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REBUTTAL TESTIMONY of

CHRISTOPHER J. GILBERT, KATHERINE L. BEALE, THOMAS D. COATNEY,

DANIEL H. FISHER, and REBECCA E. FREDRICKSON

Witnesses for Bonneville Power Administration

SUBJECT: ANCILLARY AND CONTROL AREA SERVICES RATE DESIGN

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Christopher J. Gilbert, and my qualifications are contained in BP-14-Q-BPA-23.

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.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the ACS-14 Ancillary and Control Area Services Rate Design issues raised by the parties in their direct testimony and to explain our proposed changes to the ACS rate design since the Initial Proposal. Specifically, our rebuttal testimony responds to the direct testimony filed by several parties on topics discussed in our direct testimony and Generation Inputs Study, BP-14-E-BPA-05 (Study), and Generation Inputs Documentation, BP-14-E-BPA-05A-E01 (Documentation), including Industrial Customers of Northwest Utilities (ICNU), BP-14-E-IN-01; Simpson Tacoma Kraft Company (Simpson), BP-14-E-ST-01; Iberdrola Renewables,

BP-14-E-IR-01; JP03, BP-14-E-JP03-01; JP08, BP-14-E-JP08-01; Southern California Edison Company, BP-14-E-SC-01; JP07, BP-14-E-JP07-01; M-S-R Public Power Agency (MSR), BP-14-E-MS-01; Western Public Agencies Group (WPAG), BP-14-E-WG-02; and Renewable Northwest Project, BP-14-E-RN-01.

Section 2: Dispatchable Energy Resource Balancing Service (DERBS) Rate

Q. *ICNU states, "the DERBS rate causes an undue detriment to the development of efficient and environmentally beneficial cogeneration resources within the BPA balancing authority area, which is contrary to Federal energy policy." Deen, BP-14-E-IN-01, at 3. Do you agree?*

A. No. We have designed the DERBS rate based on the principle of cost causation, which ensures that the entities that create the costs pay for the associated costs they create. Jackson *et al.*, BP-14-E-BPA-28, at 40; *see also* Klippstein *et al.*, BP-14-E-BPA-24, at 2. Staff has explained the benefits of basing cost allocation for ancillary and control area services on cost causation and equitable allocation of costs. Fisher *et al.*, BP-14-E-BPA-21, at 41. We are aware that Federal energy policy seeks to encourage cogeneration resources, and we do not believe the DERBS rate is contrary to that policy. The DERBS rate is designed to recover the costs associated with the use of balancing reserve capacity that are created by dispatchable energy resources. Nothing about this approach is inconsistent with national policy. As we discuss in more detail below, we propose several changes to the rate design for DERBS that will provide additional flexibility to DERBS customers to manage their use of balancing reserve capacity under DERBS.

Q. *ICNU states, "[t]he DERBS rate imposes an unnecessary charge on operators of CHP [combined heat and power] and cogeneration facilities in BPA's balancing authority."*

Deen, BP-14-E-IN-01, at 5. Why is it appropriate to charge the DERBS rate to CHP facilities?

A. The proposed DERBS rate is designed to collect the costs imposed upon the BPA system by non-Federal thermal generators, including CHP facilities. Jackson *et al.*, BP-14-E-BPA-28, at 40-41. Cogeneration customers, like all other DERBS customers, pay for DERBS to compensate BPA for the cost of having balancing reserve capacity available to absorb their generation imbalances. *Id.* at 40.

Q. ICNU suggests that BPA should abandon its DERBS rate proposal. Deen, BP-14-E-IN-01, at 2. Do you agree?

A. No.

Q. Why is it important to maintain a DERBS rate?

A. DERBS is necessary to help maintain system frequency at 60 Hz and to conform to NERC and WECC reliability standards. Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-10, at 71. BPA's balancing reserve capacity has become a scarce commodity that is in high demand. For example, Staff explains that no more balancing capacity is available than BPA has already committed to providing, even though it is requested by parties. Connolly *et al.*, BP-14-E-BPA-49, at 2. The costs of providing a portion of this capacity to non-Federal thermal generators, the DERBS customers, should be borne by these customers, because they are creating the costs associated with making balancing reserve capacity available for their use. Jackson *et al.*, BP-14-E-BPA-28, at 40.

Q. ICNU suggests that BPA adopt certain non-rate measures to limit the costs of reserves used by non-Federal thermal generators. Deen, BP-14-E-IN-01, at 11. ICNU states, "BPA could work with customers on an individual level to improve customer scheduling practices and also to better understand the operational characteristics of individual *plants so that BPA would be able to hold fewer reserves for non-Federal thermal plants, particularly during times of ramping, start-up, or shutdown." Id. at 3-4. ICNU states that BPA could pursue changes to its scheduling regime, such as a committed intra-hour scheduling option for non-Federal thermal generators. Id. at 4. Does BPA find merit in ICNU's suggestions for non-rate measures?*

A. Yes, we believe there is merit in ICNU's suggestions for non-rate measures. We note, however, that even though these measures may be available, implementation by all non-Federal thermal generators is not guaranteed. The idea of a committed intra-hour scheduling discount was proposed for VERBS customers because of their nameplate-based billing factor, which would not recognize the decrease in use of balancing reserves when they improved their scheduling practice by scheduling within the hour. *See* Jackson *et al.*, BP-14-E-BPA-28, at 17-20; Study, BP-14-E-BPA-05, at 120. This credit is not needed for DERBS customers, because they have a usage-based rate. When a DERBS customer improves its scheduling practice, its usage-based billing factor automatically results in a decrease in its DERBS bill. Other non-rate alternatives are also available to non-Federal thermal generators. For example, customers may request (by April 1, 2013, for DERBS) to self-supply or to make third-party supply arrangements for the rate period. We acknowledge that a generic business practice for self-supply or third-party supply of DERBS has not yet been developed; however, BPA is willing to explore the development of such options with customers.

Q. ICNU states that because actual DERBS usage in FY 2012 was 31.3 percent below forecast for incs *and 20.4 percent below forecast for* decs, *DERBS rates should be reduced by those amounts. Deen, BP-14-E-IN-01, at 7. In addition, ICNU states, "[g]iven the downward trend in thermal reserves usage, the potential steps by BPA and customers to improve scheduling and operations, and the significant impact on* *generators," DERBS rates should be reduced by an additional 5 percent. Id. at 8. ICNU claims that reducing the rates by the amounts it suggests would yield an overall reduction in* inc *usage of 36 percent and* dec *usage of 25 percent. Id. What is your response?*

A. The DERBS rate in the Initial Proposal is based on forecast billing factors that were based on the FY 2012 DERBS billing factors and a revenue requirement based on the balancing reserve capacity quantity forecast. ICNU's proposed rate decrease is based on an assumption that it will result in further reductions in billing factors, but this logic is flawed. DERBS customers reduced their balancing reserve capacity usage, at least in part, as a response to the introduction of the DERBS rate. *See, e.g.*, Wolverton, BP-14-E-ST-01, at 8. Lowering the rate would decrease an incentive that prompted those generators to reduce their station control error in the first place.

Additionally, the design of the DERBS rate is based on more than just the billing factor. In general, the rate for a particular rate class equals the revenue requirement for that rate class divided by the class's billing factor. Study, BP-14-E-BPA-05, at 127-28. If, as ICNU proposes, the rate decreases, and the denominator (billing factor) decreases, then the numerator (revenue requirement) must decrease by even more than the billing factor. The DERBS revenue requirement is based on the balancing reserve capacity quantity forecast. The balancing reserve capacity quantity forecast, in turn, is a function of peak reserve usage. The forecast is largely unchanged, however, because the peak usage is relatively unchanged. Puyleart *et al.*, BP-14-E-BPA-48, at 5. Therefore, the numerator in the rate design formula has not decreased. Adopting ICNU's proposal would lead to rates based on something other than the costs of providing DERBS.

Q. *Both Simpson and ICNU recommend that BPA increase the deadband under DERBS from 2 MW to 3 MW. Wolverton, BP-14-E-ST-01, at 6; Deen, BP-14-E-IN-01, at 9. Do you agree?*

A. Yes. BPA Staff supports Simpson's and ICNU's suggestion to increase the DERBS deadband from 2 MW to 3 MW. As we explain further below, we base our proposal to increase the deadband on a modest improvement in cost causation for DERBS.

Q. *How would a 3 MW deadband affect the* inc *and* dec *charges under DERBS?*

A. A 3 MW deadband, all else being equal, will increase the *inc* and *dec* rates, because the revenue requirement would be spread across a smaller level of billing determinants. The resulting rate increase will increase the incentive to manage large deviations from schedule.

Q. *Why is a 3 MW deadband consistent with the principle of cost causation?*

A. The DERBS costs are driven by large deviations of the group of DERBS generators from their combined schedule, specifically the deviations in excess of the 99th percentile, or over several hundred megawatts. Attachment 1. For any of these large deviations, it is almost certain that at least one of the largest six plants has a large station control error, because these six plants constitute 88 percent of the total DERBS nameplate capacity. Attachment 2. The remaining 19 smaller DERBS plants make up just 12 percent of the nameplate capacity of the total group, with a maximum individual nameplate rating of 64 megawatts. *Id.* The smaller DERBS generators can add to the large deviations, but individually they are incapable of causing a large deviation from schedule that is over 64 MW. This means that an increase in the deadband from 2 MW to 3 MW (which would still have little impact on BPA) would shift a modest portion of imbalance costs to the larger plants, which have the larger contribution to the need for DERBS, while not excluding any of the smaller plants from making a DERBS payment. We believe this outcome is consistent with the principle of cost causation.

Section 3: Variable Energy Resource Balancing Service (VERBS) Rates

Section 3.1: VERBS Rate Design

Q. RNP and WPAG see potential benefits associated with 15-minute scheduling. Yourkowski et al., BP-14-E-RN-01, at 35-38; Saleba et al., BP-14-E-WG-01, at 22. Has BPA made a decision regarding 15-minute scheduling?

A. RNP notes that Commission Order No. 764 "requires jurisdictional utilities (and non-jurisdictional utilities, for reciprocity purposes) to provide all transmission customers with the option" of 15-minute scheduling. Yourkowski *et al.*, BP-14-E-RN-01, at 34. Staff's direct testimony stated that BPA had not yet decided whether to offer 15-minute scheduling but would do so in "early 2013." Fisher *et al.*, BP-14-E-BPA-21, at 17-18. BPA has now decided to offer 15-minute scheduling during the FY 2014–2015 rate period. In order to implement 15-minute scheduling, a number of changes to BPA's commercial and operating systems are necessary. Based on current information concerning this and other systems work planned for FY 2013, it does not appear likely that BPA will be able to implement 15-minute scheduling until the latter half of FY 2014.

Q. RNP states that BPA should offer a committed scheduling option for 15-minute scheduling, with a rate discount of at least 38 percent from the rate for 30/60 committed scheduling. Do you agree?

A. We agree that a discount based on 15-minute committed scheduling should be included under VERBS. Data in the Initial Proposal indicate a 38 percent discount from the 30/60 committed scheduling rate. Documentation, BP-14-E-BPA-05A-E01, Table 2.28.

Because the amount of the discount depends on the decreased need for balancing reserve capacity, however, Staff will reevaluate the discount value as part of the Final Proposal.

Q. Will rate case parties have the option to move to a committed 15-minute scheduling rate option mid-rate period?

A. Yes. BPA will provide customers the option to elect 15-minute scheduling on April 1, 2014, to begin October 2014 at the earliest, or when the systems are ready.

Q. WPAG states that customers need to better understand what "unknown operational and cost implications" 15-minute scheduling could have. Saleba et al., BP-14-E-WG-01, at 20. WPAG notes that the Slice/Block contract does not allow for 15-minute scheduling, and Slice software would require extensive modifications. Id. at 21. What is your response?

A. The availability of 15-minute scheduling would not affect the terms and conditions of any existing contracts between BPA and any entities. Furthermore, the BPA balancing authority area decision to allow 15-minute scheduling intervals does not mean that all power products would need to be sold on a 15-minute scheduling basis. We anticipate that most transactions will continue to be scheduled hourly.

Section 3.2: VERBS Credit

Q. Iberdrola argues that BPA is using the credit to try to alleviate the "unduly discriminatory impacts of its oversupply events." Froese et al., BP-14-E-IR-01, at 21. What is your response?

A. The VERBS credit is not linked to any particular reliability and operational cause for reductions of balancing reserve capacity from the FCRPS. Nor is the credit designed to mitigate the cost exposure associated with any particular cause of a reduction to FCRPS capability. Rather, the VERBS credit functions as a reimbursement of the costs paid by

VERBS customers for service that was not received, and, if replacement purchases are made, to avoid over-collection of costs. Indeed, in the Initial Proposal, we proposed to make Type 2 purchases of non-Federal balancing reserve capacity to replace any balancing reserve capacity that becomes unavailable during the rate period. Study, BP-14-E-BPA-05, at 65; Klippstein *et al.*, BP-14-E-BPA-24, at 52. As discussed further below, the issue of whether BPA should make Type 2 purchases will be decided by the Administrator in this rate proceeding. If any Type 2 purchases are made, the VERBS credit ensures that VERBS customers do not overpay for balancing services.

Furthermore, VERBS is, and has always been, a service that is subject to non-power requirements. Fisher *et al.*, BP-14-E-BPA-21, at 2-3. BPA Staff has explained that the cost of VERBS would likely increase, and the amount available from the FCRPS would decrease, if BPA were to define VERBS as available with 100 percent certainty. *See* Puyleart *et al.*, BP-14-E-BPA-22, at 23; Kerns *et al.*, BP-14-E-BPA-23, at 14. In this rate proceeding, BPA Staff has proposed to make a significant amount of FCRPS capacity available for balancing services with the express condition that FCRPS balancing reserve capacity may not be available in all hours. Kerns *et al.*, BP-14-E-BPA-23, at 17-18. We propose to apply the VERBS credit to customers affected when capacity becomes unavailable from the FCRPS. Study, BP-14-E-BPA-05, at 125. BPA's decision to provide a VERBS credit is independent from any operational and reliability decisions that reduce the availability of FCRPS balancing reserve capacity for balancing services.

Q. Iberdrola states that BPA's proposal for a credit provides no transparency regarding decisions to reduce reserves and provide a credit. Froese et al., BP-14-E-IR-01, at 22. Iberdrola asserts that to the extent BPA holds back balancing reserves it could have provided, it becomes an economic issue and not a reliability issue. Id. What is your response?

A. First, BPA does not withdraw FCRPS balancing reserve capacity arbitrarily. As we explained in the Initial Proposal, BPA is subject to non-power requirements that limit the availability of balancing reserve capacity from time to time. Kerns *et al.*, BP-14-E-BPA-23, at 6-8. BPA provides advance notice of any operational and reliability impacts to its provision of balancing services, which provides transparency regarding BPA's decisionmaking with respect to any limitations on balancing services.

Second, the VERBS credit is not a part of the decisionmaking for assessing the operational constraints of the FCRPS. Nor is any decision related to a reduction of FCRPS balancing reserve capacity dependent on the availability or existence of a VERBS rate credit. Instead, the VERBS credit functions as an after-the-fact reimbursement of costs for balancing services that were not provided from FCRPS balancing reserve capacity.

Finally, as we explained in the Initial Proposal, 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. Fisher *et al.*, BP-14-E-BPA-21, at 45. 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." *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, at P 321 (2012). Consequently, 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.

Q. *Iberdrola asserts that the "rate credit is not a fair trade . . . as the opportunity to regain a small hourly credit does not compensate for the fundamental denial of the balancing reserve product when wind generators need it, nor the associated harm in the market to wind generators who are being curtailed for non-reliability purposes." Froese et al., BP-14-E-IR-01, at 21. Is the VERBS credit appropriate compensation for reductions in FCRPS balancing reserve capacity for VERBS?*

A. As described above, the VERBS credit is appropriate because it is designed to reimburse customers for services that were charged for but not provided from the FCRPS, and to ensure that customers do not overpay for services when BPA replaces FCRPS capability with non-Federal reserves. The VERBS credit is an after-the-fact calculation. As noted above, to the extent Iberdrola believes that BPA should replace FCRPS balancing reserve capacity for balancing services when FCRPS balancing reserve capacity becomes unavailable because of non-power requirements, Iberdrola should state its position on Type 2 purchases in its Initial Brief.

Section 3.3: VERBS Rate for Solar Resources

Q. *RNP states that for the FY 2014–2015 rate period, BPA should set the solar VERBS rate to zero until a thorough analysis can be completed. Yourkowski et al., BP-14-E-RN-01, at 59. RNP states that based on BPA's numbers, the under-recovery from setting the solar rate at zero would be only $44,142 per year—a de minimis amount. Id. Do you agree that BPA should eliminate the VERBS solar rate?*

A. No. We believe there is value in having a rate established for the rate period to charge for balancing reserves necessary to support solar resources operating in the BPA balancing authority area. The establishment of the VERBS rate for solar resources is based on cost causation principles. Staff analyzed the use of balancing reserve capacity by a solar resource near the location where solar generation is expected to be online in the BPA balancing authority area. Study, BP-14-E-BPA-05, at 121; Puyleart *et al.*, BP-14-E-BPA-22, at 19-20. Staff's analysis identified costs associated with that balancing reserve capacity use. Study, BP-14-E-BPA-05, at 121. The VERBS rate for solar resources ensures that BPA will recover its costs from the entities that create the costs. If BPA did not establish a rate, the costs associated with balancing solar resources would be shifted to other customers.

Indeed, the data indicate that solar resources do require balancing reserve capacity, which is likely to result in significant costs in future rate periods if there is growth in solar resources with no attempt to mitigate these impacts and costs. *See* Documentation, BP-14-E-BPA-05A-E01, Table 2.22. By establishing a balancing service rate for solar resources, new solar resources will receive an accurate price signal and be motivated to avoid those costs by decreasing their use of balancing reserve capacity and scheduling accurately.

Section 4: Generation and Energy Imbalance Services

Section 4.1: Waiver for Extraordinary Circumstances

Q. JP08 states that unexpected or extraordinary circumstances that prevent accurate scheduling in discrete cases may arise beyond the control and best practices of a customer. Deen and Huhta, BP-14-E-JP08-01, at 3. In such circumstances, JP08 states, an incentive or penalty rate does not serve the intended purpose of motivating proper scheduling behavior. Id. JP08 suggests that BPA adopt a waiver provision under energy *and generation imbalances that would excuse charges based on extraordinary circumstances. Id. at 2. What is your response?*

A. We believe that the contingency reserve process addresses this issue for generation imbalance: for generation imbalances, for any hour in which a contingency is declared and contingency reserves are taken, the generation imbalance service is not taken, and therefore the rate is not applied. *See* Generation Imbalance Service Business Practice, Version 9 (June 28, 2012), *available at* http://transmission.bpa.gov/ts_business_practices. For energy imbalance, because the end-use loads are typically diverse, a similar provision does not exist. We are concerned about the increased administrative burden associated with a new waiver process as proposed by JP08. For example, based on our experience with waiver requests for persistent deviation penalty charges, the review and investigation of each waiver request consumes significant time and resources. Generation and energy imbalance service charges occur more frequently than persistent deviation penalty charges, which will likely result in substantially more waiver requests and thus require significantly more time and resources. Finally, we believe that having a charge for imbalance that is higher than the market rate provides a price signal that helps to motivate accurate scheduling.

Section 4.2 Incremental Cost Calculation

Q. JP09 proposes an alternative to BPA Staff's proposed incremental cost calculation for energy and generation imbalance. Baker et al., BP-14-E-JP09-01, at 8-9. JP09 states that BPA should forecast the amount of energy it will deploy from Type 1, 3, and 4 purchases of reserve capacity and the difference between the market price and contract price for the energy. Id. at 8. JP09 states that the difference should then be added to the *hourly energy index price charged to the participating wind plants for their imbalances. Id. What is your response?*

A. Despite the complexity of JP09's proposed method, there is merit in an allocation that attempts to tier the cost of supply and match that supply based on least cost to the station control error in an hour. Those with the largest station control error would be allocated all of, or more of, the deployment cost of the more expensive resources. However, the complexity of this approach would be considerable, and a forecast cost-based allocation could result in risk that would need to be allocated appropriately as well. Therefore, we do not recommend adopting JP09's approach for this rate period.

Q. JP09 states that BPA provides no metric for how it would determine a reasonable aggregate price, how it would fairly price energy versus capacity, or what recourse customers might have to challenge unfair pricing. Baker et al., BP-14-E-JP09-01, at 9. What is your response?

A. JP09 raises concerns related to BPA's acquisition strategy that are unrelated to BPA's proposed rate design for generation and energy imbalance services. We encourage JP09 to raise its concerns about the reasonableness of purchase costs in the Ancillary and Control Area Services Practices forum.

Q. MSR argues that VERBS customers are charged for the energy they actually use and then again charged for the energy and potential capacity they may or may not need on any given hour. Arthur, BP-14-E-MS-01, at 9. Do you agree that VERBS customers are charged twice for their energy requirements?

A. No. VERBS is a capacity-based service, Jackson *et al.*, BP-14-E-BPA-28, at 24, and the VERBS rate does not recover the costs of energy provided under Generation Imbalance Service. Conversely, Generation Imbalance is a charge for energy, *id.* at 4, and does not recover the costs of balancing reserve capacity associated with VERBS.

Section 4.3: Persistent Deviation for Imbalance Services

Q. *Iberdrola argues that the persistent deviation penalty does not encourage best scheduling practices. Froese et al., BP-14-E-IR-01, at 38-39. Iberdrola states that the schedule change to avoid the persistent deviation penalty is often contrary to the scheduling change indicated by forecast. Id. Iberdrola claims that the persistent deviation penalty affects customers that adjust schedules using best forecasting methods. Id. at 40. If a forecast is made near real time and is unbiased, will scheduling to that forecast cause a persistent deviation penalty charge to be incurred?*

A. It is possible, but fairly unlikely, for a one-hour-ahead forecast to result in a persistent deviation penalty. Because longer-term forecasts can be incorrect about the timing of wind ramp events, or because they may err in one direction by large amounts for a few hours, scheduling agents should be ready to correct the schedule closer to real time if the forecast seems wrong. Jackson *et al.*, BP-14-E-BPA-28, at 14. The combination of scheduling to a near-term forecast, such as an hour-ahead forecast, plus schedule corrections when the forecast is proving to be incorrect, should allow the scheduling entity to avoid persistent deviation penalties. *Id.* at 10. We believe that the failure to correct schedules when earlier forecasts are wrong is a primary source of persistent deviation events.

Q. *Is scheduling based only on a forecast, particularly a two-hour-ahead or three-hour-ahead forecast, a best scheduling practice for wind generation?*

A. No. Forecast-based scheduling without subsequent correction when the forecast is in error does not result in the most accurate scheduling possible. Wind forecast accuracy declines significantly each hour farther ahead of time the forecast is made. Parties marketing wind through hour-to-hour sales should be prepared to adjust their schedules to actual wind output very close to real time to ensure the most accurate scheduling.

Q. Is it a best scheduling practice to make intra-hour adjustments when a forecast is incorrect?

A. Yes. BPA encourages entities marketing and scheduling wind energy to ensure that their market arrangements allow for the best possible scheduling practices. BPA established VERBS to cover unavoidable scheduling errors, not to cover scheduling errors associated with parties' forward marketing decisions. Fisher *et al.*, BP-14-E-BPA-21, at 11.

Q. Are wind generators required to schedule to a forecast?

A. No; in fact, BPA encourages wind generators that elect 30/30 committed scheduling to schedule to a persistence value because, in the very short term, persistence is generally more accurate and less biased than a forecast.

Q. If a wind generator schedules using 30-minute persistence, will it be subject to persistent deviation penalties?

A. No. In fact, even for wind generators that are not using 30-minute persistence, any scheduling interval within a persistent deviation that is at least as accurate as a 30-minute persistence schedule is exempt from the penalty. Transmission, Ancillary & Control Area Service Rate Schedules & General Rate Schedule Provisions, BP-14-E-BPA-10, at 57.

Q. Does a wind generator need to participate in a committed scheduling program to submit schedules using 30-minute persistence?

A. No. Wind generators may adjust their schedules based on a persistence value for any half-hour interval.

Q. Can a wind generator use intra-hour schedule adjustments to avoid persistent deviation penalties?

A. Yes. For example, a wind generator using hourly scheduling that observes schedule error that exceeds the persistent deviation band could adjust its schedule at the next half-hour scheduling interval to reduce that schedule error. We understand from wind generators that this is more easily done for some types of market agreements than others. However, BPA encourages wind generators to find ways to participate in shorter-interval marketing or off-take agreements to avoid persistent deviations.

Q. Are there factors considered in the waiver process that would account for a wind generator's use of "best forecasting methods"?

A. Yes. BPA's Generation Imbalance Service Business Practice states:

> [Transmission Services] will take into consideration a Customer's forecasted generator output if the Customer electronically submits the forecast before the start of each operating hour. Contact windoperations@bpa.gov for more information on how to establish electronic forecast submittal.

Generation Imbalance Service Business Practice, section C.5.a. In evaluating a waiver request, BPA also compares the actual schedule to a persistence-based schedule and exempts any hours that meet or beat the accuracy of the persistence-based schedule. *Id.* Most near-term forecasts are heavily weighted toward persistence-based forecasting. However, "best forecasting methods" for scheduling wind generation accurately do not involve basing the schedule on forecasts made several hours in advance.

Q. Iberdrola argues that costs mitigated by the persistent deviation penalty are already recovered in other rates, and Power Services is already compensated for managing imbalance accumulation. Froese et al., BP-14-E-IR-01, at 41. What costs does the VERBS rate recover?

A. BPA's balancing service (including VERBS) rates cover the embedded costs associated with use of the system and variable costs associated with use of the projected amount of capacity and energy. Study, BP-14-E-BPA-05, sections 3.2 and 3.4. The basis of projected requirements is an assumed 45/60 persistence schedule for uncommitted scheduling, an assumed 30/60 persistence schedule for committed hourly scheduling, and an assumed 30/30 persistence schedule for committed intra-hour scheduling. *Id.* at 19. BPA does not project capacity costs or energy imbalance use associated with using forecasts made several hours in advance. Therefore, costs associated with persistent deviations or scheduling based on longer-term forecasts are not included in BPA's rates for balancing service.

Q. What costs are offset by the persistent deviation penalties?

A. The persistent deviation penalty charge is set high enough to provide a clear price signal to encourage accurate scheduling behavior. It is not cost-based. *See* Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-10, at 50; Jackson *et al.*, BP-14-E-BPA-28, at 11.

Q. What is the difference between the imbalance energy and capacity energy shift costs and the cost of managing imbalance accumulation?

A. Imbalance energy cost is the index price of energy associated with the hour in which the energy is taken from or put into the FCRPS, plus (or minus) the Deviation Band 2 or Band 3 imbalance energy charge. Study, BP-14-E-BPA-05, section 10.7. The energy shift cost component of BPA's VERBS covers the cost of shifting generation from peak hours to light load hours (LLH) to ensure BPA has sufficient *dec* capability during LLH and sufficient *inc* capability during heavy load hours (HLH). *Id.*, section 3.4.3.1. The cost of managing imbalance accumulation, however, is associated with a real-time disruption of operational plans that occurs because energy is unexpectedly taken from or put into the FCRPS. *See* Jackson *et al.*, BP-14-E-BPA-28, at 12.

Q. Iberdrola claims that passing the persistent deviation penalty revenue to Power Services creates "an inappropriate windfall for power customers." Froese et al., BP-14-E-IR-01, *at 41. Iberdrola proposes that BPA redistribute all persistent deviation penalty revenue to non-offending transmission customers. Id. at 41-42. What is your response?*

A. Any revenues from persistent deviation penalties accrue to Power Services because Power Services is required to recover the costs of the FCRPS generating resources (the resources that provide balancing reserve services). Power Revenue Requirements Study, BP-14-E-BPA-02, at 4. BPA sets its rates prospectively, based on forecast loads, revenues, and costs. BPA forecasts zero costs and revenues of managing imbalance accumulations that result from persistent deviations, because BPA assumes that, over time, schedule errors will be randomly distributed around an error of zero, and BPA does not assume in advance that there will be persistent deviations. *See* Jackson *et al.*, BP-14-E-BPA-28, at 11-12. The persistent deviation penalty charge is designed to motivate more-accurate scheduling to prevent persistent deviations from occurring and keep schedule error evenly distributed around zero. When persistent deviations do occur, they result in real impacts with real costs, including staff time to identify and bill the errors and operational management of the imbalances. *Id.* at 12; Study, BP-14-E-BPA-05, section 10.8.5. In addition, parties are effectively exercising an option they did not purchase. The revenues received relate to costs that BPA did not plan in the rate case and that BPA has not otherwise been compensated for. Therefore, such revenues do not constitute a "windfall."

Q. SCE states that BPA should confirm that approved waivers and the exception for periods that meet or beat 30-minute persistence will remain in effect for next rate period. Nelson, BP-14-E-SC-01, at 15. Does BPA propose to retain these provisions?

A. Yes.

Q. SCE argues that BPA should remove all references to "penalty" and simply refer to "persistent deviation charge," because persistent deviation cannot always be avoided *and is not always due to improper behavior, making persistent deviation just a charge. Nelson, BP-14-E-SC-01, at 15-16. Does BPA propose to revise the name of the persistent deviation penalty charge?*

A. No.

Q. Why does BPA describe billing for persistent deviation as a penalty?

A. We believe describing it as a penalty helps to motivate parties to schedule accurately. Cost-based charges generally are not high enough to serve as a penalty or provide an effective price signal and thus provide sufficient incentive for parties to schedule accurately. We believe a penalty charge is needed to ensure that parties schedule as accurately as possible.

Q. RNP argues that the persistent deviation penalty should not apply during periods of transmission reliability curtailments, because a wind generator may set its generation setpoint just below the mandated scheduling limit and under-generate for several hours until the reliability curtailment order is concluded. Yourkowski et al., BP-14-E-RN-01, at 48-49. What could a wind generator do to avoid a persistent deviation penalty in such instances?

A. A plant that under-generates by a few megawatts in the scenario RNP describes would not have schedule errors that exceed the limits for the persistent deviation penalty. BPA does not encourage wind generators to under-generate by more than 20 MW or 15 percent of schedule, because that would trigger a persistent deviation penalty if the transmission reliability curtailment lasted longer than three hours. If a persistent deviation penalty is incurred for small amounts of under-generation during a longer transmission reliability curtailment, the wind generator may submit a waiver request for that persistent deviation event. Jackson *et al.*, BP-14-E-BPA-28, at 14-15.

Q. *Iberdrola proposes that BPA eliminate the persistent deviation penalty. Froese et al., BP-14-E-IR-01, at 41. As an alternative, Iberdrola proposes that BPA return to the four-hour metric for large persistent deviation events. Id. at 41-42. What is your response to these proposals?*

A. Iberdrola also recommended in the BP-12 rate proceeding that the persistent deviation penalty be eliminated. That recommendation was rejected in the BP-12 case, Administrator's Final Record of Decision (ROD), BP-12-A-02, at 456, and we recommend rejecting it for the next rate period also. Iberdrola also favored a four-hour window in the BP-12 rate proceeding. *Id.* at 459-60. We believe that the reasoning from the BP-12 rate case regarding the shift to the three-hour window continues to hold true. Specifically, with the availability of intra-hour scheduling, parties have four or five opportunities to correct their schedules once they notice a significant schedule error in an hour. The persistent deviation penalty is intended to motivate generators to make corrections as soon as possible. Jackson *et al.*, BP-14-E-BPA-28, at 11. This rationale for retaining the three-hour metric will become even more applicable when 15-minute scheduling is implemented during the BP-14 rate period, because parties will have twice as many opportunities to correct their schedules.

Q. *Does this conclude your testimony?*

A. Yes.

DERBS Peak* Imbalance Needs

Fiscal Year	INC MW	DEC MW
FY08	224	-250
FY09	263	-257
FY10	265	-298
FY11	245	-282
FY08-11	251	-267

Includes only plants estimated to be in BPA BA during BP-14 rate period.

*Inc: top 99.75%, Dec: bottom 0.25%

DERBS Plant Capacities

(Plants Planned in BP-14, Capacities from footnote souces)

Plant Name (in decreasing capacity order)	Capacity[1]	Cum Cap	Cum % Cap
Centralia & Big Hanaford	1,653	1,653.0	36.7%
Grays Harbor Energy	650	2,303.0	51.2%
Hermiston Power Project	650	2,953.0	65.6%
Klamath CoGen	636	3,589.0	79.8%
River Road Gen	235	3,824.0	85.0%
Frederickson	135	3,958.5	88.0%
Weyerhaeuser - Longview	64	4,022.9	89.4%
Boardman - PNGC	60	4,083.0	90.8%
Longview Fibre	60	4,143.0	92.1%
Simpson Tacoma Kraft	55	4,198.0	93.3%
International Paper - Springfield	51	4,249.2	94.4%
Franklin - Pasco	44	4,293.2	95.4%
Roosevelt Landfill (H.W. Hill)[2]	37	4,329.7	96.2%
Wauna	36	4,365.7	97.0%
Georgia Pacific Toledo	30	4,395.7	97.7%
Seneca Sawmill	19	4,414.5	98.1%
Sierra Pacific Sawmill	18	4,432.5	98.5%
Harbor Paper	16	4,448.0	98.9%
Cosmopolis Specialty Fibers	15	4,463.0	99.2%
Loki	11	4,474.0	99.4%
Hampton Lumber Mill	7	4,481.2	99.6%
Olympic View	6	4,487.1	99.7%
Finley Butte	4	4,491.1	99.8%
River Bend	4	4,495.1	99.9%
University of Oregon Co-Gen	4	4,499.1	100.0%

[1] http://www.nwcouncil.org/energy/powersupply/

[2] http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx