

**2014 Wholesale Power and Transmission Rate  
Adjustment Proceeding (BP-14)**

**ADMINISTRATOR'S  
RECORD OF DECISION  
ON SETTLEMENT PROPOSAL FOR  
GENERATION INPUTS AND  
TRANSMISSION ANCILLARY AND  
CONTROL AREA SERVICES RATES**

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May 2013

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BP-14-A-01



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## 1.0 GENERAL TOPICS

### 1.1 Introduction

This Final Record of Decision (ROD) contains decisions of the Bonneville Power Administration (BPA) with respect to the adoption of the Settlement Proposal (based on the Partial Settlement Agreement for Generation Inputs and Transmission Ancillary and Control Area Services Rates (Agreement)) for the two-year rate period October 1, 2014, through September 30, 2015 (Fiscal Years (FY) 2014-2015).

This ROD presents the limited issues raised by the parties with respect to the Agreement.

### 1.2 Procedural History

In February 2013, BPA and the rate case parties began negotiating a global “blackbox” non-precedential settlement of all issues concerning generation inputs and transmission ancillary and control area services rates. The parties met on February 20, February 28, March 7, March 15, March 26, April 4, May 2, and May 6, 2013. The rate case parties negotiated in good faith all terms included in the Settlement Proposal. On May 7, 2013, BPA filed a motion with the hearing officer to notice for signature the availability of the final Settlement Proposal to all BP-14 rate proceeding parties. The Hearing Officer issued an order the same day, stating:

Parties who do not intend to sign must file their objection to the Settlement Proposal, the basis for their objection, and identify each issue included in the Settlement Proposal that they choose to preserve in the BP-14 rate proceeding. Objections must be uploaded to the 2014 Rate Adjustment Proceeding Secure Website by 4:30 p.m., PST, on May 9, 2013.

Any party that does not file an objection to the Settlement Proposal by 4:30 p.m., PST, on May 9, 2013 will waive its right to preserve any objections to the Settlement Proposal and will be treated as an Assenting Party for all purposes under the Settlement Proposal and on the record in the BP-14 rate proceeding.

Order on Proposed Settlement of Generation Inputs and Transmission Ancillary and Control Area Services Rates, BP-14-HOO-49 (May 7, 2013) (footnotes omitted).

Powerex Corporation filed timely objections to the Settlement Proposal with the Hearing Officer on May 9, 2013, and urged the Administrator not to adopt the Settlement Proposal. Response of Powerex Corp. to Notice of Proposed Settlement of Generation Inputs and Transmission Ancillary and Control Services Rates, BP-14-M-PX-01, at 5 (Powerex Objection). Specifically, Powerex objected to the waiver provisions relating to BPA’s operational protocols under Dispatcher Standing Order No. 216 (DSO 216) during the FY 2014-2015 rate period and expressly preserved its rights to challenge such operational protocols. *Id.* at 1. In addition, Powerex objected to the Settlement Proposal’s potential reliance on \$2.5 million of transmission

financial reserves each year to decrease the rates applicable to BPA's Variable Energy Resource Balancing Service (VERBS) and Dispatchable Energy Resource Balancing Service (DERBS) during the rate period. *Id.* BPA addresses Powerex's objections to the Settlement Proposal in this ROD. Powerex did not file an Initial Brief or offer any evidence or testimony with respect to issues concerning generation inputs and transmission ancillary and control area services rates in the BP-14 rate proceeding.

Despite Powerex's objection to the Settlement Proposal, the Agreement was signed by the Parties listed in Attachment 2 to this ROD. In addition, in accordance with the Hearing Officer's order, all rate case parties that did not expressly preserve their objections to the Settlement Proposal became "Assenting Parties" to the Settlement Proposal. These parties are also listed in Attachment 2.

Based on the Settlement Proposal in the BP-14 rate proceeding record, and the reasons explained under the issues below, the Administrator adopts the Settlement Proposal. On May 15, 2013, BPA moved to enter the Settlement Proposal into the BP-14 record, which was granted by the Hearing Officer.

### **1.3 Legal Guidelines Governing Establishment of Rates**

#### **1.3.1 Statutory Guidelines**

Section 7(a)(1) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act) directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. 16 U.S.C. § 839e(a)(1). Rates are to be set to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are to be derived.

Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of section 5 of the Flood Control Act of 1944 (Flood Control Act), which directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 of the Flood Control Act provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years. *Id.*

Section 7(a)(1) of the Northwest Power Act also reaffirms the applicability of sections 9 and 10 of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 (Transmission

System Act), which contains requirements similar to those of the Flood Control Act. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, providing that rates shall be established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay, when due, the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. Section 10 of the Transmission System Act, 16 U.S.C. § 838h, allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

### **1.3.2 The Broad Ratemaking Discretion Vested In the Administrator**

The Administrator has broad discretion to interpret and implement statutory directives applicable to ratemaking. These directives focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pac. Power & Light v. Duncan*, 499 F. Supp. 672 (D. Or. 1980); *accord City of Santa Clara, Cal. v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) (“widest possible use” standard is so broad as to permit “the exercise of the widest administrative discretion”); *ElectriCities of North Carolina, Inc. v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) has recognized the Administrator’s ratemaking discretion. *Cent. Lincoln Peoples’ Util. Dist. v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (“Because BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA’s statutory interpretation”); *PacifiCorp v. FERC*, 795 F.2d 816, 821 (9th Cir. 1986) (“BPA’s interpretation is entitled to great deference and must be upheld unless it is unreasonable”); *Atl. Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA’s rate determination upheld as a “reasonable decision in light of economic realities”); *Dep’t of Water and Power of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) (“Insofar as agency action is the result of its interpretation of its organic statutes, the agency’s interpretation is to be given great weight”); *Pub. Power Council v. Bonneville Power Admin.*, 442 F.3d 1204, 1211 (9th Cir. 2006) (“[The General Rate Schedule Provisions] are entirely bound up with BPA’s rate making responsibilities, and we owe deference to the BPA in that area”). The Supreme Court of the United States has also recognized the Administrator’s ratemaking discretion. *Aluminum Co. of Am. v. Cen. Lincoln Peoples’ Util. Dist.*, 467 U.S. 380, 389 (1984) (“The Administrator’s interpretation of the [Northwest Power Act] is to be given great weight.”).

### **1.3.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates**

BPA's rates become effective upon confirmation and approval by the Federal Energy Regulatory Commission (Commission). 16 U.S.C. §839e(a)(2) and (k). The Commission's review is appellate in nature, based on the record developed by the Administrator. *United States Dep't of Energy—Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator but may only confirm, reject, or remand them. *United States Dep't of Energy—Bonneville Power Admin.*, 23 FERC ¶ 61,378, 61,801 (1983). Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. §839e(i)(6), the Commission has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

### **1.3.4 Standard of Commission Review**

The Commission reviews BPA's rates under the Northwest Power Act to determine whether they (1) are sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; and (2) are based on BPA's total system costs. With respect to transmission rates, Commission review includes an additional requirement: to ensure that the rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2); *see United States Dep't of Energy—Bonneville Power Admin.*, 39 FERC ¶ 1,078, 61,206 (1987). The limited Commission review of rates permits the Administrator substantial discretion in the design of rates and the allocation of power costs, neither of which is subject to Commission jurisdiction. *Cent. Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

## 2.0 PARTIAL SETTLEMENT AGREEMENT AND SETTLEMENT PROPOSAL

### Issue 2.1

*Whether the waiver provisions of the Settlement Proposal are relevant to the statutory standards that apply to BPA ratemaking.*

### Party Position

In its objection to the Settlement Proposal, Powerex states that it continues to oppose BPA's use of DSO 216. Powerex Objection, BP-14-M-PX-01, at 2. Powerex also states that it does not wish to waive its rights to challenge DSO 216 outside of the BP-14 rate proceeding. *Id.* at 3.

### Evaluation of Positions

Powerex, citing the Federal Register notice initiating the rate proceeding, complains that "it is inappropriate for BPA to foreclose discussion of the merits of DSO 216 in this rate proceeding and to now insist that parties waive their rights to address DSO 216 elsewhere." *Id.* Whether Powerex agrees to waive its rights to challenge non-rates terms and conditions is irrelevant to this section 7(i) rate proceeding.

The Federal Register notice identified those topics that were part of this rate proceeding, including "[t]he forecast amount of generation inputs, the pricing methodologies BPA is proposing to use, to determine the generation input costs, and associated proposed Ancillary and Control Area Services rates[.]" Fiscal Year (FY) 2014–2015 Proposed Power and Transmission Rate Adjustments; Public Hearing and Opportunity for Public Review and Comment, 77 Fed. Reg. 66,966, 66,968 (Nov. 8, 2012). The Administrator directed the Hearing Officer

to exclude from the record all argument, testimony, or other evidence that seeks in any way to revisit the appropriateness or reasonableness of any other issues related to the generation inputs or Ancillary and Control Area Services. This exclusion includes, but is not limited to, issues regarding reliability of the transmission system [and] dispatcher standing orders .... These non-rates issues are generally addressed by BPA in accordance with industry, reliability, and other compliance standards and criteria and are not matters appropriate for the rate proceeding.

*Id.* As can be seen from the Federal Register notice, DSO 216 was excluded from the defined scope of the rate proceeding. Thus, even if BPA did not adopt the Settlement Proposal, Powerex would have no ability to contest the "appropriateness or reasonableness" of DSO 216 as a reliability tool in this proceeding. The other rate case parties agreed (or did not dispute) that it was in their interests to forgo litigating certain issues, including new attacks on DSO 216, in order to help foster settlement. Ultimately, however, whether Powerex agrees to waive its rights to contest non-rates terms and conditions is irrelevant to the rates established by the Settlement Proposal.

As discussed further below, the Settlement Proposal satisfies BPA's statutory ratemaking standards. These standards do not depend on whether Powerex has waived the right to any future litigation. Thus, Powerex's retention of its ability to litigate non-rates issues in other proceedings does not bear on the validity of the proposed rates.

Powerex may be arguing that it is inappropriate to condition a rates settlement on waiver of making certain objections to a non-rates matter, here DSO 216. That brings into play the issue of whether the settlement is of such value, and as such is important to the achievement of sound business objectives, that it is appropriate to condition settlement of a rate matter on what to BPA is a non-rates matter. That issue is addressed in Issue 2.3 below.

### **Decision**

*This decision is made for purposes of settlement. Powerex's decision not to waive its right to challenge non-rate case issues in other forums is not relevant to the adoption of the Settlement Proposal and the establishment of rates in accordance with the Settlement Proposal.*

### **Issue 2.2**

*Whether the Administrator has the discretion to utilize transmission reserves to fund transmission costs associated with transmission ancillary and control area services rates.*

### **Party Position**

Powerex urges the Administrator to reject the Settlement Proposal because Powerex objects to "[t]he proposed use of financial reserves attributed to Transmission Services ('Transmission Reserves') to fund revenue shortfalls under the Settlement Agreement." Powerex Objection, BP-14-M-PX-01, at 1. Powerex states that the proposed settlement "establishes rates for Variable Energy Resource Balancing Service ('VERBS') and Dispatchable Energy Resource Balancing Service ('DERBS') that are insufficient to cover the expected costs of providing the services and that funds from Transmission Reserves will be used to cover a portion of the remaining costs." *Id.* at 3.

### **Evaluation of Positions**

To encourage settlement, the Settlement Proposal provided transmission ancillary and control area services customers with added rate certainty and a small rate decrease for VERBS and DERBS customers from the rates proposed in the BP-14 Initial Proposal. The rate certainty is provided through the mitigation of the cost exposure associated with purchases and deployment of non-Federal balancing reserve capacity. These non-Federal balancing reserve capacity purchases are made and deployed to maintain transmission ancillary and control area services.

This mitigation and rate decrease creates transmission services risk that has the potential to total approximately \$2.5 million per year of the rate period. Attachment 1, Agreement, section 4.

Powerex opposes and preserves its rights to object to the Administrator's discretion to utilize financial reserves to fund transmission costs in accordance with the Settlement Proposal. According to Powerex, "[u]nder well-established principles of cost causation, Transmission Reserves, which are collected from transmission customers through their rates, should be used to the benefit of all transmission customers. Use of Transmission Reserves to benefit a limited class of transmission customers would violate these principles." Powerex Objection, BP-14-M-PX-01, at 3-4. In so arguing, Powerex appears to believe that it has an undivided interest in every dollar of transmission reserves. Powerex's apparent claim of entitlement is misguided.

At the end of FY 2012, actual fiscal year-end financial reserves attributable to transmission services and available for risk amounted to \$486.9 million. Holland *et al.*, BP-14-E-JP04-01, at 4, relying on BPA's response to data request PC-BPA-7. These reserves can be tracked to no particular customer or subset of customers, but rather are a factor of costs and revenues varying from what was projected when the rates were established. For example, interest costs may have been less than projected, offset in part by interest costs on reserves being less than projected at a particular time. Similarly, revenues from some services may have been less than projected, and some may have been more than projected. There is no sound basis for Powerex's claim of entitlement. As indicated, reserves are the product of a wide variety of causes, not of any one customer or all customers.

Second, the law is clear that all BPA monies, from whatever source, are to be deposited in the Bonneville fund. 16 U.S.C. § 838i(a). Those monies include the reserves at issue here. As a manner of financial management, Congress has vested the Administrator with discretion to make expenditures from the Bonneville fund for a host of purposes, 16 U.S.C. § 838i(b), and has prioritized the way payments shall be made, 16 U.S.C. § 838k(b). Expenditures to further a lawful settlement fall within the Administrator's discretionary authority, just as would expenditures to pay for capital items if appropriate to preserve BPA's borrowing authority. On the other hand, there is no Congressional expression that monies in the Bonneville fund must be dedicated to a particular customer, or that a particular customer may lay claim to an undivided interest in the reserves.

Third, Powerex argues that the Administrator's use of cash reserves is constrained by the principle of cost causation. Notably, however, the regional consensus supporting the settlement demonstrates the Settlement Proposal's fairness regarding cost recovery, and the establishment of rates consistent with sound business principles. Moreover, the Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pac. Power & Light Co. v. Duncan*, 499 F. Supp. 672, 683 (D. Or. 1980); *accord City of Santa Clara, Cal. v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978)

(“most widespread use” standard is so broad as to permit “the exercise of the widest administrative discretion”); *Electricities of North Carolina, Inc. v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985). Furthermore, the Ninth Circuit has stated that “the BPA Administrator has broad powers to enter and modify contracts, including the power to compromise or settle claims.” *Alcoa, Inc. v. Bonneville Power Admin.*, 698 F.3d 774, 792 (9th Cir. 2012).

In addition, the Administrator is charged with establishing rates “with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles ....” 16 U.S.C. § 838g. Rates are to be established to “recover, in accordance with sound business principles, the costs” borne by BPA. 16 U.S.C. § 839e(a)(1). While no one particular customer can lay claim to the extraordinarily small part of reserves at issue here, it is certainly more probable that if a claim could be legitimately made, it would be by the overwhelming majority of customers that support or do not object to the settlement. Reliance on reserves to recover a small portion of BPA’s costs, and to thereby support a settlement enjoying overwhelming customer support, is consistent with sound business principles. With the settlement, the Administrator is not simply building customer good will, but he is achieving all the objectives laid out in the settlement. Those objectives are consistent with sound business principles. It is also businesslike to respond to regional views on comparable rates, terms, and conditions for use of the Federal Columbia River Transmission System.

With respect to transmission rates, section 7(a)(2)(C) of the Northwest Power Act provides that the Commission will confirm and approve BPA’s rates upon a finding that such rates “equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing [the] system.” 16 U.S.C. § 839e(a)(2)(C). In addition to the equitable allocation standard, section 7(a)(1) of the Northwest Power Act and section 9 of the Transmission System Act provide that the rate must be established to recover the costs associated with transmission of electric power “in accordance with sound business principles.” 16 U.S.C. § 839e(a)(1); 16 U.S.C. § 838g. Section 7(a)(1) of the Northwest Power Act incorporates by reference section 9 of the Transmission System Act, which provides that rates “shall be fixed and established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles ....” 16 U.S.C. § 838g. Similar language is contained in section 5 of the Flood Control Act. 16 U.S.C. § 825s.

Taken together, the “equitable allocation” and “widest possible use consistent with sound business principles” standards evince a Congressional intent to give BPA substantial ratemaking discretion. The equitable allocation standard does not expressly or implicitly mandate that each of BPA’s transmission rates must reflect costs that are equitably allocated between Federal and non-Federal power. It requires fairness in allocating the transmission costs between Federal and

non-Federal power using the system in the aggregate. This is achieved by the regional settlement of generation inputs cost allocation issues in this proceeding.

Moreover, by virtue of the settlement, the use of cash reserves to fund transmission costs for both Federal and non-Federal power users of the transmission system ensures equitable allocation of costs. Powerex does not assert that the Settlement Proposal results in inequitable allocation of costs under the Northwest Power Act. Nevertheless, as demonstrated by regional consensus from all other rate case parties, costs are equitably allocated under the Settlement Proposal.

It is consistent with businesslike operation to arrive at a mutually agreeable settlement for determining generation inputs and ancillary and control area services issues in this rate proceeding. Given the uncertainty in the utility industry in general at this time, it is consistent with sound business principles to offer an element of certainty to customers based on a proposal that is embraced by all but one customer. Such certainty promotes the widest possible diversified use of BPA's power and transmission services.

Powerex argues that BPA is intentionally setting rates to under-recover its costs because BPA intends to fund "revenue shortfalls" under the Settlement Proposal with transmission cash reserves. Powerex Objection, BP-14-M-PX-01, at 1. Powerex, however, provides no legal basis to suggest that the Administrator has no authority to utilize cash reserves to mitigate rate impacts. Indeed, consistent with BPA's statutory authorities, the Administrator has, on a non-precedential basis, utilized cash reserves in several rate proceedings as a tool to mitigate rate increases. *See, e.g.*, BP-12 Final Record of Decision, BP-12-A-02, at 474.

Notably, despite Powerex's own arguments to the contrary, Powerex acknowledges that the Administrator has the discretion to utilize cash reserves to fund specific transmission costs for specific transmission customers within a rate period. Powerex argues that Transmission reserves could be "temporarily utilized to mitigate rate impacts on Utility Delivery Charge (UDC) customers that may experience rate shock from properly aligning the UDC with the cost of providing service on the Utility Delivery segment; however, any reserves used for such purpose should ultimately be replenished, in order to avoid cross-subsidies to a particular class of customer." Powerex Objection, BP-14-M-PX-01, at 4 (emphasis omitted). Essentially, Powerex argues that the Administrator may "temporarily" utilize cash reserves to fund discrete transmission costs, but that such cash reserves must be replenished to avoid cross-subsidies. Powerex, however, cites no legal authority to support such a constrained interpretation of the Administrator's discretion.

Powerex's claim that the use of financial reserves subsidizes one group of customers at the expense of another group is also incorrect. *See id.* Subject to the rate schedule provisions, transmission customers must take certain ancillary or control area services as part of their transmission service. No customer, including Powerex, has a unique right or claim to the use of such cash reserves. Under the Settlement Proposal, the costs mitigated by transmission cash

reserves are transmission costs associated with transmission ancillary and control area services rates. There is no improper benefit attributed to customers of required transmission ancillary and control area services.

### **Decision**

*This decision is made for purposes of settlement. The Administrator has the discretion to utilize transmission cash reserves to fund transmission costs. The Administrator is not required to use transmission cash reserves to provide benefits to any specific transmission customer or customer class. Finally, the Administrator's decision to utilize transmission cash reserves in accordance with the Settlement Proposal is consistent with sound business principles, cost recovery, and the equitable allocation of costs among Federal and non-Federal power users of the transmission system.*

### **Issue 2.3**

*Whether the Administrator should adopt the Settlement Proposal to establish Transmission Ancillary and Control Area Services Rates.*

### **Party Position**

Powerex urges the Administrator to reject the Settlement Proposal based on two aspects of the Agreement: (1) Section 5 of the Agreement, which requires Assenting Parties to the Proposed Settlement to waive their rights to address certain "Underlying Assumptions" (including but not limited to Dispatcher Standing Order 216); and (2) the proposed use of financial reserves attributed to Transmission Services to fund revenue shortfalls under the Agreement. Powerex Objection, BP-14-M-PX-01, at 1. Powerex has not objected to any other aspect of the Settlement Proposal.

### **Evaluation of Positions**

Consistent with the Agreement, BPA Staff proposes FY 2014-2015 transmission and ancillary and control area services rates for the following services:

#### Ancillary Services

1. Regulation and Frequency Response Service
2. Energy Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service

## Control Area Services

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

The Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service rates are not included in the Settlement Proposal. All of the proposed FY 2014-2015 final transmission ancillary and control area services rates are included in the Settlement Proposal.

Under the Settlement Proposal, the transmission and ancillary services rate schedules are revised as indicated in Attachment 1 to the Agreement. In addition, the Agreement provides certain Rate Period Terms that address issues concerning BPA's provision of ancillary and control area services. These terms are indicated in Attachment 2 to the Agreement. All these matters were the subject of considerable dispute in the rate case.

Notwithstanding that, as noted above, there was substantial consensus for the Administrator to adopt the Settlement Proposal. Powerex is the only rate case party that preserved the right to object to the Settlement Proposal. Powerex did not file an Initial Brief or expert testimony with respect to generation inputs or transmission and ancillary and control area services rates. Consequently, it appears that Powerex's primary rate concern is the Administrator's use of transmission cash reserves to fund certain transmission costs under the Settlement Proposal. This issue is discussed in Issue 2.2 above.

The Administrator must weigh Powerex's concerns against BPA's ratemaking standards and the benefits achieved by regional consensus and the Settlement Proposal. As explained above, with respect to transmission rates, section 7(a)(2)(C) of the Northwest Power Act provides that the Commission will confirm and approve BPA's rates upon a finding that such rates "equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing [the] system." 16 U.S.C. § 839e(a)(2)(C). In addition to the equitable allocation standard, section 7(a)(1) of the Northwest Power Act and section 9 of the Transmission System Act provide that the rate must be established to recover the costs associated with transmission of electric power "in accordance with sound business principles." 16 U.S.C. § 839(a)(1); 16 U.S.C. § 838g. Section 7(a)(1) of the Northwest Power Act incorporates by reference section 9 of the Transmission System Act, which provides that rates "shall be fixed and established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles."

16 U.S.C. § 838g. Similar language is also contained in section 5 of the Flood Control Act.  
16 U.S.C. § 825s.

As described earlier, BPA's rates are to be set to "recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid by power revenues) over a reasonable period of years ...." 16 U.S.C. § 839e(a)(1). As explained here and in Issue 2.2, BPA finds that the partial settlement of the issues in this rate proceeding is consistent with sound business principles and results in equitable allocation of costs.

As explained by the Administrator in the 1993 Record of Decision:

If, viewed as a whole, all reasonable rates actions have been taken to establish the rates as low as possible consistent with sound business principles--and here it must be understood that decisions on many issues trade off and factor into decisions on other issues--the consequence is that the rates are the lowest consistent with sound business principles. If those rates, however, are not competitive--meaning for rate determination purposes that BPA cannot recover its costs--the consequence is that BPA must change some aspect of its business to attain competitive rates.

1993 Record of Decision, WP-93-A-02, at 14. In this rate proceeding BPA and the parties have reached agreement regarding rates and have committed to work collaboratively during the rate period on issues concerning generation inputs and ancillary and control area services, which is surely consistent with sound business principles, while at the same time recovering BPA's costs.

Reviewing the statutory underpinnings of "sound business principles," the Administrator noted that the "congressional intent behind [section 2(f) of the Bonneville Project Act] was 'to enable the Administrator to employ business principles and methods in the operation of a business enterprise . . . ' H.R. Rep. No. 777, 79th Cong., 1st Sess., 3 (June 21, 1945)." *Id.* at 15-16. A similar purpose was recognized for the budgeting provisions of the Transmission System Act:

One of the primary purposes of the Transmission System Act was to enable BPA to rely on stable and flexible funding, so that it could thereby better act in a timely, orderly and businesslike fashion. *E.g.*, S. Rep. 93-1030, 93rd Cong., 2d Sess., 7-8 (July 25, 1974). Section 11(c) of the Transmission System Act applies the provisions of the Government Corporation Control Act to BPA, [which] provides that the budget program of each wholly owned Government corporation shall "provide for emergencies and contingencies and otherwise be flexible so that the corporation may carry out its activities." 31 U.S.C. § 9103(b)(3).

*Id.* at 16. Indeed, it is the businesslike flexibility that that enables the Administrator to utilize transmission cash reserves in the context of settlement of rates. *See also* Issue 2.1 above.

Finally,

With the passage of the Northwest Power Act, the Administrator's responsibilities were significantly expanded. Now, the Administrator would be charged with encouraging cost-effective resource development; assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply; protecting, mitigating, and enhancing fish and wildlife resources; and many other responsibilities. In all of these undertakings, Congress charged in section 9(b) of the Northwest Power Act that "The Secretary of Energy, the [Regional] Council, and the Administrator shall take such steps as are necessary to assure the timely implementation of this Act in a sound and business-like manner." 16 U.S.C. § 839f(b).

*Id.* The settlement provides the parties the opportunity to collaborate to address the many rate and non-rate issues covered by the settlement. That is much more conducive to achieving the purposes of the Northwest Power Act than engaging in protracted, often bitter litigation over the matters.

Many of the items discussed in the Agreement have proven to be important, contentious, and difficult to resolve. The Agreement allows BPA and its customers to collaboratively develop long-term, sustainable solutions to these complex issues, which provides business value. The parties have already dedicated a significant amount of time and resources to resolving these issues, and though a complete solution has not been developed, it is significant that these same parties prefer a two-year pause in order to continue working on the issues that affect the services BPA provides to its customers. The Agreement will allow BPA and the parties to focus on addressing those issues in a positive and productive manner as opposed to potentially protracted and costly litigation. Thus, the settlement provides financial and business value to BPA, as well as its customers, in a number of ways, including: (1) reduced expenses associated with litigation; (2) predictability regarding rate period workshops and commitments; (3) increased flexibility during the rate period to focus on issues concerning BPA's services, including non-rates issues; and (4) finality with regard to the BP-14 transmission ancillary and control area services rates.

Furthermore, many of the issues at dispute in this rate proceeding revolve around allocating the costs of acquisitions of additional amounts of reserve capacity to support the provision of transmission ancillary and control area services. The parties to the settlement recognized that many changes are occurring in the wider electricity markets during this timeframe with implementation of 15-minute scheduling through the Commission's Order No. 764, which may ultimately impact BPA's need to make additional acquisitions of reserve capacity and reduce or eliminate that need. In addition, many parties are concerned about the cost of acquisitions of

reserve capacity and the liquidity of markets for procuring that capacity. The provisions of the settlement establish an agreed means of allocating the risk that costs of reserve capacity may be greater than forecast or that reserve capacity may be unavailable in certain time periods. Since BPA had not faced the need to make acquisitions during prior rate periods, the settlement provides a transition period to allow BPA to implement that capability with known risks to all rate case parties.

The Settlement Proposal is the product of regional consensus. The Federal Energy Regulatory Commission has recognized the importance of regional consensus in the implementation of open and comparable transmission access. *See, e.g., Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21,540, at 21,666-67 (1996). Numerous cases demonstrate that the Commission views settlements of disputes reached by the interested parties favorably. *See, e.g., Westmoreland-LG&E Partners*, 94 FERC ¶ 61,211, at 61,786 (2001) (it is Commission policy to encourage settlements); *SFPP, L.P.*, 139 FERC ¶ 61,266, at P 9 (2012) (the Commission consistently encourages parties to resolve rate filing disputes through settlement); *ISO New England Inc.*, 137 FERC ¶ 61,056, at P 29 (2011) (the Commission emphasizes that it is always supportive of parties' efforts to settle disputed matters); *PJM Interconnection, L.L.C. & Allegheny Power*, 116 FERC ¶ 61,253, at P 19 (2006) (the Commission strongly encourages parties to settle instead of incurring substantial time and costs in litigation); *Am. Elec. Power Serv. Corp.*, 71 FERC ¶ 61,393, at 62,542 (1995) (AEP) (may settle in accordance with the NOPR pro forma tariffs or other "agreed to terms that are fair and reasonable"). The Settlement Proposal is thus consistent with the Commission's policy to encourage settlement of issues.

The value of the settlement, and its importance to the achievement of sound business objectives, is substantial. With regard to Powerex's objection that the settlement conditions settlement of a rates matter on what to BPA is a non-rates matter (not objecting for a short period to DSO 216), that objection is outweighed by the value and importance of the settlement, for all the reasons outlined above.

### **Decision**

*This decision is made for purposes of settlement. The Administrator adopts the Settlement Proposal as consistent with applicable statutory ratemaking standards.*

### 3.0 CONCLUSION

Based upon the decisions expressed in this Record of Decision and all requirements of applicable law, I hereby adopt the Settlement Proposal.

Issued at Portland, Oregon, this 15th day of May, 2013.

*/s/ William Drummond*

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William Drummond

Administrator and Chief Executive Officer

## PARTIAL SETTLEMENT AGREEMENT

### **Bonneville Power Administration 2014 Rate Case Generation Inputs and Transmission Ancillary and Control Area Services Rates**

THIS PARTIAL SETTLEMENT AGREEMENT (“AGREEMENT”), dated and effective as of the date established pursuant to Section 3 of this Agreement, is among the Bonneville Power Administration (“Bonneville”) and the BP-14 rate case parties (in the singular, “Party,” in the plural, “Parties”).

#### WHEREAS

- A. Starting in November 2012, Bonneville and the Parties have been engaged in formal hearings to establish the costs of generation inputs and rates for certain transmission ancillary and control area services for the FY 2014-2015 Rate Period (“Rate Period”);
- B. Bonneville and the Parties wish to settle their disputes concerning generation inputs and transmission ancillary and control area services rates for the Rate Period;
- C. Bonneville and the Parties recognize that both the rate structure and the operations related to the integration of variable energy resources and dispatchable energy resources in Bonneville’s balancing authority area are in a transitional period; that there is considerable disagreement about how to design Bonneville’s transmission ancillary and control area services rates, terms and conditions; and that there is disagreement about the allocation of balancing reserve capacity and energy costs; and
- D. The purpose of this Agreement is to settle those differences for the Rate Period, without precedent for subsequent rate periods, so that Bonneville and the Parties can work collaboratively on developing operational tools, terms and conditions, and proposals for rates and the allocation of costs for the services necessary to balance the system in future rate periods.

NOW, THEREFORE, Bonneville, the undersigned Party signatories (“Party Signatories”), and Parties who otherwise indicate assent to this Agreement by not objecting to this Agreement or the Settlement Proposal (as defined in section 1) on the record of the BP-14 rate proceeding pursuant to section 3 (“Non-Objecting Parties”, and collectively with the Party Signatories, the “Assenting Parties”) agree to the following:

1. In the BP-14 rate proceeding, Bonneville staff will propose that the Administrator adopt a proposal to establish the costs of generation inputs and rates for transmission ancillary and control area services for the Rate Period (“Settlement Proposal”). The Settlement Proposal will include only the rate schedules and general rate schedule provisions specified in Attachment 1, the terms specified in Attachment 2, and the terms of this Agreement.
2. During the Rate Period, Bonneville and the Assenting Parties will abide by the terms specified in Attachment 2.
3. Bonneville and the Party Signatories shall sign this Agreement by 4:30 pm on May 9, 2013. Bonneville will notify the Hearing Officer of the Agreement and move the Hearing Officer to (1) require any Party that does not intend to sign the Agreement to state its objection to the Settlement Proposal, the basis for its objection, and to identify each issue included in the Settlement Proposal that such Party chooses to preserve in the BP-14 rate proceeding by 4:30 pm on May 9, 2013; and (2) specify that any Party that does not state its objection to the Settlement Proposal by 4:30 pm on May 9, 2013, will waive its rights to preserve any objections to the Settlement Proposal and shall be treated as an Assenting Party for all purposes under this Agreement and on the record in the BP-14 rate proceeding. Unless this Agreement terminates under the terms set forth in section 4, below, this Agreement will become effective on May 9, 2013 and will terminate on September 30, 2015. If a Party has not preserved any issues originally through an objection to the Settlement Proposal, the Party waives its right to preserve such issue. This Agreement will be entered into the record only if adopted by the Administrator.
4. If, in response to the Hearing Officer’s order made pursuant to section 3, any Party states an objection to the Settlement Proposal, Bonneville or any Assenting Party may withdraw its support for the settlement by 4:30 pm on May 13, 2013. If Bonneville or any Assenting Party withdraws its support for the settlement, this Agreement will become void *ab initio*. If no Party withdraws its support for the Settlement Proposal, the Parties agree that the Administrator may consider the Settlement Proposal notwithstanding that it has not been entered into the record. The Administrator will notify the Parties by 4:30 pm on May 15 whether he adopts the Settlement Proposal. If the Administrator adopts the Settlement Proposal, Bonneville will move the Hearing Officer to enter the Settlement Proposal into the record. If the Administrator does not adopt the Settlement Proposal, this Agreement and the Settlement Proposal will terminate upon the date the Administrator declines to adopt the Settlement Proposal.

## 5. Waiver

### a. **Preservation of BP-14 ACS Rates and Settlement Proposal**

- i. The Parties agree that this is a black box settlement. If the Administrator adopts the Settlement Proposal, Bonneville and the Assenting Parties agree not to contest this Agreement, including the Settlement Proposal and rates and rate schedule provisions in Attachment 1, from the effective date through September 30, 2015.
- ii. Except as provided in section 6(d) and (e), the Assenting Parties will not oppose or challenge in any forum by any means during the Rate Period the Underlying Assumptions. For purposes of this Agreement, Underlying Assumptions shall mean
  1. the implementation of DSO 216 curtailments to maintain system reliability requirements and limit balancing reserve capacity deployment amounts and
  2. any operating practices described in Attachments 1 and 2; both consistent with this Agreement. Nothing in this paragraph precludes any Party from raising during the Rate Period any issues in any workshop, rate proceeding or subsequent review thereof relating to rates or terms proposed to be applicable after the Rate Period.

### b. **Reciprocity**

In the event that any Underlying Assumption used to establish rates under the Settlement Proposal is determined in a Pending Proceeding (see section 6(d) below) to be inconsistent or incompatible with a reciprocity transmission tariff, the Assenting Parties agree that such Underlying Assumption shall nonetheless remain in effect for the remainder of the Rate Period.

### c. **No Precedent or Issue Preclusion beyond the Rate Period**

- i. Bonneville and the Assenting Parties understand, and will not argue otherwise, that this Agreement does not constitute consent or agreement in any future rate proceedings to the transmission ancillary and control area services rates and rate schedule provisions in Attachment 1 or to any rate, charge, rate schedule provision, or Underlying Assumptions, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such matters.

- ii. The Assenting Parties and Bonneville acknowledge that this Agreement is a package, and that acceptance of the package does not create or imply any agreement with individual components of the package. Therefore, the Assenting Parties and Bonneville agree that they will not assert in any forum that anything in the Settlement Proposal, or that any action taken or not taken with regard to this Agreement by any Assenting Party, the Hearing Officer, the Administrator, the Commission, or a court, creates or implies (1) any procedural or substantive precedent (including, but not limited to, a substantive precedent with respect to rate design and a 3 MW dead band under the Dispatchable Energy Resource Balancing Service rate); (2) agreement to any particular or individual treatment of costs, expenses, or revenues; (3) agreement to any particular interpretation of Bonneville's statutes; (4) any precedent under any contract or otherwise between Bonneville and any Party; or (5) any basis for supporting any Bonneville rate, terms or conditions for any period after the Rate Period.

## **6. Reservation of rights**

- a. Except as provided in section 5(a) above, no Assenting Party waives any of its rights, under Bonneville's enabling statutes, the Federal Power Act or other applicable law, to pursue dispute resolution procedures consistent with Bonneville's open access transmission tariff, or to pursue any claim that a particular charge, methodology, practice, or rate schedule has been improperly implemented.
- b. Bonneville and the Assenting Parties reserve the right to file new complaints, petitions, or litigation related to any rates, terms and conditions, or other matters that are not a part of the Settlement Proposal.
- c. Bonneville and the Assenting Parties reserve the right to litigate any transmission or power rate at issue in the BP-14 rate proceeding that is not included in the Settlement Proposal. In addition, Bonneville reserves the right to propose changes to the transmission and power rates, rate schedules, and associated general rate schedule provisions for services that are not included in the Settlement Proposal.

- d. Bonneville and the Assenting Parties reserve the right to litigate and advance any arguments (1) in proceedings that are pending before the Commission, the United States Court of Appeals for the Ninth Circuit, or any other judicial forum as of the effective date of this Agreement; and (2) in administrative or judicial review, now or hereafter pending, of such proceedings (collectively, "Pending Proceeding(s)").
  - e. Bonneville and the Assenting Parties reserve the right to respond during the Rate Period to any new filings, protests, or claims, by Bonneville or others; however, Bonneville and the Assenting Parties will not support a challenge to any rates, terms and conditions, or other matters described in section 5(a)(ii) for the Rate Period.
7. If because of a legal challenge, Bonneville is required to materially modify or discontinue the use of Dispatcher Standing Order No. 216 during the Rate Period, Bonneville will seek, and the Assenting Parties agree to support or not contest, a stay of enforcement of that ruling until after the Rate Period. If Bonneville is unable to obtain a stay of the enforcement of that ruling, Variable Energy Resource Balancing Service customers will be required to pay for Variable Energy Resource Balancing Service Full Service in accordance with the rate schedule provisions in Attachment 1, section III.E, Variable Energy Resource Balancing Service.
8. Attachment 1 (Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions) and Attachment 2 (Rate Period Terms) are incorporated by reference into this Agreement.
9. Section 5(c) (No Precedent or Issue Preclusion beyond the Rate Period) of this Agreement will survive termination or expiration of this Agreement.

This Agreement may be executed in counterparts.

\_\_\_\_\_  
[Print Party Name]

By: \_\_\_\_\_

Name: \_\_\_\_\_  
(Print/Type)

Title: \_\_\_\_\_

Date: \_\_\_\_\_

**ATTACHMENTS**

**Attachment 1, Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions**

**Attachment 2, Rate Period Terms**

**ACS-14**  
**ANCILLARY AND CONTROL AREA SERVICES RATES**

**SECTION II. ANCILLARY SERVICE RATES**

**C. REGULATION AND FREQUENCY RESPONSE SERVICE**

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

**1. RATE**

The rate shall not exceed 0.12 mills per kilowatthour.

**2. BILLING FACTOR**

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

## **D. ENERGY IMBALANCE SERVICE**

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the same basis as the intra-hour scheduling period.

### **1. RATES**

#### **a. Imbalances Within Deviation Band 1**

Deviation Band 1 applies to deviations that are less than or equal to (i)  $\pm 1.5$  percent of the scheduled amount of energy, or (ii)  $\pm 2$  MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

- (1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.
- (2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

#### **b. Imbalances Within Deviation Band 2**

Deviation Band 2 applies to the portion of the deviation (i) greater than  $\pm 1.5$  percent of the scheduled amount of energy or (ii)  $\pm 2$  MW,

whichever is larger in absolute value, up to and including (i)  $\pm 7.5$  percent of the scheduled amount of energy or (ii)  $\pm 10$  MW, whichever is larger in absolute value.

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

**c. Imbalances Within Deviation Band 3**

Deviation Band 3 applies to the portion of the deviation (i) greater than  $\pm 7.5$  percent of the scheduled amount of energy, or (ii) greater than  $\pm 10$  MW of the scheduled amount of energy, whichever is larger in absolute value.

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

**2. OTHER RATE PROVISIONS**

**a. BPA Incremental Cost**

BPA's incremental cost will be based on ~~a weighted hourly average cost of energy deployed by BPA for Energy Imbalance Service. Costs of Federal resources deployed are at~~ an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index. ~~Costs of non-Federal resources are at the offer price for energy deployed.~~

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

**b. Spill Conditions**

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

- (1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.
- (2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

**c. Persistent Deviation**

The following penalty charges shall apply to each Persistent Deviation:

- (1) No credit is given when energy taken is less than the scheduled energy.
- (2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1 of this ACS-14 schedule.

**Reduction or Waiver of Persistent Deviation Penalty**

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Persistent Deviation was caused by extraordinary circumstances.

**E. OPERATING RESERVE – SPINNING RESERVE SERVICE**

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer’s Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

**1. RATES**

- a. For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA, the rate shall not exceed 10.86 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.49 mills per kilowatthour.

For energy delivered, the generator shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

**2. BILLING FACTORS**

- a. The Billing Factor for the rates specified in sections 1.a and 1.b is the Transmission Customer’s Spinning Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2014-2015 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserve Requirement posted on its OASIS Web site accordingly.
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

**F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE**

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer’s Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

**1. RATES**

- a. For customers that elect to purchase Operating Reserve –Supplemental Reserve Service Transmission Services, the rate shall not exceed 9.95 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 11.44 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

**2. BILLING FACTORS**

- a. The Billing Factor for the rates specified in sections 1.a and 1.b is the Transmission Customer’s Supplemental Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2014-2015 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserve Requirement posted on its OASIS Web site accordingly.
- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.



### **SECTION III. CONTROL AREA SERVICE RATES**

#### **A. REGULATION AND FREQUENCY RESPONSE SERVICE**

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

##### **1. RATE**

The rate shall not exceed 0.12 mills per kilowatthour.

##### **2. BILLING FACTOR**

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

## **B. GENERATION IMBALANCE SERVICE**

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the same basis as the intra-hour scheduling period.

### **1. RATES**

#### **a. Imbalances Within Deviation Band 1**

Deviation Band 1 applies to deviations that are less than or equal to (i)  $\pm 1.5$  percent of the scheduled amount of energy, or (ii)  $\pm 2$  MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

- (1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.
- (2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

#### **b. Imbalances Within Deviation Band 2**

Deviation Band 2 applies to the portion of the deviation (i) greater than  $\pm 1.5$  percent of the scheduled amount of energy or (ii)  $\pm 2$  MW, whichever is larger in absolute value, up to and including (i)  $\pm 7.5$  percent

of the scheduled amount of energy or (ii)  $\pm 10$  MW, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

**c. Imbalances Within Deviation Band 3**

Deviation Band 3 applies to the portion of the deviation (i) greater than  $\pm 7.5$  percent of the scheduled amount of energy, or (ii) greater than  $\pm 10$  MW of the scheduled amount of energy, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

**2. OTHER RATE PROVISIONS**

**a. BPA Incremental Cost**

BPA's incremental cost will be based on ~~a weighted hourly average cost of energy deployed by BPA for Generation Imbalance. Costs of Federal resources deployed are at~~ an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index. ~~Costs of non-Federal resources are at the offer price for energy deployed.~~

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

**b. Spill Conditions**

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

- (1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.
- (2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

**c. Persistent Deviation**

The following penalty charges shall apply to each Persistent Deviation:

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section III.B.1 of this ACS-14 schedule.

Customers participating in committed scheduling to receive [\(i\) BPA's 30-minute signal for each 15-minute schedule period \(30/15 committed scheduling\)](#), each 30-minute schedule period (30/30 committed scheduling), or each 60-minute schedule period (30/60 committed scheduling), [or \(ii\) BPA's 40-minute signal for each 15-minute schedule](#)

period (40/15 committed scheduling), and that submit schedules that are consistent with or result in less imbalance for the committed scheduled period are exempt from the Persistent Deviation penalty charge.

For variable energy resources (wind and solar resources), BPA will remove specific scheduled periods for billing purposes from a persistent deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those scheduled periods.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

### **Reduction or Waiver of Persistent Deviation Penalty**

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

#### **d. No Credit for Negative Deviations During Curtailments**

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

#### **e. Exemption from Deviation Band 2**

The 10 percent penalty charge under section 1.b, Imbalances Within Deviation Band 2, will not apply to customers participating in ~~30/30 committed scheduling~~ (or the shortest scheduling period available for committed scheduling).

#### **f. Exemptions from Deviation Band 3**

The following resources are not subject to Deviation Band 3:

- (1) wind resources
- (2) solar resources
- (3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this section 2, all deviations greater than  $\pm 1.5$  percent or  $\pm 2$  MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

**C. OPERATING RESERVE – SPINNING RESERVE SERVICE**

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Transmission Customer’s Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

**1. RATES**

- a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed 10.86 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.49 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

**2. BILLING FACTORS**

- a. The Billing Factor for the rates specified in sections 1.a and 1.b is the Spinning Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2014-2015 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserves Requirement posted on its OASIS Web site accordingly.
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

## **D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE**

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Transmission Customer’s Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

### **1. RATES**

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 9.95 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 11.44 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

### **2. BILLING FACTORS**

- a. The Billing Factor for the rates specified in sections 1.a and 1.b is the Supplemental Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2014-2015 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserves Requirement posted on its OASIS Web site accordingly
- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

**E. VARIABLE ENERGY RESOURCE BALANCING SERVICE**

**1. APPLICABILITY**

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2.c of this rate schedule.

**Variable Energy Resource Balancing Service Base Service (“Base Service”)** is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator’s schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

**Variable Energy Resource Balancing Service Full Service (“Full Service”)** is an optional quarterly service except as provided in section 2.c.3. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Under this Full Service option, the amount of balancing reserve capacity available to the customer under a committed scheduling Base Service option is augmented through BPA purchases of additional balancing reserve capacity.

**Variable Energy Resource Balancing Service Supplemental Service (“Supplemental Service”)** is an optional monthly service. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Purchase of this Supplemental Service augments balancing reserve capacity available to the Customer to mitigate the effects of DSO 216 curtailments on variable energy resource schedules.

## 2. BASE SERVICE FOR WIND RESOURCES

The total charge for Base Service is the applicable Base Service rate in section 2.a below, plus ~~Type 1, 2, and 4~~ Purchases Charges for Direct Assignment under section 6.

~~The Variable Energy Resource Balancing Service Credit under section 7 applies to a customer's bill when balancing reserve capacity from the FCRPS is not provided for the service because of hydro system conditions.~~

### Aa. BASE SERVICE RATES

#### (1) Rate for 30/60 Committed Scheduling

This rate is applicable to customers taking Base Service that commit to receive BPA's 30-minute signal for each 60-minute schedule period (30/60 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves ~~\$0.36~~ \$0.32 per kilowatt per month
- (c) Imbalance Reserves ~~\$0.70~~ \$0.80 per kilowatt per month

#### (2) Rate for 40/15 Committed Scheduling

This rate is applicable to customers taking Base Service that commit to receive BPA's 40-minute signal for each 15-minute schedule period (40/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.54 per kilowatt per month

#### (23) Rate for 30/30 Committed Scheduling

This rate is applicable to customers taking Base Service that commit to receive BPA's 30-minute signal for each 30-minute schedule period (30/30 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves ~~\$0.36~~ \$0.32 per kilowatt per month
- (c) Imbalance Reserves ~~\$0.39~~ \$0.47 per kilowatt per month

**(34) Rate for 30/15 Committed Scheduling**

This rate is applicable to customers taking Base Service that commit to receive BPA’s 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.33 per kilowatt per month

**(345) Rate for Uncommitted Scheduling**

This rate is applicable to customers taking Base Service that do not commit to 30/60 or 30/30 scheduling (“uncommitted scheduling”).

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves ~~\$0.36~~ \$0.32 per kilowatt per month
- (c) Imbalance Reserves ~~\$0.95~~ \$1.08 per kilowatt per month

**b. BILLING FACTOR**

The Billing Factor for rates in section 2.a is as follows:

- (1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.
- (2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.
- (3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior

to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

**c. EXCEPTIONS**

- (1) The rates under section 2.a above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.
- (2) Individual rate components under section 2.a.(1)-(543) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of balancing service, including by contractual arrangements for third-party supply.
- (3) Application of Full Service charge to all Base Service Customers: If because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially, except as provided in sections 2.c and 5 of this rate schedule, all Base Service customers shall pay the total Full Service charge in accordance with section 3 below.

**3. FULL SERVICE FOR WIND RESOURCES**

The total charge for Full Service is:

- a. the applicable Base Service rate in section 2.a.(1), ~~or 2.a.(2), 2.a.(3), or 2.a.(34)~~ plus any ~~Type 1, Type 2, or Type 4~~ Purchases Charges for Direct Assignment; plus
- b. ~~Type 3~~ Purchases Charges for Full Service under section 6.

~~The Variable Energy Resource Balancing Service Credit under section 7 applies to a customer's bill when balancing reserve capacity from the FCRPS is not provided for the service because of hydro system conditions.~~

**4. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR SOLAR RESOURCES**

The total charge for this service is the applicable rate below, plus ~~Type 1, Type 2, and Type 4~~ Direct Assignment Purchases Charges under section 6.

**a. RATES**

- (1) Regulating Reserves \$0.04 per kilowatt per month
- (2) Following Reserves ~~\$0.21~~ \$0.17 per kilowatt per month

**b. BILLING FACTOR**

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

**c. EXCEPTIONS**

See section 2.c above.

**5. SUPPLEMENTAL SERVICE**

**a. RATES**

The monthly Supplemental Service rate in \$/MW shall equal:

Purchase Cost / Imbalance Reserve

Where:

Purchase Cost = The sum of all purchase costs incurred by BPA to supply Supplemental Service for the relevant number of months to customers that commit to take such service, in dollars (\$).

Imbalance Reserve = The sum of all imbalance reserves purchased by BPA to supply Supplemental Service for the relevant month or months for customers that commit to take such service, in MW-months.

**b. BILLING FACTOR**

The billing factor shall be the monthly amount of reserve that the Supplemental Service customer has contractually committed to purchase.

**c. EXCEPTIONS**

None.

**6. FORMULA PURCHASES CHARGES**

These charges will recover the cost of *inc* balancing reserve capacity purchases.

~~For purchases of balancing reserve capacity for a term of longer than two months, BPA will provide 15 calendar days' advance notice on its OASIS Web site of a public meeting to discuss the proposed purchase of balancing reserve capacity and the expected charge. Written comments on the proposed purchase will be accepted for 15 calendar days after the public meeting. BPA will notify customers on its OASIS Web site within 30 days of the public meeting of its decisions regarding the purchase and the applicable charge.~~

~~**(1) Type 1 Purchases Charge for Purchases of Balancing Reserve Capacity on a Planned Basis**~~

~~BPA will apply the Type 1 Purchases Charge if BPA purchases balancing reserve capacity because the capability of the FCRPS on a planned basis is insufficient to provide the forecast balancing reserve capacity requirements.~~

~~**Type 1 Purchases Charge:**~~

~~For each customer, the monthly charge for Type 1 Purchases shall be:~~

$$\text{Type 1 \$} = (\text{Plan Acq} / \text{Total BF}) * \text{Billing Factor}$$

*Where:*

~~Type 1 \$ = — The monthly charge for each Variable Energy Resource for Type 1 purchases of balancing reserve capacity that are made to provide sufficient balancing reserve capacity on a planned basis, in \$.~~

~~Plan Acq = — The total costs associated with purchases of balancing reserve capacity, in \$/mo.~~

~~Total BF = — The sum of all Variable Energy Resources' inc reserve requirements for all components of Variable Energy Resource Balancing Service Base Service, for the month for which the balancing reserve capacity was purchased, in kilowatts.~~

~~Billing Factor = — The Variable Energy Resource's inc reserve requirement for all components of base Variable Energy Resource Balancing for the month for which the balancing reserve capacity was purchased, in kilowatts.~~

~~For "Total BF" and "Billing Factor," the reserve requirements will be calculated based on nameplate capacities and service elections of each generation facility.~~

~~(2) — **Type 2 Purchases Charge for Replacement of Federal Balancing Reserve Capacity that Becomes Unavailable**~~

~~BPA will apply the Type 2 Purchases Charge if BPA purchases non-Federal balancing reserve capacity to replace Federal balancing reserve capacity that it has determined is no longer available.~~

~~**Type 2 Purchases Charge:**~~

~~For each customer, the monthly charge for Type 2 Purchases shall be:~~

$$\text{Type 2 \$} = ((\text{VERBS \%} * \text{Cost}) / \text{Total BF}) * \text{Billing Factor}$$

*Where:*

~~Type 2 \$ = — The monthly charge for each Variable Energy Resource for Type 2 purchases of non-Federal balancing reserve capacity to replace Federal~~

~~balancing reserve capacity that becomes unavailable, in \$.~~

~~VERBS % = The Variable Energy Resource Balancing Service total Base Service rate charges for the month for which the purchase of balancing reserve capacity was made divided by the sum of the total Dispatchable Energy Resource Balancing Service *inc* and *dec* charges (see ACS-14 rate schedule, section III.F.) plus the total VERBS Base Service rate charges for the same period.~~

~~Cost = 95 percent of total costs associated with purchases of balancing reserve capacity to replace the FCRPS, in \$/mo.~~

~~Total BF = The sum of all Variable Energy Resources' *inc* reserve requirements for all components of Variable Energy Resource Balancing Service Base Service for the month for which the balancing reserve capacity was purchased, in kilowatts.~~

~~Billing Factor = The Variable Energy Resource's *inc* reserve requirement for all components of Variable Energy Resource Balancing Service Base Service for the month for which the balancing reserve capacity was purchased, in kilowatts.~~

~~For "Total BF" and "Billing Factor," the reserve requirements will be calculated based on nameplate capacities and service elections of each generation facility.~~

**(13) Type 3 Purchases Charge for Purchases of Balancing Reserve Capacity to Support Full Service**

BPA will apply the Type 3 Purchases Charge for Full Service to customers taking Full Service if BPA purchases balancing reserve capacity beyond the level of balancing reserve capacity that is made available under a committed scheduling Base Service election to meet the increased balancing reserve capacity requirements of Full Service customers.

**Type-3 Purchases Charge for Full Service:**

For each Full Service customer, the monthly charge for Type-3-Full Service Purchases shall be:

$$\text{Type-3 Full Svc } \$ = (\text{Aug Cost} / \text{Svc BF}) * \text{Billing Factor}$$

Where:

Type-Full Service \$ = The monthly charge for each Full Service customer for Type-3 purchases of balancing reserve capacity to support the Full Service option, in \$.

Aug Cost = The total costs associated with acquiring balancing reserve capacity to augment the balancing capacity needs of Full Service customers, in \$/mo.

Svc BF = The sum of the billing factors, as identified in section 2.b., for the month for which the balancing reserve capacity was purchased for Variable Energy Resources that take Full Service, in kilowatts.

Billing Factor = The Variable Energy Resource billing factor, as identified in section 2.b for the month for which the balancing reserve capacity was purchased, in kilowatts.

**(24) Type-4 Purchases Charge for Direct Assignment of Costs to a Customer**

BPA shall directly assign to the customer the cost of balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service to the customer if:

- (a) the customer elected to self-supply in accordance with section 2.c but is unable to continue self-supplying one or more components to Variable Energy Resource Balancing Service; or
- (b) the customer has a projected generator interconnection date after FY 2015, but chooses to interconnect during the FY 2014-2015 rate period; or
- (c) the customer elected to take service under sections 2.a.(1), ~~or~~ 2.a.(2), 2.a.(3), or 2.1a.(34) above, but fails to conform to the

committed scheduling criteria specified in BPA business practices;  
or

- (d) the customer elected to take service under sections 2.a.(1), ~~or~~ 2.a.(2), 2.a.(3), or 2.a.(34) above, but chooses to take a Base Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices.

~~7. VARIABLE ENERGY RESOURCE BALANCING SERVICE CREDIT~~

~~a. APPLICABILITY~~

~~Base Service customers that take and pay for all three components of Variable Energy Resource Balancing Service under section 2.a will receive a credit pursuant to this section 7 for *inc* and *dec* balancing reserve capacity from the FCRPS that becomes unavailable because of hydro system conditions.~~

~~b. CREDIT RATE~~

- ~~(1) *Inc* Balancing Reserves \$7.30 per kilowatt per month~~
- ~~(2) *Dec* Balancing Reserves \$0.60 per kilowatt per month~~

~~c. CREDIT ADJUSTMENT~~

~~A credit adjustment is available for both *inc* and *dec* balancing reserve capacity. The combined *inc* and *dec* credit amount is not to exceed the total charge for Variable Energy Resource Balancing Service at the base rates, for the month.~~

$$~~Inc Cr Adj. = Reduction * CR * BF Ratio~~$$

$$~~Dec Cr Adj. = Reduction * CR * BF Ratio~~$$

~~Where:~~

~~*Inc Cr Adj* = The credit amount for *inc* balancing reserve capacity when balancing reserve capacity from the FCRPS is not provided for the service because of hydro system conditions, in \$.~~

~~*Dec Cr Adj* = The credit amount for *dec* balancing reserve capacity when balancing reserve capacity from the FCRPS is not provided for the service because of hydro system conditions, in \$.~~

~~Reduction =~~ ~~The average reduction of balancing reserve capacity provided by the FCRPS for the month is the average hourly reserves forecast less the average hourly balancing reserve capacity provided, for either *inc* or *dec* balancing reserve capacity, in kilowatts.~~

~~CR =~~ ~~The applicable Credit Rate from section 7.b above for either *inc* or *dec* balancing reserve capacity, in \$/kW/month.~~

~~BF Ratio =~~ ~~The ratio of the Variable Energy Resource billing factor as identified in section 2.b to the sum of the billing factors, as identified in section 2.b for all Variable Energy Resources, in kilowatts.~~

~~d. EXCEPTIONS~~

~~See section 2.c above.~~

## F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all non-Federal Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section III.F.3. Dispatchable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for service is the charge for the applicable rate in section 1 below, plus ~~Type 2 and Type 4~~ Purchases Charges for Direct Assignment in section 4 below.

### 1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

- a. Incremental Reserves = ~~22.74~~18.15 mills per kW maximum hourly deviation
- b. Decremental Reserves = ~~2.71~~3.94 mills per kW maximum hourly deviation

### 2. BILLING FACTORS

- a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative station control error (under-generation), including ramp periods, that exceeds ~~23~~ MW for that hour.
- b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive station control error (over-generation), including ramp periods, that exceeds ~~23~~ MW for that hour.

### 3. EXCEPTIONS

- a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.
- b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

- c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.
- d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

#### 4. FORMULA PURCHASES CHARGES

~~For purchases of balancing reserve capacity for a term of longer than two months, BPA will provide 15 calendar days' advance notice on its OASIS Web site of a public meeting to discuss the proposed purchase of balancing reserve capacity and the expected charge. Written comments on the proposed purchase will be accepted for 15 calendar days after the public meeting. BPA will notify customers on its OASIS Web site within 30 days of the public meeting of its decisions regarding the purchase and the applicable charge.~~

~~**a. Type 1 Purchases Charge for Purchases of Balancing Reserve Capacity on a Planned Basis**~~

~~This rate is not applicable for the FY 2014-2015 rate period.~~

~~**b. Type 2 Purchases Charge for Replacement of Federal Balancing Reserve Capacity that Becomes Unavailable**~~

~~BPA may apply a Type 2 Purchases Charge to recover the purchase cost of non-Federal balancing reserve capacity if BPA determines that it can no longer provide the level of balancing reserve capacity for the proportion of Dispatchable Energy Resource Balancing Service that BPA forecast it could provide for the rate period and BPA purchases non-Federal balancing reserve capacity to replace the unavailable Federal balancing reserve capacity.~~

~~**Type 2 Purchases Charge:**~~

$$\text{Type 2 \$} = ((\text{DERBS \%} * \text{Cost}) / \text{Total BF}) * \text{Billing Factor}$$

*Where:*

~~Type 2 \$ = — The charge for *inc* purchases of non-Federal balancing reserve capacity to replace Federal balancing reserve capacity that becomes unavailable, in \$.~~

~~DERBS % = — The Dispatchable Energy Resource Balancing Service total *inc* and *dec* charges for the month for which the purchase of balancing reserve capacity was made divided by the sum of the total DERBS *inc* and *dec* charges plus the total base Variable Energy Resource Balancing Service charges (*see* ACS 14 rate schedule, section III.E.), for the same period.~~

~~Cost = — 95 percent of total costs associated with acquiring *inc* balancing reserve capacity to replace the FCRPS, in \$/mo.~~

~~Total BF = — The sum of the *inc* billing factors, as identified in section 2.a, for the period for which the balancing reserve capacity was purchased, in kilowatts.~~

~~BF = — The *inc* billing factor, as identified in section 2.a, for the period for which the balancing reserve capacity was purchased, in kilowatts.~~

**ea. Type 3 Purchases Charge for Full Service**

Not applicable.

**db. Type 4 Purchases Charge for Direct Assignment of Costs to a Customer**

BPA shall directly assign to the customer the cost of balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service to the customer if:

- (1) the Customer elected to self-supply but is unable to continue self-supplying the Dispatchable Energy Resource Balancing Service; or
- (2) a Customer has a projected generator interconnection date after FY 2015 but chooses to interconnect during the FY 2014-2015 rate period; or

- (3) a Customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2014-2015 rate period.

## **SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS**

### **B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS**

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service under this rate schedule are subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms specified in GRSP II.H.

## GENERAL RATE SCHEDULE PROVISIONS

### SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

#### H. CRAC, DDC, AND NFB MECHANISMS

The Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.C, II.E, and II.N.

The CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The DDC is a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a CRAC during a fiscal year. Except as otherwise provided, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service
- Variable Energy Resource Balancing Service (VERBS)

Exception: For the VERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.E.6, Formula Purchases Charges; nor to the Supplemental Service rate, section III.E.5.

- Dispatchable Energy Resource Balancing Service (DERBS)

Exception: For the DERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.F.4, Formula Purchases Charges.

#### 1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

**2. CUSTOMER CREDIT FOR THE ACS DDC**

The ACS DDC Amount is the share, in dollars, of the total DDC Amount that is to be distributed from the ACS rates specified above; the balance of the DDC Amount is to be distributed from specified Power rates. The ACS DDC Amount is converted to an ACS DDC Percentage by dividing the ACS DDC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the DDC.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS DDC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

**3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE**

The ACS Surcharge amount is the share, in dollars, of the total Surcharge Amount that is to be collected from the ACS rates specified above; the balance of the Surcharge Amount is to be collected from specified Power rates. The ACS Surcharge is converted to an ACS Surcharge Percentage by dividing the ACS Surcharge by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the Emergency NFB Surcharge.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

**4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS**

The CRAC, DDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.C, II.E, and II.N, are incorporated by reference.

## GENERAL RATE SCHEDULE PROVISIONS

### SECTION III. DEFINITIONS

#### 1. ANCILLARY SERVICES

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

- a. Scheduling, System Control, and Dispatch
- b. Reactive Supply and Voltage Control from Generation Sources
- c. Regulation and Frequency Response
- d. Energy Imbalance
- e. Operating Reserve – Spinning
- f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

#### 3. CONTROL AREA

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);
- b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

#### 4. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area

Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and the Northwest Power Pool (NWPP) reliability criteria. Control Area Services, include, without limitation:

- a. Regulation and Frequency Response Service
- b. Generation Imbalance Service
- c. Operating Reserve – Spinning Reserve Service
- d. Operating Reserve – Supplemental Reserve Service
- e. Variable Energy Resource Balancing Service
- f. Dispatchable Energy Resource Balancing Service

## **8. DISPATCHABLE ENERGY RESOURCE**

For purposes of Dispatchable Energy Resource Balancing Service, a Dispatchable Energy Resource is any non-Federal thermally-based generating resource that schedules its output or is included in BPA’s Automatic Generation Control systems.

## **9. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE**

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator’s schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

## **10. DYNAMIC SCHEDULE**

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

## **11. DYNAMIC TRANSFER**

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

## **13. ENERGY IMBALANCE SERVICE**

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA’s Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in the Transmission Customer’s Service Agreement to satisfy its Energy Imbalance Service obligation.

**16. GENERATION IMBALANCE**

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

**17. GENERATION IMBALANCE SERVICE**

Generation Imbalance Service a service provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

**37. OPERATING RESERVE – SPINNING RESERVE SERVICE**

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission or Control Area Service Customer’s obligation is determined consistent with NERC, WECC, and NWPP criteria.

**38. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE**

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer’s obligation is determined consistent with NERC, WECC, and NWPP criteria.

**39. OPERATING RESERVE REQUIREMENT**

Operating Reserve Requirement is a party’s total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, “Contingency Reserve Sharing Procedure,” and WECC Standards.

#### 40. PERSISTENT DEVIATION

A Persistent Deviation event is one or more of the following:

a. **For Generation Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. **For Energy Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

**48. REGULATION AND FREQUENCY RESPONSE SERVICE**

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

**60. SPILL CONDITION**

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

**61. SPINNING RESERVE REQUIREMENT**

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

**62. SUPPLEMENTAL RESERVE REQUIREMENT**

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

**68. VARIABLE ENERGY RESOURCE BALANCING SERVICE**

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

### RATE PERIOD TERMS

1. The terms and conditions set out in sections 2 through 10 of this Attachment 2 shall apply to and be binding on Bonneville and the Assenting Parties during the FY 2014-15 Rate Period (“Rate Period”), but shall expire and not survive in any form after September 30, 2015.
2. Using a 99.5 percent planning standard to determine the total amount of Variable Energy Resource Balancing Service (“VERBS”) Base Service reserves needed for each month of the Rate Period (FY 2014-2015), absent operational constraints Bonneville will provide from the FCRPS the amount required each month, up to a maximum amount of 900 MW of *inc* and 1,100 MW of *dec* of Bonneville’s total balancing reserve capacity requirement on a planning basis. Bonneville and the Assenting Parties acknowledge that operational constraints may limit Bonneville’s ability to provide balancing reserve capacity from the FCRPS at times during the Rate Period.
3. Bonneville will take reasonable steps to acquire capacity when Bonneville’s total *inc* balancing reserve capacity requirement for VERBS Base Service, as determined with the 99.5 percent planning standard, exceeds 900 MW.
  - a. Bonneville shall treat any cost difference between the purchase price of capacity and \$8.65/kW/month as a transmission cost or credit.
  - b. If Bonneville reasonably determines that the FCRPS is available on a short-term basis to supply balancing reserve capacity under this section 3, Bonneville may, at its sole discretion, make that capacity available in its capacity acquisition process at a cost based on \$8.65/kW/month.
  - c. Bonneville shall post quarterly Dispatcher Standing Order No. 216 (“DSO 216”) reports that provide the estimated tag curtailment events and the actual amount of curtailment events each month. If the actual number of DSO 216 tag curtailment events exceeds 150 percent of the estimate in any given month, Bonneville will include in that report an explanation why the DSO 216 tag curtailment events increased from the estimate.
4. Acquisition Budget for the FY 2014-2015 rate period.
  - a. Bonneville shall establish a \$2 million annual budget to be used for the purposes set forth in 4(b) (“Acquisition Budget”).
  - b. Bonneville will utilize the Acquisition Budget to (1) purchase *inc* capacity (not to exceed the cap of 900 MW *inc*) during times when, due to operational constraints, the FCRPS is unable to provide the reserves required by a 99.5 percent planning standard for VERBS Base Service; and (2) manage risk of any differences between the cost incurred for third-party capacity deployment costs and the hourly energy index in the Pacific Northwest.
  - c. When the Acquisition Budget is exhausted, Bonneville will not be obligated to attempt to purchase additional *inc* capacity in the event the FCRPS is unable to provide the reserves required to supply a 99.5 percent planning standard for VERBS Base Service. If Bonneville purchases such additional *inc* capacity, Bonneville shall treat the costs of such purchases as transmission costs.

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- d. Bonneville will provide quarterly reports on its OASIS website on the types and amounts of expenditures made in the previous quarter and the status of the Acquisition Budget.
  - e. Bonneville shall not use the Acquisition Budget to fund incremental purchases of capacity that may be required to meet Bonneville's total *inc* balancing reserves requirement above 900 MW.
  - f. Bonneville may, after consultation with customers, change the intended utilization of the Acquisition Budget set out in section 4(b)(1) of this Attachment 2. Such change would be to allow Bonneville to utilize the Acquisition Budget to strategically target high volatility wind events (*see* section 10.e below).
5. Bonneville shall not make any *dec* acquisitions unless (1) a customer requests the purchase of *dec* reserve capacity purchases under Supplemental Service and agrees to pay these costs in accordance with the terms of the Supplemental Service; or (2) Bonneville determines *dec* acquisitions are necessary to maintain system reliability.
6. Bonneville will offer VERBS customers a mid-Rate Period election opportunity to change their scheduling elections to a superior scheduling commitment, to elect self-supply, use Dynamic Transfer Capability ("DTC") to transfer out of Bonneville's balancing authority area, or to elect to participate in Customer Supplied Generation Imbalance ("CSGI"). These election changes will be capped at 1550 MW of nameplate movement offered on a first-come first-serve basis. The notification deadline to change service will be April 4, 2014, and the effective date of the election change will be October 1, 2014. The expansion of self-supply, including the CSGI program, and DTC will be limited to a total of 600 MW and will count towards the 1550 MW cap on nameplate movement. Customers will pay the posted rates associated with their revised election choice.
7. Bonneville shall implement 15-minute scheduling as soon as feasible. Bonneville will take reasonable steps to implement 15-minute minute scheduling by October 1, 2014. The VERBS rates associated with a 30/15 committed scheduling election and a 40/15 committed scheduling election in Attachment 1 will apply only if Bonneville posts on its OASIS website before April 4, 2014, that Bonneville will implement 15 minute scheduling by October 1, 2014.
8. 8.2 percent of the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) will apply to the balancing reserve capacity-based rates specified in Section H of the General Rate Schedule Provisions in Attachment 1.
9. Bonneville shall allocate the total Rate Period cost of \$840,000 that is associated with development of intra-hour scheduling and dynamic transfer to the Scheduling, System Control and Dispatch Service rate.
10. Bonneville commits to engage customers on issues specified below during the Rate Period. Bonneville and the Assenting Parties agree that nothing in this section 10 obligates Bonneville or Assenting Parties to any specific outcome or decision with respect to participation in any process or to any outcome or decision regarding any Bonneville rates or terms and conditions for transmission ancillary and control area services. Bonneville retains its full discretion to make decisions regarding the merits of any

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proposal, its statutory requirements and authorities, and its interests to the full extent of its statutory authorities, none of which is waived or circumscribed by entering into this Agreement, of which this Attachment 2 is a part.

- a. Bonneville shall continue to participate in the Northwest Power Pool Market Assessment and Coordination Committee's collaborative analytical process with regional partners to make objective determinations regarding region-wide initiatives, including whether to move toward an Energy Imbalance Market or adopt other Enhanced Market and Operational Tools.
- b. Bonneville will prepare and review a project plan with customers regarding future balancing reserve initiatives.
- c. Bonneville and the Assenting Parties will discuss and evaluate customer-proposed alternatives to DSO 216. To inform the discussion, Bonneville will share information related to DSO 216 curtailments with customers. Bonneville and the Assenting Parties will evaluate proposed alternatives consistent with the following principles: (1) Bonneville maintains discretion to determine physical feasibility of the FCRPS in advance of real-time and to limit provision from the FCRPS to these Bonneville-determined amounts; (2) maintenance of load and resource balance in Bonneville's balancing authority area in full compliance with NERC and WECC requirements and with Good Utility Practice; and (3) fair and full compensation for the capacity used to provide imbalance energy.
- d. Bonneville will participate in a joint effort with customers to work with the CAISO on 15-minute scheduling to reduce seams issues and to maximize opportunities for customers to participate in the CAISO 15-minute markets and minimize Bonneville's balancing reserve capacity requirement. Bonneville will also explore with customers the costs and benefits of developing an intra-hour transmission product.
- e. Bonneville will develop a method to determine balancing reserve capacity needs on a short-term basis (*e.g.*, the Real-Time Reserve Requirement Tool or "R3T"). Bonneville will discuss and refine this method with customers.
- f. Bonneville and customers will jointly review any identified benefits and drawbacks, and Bonneville will determine how and whether to apply the method to acquisitions made with the Acquisition Budget or to the overall structure of balancing service provided by Bonneville in future rate periods.
- g. Bonneville and the Assenting Parties will explore customer proposals on rate design for balancing services. Specific workshop agenda topics will be determined by customers' proposals and may include embedded and marginal cost allocation, Solar VERBS rate design, and risk mitigation. In order to help inform customers' proposals, Bonneville will conduct an educational workshop with information pertaining to the cost basis and rate design of Bonneville's balancing services. This educational workshop will include information and discussion of:
  - i. The 120-hour and 1-hour peaking capability and associated energy content;
  - ii. The cost basis of balancing services (including net revenues from secondary sales); and
  - iii. The use and availability of balancing reserve capacity for Load, Dispatchable Energy Resources, and Variable Energy Resources.

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- h. Bonneville will discuss with customers the concept of sub-hourly scheduling of the FCRPS for customers that purchase firm requirements power from Bonneville under CHWM contracts. Bonneville agrees to provide aggregated annual information on any capacity amounts sold under section 3(b) of this Attachment 2 during the FY 2014-2015 period. Bonneville will discuss with customers how these sales should impact customers that purchase firm requirements power from Bonneville under CHWM contracts in subsequent rate periods.
- i. Bonneville will post an annual report on its OASIS that provides the actual balancing reserve capacity held each hour of the previous fiscal year (both Federal and non-Federal) and the amount of MWh deployed during each hour (both *inc* and *dec* MWh).

## ATTACHMENT 2

### SIGNATORIES AND ASSENTING PARTIES TO THE PARTIAL SETTLEMENT AGREEMENT

#### **Signatories:**

Bonneville Power Administration  
Cowlitz County Public Utility District No. 1  
Eugene Water & Electric Board  
Franklin County Public Utility District No. 1  
Industrial Customers of Northwest Utilities  
Northwest Requirements Utilities  
Public Power Council  
Renewable Northwest Project  
Southern California Edison Company  
Snohomish County Public Utility District No. 1  
Simpson Tacoma Kraft Company, LLC  
City of Tacoma, dba Tacoma Power

#### **Assenting Parties:**

Avista Corporation  
Alcoa, Inc.  
Association of Public Agency Customers  
Benton County Public Utility District No. 1  
Clark County Public Utility District No. 1  
Calpine Corporation  
Caithness Shepherds Flat, LLC  
EDP Renewables North America, LLC  
Grant County Public Utility District No. 2  
Grays Harbor Energy, LLC  
Idaho Power Company  
Iberdrola Renewables, LLC  
J.P. Morgan Ventures Energy Corporation  
Lewis County Public Utility District No. 1  
M-S-R Public Power Agency  
NextEra Energy Resources, LLC  
Northwest & Intermountain Power Producers Coalition  
Northwestern Energy  
Northwest Irrigation Utilities  
NW Energy Coalition  
PacifiCorp  
Portland General Electric Company  
Pacific Northwest Generating Cooperative  
Pend Oreille County Public Utility District No. 1  
Puget Sound Energy, Inc.  
Public Utility Commission of Oregon  
City of Seattle  
TransAlta Energy Marketing (U.S.)  
Turlock Irrigation District  
Willow Creek Energy, LLC  
Western Public Agencies Group  
Western Montana Electric Generating & Transmission Coop.  
Yakama Power