

Q. What are the projected PS revenues for Discretionary Redispatch for the FY 2014–2015 rate period?

A. The projected PS revenues for Discretionary Redispatch for the 2014–2015 rate period are $50,000 per year. Study section 7.2. This is a reduction from previous years' forecasts and is based on the lower-than-forecast actual revenues in FY 2010 and FY 2011 ($46,439 in FY 2010 and $11,355 in FY 2011). *Id.* The reduction in the projected PS revenues for Discretionary Redispatch is also based on increasing constraints on PS's ability to provide Discretionary Redispatch on a monthly and seasonal basis. *Id.* The projected revenues for FY 2014 and FY 2015 are greater than actual revenues in FY 2010 and FY 2011 to reflect the unpredictable nature of transmission congestion and the need for Discretionary Redispatch, and market price uncertainty. *Id.*

Q. What are the projected PS revenues for NT Firm Redispatch for the FY 2014–2015 rate period?

A. We are forecasting PS revenues for NT Firm Redispatch for the FY 2014–2015 rate period of $350,000 per year. *Id.* section 7.3. PS Revenues for NT Firm Redispatch varied widely over the FY 2010–2011 rate period: actual revenues were $49,261 in FY 2010 and $470,500 in FY 2011. The revenues forecast for FY 2010–2011 were $225,000 per year. *Id.* We are forecasting revenues for FY 2014 and 2015 at $350,000 per year given the increased need for NT Firm Redispatch in FY 2011, which we expect to continue, and higher-than-forecast average annual revenues in the FY 2010–2011 rate period and to reflect the unpredictable nature of the need for NT Firm Redispatch and the variability in transmission and power prices (the basis of the cost of NT Firm Redispatch) on a monthly and seasonal basis. *Id.*

Q. What are the projected PS revenues for Emergency Redispatch for the FY 2014–2015 rate period?

A. We project no PS revenues for Emergency Redispatch for the FY 2014–2015 rate period because Emergency Redispatch events are not expected and are unlikely to occur. *Id.* section 7.4. Further, the actual costs of Emergency Redispatch incurred during FY 2010 and FY 2011 were very low. *Id.* The actual PS revenues for Emergency Redispatch for FY 2010 totaled $1,510, resulting from one Emergency Redispatch event. *Id.* No Emergency Redispatch was provided in FY 2011. *Id.*

Q. What are the total projected PS revenues for redispatch services for the FY 2014–2015 rate period?

A. We forecast total PS revenues for redispatch services of $400,000 per year for the FY 2014–2015 rate period. *Id.* section 7.5.

Section 3: COE and Reclamation Segmentation Analysis

Q. Please explain the proposed segmentation of COE and Reclamation transmission costs.

A. COE and Reclamation own certain transmission facilities associated with their generation projects that make up a small portion of the COE and Reclamation investment. These transmission facilities have annual costs associated with them, consisting of operation and maintenance expenses (O&M), depreciation, interest expense, and Minimum Required Net Revenue (MRNR). The annual costs of these COE and Reclamation investments, including costs associated with transmission facilities, are included in the power repayment study and the power revenue requirements. Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2, Tables 2I and 2J. Although all annual costs are paid by Power Services (PS), the costs associated with the Integrated Network and Utility Delivery transmission segments are functionalized to Transmission Services

(TS) and assigned to the appropriate transmission segment in the Transmission Revenue Requirement study. BP-14-E-BPA-08, chapter 2, Table 2-6. PS recovers the costs of transmission facilities that perform an Integrated Network or Utility Delivery function from TS as a revenue credit. BPA has used this methodology since the WP-02 rate case, and we propose to continue this treatment for the COE and Reclamation transmission costs for the upcoming rate period.

Q. Why is it necessary to assign the investments of COE and Reclamation transmission facilities to the transmission segments?

A. It is necessary to assign the investments of COE and Reclamation transmission facilities to the transmission segments so the annual costs of the transmission facilities can be properly allocated between PS and TS. COE and Reclamation transmission facilities perform Generation Integration, Integrated Network, and Utility Delivery functions. The costs of transmission facilities that perform a Generation Integration function are assigned to PS and recovered through power rates, while the costs of transmission facilities that perform an Integrated Network or Utility Delivery function are assigned to TS and recovered through transmission rates. Study section 8.1.

Q. How are the COE and Reclamation transmission facility investments assigned to the various segments?

A. The investment in facilities that connect Federal generation to the BPA Transmission Network is assigned to the Generation Integration segment. This includes generator step-up transformers (GSUs), powerhouse lines or cables, and switching equipment at the Network station for the powerhouse line. *Id.* section 8.2. Investment in facilities that provide transmission of bulk power are assigned to the Integrated Network segment. *Id.* section 8.3. Investment in facilities that deliver power to BPA customers at voltages below 34.5 kilovolts are assigned to the Utility Delivery segment. *Id.* section 8.4. These

definitions are consistent with the Transmission Segmentation Study, BP-14-E-BPA-06, section 2.

Q. Why are the costs of the land associated with the Reclamation switchyards included in the total costs of the switchyards?

A. An underlying tenet of generally accepted accounting principles is that the cost of property, plant, and equipment includes the purchase price of the asset and all expenditures necessary to prepare the asset for its intended use. Accordingly, in determining the cost of an electrical switchyard, it is necessary to include the cost of the land upon with the switchyard is built.

Section 4: Station Service

Q. What is Station Service?

A. Station Service refers to real power taken directly off the BPA power system for use at BPA's substations and other facilities located at the Ross and Big Eddy/Celilo complexes. Study section 9.1.

Q. What costs are allocated to Station Service?

A. The costs allocated to Station Service are the real power costs for power supplied by BPA for use at BPA substations. This does not include Station Service that TS purchases from another utility or that is supplied by another utility.

Q. How do you forecast the quantity of Station Service used by BPA?

A. Because most locations on the BPA system do not have meters to measure Station Service usage, we developed a methodology to estimate the amount of energy usage at BPA substations. The Ross and Big Eddy/Celilo complexes include facilities that are not typical substation loads. The energy estimate for these two complexes is based on historical data. For other substations, the methodology consists of the following steps:

(1) establish the amount of installed station service transformation capacity (measured in kilovolt amperes (kVA)); (2) determine the historical monthly average station service energy usage for those substations for which load data exists; (3) derive an average load factor based on the ratio of installed station service transformation and historical energy usage; and (4) apply the derived load factor to the installed transformation for all substations to determine the quantity of Station Service energy usage for all substations on the BPA system. This amount is then added to the historical use at the Ross and Big Eddy/Celilo complexes to determine total station service energy use, which is then adjusted to reflect transmission losses. *Id.* section 9.2.

Q. What is "installed station service transformation"?

A. Power is transformed from a higher transmission voltage to a lower voltage to supply power to the buildings and equipment at the substations. "Installed station service transformation" is the equipment installed at the substation to perform this transformation. The maximum power-carrying capability of these transformers is measured in kVA.

Q. Why did you perform a separate calculation for BPA substations but not the Ross and Big Eddy/Celilo complexes?

A. Two reasons. First, the Ross and Big Eddy/Celilo complexes are not typical substations. These complexes include loads not found at other substations and therefore do not necessarily have the same relationship between installed transformation and energy that is typical for a substation. Second, there is historical data on which calculations can be based for those two complexes.

Q. What is the forecast amount of Station Service?

A. The total forecast quantity of Station Service average usage, not including transmission losses that BPA supplies for substations and other facilities, is estimated to be

81,123,717 kWh per year. *See id.* section 9.6; Documentation Table 9.2, line 6. The total forecast amount of Station Service, including transmission losses, is 82,665,068 kWh per year. Study section 9.6; Documentation Table 9.2, line 6.

Q. How are transmission losses calculated in the forecast of Station Service?

A. The BPA Transmission Network loss factor is applied to the estimated use to account for transmission losses. This is the same Network loss factor that BPA applies to transmission schedules. Currently the Network loss factor is 1.9 percent. BPA Open Access Transmission Tariff, Schedule 11.

Q. Why do you include transmission losses?

A. Energy used for Station Service experiences transmission losses just as does other energy used on the Network. By including transmission losses, we are recovering the full cost of station service.

Q. To which segments are the costs for Station Service assigned?

A. Station Service costs are allocated to all transmission segments. The total cost is prorated to the segments based on the three-year average substation Operations and Maintenance expenses associated with the respective segments, as determined in the Transmission Segmentation Study, BP-14-E-BPA-06, section 3.3.

Q. How do you propose to price energy supplied for Station Service?

A. We propose to price the energy supplied for Station Service at the annual average forecast market price.

Q. Why do you use the market price forecast to price Station Service energy?

A. The market price forecast is the same price forecast that is used to forecast surplus sales from the PS Trading Floor. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. If the energy was not being provided for Station Service, it would be sold on the Trading Floor. Using the market price forecast to price Station Service provides the

same revenue credit to the Composite cost pool as it would if this energy was not being used for Station Service.

Q. What is the revenue forecast for Station Service?

A. The revenue forecast for Station Service is $2,405,552 per year. Study section 9.7; Documentation Table 9.2, line 6.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

MARK A. JACKSON, KATHERINE L. BEALE, THOMAS D. COATNEY,

DANIEL H. FISHER, REBECCA E. FREDRICKSON, and CHRISTOPHER J. GILBERT

Witnesses for Bonneville Power Administration

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TESTIMONY of

MARK A. JACKSON, KATHERINE L. BEALE, THOMAS D. COATNEY,
DANIEL H. FISHER, REBECCA E. FREDRICKSON, and CHRISTOPHER J. GILBERT
Witnesses for Bonneville Power Administration

SUBJECT: ANCILLARY AND CONTROL AREA SERVICE RATE DESIGN

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Mark A. Jackson, and my qualifications are contained in BP-14-Q-BPA-28.

A. My name is Katherine L. Beale, and my qualifications are contained in BP-14-Q-BPA-03.

A. My name is Thomas D. Coatney, and my qualifications are contained in BP-14-Q-BPA-11.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is Christopher J. Gilbert, and my qualifications are contained in BP-14-Q-BPA-23.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the ACS-14 Ancillary and Control Area Services Rate Design section in the Generation Inputs Study, BP-14-E-BPA-05 (Study), and Generation Inputs Documentation, BP-14-E-BPA-05A (Documentation), and the associated ACS-14 Ancillary and Control Area Service rates (ACS-14 Rate Schedule), BP-14-E-BPA-10.

Section 2: Ancillary and Control Area Services

Q. What are Ancillary Services?

A. Ancillary Services are needed to maintain reliability within and among the balancing authority areas affected by transmission service. All transmission service agreement holders must satisfy the reliability requirements associated with their energy transactions. BPA is required to provide, and transmission customers are required to purchase, Scheduling, System Control and Dispatch Service, and Reactive Supply and Voltage Control from Generation Sources Service. BPA is also required to offer to provide the following Ancillary Services to transmission customers serving load or integrating generation within the BPA balancing authority area: Regulation and Frequency Response Service, Operating Reserve Services (Spinning and Supplemental), and Energy Imbalance Service.

Q. What are Control Area Services?

A. Control Area Services are required for energy transactions in the BPA balancing authority area when the reliability obligations have not been met through Ancillary Services or some other arrangement, such as self-supply or dynamic transfer of the energy transaction to another balancing authority area. Resources or loads in the BPA balancing authority area must purchase Control Area Services from BPA to the extent they do not otherwise satisfy the reliability requirements associated with their energy transactions. BPA currently offers the following Control Area Services: Regulation and Frequency Response, Generation Imbalance, Operating Reserve (Spinning and Supplemental), Variable Energy Resource Balancing Service (VERBS), Supplemental Service, and Dispatchable Energy Resource Balancing Service (DERBS).

Q. Where is the description of the calculation of the Ancillary and Control Area Service rates?

A. The calculation for each Ancillary and Control Area Service rate is described in Study section 10. Each Ancillary and Control Area Service rate is also described in the proposed Transmission, Ancillary and Control Area Services Rate Schedules, BP-14-E-BPA-10.

Q. Other than rate updates, are you proposing any significant changes to any existing Ancillary and Control Area Service rates?

A. Yes.

Q. Please identify the rates that you are proposing to significantly modify in this rate proceeding.

A. We are proposing several significant changes to the VERBS rate. In addition, we are proposing modifications to the DERBS rate and modifications to the Generation Imbalance Service and Energy Imbalance Service rates.

Q. Are you proposing to apply the Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and Emergency NFB Mechanisms to balancing reserve capacity-based Ancillary and Control Area Services rates in this rate proceeding?

A. Yes. *See* Mandell *et al*., BP-14-E-BPA-15, section 3.

Section 3: Regulation and Frequency Response Service

Q. What is Regulation and Frequency Response Service?

A. Regulation and Frequency Response Service provides the generation capability to (1) follow the moment-to-moment variations of loads in the BPA balancing authority area; and (2) maintain the power system frequency at 60 Hertz in conformance with

North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards.

Q. Who is charged for Regulation and Frequency Response Service?

A. Transmission customers serving load in the BPA balancing authority area are charged for Regulation and Frequency Response Service as an Ancillary Service. Loads in the BPA balancing authority area that are not served by a BPA transmission customer are charged for the Control Area Service of Regulation and Frequency Response, unless the customer can demonstrate to BPA's satisfaction that this obligation is met through other arrangements.

Q. What is the proposed rate for Regulation and Frequency Response Service?

A. The proposed rate is 0.12 mills per kilowatthour. Study Table 4, line 37. The costs for this service are developed in Study section 3 and recovered under the proposed ACS-14 Regulation and Frequency Response Service rate. Study section 10.3; ACS-14 Rate Schedule II.C and III.A.

Section 4: Imbalance Services

Q. What are Imbalance Services?

A. Imbalance Services are energy services that are required to balance positive or negative deviations for load or generation in the BPA balancing authority area. The two imbalance services are Energy Imbalance Service, which applies to load in the balancing authority area, and Generation Imbalance Service, which applies to generation in the balancing authority area. The rates for these services recover the cost of energy and do not recover the cost of balancing reserve capacity that BPA utilizes to provide Imbalance Services. Wellschlager *et al.*, BP-14-E-BPA-26, section 4; Study section 10.7.

Q. Please describe Energy Imbalance Service.

A. Energy Imbalance is provided when a load in the BPA balancing authority area receives an amount of energy different from the amount that the customer scheduled for delivery during a schedule period. To the extent that the BPA balancing authority absorbs or delivers an amount of energy that is different from the amount the customer scheduled for its load, BPA provides Energy Imbalance Service. Study section 10.7.1.

Q. Please describe Generation Imbalance Service.

A. Generation Imbalance Service is provided when a generator in the BPA balancing authority area generates an amount of energy different from the amount that the customer scheduled for delivery from the generator during a schedule period. To the extent that the BPA balancing authority absorbs or delivers an amount of energy that is different from the amount the customer scheduled for its generation, BPA provides Generation Imbalance Service. *Id.* section 10.7.2.

Q. Are you proposing any changes to the Generation Imbalance Service rate?

A. Yes, we are proposing to make three changes. First, we propose not to provide generator imbalance credit to generators that over-generate relative to remaining schedules during a scheduling period in which a generator's schedules have been curtailed. Second, we propose to change the definition of incremental cost for pricing Imbalance Energy. Finally, we propose to exempt variable energy resource customers that participate in the best available scheduling practice (currently 30/30 committed scheduling) from the 10 percent Deviation Band 2 charge under Generation Imbalance Service.

Q. Why are you proposing to provide no credit for negative deviations (where actual generation is greater than scheduled amounts) that occur during a scheduling period in which BPA has issued a curtailment or validated a curtailment issued by another balancing authority?

A. BPA has an obligation to maintain reliability within its balancing authority area and keep power flows within system operating limits. Generators must keep generation at or below curtailed schedule amounts so that BPA can manage the system and appropriately respond at the interchanges to curtailments issued by another balancing authority. Generator Imbalance Service is not a curtailment management service, and BPA does not want to encourage generators to over-generate during curtailments by paying for over-generation under those conditions.

Q. Why are you proposing to change the definition of incremental cost for Imbalance Energy?

A. As explained in Fisher *et al.*, BP-14-E-BPA-21, section 7, we are proposing to change the calculation of BPA's incremental cost for both Energy and Generator Imbalance Services from an hourly market index to a weighted average cost of energy deployed. Study section 10.7. We are proposing this change to better align the pricing of Imbalance Energy with the cost of providing that energy.

Q. What is the policy rationale for the proposed change for incremental cost?

A. The policy rationale for changing the definition of incremental cost is explained in the testimony of Fisher *et al.*, BP-14-E-BPA-21, section 7.

Q. Why are you proposing to exempt variable energy resources that participate in the best available scheduling practice, which currently is 30/30 committed scheduling, from the Deviation Band 2 charge under Generation Imbalance Service?

A. The purpose of the Deviation Band 2 charge is to encourage accurate scheduling behavior. Currently, customers cannot schedule better than 30/30 committed scheduling; thus, the 10 percent charge is unlikely to provide any additional incentive for customers to improve their scheduling accuracy.

If BPA offers 15-minute scheduling and an associated 30/15 committed scheduling Base Service, we would expect BPA to move the Deviation Band 2 exemption to apply solely to that service because 30/15 committed scheduling would then be the shortest committed scheduling period available. However, we are not proposing a 15-minute scheduling rate in this Initial Proposal. *See* Fisher *et al.*, BP-14-E-BPA-21, section 5.1.

Q. Why is it appropriate to retain the Deviation Band 2 charge for customers that participate in 30/60 committed scheduling or uncommitted scheduling?

A. As discussed above, the purpose of the Deviation Band 2 charge under generator imbalance service is to encourage accurate scheduling behavior. Retaining the Deviation Band 2 charge provides scheduling entities with an incentive to take actions to mitigate their schedule imbalances or to make investments to move toward intra-hour scheduling, which enables customers to reduce their schedule imbalances and the costs associated with generation imbalance service and balancing reserve capacity. Customers that elect 30/60 committed scheduling or uncommitted scheduling will have chosen a less accurate scheduling approach and could still adjust their schedules within hour to the 30/30 schedule amounts to reduce imbalance accumulation. Therefore, we are proposing to

retain the Deviation Band 2 charge for customers that elect 30/60 committed scheduling or uncommitted scheduling.

Section 4.1: Persistent Deviation Penalty Charge

Q. Please explain the Persistent Deviation penalty charge for Imbalance Services.

A. "Persistent Deviation" is defined in section III of the Transmission General Rate Schedule Provisions. Transmission Rate Schedules, BP-14-E-BPA-10, General Rate Schedule Provisions (GRSP) III.39. In general, Persistent Deviation refers to a difference between scheduled and actual generation, or between scheduled and actual load, that continues in the same direction longer than a certain period of time (*e.g.,* three hours) and greater than a certain megawatt amount (*e.g.,* 20 MW).

Q. Are you proposing to retain the Persistent Deviation penalty charge in the FY 2014–2015 rate period?

A. Yes. We are proposing to retain the Persistent Deviation penalty, with one change, which is to specify that customers participating in either form of committed scheduling (30/30 or 30/60 committed scheduling) will be exempt from the Persistent Deviation penalty charge.

Q. Why are you proposing to exempt customers participating in committed scheduling from the Persistent Deviation penalty charge?

A. Committed scheduling reduces schedule error and reduces bias in the pattern of schedule error, which in turn reduces imbalance energy accumulation. Study section 10.8.5. By proposing an exemption from Persistent Deviation penalties for 30/30 committed scheduling and 30/60 committed scheduling, we hope it motivates parties to elect a committed scheduling approach and thereby decrease bias in schedule error and overall energy imbalance accumulation.

Q. How long has BPA had a Persistent Deviation penalty charge?

A. In the WP-10 rate proceeding, BPA renamed the "Intentional Deviation" penalty charge to Persistent Deviation to remove the concept of intent and to define more objective criteria for identifying large and excessive schedule errors. Prior to the FY 2010–2011 rate period, BPA had a penalty charge for Intentional Deviations since FY 2002.

Q. What is the proposed rate for the Persistent Deviation penalty charge?

A. The proposed rate is the same as the ACS-12 rate. *See* ACS-12 Rate Schedule, BP-12-A-02C, II.D.2.c and III.B.2.c.

Q. Is the Persistent Deviation penalty charge effectively a "wind-only" penalty charge?

A. No. The Persistent Deviation penalty charge applies to all types of generation and load in the BPA balancing authority area.

Q. Based on your analysis, how frequent are Persistent Deviation penalty charges for load?

A. Load customers had 13 penalized persistent deviation events in October 2011, which was the first month in which new criteria for Persistent Deviation went into effect. Documentation Table 10.1, line 15. Since that time, we have observed an average of about three events per month. *See id.* lines 16-26. As a percentage of time, load customers incurred persistent deviation events less than 0.63 percent of the time in FY 2012. *Id.* line 28. In the months since October, loads avoided persistent deviations 99.6 percent of the scheduled hours. *See id.* lines 16-26.

Q. Based on your study of actual scheduling data, how frequent are Persistent Deviation penalty charges for wind generators?

A. The fleet average percentage of hours that were subject to Persistent Deviation penalties was 0.32 percent in FY 2011 and 0.49 percent in FY 2012. *Id.* lines 14 and 28. Some plants had no Persistent Deviation events. Almost 38 percent of the Persistent Deviation

events were incurred by three plants. Over 99 percent of the Persistent Deviation events accrued to less than half the wind fleet. Study section 10.8.4.

Q. Is it possible for load and generation customers to avoid the Persistent Deviation penalty?

A. Yes. Persistent and large schedule errors can be avoided by ensuring that the hourly schedule is established with as much available information as possible (close to the delivery hour) and by ensuring that schedule errors are observed and corrected as quickly as possible. Load and generation customers successfully avoided the Persistent Deviation penalty in over 99 percent of all hours, on average, in FY 2012. Documentation Table 10.1, line 28.

Q. Are Persistent Deviation penalty charges avoidable only by small generators?

A. No. Large wind generators (greater than 150 MW) and small wind generators (*e.g.*, less than 50 MW) both avoided Persistent Deviation penalties completely in some months. With the proposed change to exempt both 30/30 committed and 30/60 committed scheduling from Persistent Deviation charges, wind generators have an additional option to avoid Persistent Deviation penalties altogether.

Q. How does the Persistent Deviation penalty charge support BPA's balancing services, such as VERBS?

A. BPA's balancing services are used to manage variability caused by variable energy resources, loads, and dispatchable energy resources. BPA stands ready to deploy balancing reserve capacity for balancing services in real time to make up for schedule errors (generation different from scheduled amount or load different from the load schedule). In order to establish a quantity of balancing reserve capacity for balancing services, BPA must establish an assumed level of scheduling accuracy and identify the portion of the distribution of schedule errors that is covered by the balancing service. As

described in section 7, BPA will offer parties a choice of scheduling options and then will reflect those choices in its assessment of the total reserve capacity requirement. The Persistent Deviation penalty charge provides an incentive—as part of a suite of incentives—for parties to schedule accurately, and it helps ensure that large schedule errors are corrected quickly. Because balancing reserve capacity is treated as a pooled resource, Persistent Deviation penalties help ensure that no single party overuses the flexibility provided by the reserve capacity.

Q. Does BPA provide longer-term (hours-long or week-long) energy storage for generation and loads that are scheduled on the system as part of its balancing services, such as VERBS?

A. No. For balancing services such as VERBS, BPA provides system capability to increase or decrease generation over short time periods, but operational planning does not include providing storage capability over longer periods. BPA would need to make different assumptions about the nature of balancing service if it were to provide storage capability over longer periods as part of the service. Similarly, the timing and optimization of BPA's short-term marketing is planned without assuming that large amounts of energy will be used or stored over time as a result of generation and energy imbalance.

Q. What operational impacts do Persistent Deviations and energy imbalance accumulations have on BPA?

A. In order to successfully operate a large, integrated hydro system within required reliability and operating constraints, BPA must plan its operations and marketing in advance to manage the flow of water through the system. Kerns *et al.*, BP-14-E-BPA-23. BPA provides balancing reserve capacity for balancing services to maintain system reliability but assumes that schedule errors that cause deployment of that balancing reserve capacity are generally randomly distributed over time around an average schedule

error of approximately zero (*i.e.*, BPA expects to observe schedule deviations both above and below the scheduled amount, hour to hour). When this is the case, energy accumulates for only short periods of time in either direction, and storage or release of water does not accumulate. When the pattern of imbalance accumulation differs from that expectation, BPA must market or purchase power to return the BPA system to planned operations levels. Study section 1.8.5.

When schedules are inaccurate in the same direction for an extended period of time, BPA's ability to stay within its operating constraints may be jeopardized as the limited capability to store or release energy that is available for real-time balancing of schedule error is consumed by energy accumulation from past schedule error. Similarly, if schedules are routinely inaccurate at specific times of day or schedule inaccuracies follow a specific pattern, FCRPS generation operations can stray from the planned range during or after the schedule inaccuracies.

At times of tight constraints, reliability of load service can potentially be jeopardized if BPA is unable to recover from the imbalance accumulation through market purchases. Furthermore, if BPA's power supply obligations run significantly higher or lower than expected, BPA can be forced to make significant last-minute sales or purchases at or below market prices, spill water that could otherwise be used to produce energy, limit wind generators to schedules, or curtail transmission schedules. Because it is uncertain whether energy will be needed or available in the spot energy markets, BPA bears the risk of violating project or system constraints that BPA is statutorily obligated to maintain. If a violation occurs, BPA may incur power costs or forgo market opportunities in subsequent periods to restore an operation that is consistent with the safe and reliable implementation of all FCRPS statutory requirements.

Since it is uncertain whether the accumulated error will disappear over time, energy accumulation on the Federal system causes operational planning in the near term to become more uncertain. This relationship between past and current response to schedule errors is unique to large interconnected hydro systems.

Q. Does the use of opposite direction schedule error to avoid Persistent Deviation penalty charges cause problems for BPA?

A. Yes. We have observed patterns of schedule errors in which there is a large schedule error for two hours followed by a strong correction in the opposite direction. *Id.* Figure 10-5. When a scheduling agent schedules an amount of load or generation in the opposite direction of the schedule error observed in past hours, it affects BPA by depleting the balancing reserve capacity that is expected to be available for real-time errors. If scheduling agents deliberately include avoidable error in their schedules, they are effectively dispatching the FCRPS for their purposes, at the time they choose, without requesting the dispatch through a transaction or schedule. We believe such scheduling behavior is inconsistent with industry standard practice for best scheduling practices.

As noted above, BPA provides balancing services to cover unavoidable, unpredictable schedule errors caused by short-term variability in loads and variable energy resources or by unexpected events affecting dispatchable generators. Managing additional uncertainty to correct past schedule errors is not part of the service that BPA offers. In addition to creating additional risk for operational planning, if BPA were to assume parties would use balancing reserve capacity for both past and present schedule errors at the same time, or use schedule error to dispatch the FCRPS for other marketing reasons, it would increase the overall balancing reserve capacity requirement.

Q. Why do you want to motivate parties to adjust schedules close to or during the delivery hour?

A. Actual current conditions are a key factor in predicting near-term conditions. Particularly for variable energy resources, forecasts become significantly more accurate the closer they are to the delivery hour. Although loads are more predictable, the same holds generally true for loads. Schedule errors are minimized when the best possible forecasts are used.

Q. Do you expect customers that experience wind ramps or extreme, unpredictable events to incur Persistent Deviation penalty charges? Please explain.

A. BPA has established time windows for Persistent Deviation that are longer than most wind ramps. For the shortest time window of Persistent Deviation, BPA allows a fairly wide megawatt margin of error: the schedule error must exceed both 20 MW and 15 percent of the schedule. BPA expects that scheduling entities would be able to achieve that level of accuracy at least once every three hours, even during wind ramps or extreme events. Documentation Table 10.2. In our analysis, we discovered that wind ramps larger than the 20 MW and 15 percent of schedule criteria last two hours only 1.8 percent of the time, and they last three hours only 0.43 percent of the time. *Id.* Because wind ramps are less than the persistent deviation criteria more than 98 percent of the time, we believe scheduling agents should be able to react to wind ramps within the time window allowed. Wind ramps alone are unlikely to cause Persistent Deviations if scheduling agents are adjusting their schedules each hour.

Q. Does BPA waive the Persistent Deviation penalty charge for some events?

A. Yes. Customers and their scheduling agents that experience extraordinary circumstances or can demonstrate mitigating actions taken to reduce the duration or magnitude of their schedule errors may be eligible for a waiver of all or part of any Persistent Deviation

penalty charge. ACS-14 Rate Schedule II.D.2.c and III.B.2.c. Consistent with the FY 2012–2013 rates, we propose that BPA will consider such requests on a case-by-case basis, and will determine, at its sole discretion, whether to grant a partial or complete waiver. *Id.*

Section 5: Operating Reserve Services

Q. What is Operating Reserve?

A. Operating Reserve is the generating capacity necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment. Operating Reserve is required for the reliable operation of the interconnected power system. Within a balancing authority area, adequate generating capacity must be available at all times to maintain scheduled frequency and to avoid loss of firm load following transmission or generation contingencies. Operating Reserve is described as "contingency reserves" in the WECC standard, but for the purpose of this testimony and the Study, BPA refers to contingency reserves as Operating Reserve.

Q. Where is the forecast use of Operating Reserve services established?

A. The forecast use of Operating Reserves is established in the Operating Reserve Cost Allocation Study, Study section 4. Power Services provides the generation inputs for Operating Reserve based on a TS forecast of TS needs. TS forecasts the PS generation input requirement based on the historical Operating Reserve requirement in the BPA balancing authority area. Study section 4.3; Messinger *et al.*, BP-14-E-BPA-25, section 2.

Q. Are transmission customers allowed to obtain Operating Reserve from other suppliers?

A. Yes. Customers may self-supply Operating Reserve or obtain it from a third-party supplier. Customers must elect their supplier of Operating Reserve for the two-year rate period.

Q. What happens if a customer that self-supplies or acquires Operating Reserve from a third party fails to meet BPA's Operating Reserve criteria?

A. If a customer fails the criteria for self-supply or third-party supply established in the Operating Reserves Business Practice, it must take Operating Reserve from BPA to meet the reserve requirement and pay the default rates for Spinning and Supplemental Operating Reserves.

Q. How are the proposed default rates determined?

A. The default rate is a penalty rate to encourage customers to meet their commitment to self-supply or third-party supply Operating Reserve. The rate is 15 percent higher than the rate for normal service and is the same percentage as used in the FY 2012–2013 rate schedules. We consider this to be a reasonable penalty at this time to encourage compliance with BPA's self-supply and third-party supply criteria. No parties have defaulted in the FY 2012–2013 rate period as of October 2012. The default rate is applied the same as the normal rate to the billing factors of those customers in default. Study section 10.4.3.

Section 6: Variable Energy Resource Balancing Service

Q. Please briefly describe Variable Energy Resource Balancing Service (VERBS).

A. VERBS provides the generation capability (ability to both increase and decrease generation) to follow within-hour variations of variable energy resources, primarily wind, in the BPA balancing authority area. VERBS is required to maintain the power system

frequency at 60 Hertz in conformance with NERC and WECC reliability standards and provide the regulation, following, and imbalance reserve capacity needed to support wind resources. The VERBS service is separated into three components: regulation, for moment-to-moment variability; following, for longer-term variability within the hour; and imbalance, for additional longer-term variability within the hour caused by scheduling error. Puyleart *et al.*, BP-14-E-BPA-22, section 2.

Q. What changes do you propose to make to the VERBS rate for BP-14?

A. We propose to establish three VERBS "Base Service" rates, which are based on the scheduling election of the variable energy resource customer.

First, we propose a 30/60 committed scheduling Base Service rate that is based on a 30/60 scheduling accuracy assumption for wind generators that BPA used for the FY 2012–2013 rates. Fisher *et al.*, BP-14-E-BPA-21, section 5.

Second, for customers that choose to participate in 30/30 committed scheduling, we propose a 30/30 committed scheduling Base Service rate that is based on a 27 percent discount to the 30/60 committed scheduling Base Service rate. *Id.* In the FY 2012–2013 rate period, BPA established a Committed Intra-Hour Scheduling Pilot that enabled customers to receive a rate discount if they agreed to submit a schedule consistent with or better than the scheduling quantity that BPA communicates to the customer 30 minutes prior to the start of every hour. Our 30/30 committed scheduling Base Service rate proposal transitions the 30/30 Committed Intra-Hour Scheduling Pilot that BPA established in FY 2012–2013 out of "pilot" status.

Third, we propose a higher rate for customers that elect to pay the "uncommitted scheduling" Base Service rate, where customers retain flexibility to schedule both on an hourly and an intra-hour basis without any requirement to follow a consistent scheduling accuracy benchmark. We propose to base the rate for uncommitted scheduling on a

45/60 scheduling assumption. *Id.* (explaining the policy rationale for a 45/60 scheduling assumption for uncommitted scheduling); *see also* Puyleart *et al.*, BP-14-E-BPA-22 (calculating the balancing reserve capacity requirement for uncommitted scheduling). The rate premium for this service is 22 percent higher than the imbalance component rate under 30/60 committed scheduling Base Service. Study section 10.5.1.

In addition to VERBS Base Service rates, we are proposing a new "Full Service" charge. We also propose to replace the formula rate adjustments established in FY 2012–2013 with four new formula charges to ensure cost recovery for balancing reserve capacity purchases made during the rate period to provide balancing services under certain conditions. *See also* Klippstein *et al.*, BP-14-E-BPA-24, section 6 (explaining the cost allocation methodology for Type 1, 2, 3, and 4 purchases of balancing reserve capacity).

Additionally, we are proposing a VERBS Credit to VERBS customers for balancing reserve capacity from the FCRPS that becomes unavailable to provide VERBS Base Service during the rate period.

Finally, we propose to eliminate the rate for Provisional VERBS (also known as "Provisional Balancing Service").

Q. Where is the policy rationale for VERBS Base Service and Full Service described?

A. The policy rationale for VERBS Base Service and Full Service in the Generation Inputs is explained in the testimony of Fisher *et al.*, BP-14-E-BPA-21, section 5.

Q. Where are the proposed rates for VERBS Base Service stated?

A. The rates for VERBS Base Service, which include rates for 30/30 committed scheduling, 30/60 committed scheduling, and uncommitted scheduling options, and rate exceptions, are stated in the ACS-14 Rate Schedule III.E.2.a and Study section 10.5.1.

Q. If because of a legal challenge to Dispatcher Standing Order 216 (DSO 216), BPA is prevented from implementing DSO 216 or is required to amend it materially, what rate will apply to VERBS Base Service customers?

A. In the BP-12 rates, BPA included a formula rate adjustment that enabled BPA to recover its costs for purchases of balancing reserve capacity if a legal proceeding prevented BPA from utilizing DSO 216. For the upcoming rate period, we are proposing to replace that formula rate adjustment with the requirement for VERBS Base Service customers to purchase Full Service at the total Full Service charge. ACS-14 Rate Schedule III.E.2.c.3. This will enable BPA to continue to provide VERBS to its customers and ensure cost recovery if BPA is required to materially change its application of DSO 216 as a reliability and operational protocol.

Q. Who is subject to the proposed rates for VERBS?

A. All wind and solar variable energy resources in the BPA balancing authority area that do not self-supply some or all of their balancing reserve requirement are subject to the applicable VERBS Base Service rate. *Id.* III.E.2.c.

Q. Under your proposal, why do customers that participate in 30/30 committed scheduling receive a Base Service rate discount?

A. The balancing reserve capacity requirement for the imbalance component of VERBS depends on scheduling accuracy. In contrast, the regulation and following components are not significantly affected by the scheduling accuracy. Under 30/30 committed scheduling, the level of scheduling accuracy that a customer must meet is predetermined, which allows BPA to assume a reduction in the imbalance balancing reserve capacity requirement. The reduction to the imbalance component relative to the imbalance requirement for committed 30/60 hourly scheduling forms the basis for rate reduction.

See Fisher *et al.*, BP-14-E-BPA-21, section 5.1; Puyleart *et al.*, BP-14-E-BPA-22, section 7.

Q. *How do you calculate the rate discount?*

A. We developed preliminary estimates of the rate discount by running a case study that assumed the entire wind fleet elected to use 30/30 committed scheduling, which produced a reduced balancing reserve capacity requirement for wind. We then calculate that difference into the balancing reserve capacity requirement and applied the resulting cost savings to the VERBS Base Service 30/30 committed scheduling rate. *See* Puyleart *et al*., BP-14-E-BPA-22, section 7.

Q. *Under your proposal, why do customers that select the "uncommitted scheduling" Base Service option receive a higher VERBS Base Service rate?*

A. The balancing reserve capacity requirement for uncommitted hourly scheduling is higher than the reserve requirement for 30/60 committed scheduling. Fisher *et al.*, BP-14-E-BPA-22, section 5.1; Study section 2.10. We forecasts the balancing reserve capacity requirement for uncommitted scheduling to be equivalent to the balancing reserve capacity required under a 45/60 scheduling assumption (that is, 45-minute persistence scheduling accuracy assumption for 60-minute schedules). Fisher *et al.*, BP-14-E-BPA-21, section 5.1 (explaining the policy rationale for a 45/60 scheduling accuracy assumption for uncommitted scheduling).

Q. *How would BPA determine the Base Service billing factor for wind generators' installed capacity each month?*

A. For wind-powered variable energy resources, the proposed billing factor is the installed capacity, which is the same billing factor used in the last two rate periods. BPA would determine the installed capacity for each wind-powered variable energy resource in the BPA balancing authority each month during the rate period. *See* ACS-14 Rate Schedule

III.E.2.b. For wind projects that have completed installation of all units, the installed capacity will be the aggregate nameplate of the generating units. For projects for which some but not all units are installed before the 15th of the month that is prior to the billing month (that is, some units are generating energy), the installed capacity will be the project's highest hourly output from the generator measured from the time of the initial operation up to the end of the 15th day of the month prior to the billing month. Using the maximum hourly output of the generating units enables BPA to approximate the total installed capacity for projects that are still under construction. This approximation is necessary for wind projects still under construction because BPA will not know the exact amount of installed capacity at any given time.

Q. What is the rationale for this method?

A. This method for measuring the installed capacity of incomplete projects ensures that for each billing month, the billing factor will be as close as possible to the project's installed capacity. In addition, using the 15th day of the month as a cutoff date provides BPA sufficient time to prepare the monthly billing. Additional generating units installed after the 15th will be picked up during the next monthly billing cycle. This adjustment applies only to projects that are under construction. Once construction of the project is complete, BPA will require each generator to submit in writing the aggregate nameplate of its generating units. If the generator does not respond to BPA's request to supply its nameplate capacity after installation, BPA will use the best information available (*e.g.*, the installed capacity listed in the customer's interconnection agreement) to determine installed capacity of the generating facility.

Q. How would BPA determine the Base Service billing factor for solar generators' installed capacity each month?

A. For solar-powered variable energy resources, the billing factor is the greater of the maximum one-hour generation or the nameplate of the plant in kilowatts. *Id.* III.E.4. We expect that solar resources will interconnect the entire project within a single billing month, so BPA would use the project nameplate capacity when the facility is energized to calculate the billing factor for the following month unless a greater kilowatt quantity is delivered during some later hour prior to the 15th of the month prior to the billing month. This larger quantity will then become the new billing factor.

Q. Why are you proposing the monthly installed capacity as the billing factor for VERBS?

A. We are using installed capacity of wind and solar as the billing factor for VERBS because it correlates well with each VERBS customer's actual need for balancing reserve capacity. *See* Puyleart *et al.*, BP-14-E-BPA-22. Furthermore, installed capacity is simple to calculate and administer, easy for both BPA and its customers to understand, and readily implemented in the BPA billing system. BPA has utilized installed capacity as the billing factor for Wind Balancing Service since FY 2009.

Q. What is your concept for "Full Service" under VERBS?

A. As explained in Fisher *et al.*, BP-14-E-BPA-21, section 5.2, we expect Full Service VERBS to provide a high level of balancing reserve capacity that provides a commensurately higher level of reliability curtailment risk mitigation for customers taking the service. Under Full Service, BPA would determine the balancing reserve capacity needed based on forecast wind volatility and forecast deviations, and BPA would attempt to acquire balancing reserve capacity to meet the forecast need. *Id.* We expect BPA to make purchases of this balancing reserve capacity across several time horizons such as weekly purchases, prior to close of pre-schedule day-ahead purchases

and possibly purchases made closer to the operating hour, but not within the operating hour. *Id.*

Q. Who would be subject to Full Service?

A. VERBS customers taking either 30/30 committed scheduling or 30/60 committed scheduling are eligible to purchase Full Service. As explained in Fisher *et al.*, BP-14-E-BPA-21, section 5.2, customers that elect uncommitted scheduling are not eligible to purchase Full Service.

In addition, if because of a legal challenge to DSO 216 BPA is prevented from implementing DSO 216 or is required to amend it materially, all customers taking VERBS Base Service will be subject to Full Service and will pay the Full Service rate.

Q. What is the charge for Full Service?

A. The proposed charge is based on a monthly formula that will recover the costs for balancing reserve capacity purchases made for Full Service for each month. Study section 10.5.5.

Q. How does Generation Imbalance Service differ from VERBS?

A. The Generation Imbalance Service rate provides only the energy value required by the generation imbalance *(i.e.*, the difference between scheduled generation and actual generation). The cost of the balancing reserve capacity that stands ready to provide this energy on short notice is not included in energy charges billed under the Generation Imbalance Service. The cost of the balancing reserve capacity is instead included in the VERBS rate.

Q. Does BPA recover the cost of balancing reserve capacity that is provided to balance variable energy resources through the Generation Imbalance Service rate?

A. No. As mentioned above, the Generation Imbalance Service rate recovers only the energy costs.

Q. How does VERBS differ from Regulation and Frequency Response Service?

A. While the Regulation and Frequency Response Service rate, like VERBS, is designed to recover capacity costs, the service provides balancing reserve capacity for only the regulation component (moment-to-moment variations) for load. VERBS, in contrast, provides following and imbalance components, in addition to the moment-to-moment regulating balancing reserve capacity component, for variable energy resources. The costs of balancing reserve capacity for the following and imbalance components for load are recovered through power rates. Fisher *et al.*, BP-14-E-BPA-21, section 2.

Q. Does BPA recover the cost of balancing reserve capacity that is provided to balance variable energy resources through the Regulation and Frequency Response Service rate?

A. No. We determine the balancing reserve capacity requirement for each service and allocate costs accordingly. The rates are designed to recover the costs of the balancing reserve requirements for each specific service. As a result, there is no duplicative recovery of costs.

Section 6.1: Balancing Reserve Capacity Purchases during the Rate Period

Q. Do you expect that BPA will make any balancing reserve capacity purchases to provide VERBS during the rate period?

A. Yes, we expect BPA will attempt to make purchases of *inc* balancing reserve capacity during the rate period. *Id.* section 5.1. We do not expect BPA to purchase *dec* balancing reserve capacity. *Id.*

Q. Under which conditions would you expect BPA to make a purchase of inc *balancing reserve capacity to provide balancing services such as VERBS?*

A. We expect BPA to attempt to purchase balancing reserve capacity to: (1) make up the difference between the forecast availability of balancing reserve capacity from the

FCRPS (Kerns *et al.*, BP-14-E-BPA-24, section 4) and the forecast balancing reserve capacity need to maintain a 99.5 percent level of service (Puyleart *et al.*, BP-14-E-BPA-22, section 5) ("Type 1 purchases"); (2) replace Federal balancing reserve capacity that becomes unavailable ("Type 2 purchases"); (3) provide balancing reserve capacity sufficient to meet a higher-quality level of reserve service for customers who elect the VERBS Full Service option ("Type 3 purchases"); or (4) increase the amount of balancing reserve capacity held for BPA's balancing services ("Type 4 purchases"). Study sections 10.5.3 to 10.5.6.

Q. In the current FY 2012–2013 rates, how would BPA recover the costs of incremental purchases of balancing reserve capacity?

A. The BP-12 rates contain two formula rates that, when triggered, adjust the VERBS imbalance component rate. The formula rates were designed to ensure that BPA can recover its costs from the users that created the need for the balancing reserve capacity.

Q. How do you propose to recover the costs of purchases of balancing reserve capacity purchases in FY 2014–2015?

A. We are proposing to replace the BP-12 formula rate adjustments with four new "Formula Purchases Charges" to recover the costs associated with each type of balancing reserve capacity purchase. Our cost allocation methodology determines the balancing reserve capacity purchase costs that are recovered under each formula charge. Klippstein *et al.*, BP-14-E-BPA-24, section 6 (explaining the cost allocation methodology for purchases of balancing reserve capacity to provide balancing services, including Dispatchable Energy Resource Balancing Service and VERBS). We explain the calculation for each Formula Purchases Charge in Study sections 10.5.3 to 10.5.6.

Q. Would BPA have any incentives to minimize costs associated with purchases of balancing reserve capacity?

A. Yes. BPA would develop business practices that describe our acquisition guidelines and processes. BPA will be open and transparent regarding after-the-fact disclosure of the cost and deployment of acquired balancing capacity. Since all costs are passed through to purchasers, and BPA does not add fees to purchase prices, BPA does not have any financial motivation to select more expensive resources when lower-cost resources are available.

Q. If a Purchases Charge is triggered, would all VERBS Base Service customers receive a charge?

A. Not necessarily. Type 1 and 2 Purchases Charges would apply to all customers that take VERBS Base Service. *Id.* sections 10.5.3 and 10.5.4. However, the Type 3 Purchases Charge would apply only to customers taking Full Service. *Id.* section 10.5.5; *see also* ACS-14 Rate Schedule III.E.2.c.3. (describing the Full Service rate condition on Base Service rates). Moreover, Type 4 Purchases Charges would be directly assigned to the individual customer that creates the unanticipated increase in balancing reserve capacity to support VERBS for that customer. Study section 10.5.6.

Q. For the Type 1 and Type 2 Purchases Charges, how are you proposing to determine a variable energy resource's inc *requirement?*

A. To calculate the Type 1 and Type 2 Purchases Charges, we calculate the balancing reserve capacity requirements for each Generating Facility based on the Generating Facility's nameplate capacity and Base Service scheduling election. We calculate the balancing reserve capacity requirement for each component (regulation, following, imbalance) of VERBS as a percentage of installed capacity, and the components taken from BPA for VERBS Base service are then summed together. *See* Documentation

Table 2.31. We use these percentages to determine an individual resource's *inc* reserve capacity requirement for purposes of establishing the billing factor for allocating Type 1 and Type 2 purchases. *Id.*; Study sections 10.5.3.1 and 10.5.4.1.

Q. *Why are you proposing to use a variable energy resource's* inc *reserve capacity requirement for all components of VERBS to calculate the Type 1 and Type 2 Formula Purchases Charges?*

A. Type 1 and Type 2 purchases would be made to provide the VERBS Service. However, different resources use different components of VERBS Base Service. For example, the imbalance component for VERBS is not a part of Base Service for solar resources or for customers that elect to self-supply the imbalance component. Additionally, each variable energy resource's balancing reserve capacity requirement will vary based on the variable energy resource's scheduling election because scheduling elections with shorter scheduling periods will require less balancing reserve capacity. Using the *inc* reserve capacity requirement for each component allows BPA to allocate costs based on the individual need of each resource taking VERBS Base Service.

Q. *For the Type 2 Purchases Charge, why are you proposing to use the total monthly VERBS charges from base rates and the total of the DERBS* inc *and* dec *charges to determine the percentage for allocating costs between the two services?*

A. The rate for VERBS Base Service combines *inc* and *dec* balancing reserve capacity costs in each component. In contrast, the rates for DERBS service are separated for *inc* and *dec* balancing reserve capacity costs but combine all three balancing reserve capacity components. A total charge common denominator for allocating costs between the two services is created when both *inc* and *dec* DERBS charges are added together and all charges for VERBS Base Service rate components are added together.

We reviewed allocating the costs using: (1) the total hourly base *inc* charge; (2) the total monthly base charge; or (3) a fixed percentage established for the rate period. We are proposing to use the total monthly base charge because it is easier to implement and provides a higher level of accuracy over the fixed percentage.

Q. *Do you propose to provide notice and an opportunity to comment before BPA decides to make a purchase of balancing reserve capacity to provide VERBS during the rate period?*

A. For VERBS Base Service Type 1 and Type 2 purchases of balancing reserve capacity for a term that exceeds 60 days' duration, we propose that BPA would provide advance notice and opportunity to comment on the acquisition. For Type 1 and Type 2 purchases of balancing reserve capacity that are for a term of 60 days or less, we are proposing that BPA would give notice of the purchase after the fact. For Type 3 purchases under VERBS Full Service, however, we expect to develop the acquisition strategy and notice and comment procedures that apply to Full Service in the ACS Practices Forum. Fisher *et al.*, BP-14-E-BPA-21, section 5.2. For Type 4 purchases, we are not proposing to give public notice and comment because the cost of those purchases are directly assigned under the proposed Type 4 Purchases Charge to the customer that creates the need for the purchase of balancing reserve capacity for balancing services.

Q. *Why are you proposing that BPA would give only after-the-fact notification of short-term (60 days or less) Type 1 and Type 2 purchases of balancing reserve capacity for VERBS Base Service?*

A. There is a trade-off between having time to notice the shorter-term purchase and receive comments and executing the shorter-term agreements. We believe that if we have clear guidelines for the acquisitions, then after-the-fact notification is the best business procedure for the shorter-term purchases.

Q. When would customers see Type 1, 2, 3, and 4 Formula Purchases Charges on their billing statements?

A. The purchase costs for Type 2 Formula Purchases Charges are allocated across all VERBS and DERBS resources using the total charges at base rates for the month. This methodology will require extra time to calculate each month, therefore, the charges for these types of purchases may not be available until the billing statement following the statement for the current invoice cycle. Type 1, Type 3, and Type 4 purchases should be available on the next billing cycle.

Q. What is Provisional VERBS (also known as "Provisional Balancing Service")?

A. Provisional Balancing Service is a "default" service that is available to wind facilities that did not elect to take VERBS from BPA but interconnect during the rate period and to VERBS customers that can no longer self-supply one or more components of VERBS. Under this service, BPA does not acquire additional balancing reserve capacity, and the Provisional Balancing Service customer is subject to DSO 216 before other customers that have elected VERBS from BPA.

Q. Are you proposing to retain Provisional Balancing Service for the FY 2014–2015 rate period?

A. No.

Q. Why are you proposing to discontinue Provisional Balancing Service?

A. We are now proposing to purchase additional balancing reserve capacity and directly assign those costs under the Type 4 Purchases Charge to customers: (1) that do not elect to take VERBS from BPA but nevertheless choose to interconnect during the rate period; (2) that elect to self-supply but cannot continue to self-supply for the rate period; (3) that elect to participate in committed scheduling but fail to meet BPA's performance requirements; or (4) that elect to participate in committed scheduling but then choose to

change their scheduling election mid-rate period to a scheduling option that has a longer scheduling period. Study section 10.5.6. BPA would directly assign the costs of balancing reserve capacity purchases under the Type 4 Purchases Charge to the customer creating the need for the purchase under the above circumstances. *Id.*

Q. What does "self-supply" mean with regard to VERBS?

A. Self-supply is the provision by a VERBS customer of balancing reserve capacity either for its own use or for use by the pool of customers taking VERBS from BPA. Self-supply can take several forms, such as the current performance-based Customer Supplied Generation Imbalance (CSGI) pilot, capacity purchased by the customer or BPA on behalf of the customer for Supplemental Service, or capacity provided by a customer to BPA to deploy to meet some or all of the customer's reserve capacity requirement for Full Service.

Q. Do you expect self-supply of one or more components of VERBS during the rate period?

A. Yes. We expect self-supply of the base imbalance component in the amount of 1,505 MW nameplate of wind on average over the rate period. Study section 10.5.1; Documentation Table 2.17.

Q. How would BPA know that a variable energy resource customer intends to self-supply one or more components of VERBS during the rate period?

A. BPA would require VERBS customers to elect to take one of the Base Service scheduling options for the rate period or elect to self-supply one or more components of VERBS Base Service. Customers must make these elections by April 1, 2013.

Q. If a customer that self-supplies one or more components of VERBS fails to satisfy BPA's self-supply requirements during the rate period, what service do you propose to offer to that customer?

A. As mentioned above, the customer may elect the Base Service scheduling option that best meets its needs. The customer may also elect to take Supplemental Service, and the customer may also elect to take Full Service if it elects to take 30/60 committed scheduling or 30/30 committed scheduling. The customer will be responsible for any balancing reserve capacity purchase costs that are necessary to meet its reserve requirements for the remainder of the rate period. Study section 10.5.6.

Q. How would BPA know if a variable energy resource customer is expected to interconnect to the BPA balancing authority area during the rate period?

A. There is a significant lead time for interconnection studies, construction of interconnection facilities, and construction of wind generators. By the time BPA issues its Final Proposal, we should have a clear indication of the status and expected completion date of wind generation under development and expected to interconnect during the rate period.

Q. If a customer advances its interconnection date into the rate period from an originally expected post-2015 date, what type of service do you propose to offer to that customer?

A. As mentioned above, the customer can elect the VERBS Base Service scheduling option that best meets its needs. The customer would pay the cost of any balancing reserve capacity purchases that are needed to meet the incremental reserve requirement of that customer for the remainder of the rate period. *Id.* In addition, the customer may elect to take Supplemental Service to increase its quality level of service and mitigate its risk of curtailment under DSO 216. Finally, if the customer elects to take VERBS Base Service 30/30 committed scheduling or 30/60 committed scheduling, the customer may elect to

take Full Service. Fisher *et al.*, BP-14-E-BPA-21, section 5; *see also* ACS-14 Rate Schedule III.E.2.c.3.

Section 6.2: VERBS Supplemental Service

Q. What is VERBS Supplemental Service?

A. Supplemental Service utilizes *inc* or *dec* capacity beyond the customer's allocation of reserve capacity for Base Service to mitigate the impacts of DSO 216. Customers can elect to have BPA purchase balancing reserve capacity for deployment by BPA, or the customer can self-supply capacity to BPA, and BPA will deploy the capacity.

Q. Are you proposing any changes to the rate for Supplemental Service?

A. Yes. The rate is the same as the BP-12 rate, but as discussed in more detail below, we are proposing to remove the administrative charge that applied under the BP-12 Supplemental Service rate. In addition, in response to customer feedback, we are now proposing to make shorter-term monthly capacity purchases for the customer, and BPA will be able to recognize on-demand capacity e-Tags for capacity purchased by customers on much shorter time horizons. The details for implementation changes for Supplemental Service will be described in business practice modifications. Fisher *et al.*, BP-14-E-BPA-21, section 3 (discussing the ACS Practices Forum).

Q. How do you propose to recover the cost for VERBS Supplemental Service?

A. We propose to recover the costs through a formula rate for any acquisitions made by BPA at customer request. ACS-14 Rate Schedule section III.E.5. The formula rate includes a monthly charge for all supplemental balancing reserve capacity supplied by BPA during a month. We expect to purchase supplemental balancing reserve capacity based on customer requests for specified periods during a year. The rate for supplemental balancing reserve capacity will be established on a periodic basis for a

period of a month or longer, as established in the business practice covering Supplemental Service. We propose to base the rate on the average cost of supplemental balancing reserve capacity purchased by BPA for all customers during the period of the purchase.

Q. Are there other costs for Supplemental Service in addition to the balancing reserve capacity purchase costs?

A. There are administrative costs associated with implementing the service. However, these costs are included in the forecast of Wind Integration Team (WIT) costs. In this Initial Proposal, we propose to assign WIT costs directly to the VERBS rate. Klippstein *et al.*, BP-14-E-BPA-24, section 4. Since these costs are now included in BPA's WIT cost proposal, we have proposed to eliminate the direct administrative charge for Supplemental Service.

Q. Why is a formula rate necessary to recover the cost of VERBS Supplemental Service?

A. Because customers can elect Supplemental Service from BPA on a monthly basis, BPA needs the ability to calculate costs on a monthly basis and a rate mechanism to recover those costs from the customers that cause those costs to be incurred.

Q. Who would be subject to the proposed VERBS Supplemental Service rate?

A. Customers taking any of the VERBS base services would be eligible to take Supplemental Service. *See* ACS-14 Rate Schedule III.E.1.

Q. What type of balancing reserve capacity would BPA make available under the proposed VERBS Supplemental Service?

A. BPA will acquire either or both *inc* and *dec* capacity for Supplemental Service, or the customer can self-supply the capacity to BPA for deployment. However, with regard to *dec* reserve capacity, most parties in the region have not expressed great concern about DSO 216 limits that require feathering of the output of wind plants to scheduled amounts

during over-generation events that exhaust the total *dec* balancing reserve capacity made available in the BPA balancing authority for wind, load, and other generation. DSO 216 implementation for over-generation events effectively causes the wind plant to self-supply *dec* reserve capacity. For the BP-14 rate period, we are proposing not to acquire non-Federal *dec* balancing reserve capacity, in addition to any amounts of *dec* balancing reserve capacity that can be provided by the FCRPS, to provide VERBS Base Service. Fisher *et al.*, BP-14-E-BPA-21, section 5.1. Since we are proposing that BPA limit the amount of *dec* balancing reserve capacity it provides, we intend to expand Supplemental Service to provide individual customers the option to acquire additional non-Federal *dec* balancing reserve capacity. *Id*.

Q. How does Supplemental Service differ from VERBS Full Service?

A. Customers are in control of how much balancing reserve capacity under Supplemental Service they want to self-supply, purchase, or have BPA purchase to mitigate DSO 216 curtailment risk. In contrast, under our conceptual framework, VERBS Full Service would be based on the forecast likely imbalances of a customer that will require *inc* capacity beyond what BPA is providing under Base Service. As a result, the customer's total balancing reserve capacity requirement for Full Service will vary. As described in Fisher *et al.*, BP-14-E-BPA-21, section 5.2, BPA will determine the balancing reserve capacity acquisition strategy for Full Service customers in the ACS Practices Forum and establish requirements for customers that choose to self-supply.

Section 6.3: VERBS Rate for Solar Resources

Q. Are you proposing to make any changes to the rate design for the VERBS rate for solar resources?

A. No, the rate design will remain the nameplate of the VERBS Solar Resource.

Q. How would BPA determine the billing factor for solar-powered variable energy resource installed capacity each month?

A. BPA would use the project nameplate capacity when the facility is energized to calculate the billing factor for the following month unless a greater kW quantity is delivered during some later hour prior to the 15th of the month prior to the billing month. ACS-14 Rate Schedule III.E.4.b.

Q. Would the VERBS Solar rate be subject to the proposed Formula Purchases Charges that apply to VERBS?

A. Solar resources would be subject to the Type 1, Type 2, and Type 4 Purchases Charges. A solar resource's share of these charges is based on the total balancing reserve capacity requirements for regulating and following reserves of the resource. Study sections 10.5.3, 10.5.4, and 10.5.6.

Section 6.4: VERBS Credit for Hydro-Related Reductions in Balancing Reserve Capacity from the FCRPS

Q. Why are you proposing a VERBS Credit?

A. We are proposing a credit to the base VERBS rates, *inc* or *dec*, to reimburse customers for the cost of balancing reserve capacity that was forecast to be available from the FCRPS but is not provided for by the FCRPS because of hydro system conditions. Study section 10.5.7; *see also* Fisher *et al.*, BP-14-E-BPA-21, section 6 (discussing the policy rationale for the VERBS credit). The proposed rates for the credit are stated in ACS-14 Rate Schedule III.E.7.

Q. Who would be eligible for the VERBS Credit?

A. Customers taking all three components of VERBS Base Service would be eligible to receive the VERBS Credit. CSGI participants are not eligible for the VERBS Credit. Study section 10.10.5.7; *see* Fisher *et al.*, BP-14-E-BPA-21, section 6.

Q. Would solar resources receive a VERBS rate credit for hydro-related reductions in balancing reserve capacity?

A. No. As noted above, the VERBS Credit would apply only to customers taking all three components of Base Service. The VERBS rate for solar resources does not contain an imbalance component. Because solar resources will not receive a reduction in service during hydro-related reductions of balancing reserve capacity from the FCRPS for regulation and following, the proposed VERBS Credit will not apply.

Q. Are there any limitations to the VERBS Credit?

A. The total *inc* and *dec* credit amount for the proposed VERBS Credit will not exceed the total VERBS charge from Base Service base rates for each resource. ACS-14 Rate Schedule III.E.7.c.

Section 7: Dispatchable Energy Resource Balancing Service

Q. What is Dispatchable Energy Resource Balancing Service?

A. Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service necessary to support the within-hour deviations of dispatchable energy resources from the hourly generation estimate (*i.e.*, the generation schedule). DERBS is provided by increasing or decreasing committed online Federal generation (through the use of AGC equipment) as necessary to follow the moment-by-moment changes in thermal generation relative to the schedule, including ramps between hours. DERBS is required to maintain

the power system frequency at 60 Hertz in conformance with NERC and WECC reliability standards.

Q. Do you propose to make any changes to the DERBS rate? If so, please summarize those proposed changes.

A. We are proposing two changes to the DERBS rate. First, we are proposing to base the billing factor for the DERBS rate on measuring the maximum hourly generation imbalance for each plant using a five-minute average energy from the plant revenue meter rather than the current one-minute average of the plant Supervisory Control and Data Acquisition (SCADA) meter. Second, we are proposing to apply two Formula Purchases Charges to DERBS customers to ensure cost recovery for balancing reserve capacity purchases made during the rate period to provide balancing services.

Q. Why are you proposing to base its calculation of the DERBS rate on five-minute average revenue meter data instead of one-minute average SCADA meter data?

A. The proposed change is motivated by two factors. The SCADA meter data are not available to customers, while revenue meter data are visible, so changing to the revenue meter system promotes transparency for customers reviewing details of their bills for DERBS service. Revenue meter data are also preferred to SCADA meter data because the revenue meter system is configured to be more robust against inaccuracies than the SCADA meter system. Revenue meter data also have a process for being corrected as needed, whereas SCADA meter data do not. While one-minute averaging is possible with the SCADA meter system, the revenue meter system is currently set up to have five-minute average readings as the shortest time averaging period available.

Q. How does the proposed billing factor affect the DERBS rate?

A. The proposed billing factor increases the nominal rate but has, by itself, no effect on the overall revenue requirement being collected. All else being equal, most DERBS

customers will see little change in their monthly DERBS bill. The impact on the nominal DERBS rate is an increase of approximately six percent above what it would be for the one-minute billing factor. If BPA retained the one-minute billing factor for DERBS, the new *inc* rate would be approximately 21.42 mills per kilowatt for each hour, and the new *dec* rate would be approximately 2.55 mills per kilowatt for each hour.

Q. Is your proposal to utilize five-minute average revenue meter data to calculate the DERBS rate consistent with the Balancing Reserve Capacity Quantity Forecast for DERBS, which relies upon one-minute supervisory control and data acquisition data? Please explain.

A. Yes. The Balancing Reserve Capacity Quantity Forecast, based on one-minute data, is calculated to provide sufficient balancing reserve capacity for very rare imbalance events occurring within the BPA balancing authority area, at levels estimated to be exceeded in only one-half of one percent of all such periods during the rate period. Study section 2.7.2. Only the SCADA system can provide data with granularity this fine, and it measures the variability or capacity to which the balancing resources must respond. The billing factors, taken as the largest of the 12 five-minute intervals in each hour, also measure the imbalance caused by each DERBS generator. The Balancing Reserve Capacity Quantity Forecast is determined by the one-minute SCADA meter data, which in turn determines the revenue requirement. The expected annual total DERBS billing requirement measures the capacity used by an individual generator and will determine its monthly DERBS bill.

Q. Where is the forecast use of DERBS balancing reserve capacity established?

A. The forecast use of balancing reserve capacity for DERBS is included in Study sections 2 and 10.

Q. Did you change anything in the forecast use of DERBS capacity?

A. Yes. Our recent review of five-minute data from FY 2012 for DERBS customers indicated that the balancing reserve capacity quantity for DERBS *inc* service decreased from our initial forecast of 61 MW by about 15 percent to 52 MW. The generation inputs revenue forecast listed in Study Table 1 does not take into consideration this reduction in the balancing reserve capacity requirement because our rate studies and rate calculation tables for the Initial Proposal were already finalized and could not be updated in time for the Initial Proposal. Nevertheless, in the ACS-14 rate schedule, we adjusted the proposed DERBS rate downward based on a proposed 15 percent reduction in the balancing reserve capacity requirement for DERBS. The balancing reserve capacity-based Ancillary and Control Area Services revenue forecast listed in Study Table 1 do not account for this adjustment. In the Final Studies, however, we will update the rate calculations in Table 1 based on the best information available at that time. We will also review DERBS customers' actual use of balancing reserve capacity (starting from October 2011) and factor any changes to the balancing reserve capacity requirement into the DERBS rate for the Final Proposal.

Q. Do you expect the DERBS reserve requirement to change by the Final Proposal?

A. It is possible that the forecast balancing reserve capacity requirement for DERBS will decrease. We are aware that one large dispatchable energy resource may leave the BPA balancing authority area during the rate period. As noted above, the final rate studies will be based on the best information available regarding this possibility. It is also possible that we will need to update the balancing reserve capacity requirement based on the balancing reserve capacity requirement for DERBS customers during the period after October 2011.

Q. How is the proposed DERBS rate consistent with the principle of cost causation?

A. The revenue requirement for the DERBS rate is calculated based on the balancing reserve capacity required by DERBS customers during the test period. Study section 2.7. The expected annual billing determinant is also based on a study of DERBS customers' historical usage of generation imbalance capacity. Finally, because the DERBS rate is based on actual use and will apply to only the users of balancing reserve capacity, the DERBS rate is consistent with the principle of cost causation.

Q. Why are you proposing to retain a 2 MW dead band for the DERBS rate?

A. We propose to retain the 2 MW dead band for the FY 2014–2015 rates because we have seen no evidence that some other structure would better allocate costs to those generators causing them. A 2 MW dead band is of sufficient size to manage most station control errors. This approach also ensures that the users of DERBS compensate BPA to the extent they utilize DERBS above 2 MW.

In addition, a 2 MW dead band ensures that the balancing reserve capacity costs associated with large station control errors are not shifted to other users of DERBS. By including a dead band under DERBS, the costs associated with the balancing reserve capacity under the dead band are spread across a higher per-megawatt rate. Thus, as the size of the dead band increases, so do the costs associated with the larger dead band, which materialize in the form of a higher per-megawatt rate for all users of DERBS.

Q. Why are you proposing to exempt certain five-minute average periods from the DERBS rate calculation for schedule deviations that were caused by automatic voltage control systems that corrected a grid frequency deviation?

A. A generator's required governor will move the generator away from its current generation level to stabilize grid frequency when system frequency deviates sufficiently from 60 Hz. Under these circumstances, we are proposing that BPA not charge customers for

deviations from schedule that benefit grid stability. Exempting periods when this is occurring means that DERBS bills will not reflect generator imbalances driven by grid-stabilizing governor responses.

Q. Based on the proposed cost allocation methodology (Klippstein et al., BP-14-E-BPA-24), which type of balancing reserve capacity purchase costs are you proposing to recover from DERBS customers?

A. Based on the cost allocation methodology described in the testimony of Klippstein *et al.*, BP-14-E-BPA-24, we are proposing to recover the costs of Type 2 and Type 4 purchases of balancing reserve capacity from DERBS customers. The cost allocation methodology determined that DERBS customers are not subject to Type 1 purchase costs for the FY 2014–2015 rate period and Type 3 purchase costs are inapplicable to DERBS customers. *Id.* section 6; *see* ACS-14 Rate Schedule III.F.4.

Q. When would the proposed Type 2 Purchases Charge apply?

A. The Type 2 Purchases Charge is designed to recover the cost of purchases of non-Federal balancing reserve capacity that are necessary to replace Federal balancing reserve capacity that becomes unavailable during the rate period. Klippstein *et al.*, BP-14-E-BPA-24, section 6. The Type 2 Purchases Charge is based on the dispatchable energy resource's proportion of total costs from the purchase of non-Federal balancing reserve capacity. Study section 10.6.2.1. The proportional costs would be spread to the dispatchable energy resources by the appropriate billing factors. *Id.*

Q. For the Type 2 Purchases Charge, why are you proposing to use the total monthly VERBS charge from VERBS Base Service base rates and the total of the DERBS inc *and* dec *charges to determine the percentage for allocating costs between the two services?*

A. The rate for VERBS Base Service combines *inc* and *dec* balancing reserve capacity costs in each component. In contrast, the rates for DERBS service are separated for *inc* and

dec balancing reserve capacity costs but combines all three reserve components. A total charge common denominator for allocating costs between the two services is created when both *inc* and *dec* DERBS charges are added together and all charges for VERBS base service rate components are added together.

We also reviewed allocating the costs using (1) the total hourly base *inc* charge; (2) the total monthly base charge; or (3) a fixed percent established for the rate period. We are proposing to use the total monthly base charge because it is easier to implement and provides a higher level of accuracy over the fixed percent. The total hourly base *inc* charge method, in contrast, is more complex and difficult to administer from a billing standpoint. This is because the billing factors for VERBS and DERBS are different, and it is necessary to use the DERBS billing factor on an hourly basis to determine the allocation percentage for VERBS and DERBS.

Q. When would the proposed Type 4 Purchases Charge apply?

A. The Type 4 Purchases Charge is designed to recover the cost of additional balancing reserve capacity purchases that are necessary to provide DERBS to a customer because: (1) the customer elected to self-supply but is unable to continue self-supplying DERBS; (2) the customer has a projected generator interconnection date after FY 2015, but chooses to interconnect during the FY 2014–2015 rate period; or (3) the dispatchable energy resource operating in another balancing authority area chooses to dynamically transfer into the BPA balancing authority area during the FY 2014–2015 rate period. Study section 10.6.3.

Q. What is the policy rationale for the cost allocation of balancing reserve capacity purchases?

A. For the policy rationale, see the testimony of Fisher *et al.*, BP-14-E-BPA-21, section 6, and Klippstein *et al.*, BP-14-E-BPA-24.

Q. How does DERBS differ from Regulation and Frequency Response Service?

A. While the Regulation and Frequency Response Service rate, like DERBS, is designed to recover capacity costs, RFR service provides balancing reserve capacity only for the regulation component (moment-to-moment variations) for load. DERBS, in contrast, provides following and imbalance components, in addition to the moment-to-moment regulating balancing reserve capacity component, for dispatchable energy resources. The costs of balancing reserve capacity for the following and imbalance components for load are recovered through power rates. The different rate approaches ensure that BPA recovers its costs from the users that create the costs and is designed to avoid duplicative cost recovery for balancing reserve capacity.

Q. How does DERBS differ from Generator and Energy Imbalance Service?

A. Generation Imbalance Service provides only the energy value required by generator imbalance (*i.e.*, the difference between scheduled generation and actual generation). The cost of the balancing reserve capacity that stands ready to provide this energy on short notice is not included in energy charges billed under the Generation Imbalance Service. The cost of the balancing reserve capacity is instead included in the DERBS rate.

Energy Imbalance Service provides only the energy value required by load imbalance (*i.e.*, the difference between scheduled load and actual load). The cost of the balancing reserve capacity that stands ready to provide this energy on short notice is not included in energy charges billed under the Energy Imbalance Service. The cost of the balancing reserve capacity is instead included in the Regulation and Frequency Response rate.

Q. Does this conclude your testimony?

A. Yes.

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