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

2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12)

ADMINISTRATOR'S FINAL RECORD OF DECISION

Appendix A: Partial Transmission Settlement Agreement

July 2011

BP-12-A-02A

PARTIAL TRANSMISSION SETTLEMENT AGREEMENT
Bonneville Power Administration 2012 Rate Case
Revised 12/7/10

The undersigned signatories to this Partial Settlement Agreement hereby agree to the following:

1. In the Bonneville Power Administration (BPA) 2012 rate case, BPA will submit a proposal (Settlement Proposal) to establish rates for transmission services for fiscal years 2012-2013 (Rate Period) (including alternatives for the Montana Intertie rate depending on whether BPA terminates the exchange in the Montana Intertie agreement) as shown in Attachment 1. The Settlement Proposal will also include the following changes to existing rate schedules, all shown on Attachment 2, and no other changes:

    a. A change in the rate for the Failure to Comply Penalty Charge from 1000 mills per kilowatthour to the greater of 500 mills per kilowatthour or 150% of an hourly energy index.

    b. Deletion of Customer-Served Load provisions from the Network Integration rate schedule and addition of a short-distance discount to such rate schedule.

    c. Modification of section E of the Integration of Resources rate schedule, Ratchet Demand Relief, to provide that Ratchet Demand relief is not available in the month in which the Ratchet Demand was established and that for such month the customer will be assessed charges based upon its highest hourly Scheduled Demand for the month.

    d. Modification of the definitions of Dynamic Schedule and Dynamic Transfer to be identical to the definitions that are adopted in the Dynamic Transfer Operating and Scheduling Business Practice.

    e. Removal of the words "Short-Term Firm and Non-Firm PTP Transmission" from the definitions of Daily Service and Weekly Service; and replacement of the definitions for Monthly Firm Service and Monthly Non-Firm Service with a definition of Monthly Service that reads as follows: "*Monthly Service* is service that starts at 00:00 of any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later."

2. a) The Administrator will establish the IM and IE rates, and address possible revisions to the TGT rate that are consistent with the Montana Intertie Agreement, BPA contract number DE-MS79-81BP90210, in a contested process in the 2012 rate case. As part of the Settlement Proposal, BPA staff will propose that the Administrator establish IM and IE rates that are no higher than the rates shown in Attachment 3, and the signatories agree not to present evidence or argument in the 2012 rate case, or before FERC or in any judicial forum, that either the IM or IE rate should be higher than the rates shown in Attachment 3. However, BPA staff will propose that the Administrator adopt all of the rates shown on Attachment 1 regardless of his decisions on the level of the IM, IE, and TGT rates.

b) In addition, during the Rate Period BPA will hold a public process to discuss with all interested parties the future of the IM, IE, and TGT rates. The workshops will include discussion of the then-existing rate treatment and potential alternative rate treatments of the costs of BPA's share of Montana Intertie transmission capacity and the costs of the Eastern Intertie. BPA will include in its initial proposal in the 2014 rate case a proposal for the rate treatment of the above costs, including proposals regarding the existence and level of the IM, IE, and TGT rates

3. The ancillary services Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve − Spinning Reserve Service, Operating Reserve − Supplemental Reserve Service, and Generation Imbalance Service, and all control area services, are not included in this settlement. All rates issues concerning these services will be litigated in the 2012 rate case. BPA reserves the right to propose changes to the rates, rate schedules, and associated general rate schedule provisions for these services, and the signatories to this settlement preserve the right to litigate all issues concerning these services.

4. The signatories acknowledge that BPA expects the costs of transmission service to increase in future rate periods because of, among other things, additional cyber and physical security requirements, repairs to aging equipment, and construction of new lines. The signatories do not waive the right to challenge proposed rate increases in future rate cases, and agree to collaborate with BPA in exploring ways to reduce rate pressures in future rate periods.

5. a) During the Rate Period, BPA will engage the signatories in discussions, request and respond to written comments, and take the following actions regarding the following issues:

    i. BPA will adopt commercial practices under which BPA allocates dynamic transfer capability (DTC) on BPA's transmission system, including DTC for both imports and exports, taking into account the technical and operational requirements and the DTC needed for self-supply and other regional initiatives;

    ii. BPA will further develop methodologies to determine the availability of DTC;

    iii BPA will adopt ways to secure reliable and reasonable operational certainty for generators given the operational limits on the amount of DTC that BPA can make available;

    iv. BPA will develop and adopt methodologies for determining the infrastructure requirements and cost allocations for increasing DTC;

    v. BPA will determine the appropriate use and terms of dynamic transfer agreements to govern access to and use of DTC; and

vi. To the extent, if any, that BPA has the unilateral authority to do so, BPA will determine the appropriate use, if any, of the Northwest Power Pool Firm Contingent product code for wind.

b) During the Rate Period, BPA will hold discussions with interested parties and accept and respond to written comments regarding ways that generators can operate to prevent or mitigate cumulative imbalances and patterns of under-delivery or over-use of energy. These discussions will not include discussions of the Persistent Deviation charge or the criteria for Persistent Deviation.

c) By April 15, 2011, BPA will allocate available DTC for the Rate Period.

6. Before the start of the 2014 rate case, BPA will (a) work with interested transmission customers in an open and collaborative forum to define the parameters of a cost of service study that includes consideration of alternative methodologies for allocating demand-related costs and that determines the costs of BPA's major transmission services, (b) complete an illustrative cost of service study using forecasted data from a recent fiscal year, and (c) share the cost of service model with customers to ensure clear and transparent cost of service determinations. BPA will use the methodology from the study in the initial proposal for the 2014 rate case to prepare rate designs and allocate costs among rate classes.

7. If BPA submits a rate proposal consistent with the terms of this Partial Settlement Agreement, the signatories agree not to contest in the 2012 rate case, or before FERC or in any judicial forum, any aspect of the Settlement Proposal or of the rates or rate schedules included in the Settlement Proposal, or any of the elements thereof or the methodologies and principles used to derive such rates. The signatories further agree to waive their rights to cross-examination and discovery with respect thereto, except in response to issues raised by any party in such proceeding that is not a signatory to this Partial Settlement Agreement. Execution of the Partial Settlement Agreement by any signatory does not constitute consent or agreement in any future rate proceeding to the transmission rates or rate schedule modifications included herein or to any underlying principle or methodology.

8. The signatories will move the Hearing Officer to specify a date, within a reasonable time of the prehearing conference in the rate case, by which any party to the rate case that has not executed this Partial Settlement Agreement must object to the settlement proposed in this Partial Settlement Agreement and identify each issue included in the Settlement Proposal that such rate case party chooses to preserve for hearing. If no rate case party objects to the Settlement Proposal and preserves issues for hearing, BPA shall propose to the Administrator that he adopt the Settlement Proposal in its entirety. If any rate case party does object to the Settlement Proposal, BPA may, but shall not be required to, revise the Settlement Proposal as it believes appropriate, either after such rate case party states its objection or after parties file their direct testimony. If BPA decides to revise the Settlement Proposal, the signatories, together with any other interested rate case parties, will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing BPA a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to

such revised proposal. In that event, the signatories may contest any aspect of the revised proposal.

9. If the Administrator establishes transmission rates in accordance with the Settlement Proposal and submits such rates to FERC for confirmation and approval under the applicable standards of the Northwest Power Act, the signatories will not challenge the confirmation and approval of the rates or any element thereof, including the methodologies and principles used to establish the rates, or support or join any such challenge, and will not challenge the rates or any element thereof, including the methodologies and principles used to establish the rates, in any judicial forum.

10. The signatories will not assert in any forum that anything in this Partial Settlement Agreement or any action with regard to this Partial Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

11. By executing this Partial Settlement Agreement, no signatory waives any of its rights under the Federal Power Act or any right to pursue BPA tariff dispute resolution procedures consistent with BPA's tariff (including without limitation any complaint concerning implementation of BPA's tariff) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied.

12. Nothing in this Partial Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Partial Settlement Agreement may be executed in counterparts.

___________________________for

__________________________ Date ___________
Party

Attachment 1
Summary of Transmission Rate Levels

	Units	Proposed 2012 Rates	
		FPT-12.1	**FPT-12.3**
FPT-12.1 and FPT-12.3			
M-G Distance....................	$/kW-mi-yr	0.0587	0.0587
M-G Miscellaneous Facilities.....	$/kW-yr	3.35	3.35
M-G Terminal....................	$/kW-yr	0.68	0.68
M-G Interconnection Terminal.....	$/kW-yr	0.61	0.61
S-S Transformation..............	$/kW-yr	6.31	6.31
S-S Interconnection Terminal.....	$/kW-yr	1.73	1.73
S-S Intermediate Terminal........	$/kW-yr	2.44	2.44
S-S Distance....................	$/kW-mi-yr	0.5772	0.5772
Overall FPT Rate...............	$/kW-yr	15.93	15.93
Overall FPT Rate...............	$/kW-mo	1.327	1.327
IR-12			
Demand..........................	$/kW-mo	1.498	
NT-12			
Base Rate ($/kW-mo).............	$/kW-mo	1.298	
Load Shaping ($/kW-mo)...........	$/kW-mo	0.367	
Base plus Load Shaping.........	$/kW-mo	1.665	
PTP-12			
Demand..........................	$/kW-mo	1.298	
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).	$/kW-day	0.046	
Hourly..........................	mills/kWh	3.74	
Utility Delivery			
Demand..........................	$/kW-mo	1.119	
IS-12			
Demand..........................	$/kW-mo	1.293	
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).	$/kW-day	0.045	
Hourly..........................	mills/kWh	3.72	

Attachment 1
Summary of Transmission Rate Levels

	Units	Proposed 2012 Rates
Power Factor Penalty Charge		
Demand -- Lagging................	$/kVAr-mo	0.28
Demand -- Leading................	$/kVAr-mo	0.24
Scheduling Control and Dispatch ('12)		
Demand...........................	$/kW-mo	0.203
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.010
Daily Block 2 (day 6 and beyond).	$/kW-day	0.006
Hourly...........................	mills/kWh	0.59
Generation Supplied Reactive ('12)		
Demand...........................	$/kW-mo	0.000
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.000
Daily Block 2 (day 6 and beyond).	$/kW-day	0.000
Hourly...........................	mills/kWh	0.00

Attachment 2

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

B. FAILURE TO COMPLY PENALTY CHARGE AND ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

1. RATE FOR FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with the BPA-TS's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. The Failure to Comply Penalty Charge shall be ~~1000 mills per kilowatthour.~~<u>the greater of 500 mills per kilowatthour or 150% of an hourly energy index in the Pacific Northwest.</u>

<u>If no adequate hourly index exists, an alternative index will be used. BPA-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS determines that the existing index is no longer a reliable price index.</u>

Parties who are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a force majeure on their system will not be subject to the Failure to Comply Penalty Charge provided that they immediately notify the BPA-TS of the situation upon occurrence of the force majeure.

2. BILLING FACTORS

The Billing Factor for the Failure to Comply Penalty Charge shall be the kilowatthours that were not curtailed, redispatched, shed, changed, or limited within ten minutes after issuance of the order in any of the following situations:

a. Failure to shed load when directed to do so by BPA-TS in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by the BPA-TS in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by the BPA-TS in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

3. ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

In addition to the Failure to Comply Penalty Charge, the party will be assessed the costs of alternate measures taken by BPA-TS in order to manage the reliability of the FCRTS due to the failure to comply.

The party will also be assessed monetary penalties imposed on BPA by a Regional Reliability Organization, Electric Reliability Organization, or FERC, for a violation of a Reliability Standard authorized under Section 215 of the Energy Policy Act of 2005, if the violation was caused by the party's failure to comply.

Attachment 2

1.1 NT-12
Network Integration Rate

SECTION I. AVAILABILITY

This schedule supersedes Schedule NT-10. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities and to Transmission Customers taking Conditional Firm Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also 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-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The monthly charge will be the sum of A and B.

A. BASE CHARGE

$1.298 per kilowatt per month

B. LOAD SHAPING CHARGE

$0.367 per kilowatt per month

SECTION III. BILLING FACTORS

A. BASE CHARGE

~~If no Declared Customer-Served Load (CSL) is specified in the customer's NT Service Agreement, t~~The monthly Billing Factor for the Base Charge specified in section II.A. shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

~~a. For the billing month, if the sum of the Actual CSLs occurring during Heavy Load Hours (HLH) is greater than or equal to 60 percent of the Declared CSL multiplied by the number of HLHs in the billing month, the monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load, less Declared CSL.~~

~~b. For the billing month, if the sum of the Actual CSLs occurring during HLH is less than 60 percent of the Declared CSL multiplied by the number of HLHs in the billing month, the monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load. The Billing Factor will be reduced by any megawatts charged the NT Unauthorized Increase Charge under section IV.F. for the month.~~

~~Where:~~

~~"Declared Customer-Served Load (CSL)" is the monthly amount in megawatts of the Transmission Customer's Network Load that the Transmission Customer elects to serve on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement. The customer's Declared CSL is contractually specified for each month. Declared Customer-Served Load shall not exceed the annual amounts and shall be limited to the resources and contracts specified in the Service Agreement on October 1, 2005.~~

~~"Actual Customer-Served Load (CSL)" is the actual hourly amount in megawatts of the Network Load that the customer serves on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement.~~

B. LOAD SHAPING CHARGE

The monthly Billing Factor for the Load Shaping Charge specified in section II.B. shall be the Network Load on the hour of the Monthly Transmission Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support NT Service are also available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking NT Service over Delivery facilities are subject to the Delivery Charge specified in section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service are subject to the Failure to Comply Penalty specified in section II.B. of the GRSPs.

D. METERING ADJUSTMENT

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall be calculated by substituting 1) the sum of the highest hourly demand that occurs during the billing month at all Points of Delivery multiplied by 0.79 for 2) Network Load on the hour of the Monthly Transmission Peak Load.

E. POWER FACTOR PENALTY

Customers taking service under this rate are subject to the Power Factor Penalty Charge specified in section II.C. of the GRSPs.

~~F. UNAUTHORIZED INCREASE CHARGE~~

~~If the Network Customer's Actual CSL is less than its Declared CSL, the Unauthorized Increase Charge specified in section II.G of the GRSPs shall be assessed.~~

F. SHORT-DISTANCE DISCOUNT (SDD)

A Customer's monthly NT bill shall be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that: (i) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and (ii) uses FCRTS facilities for less than 75 circuit miles for delivery to the Network Load. A DNR that is a system sale (the DNR is not associated with a specific generating resource) does not qualify for the SDD. Any DNR that is eligible for the SDD (DNR SD) must be noted as such in the NT Service Agreement.

The NT monthly bill will be reduced by a credit equal to:

$$\text{Avg. Generation of the DNR SD during HLH} \times \text{NT Rate} \times \frac{75 - \text{Tx Distance}}{75} \times 0.4$$

Where:

Average Generation during HLH =	The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's POD(s) to the total DNR SD designated capacity. The output serving Network Load is:

i) in the case of a scheduled DNR SD, the sum of firm schedules to Network Load; and

ii) in the case of Behind the Meter Resources, the metered output of the resource.

NT Rate = NT Base Charge

Tx Distance = The contractually specified distance measured in circuit miles between the DNR SD POR and the Customer's nearest POD(s) within 75 circuit miles of the DNR SD.

i) BPA shall use the peak load for the prior calendar year for the POD nearest to the DNR SD to calculate how much of the DNR SD's designated capacity is allocated to that POD. If the peak load for the prior calendar year of the closest POD is less than the DNR SD's designated capacity, then BPA shall use the next nearest POD that is within 75 circuit miles of the DNR SD, continuing until the DNR SD's designated capacity is fully allocated to the qualifying PODs, subject to section ii below. The Tx Distance shall be the sum of the distance from the DNR SD to each of the PODs, weighted by the DNR SD designated capacity allocated to each POD.

ii) The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD's peak load.

iii) For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the TX Distance shall be zero.

Qualifying Capacity = The sum of all DNR SD designated capacity allocated to the Customer's POD(s).

For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Qualifying Capacity shall be the total DNR SD designated capacity.

Behind the Meter Resource = A resource that is used solely to serve the NT Customer's Network Load and is internal to the NT Customer's system.

G. DIRECT ASSIGNMENT FACILITIES

BPA-TS shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Customer under an applicable rate schedule.

H. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Network Customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA-TS to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

I. 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 section II.D. of the GRSPs.

Attachment 2

1.2 IR-12 Integration of Resources Rate

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

E. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA-TS may waive or reduce the Ratchet Demand. An IR customer seeking a reduction or waiver must demonstrate good cause for relief, including a demonstration that:

1. The event which resulted in the Ratchet Demand

   (a) was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and

   (b) did not result in harm to BPA-TS's transmission system or transmission services, or to any other Transmission Customer; or

2. The event which resulted in the Ratchet Demand

   (a) was inadvertent;

   (b) could not have been avoided by the exercise of reasonable care;

   (c) did not result in harm to BPA-TS's transmission system or transmission services, or to any other Transmission Customer; and

   (d) was not part of a recurring pattern of conduct by the IR customer.

If the IR customer causes a Ratchet Demand to be established in a series of months during which the IR customer has not received notice from BPA-TS of such Ratchet Demands by billing or otherwise, and the Ratchet Demand(s) established after the first Ratchet Demand were due to the lack of notice, then BPA-TS may establish a Ratchet Demand for the IR customer based on the highest Ratchet Demand in the series. This highest Ratchet Demand will be charged in the month it is established and the following 11 months. All other Ratchet Demands based on such a series (including the Ratchet Demand established in the first month if it is not the highest Ratchet Demand) will be waived.

Ratchet Demand Relief is not available in the month in which the Ratchet Demand was established. For that month, the Customer will be assessed charges based upon the highest hourly Scheduled Demand Billing Factor.

Attachment 2

1.3 Section III. Definitions

1.3.1 8. Dynamic Schedule

Add definition adopted in Dynamic Transfer Operating and Scheduling Business Practice.~~A *Dynamic Schedule* is a telemeter reading or value which is updated in real time and which is used as a schedule in the Automatic Generation Control (AGC) and Area Control Error (ACE) equation of the BPA-TS and the integrated value of which is treated as a schedule for interchange accounting purposes. One-way Dynamic Schedules are commonly used for scheduling remote generation or remote load to or from another Control Area. Two-way Dynamic Schedules are commonly used to provide supplemental regulation or operating reserve support from one entity to another, usually between Control Areas. The Receiving Party sends the Delivering Party a requested Dynamic Schedule (the first part of the two-way schedule). The Delivering Party then responds with the official Dynamic Schedule of what actually is delivered to the Receiving Party (the second part of the two-way schedule).~~

1.3.2 12. Dynamic Transfer

Add definition adopted in Dynamic Transfer Operating and Scheduling Business Practice.~~*Dynamic Transfer* is the provision of real-time monitoring, telemetering, computer software, hardware, communications, engineering, transmission capacity and energy accounting (including inadvertent interchange), and administration, including transmission scheduling, required to electronically move all or a portion of the real energy services associated with a generator or load out of one Control Area into another Control Area.~~

1.3.3 7. Daily Service

Daily Service is service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.~~*Daily Service* is Short-Term Firm and Non-Firm PTP Transmission Service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.~~

~~1.3.4 31. Monthly Non-Firm Service~~

~~*Monthly Non-Firm Service* is Non-Firm PTP Transmission Service that starts at 00:00 of any date and stops at 00:00 at least 28 days later, but less than or equal to 31 days later.~~

1.3.5 33. Monthly ~~Firm~~ Service

Monthly ~~Firm~~ Service is ~~Short-Term Firm PTP Transmission S~~service that starts at 00:00 of any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.

1.3.6 73. Weekly Service

Weekly Service is ~~Short-Term Firm and Non-Firm PTP Transmission service S~~service that starts at 00:00 of any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.

Attachment 3
Summary of Transmission Rate Levels

IM-12[1]		Exchange Terminated	Exchange Not Terminated
Demand...........................	$/kW-mo	0.598	1.312
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.028	0.061
Daily Block 2 (day 6 and beyond).	$/kW-day	0.020	0.043
Hourly...........................	mills/kWh	1.72	3.78
Intertie East			
IE-12............................	mills/kWh	1.13	1.13

[1] *Only one set of IM rates will appear in the final rate schedules, depending on whether BPA has terminated the exchange.*

SIGNATORIES TO THE
2012 TRANSMISSION RATE CASE
PARTIAL SETTLEMENT AGREEMENT

Alcoa Inc.
Asotin County PUD
Central Lincoln PUD
Chelan County Public Utility District No. 1
Emerald People's Utility District
Eugene Water & Electric Board
Grant County Public Utility District
Idaho Falls Power
Idaho Power Company
Klickitat PUD
Northwest Requirements Utilities

Signing for:
- Ashland, City of
- Benton Rural Electric Association
- Big Bend Electric Co-Op
- Bonners Ferry, City of
- Burley, City of
- Cascade Locks, City of
- Centralia, City of
- Central Lincoln PUD
- Cheney, City of
- Columbia Basin Electric Co-op
- Columbia Power Cooperative
- Columbia Rural Electric Association
- Columbia River PUD
- East End Mutual Electric Co.
- Ferry County PUD #1
- Flathead Electric Cooperative
- Forest Grove, City of
- Harney Electric Cooperative
- Hermiston Energy Services
- Heyburn, City of
- Hood River Electric Co-op
- United Electric Cooperative
- Idaho County Light & Power
- Inland Power & Light
- Kootenai Electric Cooperative
- Lower Valley Energy
- McMinnville Water & Light
- Midstate Electric Cooperative

Milton-Freewater City Light & Power
Mission Valley Power
Modern Electric Water Company
Monmouth, City of
Nespelem Valley Cooperative
Northern Wasco County PUD
Orcas Power & Light Coop
Oregon Trail Electric Co-op
Peninsula Light
Ravalli County Electric Coop
Richland, City of
Rupert, City of
Salem Electric
Skamania County PUD
South Side Electric, Inc.
Surprise Valley Electric
Tanner Electric Cooperative
Tillamook PUD
Vera Water & Power
Vigilante Electric Coop
Wasco Electric Cooperative
Wells Rural Electric

NorthWestern Energy
Pend Oreille County Public Utility District
PNGC Power

Signing For:
Pacific Northwest Generating Cooperative
Blachly-Lane County Cooperative Electric Association
Central Electric Cooperative, Inc.
Clearwater Power Company
Consumers Power, Inc.
Coos-Curry Electric Cooperative, Inc.
Douglas Electric Cooperative, Inc.
Fall River Rural Electric Cooperative, Inc.
Lane Electric Cooperative, Inc.
Lincoln Electric Cooperative, Inc.
Lost River Electric Cooperative, Inc.
Northern Lights, Inc.
Okanogan County Electric Cooperative, Inc.
Raft River Rural Electric Cooperative, Inc.
Salmon River Electric Cooperative, Inc.
Umatilla Electric Cooperative Association
West Oregon Electric Cooperative, Inc.

Public Power Council
Seattle City Light
Snohomish PUD

Southern California Edison Company
Springfield Utility Board
Tacoma Power
TransAlta
Turlock Irrigation District
Western Montana Electric G&T

Signing For:
Flathead Electric Cooperative
Glacier Electric Cooperative
Mission Valley Power
Missoula Electric Cooperative
Ravalli County Electric Cooperative
Vigilante Electric Cooperative

Western Public Agencies Group

Signing For:
Alder Mutual Light Company
Benton Rural Electric Association
Eatonville, Town of
Ellensburg, City of
Elmhurst Mutual Power and Light Company
Lakeview Light and Power Company
Milton, City of
Parkland Light and Water Company
Peninsula Light Company
Port Angeles, City of
Public Utility District No. 1 of Clallam County
Public Utility District No. 1 of Clark County
Public Utility District No. 1 of Grays Harbor County
Public Utility District No. 1 of Kittitas County
Public Utility District No. 1 of Lewis County
Public Utility District No. 1 of Mason County
Public Utility District No. 1 of Clallam County
Public Utility District No. 3 of Mason County
Public Utility District No. 2 of Pacific County
Public Utility District No. 1 of Skamania County
Public Utility District No. 1 of Wahkiakum County
Tanner Electric Cooperative

BONNEVILLE POWER ADMINISTRATION

DOE/BP-4325 July 2011