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TESTIMONY OF

REBECCA E. FREDRICKSON AND DANIEL H. FISHER

Witnesses for Bonneville Power Administration

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TESTIMONY OF

REBECCA E. FREDRICKSON AND DANIEL H. FISHER

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS AND TRANSMISSION ANCILLARY AND CONTROL AREA SERVICES RATES SETTLEMENT AGREEMENT

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-18-Q-BPA-09.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-18-Q-BPA-08.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide an overview of the BP-18 Generation Inputs and Transmission Ancillary and Control Area Services Rates Settlement Agreement (Settlement), which is attached as Appendix A to this testimony. This testimony also sponsors the ACS-18 Ancillary and Control Area Services rate schedules that are in the Settlement. *See* Appendix A, Settlement, Attachment 2.

Section 2: Settlement Agreement and Initial Rate Proposal

Q. Please describe how BPA and interested parties developed the Settlement for the BP-18 rate proceeding.

A. BPA Staff heard from customers in August 2016 that several parties were interested in exploring a settlement of the Ancillary and Control Area Services portion of the BP-18

rate case. This customer interest in exploring settlement was expressed after roughly eight months of public workshops that included five all-customer meetings and three sub-team efforts aimed at reaching collaborative solutions to the Ancillary and Control Area Service issues for the BP-18 rate period. BPA Staff responded with a presentation of a draft settlement concept to the customers on August 24, 2016. Customers provided feedback during the August 24, 2016, presentation as well as during various small meetings that occurred in the subsequent weeks. Customers and BPA Staff determined that the settlement concept presented had significant settlement potential. BPA Staff and the customers held drafting sessions on August 31, September 15, and September 20, 2016, to refine the settlement agreement. The drafting sessions resulted in a revised agreement that was released publicly on September 23, 2016.

Customers that intended to be parties to the BP-18 rate proceeding were instructed to indicate their intent to contest the Settlement by close of business on October 5, 2016. No customers did so. Avangrid Renewables, LLC, signed the Settlement. The following customers agreed not to contest the Settlement: Cowlitz County PUD; Eugene Water & Electric Board; Franklin County PUD No. 1; Industrial Customers of Northwest Utilities; Invenergy LLC; M-S-R Public Power Agency; Northwest Requirements Utilities; Pacific Northwest Generating Cooperative; Portland General Electric Company; Powerex; Public Power Council; Puget Sound Energy, Inc.; Renewable Northwest; Seattle City Light; TransAlta Energy Marketing; Turlock Irrigation District; and Western Public Agencies Group. On October 11, 2016, BPA notified customers that it did not receive any objections to the Settlement and that the BP-18 Initial Proposal would be developed using the provisions of the Settlement.

Q. Please provide an overview of the portion of the Initial Proposal that is based on the Settlement.

A. The Settlement addresses all generation inputs and Ancillary and Control Area Services rates for the BP-18 rate period except (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control from Generation Sources Service. The Settlement is expected to provide a single, high-quality balancing service to all customers. The generation capacity required to provide this service is forecast to be sourced solely from the Federal Columbia River Power System based on the incremental and decremental reserve quantities needed to support a 99.7 percent planning standard.

The Settlement also establishes the cost at which balancing reserve capacity is provided to Transmission Services by Power Services. The forecast revenue from balancing reserve capacity, combined with the revenue Power Services receives from Transmission Services for providing the other generation inputs included in the Settlement (Appendix A, Settlement, Attachment 3), is used to set power rates. Power Rates Study, BP-18-E-BPA-01, § 2.1.6.9. The recovery of these costs is included in the Transmission Rates Study and Documentation, BP-18-E-BPA-08, Table 12.

Q. Please describe the quantity of balancing reserves that the 99.7 percent planning standard results in.

A. The estimated quantities of balancing reserves needed on a monthly basis to support a 99.7 percent planning standard are shown in Appendix B. This estimate was based on mock scheduling elections BPA requested from customers in the summer of 2016 and used in the Initial Proposal to forecast Power Services revenue. However, a more up-to-

date and certain forecast of balancing reserves needed to provide the 99.7 percent planning standard will not be possible until a few months before the Final Proposal, when customers must select their service and scheduling elections for the BP-18 rate period.

Also affecting the balancing reserve requirement are the dates that several large Variable Energy Resource Balancing Service (VERBS) customers are expected to leave BPA's balancing authority area during the FY 2018–2019 rate period. The dates that these VERBS customers are forecast to leave BPA's balancing authority area also will be established when customers make their service and scheduling elections.

Q. Will the settled rates change as a result of the updated quantity of balancing reserves needed to support a 99.7 percent planning standard?

A. No, the settled rates will not change. The Settlement locked in the balancing capacity rates, the 99.7 percent planning standard, and the dollar amount Power Services is compensated for provided capacity. However, unlike the BP-16 Settlement, the BP-18 Settlement did not lock in any customer service and scheduling elections. As a result, the quantity of reserves needed to provide the 99.7 percent planning standard will change, as will the forecast amount of generation inputs revenue used to set power rates.

Q. Please describe proposed changes to the ACS-18 rate schedules that are based on the Settlement.

A. The BP-18 settled rates have changed from those in the BP-16 settlement, with some ACS rates increasing and others decreasing. *See* Table 1, Settled BP-18 Rates Compared to BP-16 Rates Summary. In addition, only a limited set of capacity-based ACS rates are subject to adjustment due to Power Services' risk mitigation mechanisms.

Regulation and Frequency Response Service rates and Operating Reserve Service rates (both Spinning and Supplemental) are subject to adjustment, whereas the VERBS and Dispatchable Energy Resource Balancing Service (DERBS) rates are not. VERBS and DERBS rates include an additional $700,000 per year in lieu of being subject to Power Services' risk mitigation mechanisms.

In addition, unlike the BP-16 rate period, there will be no opportunity for VERBS customers to change scheduling elections mid-rate period. The 40/15 Committed Scheduling option under the VERBS rate schedule was also removed. A new scheduling option was added for VERBS solar resources; it provides a rate benefit from committing to 15-minute scheduling.

Finally, the Settlement limits the applicability of the Persistent Deviation Penalty to those VERBS customers participating in the Customer Supplied Generation Imbalance Pilot Program. All other VERBS customers are subject to the Intentional Deviation Penalty Charge for Variable Energy Resources. The option for VERBS customers electing Uncommitted Scheduling to opt out of the Intentional Deviation Penalty Charge for a fee has been removed.

Q. Are there other impacts to the rates from the Settlement?

A. The Settlement sets cost allocations from Power Services to Transmission Services for synchronous condensing, generation dropping, redispatch, segmentation of COE and Reclamation network and delivery facilities, and station service. These costs are recovered in various transmission rates. *See* Appendix A, Settlement, Attachment 3.

Section 3: Equitable Allocation

Q. Do the proposed ACS-18 rates represent an equitable allocation of costs between Federal and non-Federal power, as required by section 7(a)(2) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2)?

A. Yes. The number of parties involved in the Settlement discussions was substantial and spanned the full spectrum of BPA customer types. Each of these parties has slightly different interests in the outcome of the Settlement, yet no participating party contested the Settlement. As a result, equitable allocation is demonstrated by the breadth of interests of the parties that either signed the Settlement or agreed not to contest it. These parties include requirements customers of Power Services; large wheeling customers, such as several investor-owned utilities and power marketers; and independent power producers. BPA would not have been able to obtain the agreement or consent of such a large and diverse group of customers (that is, Federal and non-Federal power users of the Federal transmission system) unless the proposed allocation of costs was equitable for the FY 2018–2019 rate period.

Q. Does this conclude your testimony?

A. Yes.

Table 1
Settled BP-18 Rates Compared to BP-16 Rates Summary

	A	B	C	D
		BP-16 Rates	**BP-18 Settled Rates**	**% Change From BP-16**
1	**DERBS rates in $ per MW maximum hourly deviation per month**			
2	*Inc*	$18.15	$20.42	13%
3	*Dec*	$3.94	$3.43	-13%
4	**VERBS Solar rates in $ per MW per month**			
5	Solar 30/15 Committed Scheduling	Not Applicable	$0.21	Not Applicable
6	Solar Hourly Scheduling	$0.21	$0.28	33%
7	**VERBS Wind rates in $ per MW per month**			
8	Wind 30/15 Committed Scheduling	$0.73	$0.71	-3%
9	Wind 30/60 Committed Scheduling	$1.20	$1.01	-16%
10	Wind Uncommitted Scheduling	$1.48	$1.22	-18%
11	Wind CSGI	$0.40	$0.49	23%
12	**Operating Reserve rates in $ per MWh per month**			
13	Operating Reserve Spinning	$11.40	$11.82	4%
14	Operating Reserve Supplemental	$10.45	$9.76	-7%
15	**Regulation and Frequency Response rate in $ per MWh per month**			
16	Regulation and Frequency Response	$0.12	$0.13	8%

DERBS: Dispatchable Energy Resource Balancing Service
VERBS: Variable Energy Resource Balancing Service
CSGI: Customer-Supplied Generation Imbalance

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Appendix A

BP-18 Generation Inputs and Transmission Ancillary and Control Area Services Rates Settlement Agreement

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BP-18 Generation Inputs and Transmission Ancillary and Control Area Services Rates Settlement Agreement

THIS SETTLEMENT AGREEMENT, including Attachments 1, 2, and 3 ("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-18 rate case parties (in the singular, "Party," in the plural, "Parties").

WHEREAS

A. Starting in January 2016, Bonneville and the Parties have been engaged in public meetings to reach agreement on the rates for certain transmission ancillary and control area services for the FY 2018-2019 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-18 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-18 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 terms specified in Attachment 1, the rate schedules and general rate schedule provisions specified in Attachment 2, the terms in Attachment 3, and the terms of this Agreement.

2. During the Rate Period, Bonneville and the Assenting Parties will abide by the terms specified in this Agreement.

3. Bonneville will notify the Hearing Officer of the Agreement and move the Hearing Officer to: (1) require any Party that did not sign or assent to 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-18 rate proceeding within 5 days of the date interventions are granted in the rate proceeding; and (2) specify that any Party that does not state its objection to the Settlement Proposal on such date 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-18 rate proceeding. Unless this Agreement terminates under the terms set forth in sections 4 and 5 below, this Agreement will become effective on November 10, 2016, and will terminate on September 30, 2019. 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.

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 will have three business days from the date of the objection to withdraw its assent to the settlement. If Bonneville or any Assenting Party withdraws its assent to the settlement, Bonneville shall promptly meet with any other interested rate case parties to discuss how to proceed.

5. If the Administrator does not adopt the Settlement Proposal in the BP-18 Final Record of Decision, this Agreement and the Settlement Proposal will terminate upon the date the Administrator declines to adopt the Settlement Proposal.

6. Waiver

    a. <u>Preservation of BP-18 ACS Rates and Settlement Proposal</u>

        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 or its implementation pursuant to its terms, including the Settlement Proposal and rates and rate schedule provisions in Attachment 2, from the effective date through September 30, 2019.

ii. The Assenting Parties agree to waive their rights to cross-examination and discovery with respect to the Settlement Proposal, except in response to issues raised by any party in the BP-18 rate proceeding that is not an Assenting Party to this Agreement.

b. <u>No Precedent or Issue Preclusion beyond the Rate Period</u>

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 2 or to any rate, charge, or rate schedule provision, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such proceedings; and

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 Federal Energy Regulatory Commission ("Commission"), or a court, creates or implies:(1) any procedural or substantive precedent; (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.

7. Reservation of rights

    a. Except as provided in section 6(a) above, no Assenting Party waives any of its rights, under Bonneville's enabling statutes, the Federal Power Act, or other applicable law, or 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 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 this Agreement.

8. If because of a legal challenge, Bonneville is otherwise required to materially modify or discontinue the rates, terms, and conditions provided in this Agreement, 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.

9. Attachment 1 (Rate Period Terms), Attachment 2 (Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions) and Attachment 3 (Inter-Business Line Allocations) are part of this Agreement.

10. Section 6(b) (No Precedent or Issue Preclusion beyond the Rate Period) of this Agreement will survive termination or expiration of this Agreement.

11. Nothing in this Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's rates or the Assenting Parties' rights to challenge such revisions.

This Agreement may be executed in counterparts.

_____

[Print Party Name]

By: _____

Name: _____

(Print/Type)

Title: _____

Date: _____

ATTACHMENTS

Attachment 1, Rate Period Terms

Attachment 2, Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions

Attachment 3, Inter-Business Line Allocations

ATTACHMENT 1, RATE PERIOD TERMS

1. **Term.** The terms and conditions in this Attachment 1 will apply to and will be binding on Bonneville and the Assenting Parties during the Fiscal Year (FY) 2018-2019 Rate Period ("Rate Period"), but must expire and not survive in any form after September 30, 2019.

2. **Imbalance Service.** Bonneville shall attempt to provide an imbalance service based on the incremental (*inc*) and decremental (*dec*) reserve quantities needed to support Bonneville's 99.7% planning standard. This is estimated to be less than 110 curtailment events in a year.

3. ***Dec* Reserve.** Bonneville will use reasonable efforts to provide *dec* balancing reserve capacity consistent with Bonneville's 99.7% planning standard from the Federal Columbia River Power System ("FCRPS") during all hours of the Rate Period. Bonneville and the Assenting Parties acknowledge that operational constraints and significant energy imbalance accumulations during operationally constrained periods of the year may limit Bonneville's ability to provide *dec* balancing reserve capacity from the FCRPS at times during the Rate Period. Bonneville shall not make any *dec* balancing reserve capacity acquisitions unless Bonneville determines *dec* balancing reserve capacity acquisitions are necessary to maintain system reliability.

4. ***Inc* Reserve.** Bonneville will use reasonable efforts to provide *inc* balancing reserve capacity consistent with Bonneville's 99.7% planning standard, as described in section 2 of this Attachment 1, from the FCRPS during all hours of the Rate Period. Bonneville is not obligated to provide more than the *inc* balancing reserve capacity amount as calculated with Bonneville's 99.7% planning standard. To the extent Bonneville cannot meet the capacity amount consistent with the 99.7% planning standard from the FCRPS, Bonneville will use reasonable efforts to acquire third-party sources to meet the 99.7% planning standard at Transmission Services' expense, taking into account the following factors in making such acquisitions :

   a. availability of *inc* balancing reserve capacity;

   b. cost of acquired *inc* balancing reserve capacity;

   c. reserve needs; and

   d. operational impacts during the affected timeframe.

5. **Inter-Business Line Allocations.**

   a. *Inc* balancing reserve capacity provided from the FCRPS will be at a cost of $0.305/kW/day. Power Services shall be compensated only for *Inc* balancing reserves provided.

   b. The cost of *Dec* balancing reserve capacity provided from the FCRPS is included in the cost of *Inc* balancing reserve capacity.

   c. Transmission Services shall be responsible for 3.48 percent of the Power Cost Recovery Adjustment Clause, Dividend Distribution Clause, and National Marine Fishery Service Federal

Columbia River Power System Biological Opinion ("NFB") Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge), however designated. Such amount will apply to the capacity-based rates specified in section 9 of this Attachment 1.

d. The rates under this Agreement are based on the assumption that Bonneville's power revenue requirement will not contain Planned Net Revenues for Risk or any risk mitigation tool that: (1) supports Bonneville's power Treasury Payment Probability; (2) supports Bonneville's credit rating; or (3) enhances Bonneville's financial strength or financial standing by improvingBonneville's cash position ("Risk Mitigation Tool" or "RMT"). If Bonneville adopts any RMT in its overall power revenue requirement as determined in the BP-18 Final Proposal, then Transmission Services shall be responsible for 3.48 percent of such RMT. Such amount will be allocated to capacity-based Ancillary and Control Area Service rates pursuant to section 9 of this Attachment 1. Variable Energy Resource Balancing Service for Wind, Variable Energy Resource Balancing Service for Solar, and Dispatchable Energy Resource Balancing Service are exempt.

e. Bonneville and Assenting Parties agree to the Inter-Business Line Allocations described in Attachment 3.

f. Transmission Services will pay Power Services an additional $700,000 per year in exchange for a lower ACS risk share. This additional amount is reflected in the Variable Energy Resource Balancing Service and Dispatchable Energy Resources Balancing Service rates in section 8 of this Attachment 1.

6. **Intentional Deviation.** One Hundred Percent (100%) of the revenue that Bonneville receives through the Intentional Deviation Charge shall remain with Transmission Services. Revenue that Bonneville receives from Energy Imbalance ("EIrev"), Generation Imbalance ("GIrev"), and Persistent Deviation ("PDrev") will be split between Power Services and Transmission Services. Power Services' share ("PSshare") in such revenue will equal:

$$PSshare = [EIrev + GIrev + PDrev] - \sum Hr3PSD \times HrIndex$$

Where:

Hr3PSD = The MWh amount of third-party *inc* balancing reserve capacity deployed each hour.

HrIndex = The hourly energy index in the Pacific Northwest during the hour when the third-party *inc* balancing reserve capacity was deployed.

7. **Revenue Credit.** Power Services will set power rates with the revenue credit expectation that all planned *inc* balancing capacity will be sourced from the FCRPS.

8. **Settlement Rates.** The following are the settlement rates prior to any rate adjustments in section 9 of this Attachment 1:

Service	Monthly Rates
Variable Energy Resource Balancing Service (VERBS) 30/15 Committed	$0.71/kW of nameplate
VERBS 30/60 Committed	$1.01/kW of nameplate
VERBS Uncommitted	$1.22/kW of nameplate
VERBS CSGI	$0.49/kW of nameplate
VERBS Solar 15-Minute	$0.21/kW of nameplate
VERBS Solar Hourly	$0.28/kW of nameplate
Dispatchable Energy Resource Balancing Service (DERBS) Inc	20.42 mills/kW
DERBS Dec	3.43 mills/kW
Regulation and Frequency Response	0.13 mills/kWh
Operating Reserve - Spinning	11.82 mills/kWh
Operating Reserve – Spinning default	13.59 mills/kWh
Operating Reserve - Supplemental	9.76 mills/kWh
Operating Reserve – Supplemental default	11.22 mills/kWh

9. **Adjusting Settlement Rates.** The ancillary and control area service rates listed below will increase to collect each rate's percentage share of Transmission Services' 3.48 percent amount of any rate or revenue requirement adjustment made under sections 5.c and 5.d of this Attachment 1. The rates will increase based on the following table:

Rates	**Percent Share**
Regulating and Frequency Response Service	0.38%
Operating Reserve - Spinning	1.55%
Operating Reserve - Supplemental	1.55%

10. **Solar Technical Work.** By January 2018, Bonneville will study and produce analysis on solar integration in Bonneville's Balancing Authority Area (BAA), though this is not a commitment to conduct a comprehensive integration study. The intent of Bonneville's analytical work will be to enhance Bonneville's current methodology and inform Bonneville and stakeholders prior to workshops leading to the BP-20 Initial Proposal. This analytical work will include:

a. A focus on the unique characteristics of integrating solar energy generation in Bonneville's BAA contrasted to that of wind energy in the Bonneville BAA.
b. The creation of a robust synthetic solar generation data set representative of a prospective geographically diverse build out of solar generation in Bonneville's BAA, forecasted based on the growth of Bonneville's interconnection queue through FY2025 as it exists on July 1, 2017 and through utilization of the University of Oregon's Solar Radiation Monitoring Laboratory datasets.

c. Analysis of the impacts on balancing reserves necessary to integrate solar energy in Bonneville's BAA with regards to solar scheduling best practices and geographic diversity benefits as shown in section 10(b) of this Attachment 1.

Bonneville will also hold stakeholder workshop(s) regarding solar generation prior to the BP-20 Initial Proposal to discuss (1) potential actions that can be taken by generators and Bonneville to reduce the balancing reserve requirement, (2) solar rate design, (3) the impact of the variable cost methodology and the incremental standard deviation methodology on balancing reserves held, and (4) the potential impact of planned reserves held in shaped amounts.

ACS-18~~6~~
ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-16~~4~~ rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling-, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service-
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. 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 must 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 transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

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

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 0.13~~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 customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 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 ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 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 ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 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 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.

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 (GRSP III.42):

(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-18~~6~~ 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 11.82~~11.40~~ 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 13.59~~13.11~~ 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 NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.

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 from BPA, the rate shall not exceed 9.76~~10.45~~ 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 11.22~~12.02~~ 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 NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.

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 0.13~~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 customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 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 ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent

of the scheduled amount of energy or (ii) ± 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 ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 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 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.

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 for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program. ~~are not subject to the Intentional Deviation Penalty Charge specified in GRSP II.H~~.

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

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 1 of this ACS-18~~6~~ Generation Imbalance Service rate schedule.

~~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 a committed 15-minute scheduling program in accordance with the ACS-18~~6~~ Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and III.E.3.a.(1).

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 ± 1.5 percent or ± 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 Control Area Service 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 11.82~~11.40~~ 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 13.59~~13.11~~ 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 NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.

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 Control Area Service 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 9.76~~10.45~~ 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 11.22~~12.02~~ 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 NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.

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 ("VERBS" or "Balancing 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.

2. BALANCING SERVICE FOR WIND RESOURCES

The total charge for Balancing Service is the applicable rate in section 2.a., below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. BALANCING SERVICE RATES

(1) Rate for 30/60 Committed Scheduling

This rate is applicable to customers taking Balancing 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	$0.13~~0.08~~ per kilowatt per month
(b)	Following Reserves	$0.42~~.32~~ per kilowatt per month
(c)	Imbalance Reserves	$0.46~~0.80~~ per kilowatt per month

~~(2) **Rate for 40/15 Committed Scheduling**~~

~~This rate is applicable to customers taking Balancing 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~~

(~~3~~2) Rate for 30/15 Committed Scheduling

This rate is applicable to customers taking Balancing 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 $0.13~~0.08~~ per kilowatt per month
(b) Following Reserves $0.42 ~~0.32~~ per kilowatt per month
(c) Imbalance Reserves $0.16 ~~0.33~~ per kilowatt per month

(~~4~~3) Rate for Uncommitted Scheduling

This rate is applicable to customers taking Balancing Service that do not commit to 30/60~~, 40/15~~ or 30/15 scheduling ("uncommitted scheduling").

(a) Regulating Reserves $0.13~~0.08~~ per kilowatt per month
(b) Following Reserves $0.42~~0.32~~ per kilowatt per month
(c) Imbalance Reserves $0.67~~1.08~~ per kilowatt per month
~~(d) Opt Out Fee~~
~~The fee for customers that opt out of the Intentional Deviation Penalty Charge (GRSP II.H) shall be $0.20 per kilowatt per month.~~

(4) **Rate for Customer Supplied Generation Imbalance**

This rate is applicable to customers taking Balancing Service under the Customer Supplied Generation Imbalance Pilot Program.

The rate shall be $0.49 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)-(3~~5~~) 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. BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rate~~s~~ in section 3.a., below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. RATES

~~**(1) Regulating Reserves $0.04 per kilowatt per month**~~
~~**(2) Following Reserves $0.17 per kilowatt per month**~~

(1) Rate for 30/15 Committed Scheduling

This rate is applicable to customers taking Balancing 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.

$0.21 per kilowatt per month

(2) Rate for Hourly Scheduling

This rate is applicable to customers taking Balancing Service that do not commit to 30/15 scheduling.

$0.28 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.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental 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 self-supply one or more components to Variable Energy Resource Balancing Service; or

b. the customer has a projected generator interconnection date after FY 2019~~7~~, but chooses to interconnect during the FY 2018~~6~~–2019~~7~~ rate period; or

c. the customer elected to take service under section 2.a.(1), 2.a.(2), or ~~2.a.(3)~~3.a.(1) above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or

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

e. the customer ~~either~~ elected to dynamically transfer its resource out of BPA's Balancing Authority Area, but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election. ~~or has successfully dynamically transferred its resource out of BPA's Balancing Authority Area, but chooses to keep its resource in BPA's Balancing Authority Area.~~

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.305~~0.29~~ per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

Customers taking Variable Energy Resources Balancing Service under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.H.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section 3 below. Dispatchable Energy Resource Balancing Service ("DERBS") 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 determined by applying the rates in section 1 below, plus Direct Assignment Charges in section 4 below.

1. RATES

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

a. Incremental Reserves 20.42~~18.15~~ mills per kW maximum hourly deviation

b. Decremental Reserves 3.43~~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 3 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 3 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. DIRECT ASSIGNMENT CHARGES

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

a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or

b. a customer has a projected generator interconnection date after FY 2019~~7~~ but chooses to interconnect during the FY 2018~~6~~-2019~~7~~ rate period;

c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2018~~6~~-2019~~7~~ rate period; or

d. the customer elected to dynamically transfer its resource out of BPA's Balancing Authority Area but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election. ~~the customer elected to dynamically transfer its resource out of BPA's balancing authority area, but chooses to keep its resource in the BPA balancing authority area.~~

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.305~~0.29~~ per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.C.

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, or Operating Reserve – Supplemental Reserve Service~~, Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service~~ under this rate schedule are subject to the Power Risk~~Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB~~ Mechanisms specified in GRSP II.G.

GENERAL RATE SCHEDULE PROVISIONS

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

G. ~~CRAC, DDC, and NFB Mechanisms~~Power Risk Mechanisms

[Note: The specific terms, descriptions, and section references will be made consistent with those used in the final BP-18 rates.]

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.2.a.(4), opt out fee, section III.E.4., Direct Assignment Charges and Intentional Deviation, GRSP II.H.~~

- ~~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., Direct Assignment 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.

H. Intentional Deviation Penalty Charge

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-18~~6~~ Variable Energy Resources Balancing Service rate.

Exceptions:

~~a. With 90 days' notice before the start of the applicable billing month, customers taking service at the VERBS rate for uncommitted scheduling can elect to opt out of the Intentional Deviation Penalty Charge for an additional Opt Out Fee (ACS-186 VERBS rate schedule, section III.E.2.a.(4)). The opt-out election will remain in place until the customer elects to change its opt-out election with 90 days' notice before the start of the applicable billing month. Once each fiscal year, a customer can: (1) opt out of the Intentional Deviation Penalty Charge, and (2) change its opt-out election. Customers that opt out of the Intentional Deviation Penalty Charge are subject to the Persistent Deviation for Generation penalty charge as specified in the ACS-186 Generation Imbalance Service rate schedule (section III.B.2.c).~~

a~~b~~. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.

b~~c~~. Customers participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be $100 per megawatthour (MWh).

An Intentional Deviation event occurs when:

ABS(Intentional Deviation Measurement Value – Resource Schedule) > 1

(See section 3, below, for definition of terms.)

3. BILLING FACTOR

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule) – 1

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following~~ three values~~:

1) for wind generating customers taking VERBS under rate schedule section 2.a.~~ at a committed scheduling rate (VERBS rate schedule, sections 2.a.(1)-(3))~~, the applicable ~~committed~~ schedule value provided by BPA;

~~2) for wind generating customers taking VERBS at the uncommitted scheduling rate (VERBS rate schedule, section 2.a.(4)), the 40-minute forecast schedule value produced by the Super Forecast Methodology; or~~

2~~3~~) for solar generating customers taking VERBS under rate schedule section 3.a~~(section 3)~~, the ~~matrix forecast schedule value or~~ applicable ~~committed~~ schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer for the scheduling period.

Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

ABS(Station Control Error) ≤ ABS(Intentional Deviation Measurement Value Error) + 1 MW

Where:

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value.

GRSP SECTION III. DEFINITIONS

(Note: Numbering of definitions may change for final rate proposal.)

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.

2. Balancing Authority Area

See definition in Control Area.

4. 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.

5. 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 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

9. Dispatchable Energy Resource

For purposes of the ACS rate schedule, 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 system.

10. 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.

11. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

14. 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.

17. 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.

39. 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 Customer 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 Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

40. Operating Reserve – Supplemental Reserve Service

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. 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 Customer 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 or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

41. 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.

42. 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.

50. 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.

62. 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.

63. 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.

64. Station Control Error

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

65. Super Forecast Methodology

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used

if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

66. 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.

72. Variable Energy Resource

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

73. 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.

Inter-Business Line Allocations

	A	B	C
	Generation Inputs	Annual Average for FY 2018-2019 Forecast Quantity (MW)	Annual Average for FY 2018-2019 Revenue Forecast
1	Regulating Reserve	60	$ 6,794,273
2	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	457	$ 30,821,241
3	Operating Reserve - Spinning	230.7	$ 23,851,605
4	Operating Reserve - Supplemental	230.7	$ 19,706,736
5	Operating Reserve Total	461.3	$ 43,558,341
6	Synchronous Condensing		$ 1,272,635
7	Generation Dropping		$ 589,232
8	Redispatch		$ 225,000
9	Segmentation of COE/Reclamation Network and Delivery Facilities		$ 8,867,000
10	Station Service		$ 1,996,009
11	Generation Inputs Total		$ 94,123,730

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Appendix B

Balancing Reserve Capacity Quantity Forecast for FY 2018–2019

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Balancing Reserve Capacity Quantity Forecast for FY 2018-2019

	A	B	C	D	E	F	G	H	I	J
	Month	Installed Capacity (MW)			Total Balancing Reserve Capacity (MW)		Load Following and Imbalance Balancing Reserve Capacity (MW)		Load Regulation, VERBS, and DERBS Balancing Reserve Capacity (MW)	
		WIND	SOLAR	DERBS	*inc*	*dec*	*inc*	*dec*	*inc*	*dec*
1	Oct-17	4784	21.2	3975.3	647.4	-800.1	186.7	-222.3	460.6	-577.9
2	Nov-17	3567	21.2	3975.3	536.7	-648.6	177.5	-215.4	359.2	-433.2
3	Dec-17	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
4	Jan-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
5	Feb-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
6	Mar-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
7	Apr-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
8	May-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
9	Jun-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
10	Jul-18	2177	30.2	3975.3	505.0	-600.7	176.6	-210.2	328.4	-390.5
11	Aug-18	2377	30.2	3975.3	509.7	-607.6	175.1	-208.3	334.6	-399.3
12	Sep-18	2377	30.2	3975.3	509.7	-607.6	175.1	-208.3	334.6	-399.3
13	Oct-18	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
14	Nov-18	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
15	Dec-18	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
16	Jan-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
17	Feb-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
18	Mar-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
19	Apr-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
20	May-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
21	Jun-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
22	Jul-19	2377	30.2	3975.3	511.2	-608.8	177.1	-210.7	334.1	-398.1
23	Aug-19	2477	30.2	3975.3	524.0	-638.1	178.4	-216.2	345.6	-421.8
24	Sep-19	2477	30.2	3975.3	524.0	-638.1	178.4	-216.2	345.6	-421.8
25	Annual Average	2468.5	29.5	3975.3	516.8	-618.1	177.3	-211.4	339.5	-406.6

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