

**Residential Exchange Program  
Settlement Agreement Proceeding (REP-12)**

**Final Proposal**

**2012 REP Settlement  
Evaluation and Analysis Study**

July 2011

REP-12-FS-BPA-01





**REP SETTLEMENT EVALUATION AND ANALYSIS STUDY**

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## COMMONLY USED ACRONYMS AND SHORT FORMS

aMW	average megawatt(s)
ASC	Average System Cost
ASCM	Average System Cost Methodology
BPA	Bonneville Power Administration
CGS	Columbia Generating Station
Commission or FERC	Federal Energy Regulatory Commission
Corps or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CRC	Conservation Rate Credit
CY	calendar year (January through December)
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC or Commission	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GRSPs	General Rate Schedule Provisions
GWh	gigawatthour
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
JOA	Joint Operating Agency
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LRA	Load Reduction Agreement
Mid-C	Mid-Columbia
MW	megawatt (1 million watts)
MWh	megawatthour
NLSL	New Large Single Load
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NWPP	Northwest Power Pool
O&M	operation and maintenance
OY	operating year (August through July)

PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
PS	BPA Power Services
PSW	Pacific Southwest
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
ROD	Record of Decision
RPS	Renewable Portfolio Standards
RPSA	Residential Purchase and Sale Agreement
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
VOR	Value of Reserves

1                                   **PART I        THE SETTLEMENT IN ITS CONTEXT**

2   **1.        INTRODUCTION**

3            I am well aware that it would be disingenuous to resolve indiscriminately the  
4            opposition of any set of men (merely because their situations might subject them  
5            to suspicion) into interested or ambitious views. ... So numerous indeed and so  
6            powerful are the causes which serve to give a false bias to the judgment, that we,  
7            upon many occasions, see wise and good men on the wrong as well as on the right  
8            side of questions of the first magnitude to society. This circumstance, if duly  
9            attended to, would furnish a lesson of moderation to those who are ever so much  
10           persuaded of their being in the right in any controversy. And a further reason for  
11           caution, in this respect, might be drawn from the reflection that we are not always  
12           sure that those who advocate the truth are influenced by purer principles than their  
13           antagonists. Ambition, avarice, personal animosity, party opposition, and many  
14           other motives not more laudable than these, are apt to operate as well upon those  
15           who support as those who oppose the right side of a question. Were there not  
16           even these inducements to moderation, nothing could be more ill-judged than that  
17           intolerant spirit which has, at all times, characterized political parties.  
18           ALEXANDER HAMILTON, FEDERALIST NO. 1.

19    In *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007)  
20    (*PGE*), the Ninth Circuit Court of Appeals (Court or Ninth Circuit) held that the 2000  
21    Residential Exchange Program Settlement Agreements (2000 REP Settlement Agreements)  
22    executed by BPA and its investor-owned utility customers (IOUs) were inconsistent with the  
23    Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). In a  
24    companion case, *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037  
25    (9th Cir. 2007) (*Golden NW*), the Court remanded BPA’s WP-02 power rates on the grounds that  
26    BPA improperly allocated to its preference customers the costs of the REP Settlement  
27    Agreements, as amended. Although the Court’s decision in *Golden NW* addressed only BPA’s  
28    WP-02 rates, BPA’s WP-07 wholesale power rates were implicated by the decisions because  
29    they contained the same infirmity identified by the Ninth Circuit.

30  
31    To respond to the Ninth Circuit’s decisions, BPA revisited its WP-02 and WP-07 rate case  
32    assumptions through a comprehensive “Lookback” construct. As explained fully in the 2007

1 Supplemental Wholesale Power Rate Proceeding Administrator’s Final Record of Decision  
2 (WP-07 Supplemental ROD, WP-07-A-05), the Lookback construct compared the amounts paid  
3 under the 2000 REP Settlement Agreements for fiscal years (FY) 2002–2008 with the amounts  
4 BPA would likely have paid qualifying IOUs under the traditional operation of the REP. *See*  
5 *also*, FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. The difference between these two  
6 amounts, subject to certain specified rules, is generally referred to as the “Lookback Amount.”  
7 The total Lookback Amount is composed of six IOU-specific Lookback Amounts. BPA  
8 determined that the Lookback Amount would be recovered from the IOUs over time through  
9 reductions in future REP benefits and returned to the eligible consumer-owned utilities (COUs),  
10 with interest, as credits on their power bills.

11  
12 A large number of parties have challenged in the Ninth Circuit BPA’s determinations in the  
13 WP-07 Supplemental ROD. Many of the litigants involved in these challenges began meeting  
14 with a professional mediator, seeking to resolve the many differences among them. The  
15 mediation concluded with an agreement in principle that resolved most aspects of the disputes  
16 and committed those signing the agreement to negotiate a settlement agreement defining the  
17 resolution of all disputed issues.

18  
19 In this section 7(i) proceeding, BPA is evaluating and analyzing a proposed settlement of the  
20 litigation to determine whether the Administrator should sign the agreement and commit the  
21 agency to abide by its provisions for the term of the agreement. This Study sets forth BPA’s  
22 evaluation and analysis of the agreement leading to the Administrator’s conclusion to adopt the  
23 settlement and sign the agreement.

## 2. BACKGROUND

### 2.1 The Residential Exchange Program

The Residential Exchange Program (REP) was established in Section 5(c) of the Northwest Power Act to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the REP, a participating utility offers to sell power to BPA, and BPA purchases such power from the utility at the utility's average system cost (ASC). A utility's ASC is established through a formal ASC review process based on a methodology established by BPA. Coincident with purchasing the power from the utility, BPA sells an equivalent amount of power to the utility at BPA's Priority Firm Power Exchange (PFx) rate. This "exchange" actually transfers no power to or from BPA; rather, it is implemented as an accounting transaction to eliminate incurring real power losses and for administrative ease. The amount of power purchased and sold between BPA and the utility is equal to the utility's qualifying residential and small farm load. The transaction is reduced to a monetary payment equal to the difference between the amount that would have been paid to the utility for the purchase of power at the utility's ASC and the amount that would have been paid to BPA for the purchase of power at the PFX rate, called "REP benefits." The Northwest Power Act requires that all of the REP benefits received by the utility be passed through directly to the utility's residential and small farm customers.

#### 2.1.1 How REP Benefits Are Determined

ASC is the unit cost of a utility's allowable generation and transmission system as determined by the Administrator through the ASC Review Process, which involves an extensive review of the utility's cost and load data. ASC (expressed in dollars per megawatthour (\$/MWh), which is equivalent to mills per kilowatthour (kWh)) equals a utility's ASC Contract System Cost divided by its ASC Contract System Load. ASC Contract System Cost and ASC Contract System Load

1 are determined by following the prescribed functionalization rules and other requirements  
2 established in BPA's 2008 Average System Cost Methodology (2008 ASCM), an administrative  
3 rule developed by BPA in consultation with its customers and other stakeholders. The Federal  
4 Energy Regulatory Commission (Commission) granted final approval to the 2008 ASCM on  
5 September 4, 2009. The Review Processes for individual utilities' ASC filings occur in a  
6 separate administrative forum that is not part of BPA's rate proceedings.

7  
8 In each rate proceeding, BPA develops PFX rates pursuant to section 7 of the Northwest Power  
9 Act. The PFX rate begins as a rate developed in common with the PF Public (PFp) rate, pursuant  
10 to section 7(b)(1). At the point in the ratemaking sequence immediately prior to the  
11 section 7(b)(2) rate test, the sole distinction between the two PF rates is that customers  
12 purchasing under the PFp rate separately acquire the transmission necessary to wheel BPA  
13 power to the customers' service territory, whereas the PFX rate includes a transmission wheeling  
14 adder to pay for an imputed delivery to the purchaser. In the event the section 7(b)(2) rate test  
15 indicates that rate protection should be afforded to BPA's preference customers, the two PF rates  
16 diverge. Preference customers' rate protection reduces the PFp rate, while the allocations of cost  
17 of the rate protection increase the PFX rate and other rates.

18  
19 Once the PFX rate has been established, two of the three necessary elements of the REP have  
20 been determined for each rate period. The third element, exchange loads, is based upon  
21 qualifying residential and small farm loads as measured by each utility participating in the REP.  
22 Subsequent to each calendar month, after each exchanging utility invoices BPA with its  
23 exchange load for the month, BPA computes the cost of purchase at the utility's ASC and the  
24 revenue from the sale at the PF Exchange rate by multiplying relevant rates by the kilowatthours  
25 of invoiced exchange load. The net payment is the utility's REP benefit for the month.



1 **2.1.2 Early Disputes Over the REP**

2 The REP was initially implemented through the 1981 Residential Purchase and Sale Agreements  
3 (RPSAs) and ASC methodology. In response to rising costs of the REP, in 1984 BPA revised  
4 the 1981 ASCM such that the ASCs for exchanging utilities were reduced by an average of  
5 26 percent. The IOUs disputed most of the changes to the ASCM. In addition, the IOUs have  
6 disputed BPA's implementation of the 7(b)(2) rate test in a number of section 7(i) proceedings,  
7 especially BPA's 1996 Wholesale Power Rate Proceeding, which reduced REP benefits from  
8 around \$200 million in FY 1996 to \$64 million in FY 1998. (FY 1997 REP benefits were  
9 increased from expected rate proceeding levels at the direction of Congress.)  
10

11 **2.2 2000 REP Settlement Agreements and WP-02 Rates**

12 Disputes over changes to the 1981 ASCM and the implementation of section 7(b)(2) were a  
13 significant subject of consideration by the Comprehensive Review of the Northwest Energy  
14 System in 1998. The Comprehensive Review led to the Federal Power Subscription Work  
15 Group process and the resulting 1998 Subscription Strategy ROD and contracts. The  
16 Subscription Strategy proposed that BPA would offer RPSAs to regional utilities, including the  
17 IOUs, to implement the REP for FY 2002–2011. The Strategy also proposed that BPA would  
18 offer the IOUs, in the alternative, settlement agreements to resolve disputes arising under BPA's  
19 implementation of the REP. All of the region's six IOUs elected to execute the 2000 REP  
20 Settlement Agreements.  
21

22 In the WP-02 rate proceeding, BPA established rates for FY 2002 through 2006 that included the  
23 payment of 2000 REP Settlement benefits to the signing IOUs. In addition to the monetary  
24 benefits, a power sale at a rate equivalent to the PFp rate was included in the 2000 REP  
25 Settlement package of benefits. It was expected that the combination of payments and the  
26 below-market power sale would result in 2000 REP Settlement benefits of about \$140 million  
27 per year for FY 2002–2006. However, before the WP-02 rates were implemented, the West

1 Coast energy crisis of 2000–2001 caused BPA to revise its rates and the 2000 REP Settlement  
2 benefits. BPA entered into Load Reduction Agreements with two IOUs that allowed BPA to  
3 monetize the expected power sales to these utilities. The payments to the IOUs were also  
4 increased because the 2000 REP Settlement Agreements set REP benefits as the difference  
5 between the market price of energy and BPA’s PFp rate; thus, as the West Coast energy crisis  
6 drove market prices upward, REP benefits increased. In all, the modifications increased the  
7 2000 REP Settlement benefits by more than \$160 million per year, resulting in over \$300 million  
8 in total benefits paid each year during FY 2002–2006. Most of these costs fell on BPA’s  
9 preference customers and their consumers.

### 11 **2.3 PGE and Golden NW**

12 After the 2000 REP Settlement Agreements had been executed, a number of preference  
13 customers and a consortium of their industrial consumers challenged the 2000 REP Settlement  
14 Agreements in the Ninth Circuit. In *PGE*, the Court concluded that the 2000 REP Settlement  
15 Agreements were contrary to sections 5(c) and 7(b) of the Northwest Power Act. More  
16 specifically, the Court invalidated BPA’s 2000 REP Settlement Agreements, holding that BPA  
17 exceeded its statutory settlement authority under section 2(f) of the Bonneville Project Act and  
18 section 9(a) of the Northwest Power Act.

19  
20 BPA’s WP-02 rates recovered the costs of the 2000 REP Settlement Agreements. After the  
21 Commission granted final confirmation and approval to the WP-02 rates, a number of parties  
22 challenged the WP-02 rates in the Ninth Circuit. In *Golden NW*, the Court concluded it was not  
23 proper for BPA to allocate to the PFp rate costs of the 2000 REP Settlement Agreements in  
24 excess of the section 7(b)(2) trigger amount. BPA’s basis for such allocation was that such costs  
25 were incurred pursuant to the Administrator’s section 2(f) contracting authority and could  
26 therefore be “equitably allocated” pursuant to section 7(g) of the Northwest Power Act. The

1 Court remanded the WP-02 rates to BPA with instructions to set rates “in accordance with this  
2 opinion.”

#### 3 4 **2.4 WP-07 Supplemental Rate Proceeding**

5 BPA responded to the Court’s remand in BPA’s WP-07 Supplemental rate proceeding. In that  
6 proceeding, in general, BPA reconstructed the period that the 2000 REP Settlement Agreements  
7 were in effect prior to the Court’s rulings. In doing so, BPA compared the amounts paid under  
8 the 2000 REP Settlement Agreements for FY 2002–2008 (the Lookback period) with the  
9 amounts BPA would likely have paid qualifying IOUs under the traditional operation of the  
10 REP. *See*, FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. In addition, BPA re-examined  
11 its Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology.

12  
13 In the WP-07 Supplemental proceeding, the Administrator revisited the WP-02 and WP-07 rates  
14 charged during the Lookback period, removing the 2000 REP Settlement Agreement costs from  
15 the rates and supplementing the record as necessary in order to calculate the rightfully due  
16 amount of REP benefits the IOUs would have received without the 2000 REP Settlement  
17 Agreements. After determining the lawful amount of REP benefits, BPA began returning the  
18 resulting overcharges as “credits” to the preference customers for past overpayments, with  
19 offsetting “debits” against REP benefits for the IOUs that were overpaid REP benefits under the  
20 2000 REP Settlement Agreements. The Administrator determined that this approach was the  
21 most lawful, appropriate, and equitable way to address the Court’s remand in *Golden NW*. *See*  
22 WP-07 Supplemental ROD, WP-07-A-05.

23  
24 The WP-07 Supplemental proceeding had two central components. First, BPA established rates  
25 for FY 2009 that complied with the Court’s order by removing the costs of the 2000 REP  
26 Settlement Agreements and replacing them with the costs of REP benefits that survived the

1 7(b)(2) rate test. Second, to provide an adequate remedy to preference customers overcharged as  
2 a result of BPA's prior actions, BPA conducted a Lookback Analysis to determine the amount of  
3 REP costs that would have been incurred by BPA had it implemented the traditional REP during  
4 the Lookback period instead of implementing the 2000 REP Settlement Agreements with the  
5 region's IOUs. Based on those determinations, BPA established the amount by which preference  
6 customers were overcharged and provided appropriate repayments to preference customers  
7 through immediate refunds from collected funds on hand and through ongoing billing credits as  
8 funds were reclaimed from the IOUs. In other words, BPA established a means to recover 2000  
9 REP Settlement Agreement overpayments through offsets to future REP benefits that would  
10 otherwise be payable to the IOUs. *See* FY 2002-2008 Lookback Study, WP-07-FS-08.

11  
12 To properly calculate the amount of REP costs for the Lookback period, BPA reviewed how  
13 ASCs would have been established during the Lookback period under the 1984 ASC  
14 Methodology and how BPA would have included REP costs in the WP-02 and WP-07 rates.  
15 BPA also determined what adjustments would have been necessary to track more closely the  
16 amount of REP benefits that would have been incurred during that period through  
17 implementation of the REP in the absence of the 2000 REP Settlement Agreements.  
18 Accordingly, BPA made a number of necessary adjustments to its calculation of the  
19 section 7(b)(2) rate test, adjustments that would have been incorporated into the WP-02 and  
20 WP-07 rates in the absence of the 2000 REP Settlement Agreements using information available  
21 when establishing the final WP-02 and WP-07 rates.

## 22 23 **2.5 Current Litigation**

24 BPA issued the Final WP-07 Supplemental ROD on September 22, 2008. In the Final ROD, as  
25 noted above, BPA redetermined the Priority Firm rates for FY 2009 to conform to the Court's  
26 opinions in *PGE* and *Golden NW* and established a method for returning to the COUs the

1 improper amounts collected from them under the WP-02 rates and the first two years (FY 2007–  
2 2008) of BPA’s WP-07 rates. The FY 2009 rates were filed with the Commission on  
3 September 29, 2008, for confirmation and approval, accompanied by the WP-07 Supplemental  
4 ROD and administrative record.

5  
6 Beginning November 14, 2008, BPA customers and constituents filed 14 petitions for review  
7 with the Ninth Circuit challenging the decisions BPA made in its WP-07 Supplemental ROD.  
8 *See Ass’n of Public Agency Customers et al. v. Bonneville Power Admin.*, Nos. 08-74725 *et al.*  
9 (*APAC*). On January 20, 2009, the Court issued an order consolidating all the petitions for  
10 review and granting interventions. Petitioner-intervenors’ briefs, respondent BPA’s brief,  
11 respondent-intervenors’ briefs, and parties’ reply briefs have been filed. The Court granted a  
12 motion to stay the consolidated cases while the parties pursue mediation and settlement.

13  
14 Beginning December 3, 2008, BPA customers and state public utility commissions filed seven  
15 petitions for review with the Ninth Circuit challenging (i) BPA’s “Short-Term Bridge Residential  
16 Purchase and Sale Agreement for the Period Fiscal Years 2009-2011 and Regional Dialogue  
17 Long-Term Residential Purchase and Sale Agreement for the Period Fiscal Years 2012-2028,  
18 Administrator’s Final Record of Decision,” and (ii) BPA’s final “RPSA Templates,” which were  
19 offered to customers eligible for the REP on September 12, 2008. *See Idaho Public Utilities*  
20 *Commission et al. v. Bonneville Power Administration*, Nos. 08-74927 *et al.* Shortly thereafter,  
21 six other petitions for review were filed by BPA customers and constituents seeking review of  
22 the same or substantially the same actions. On January 16, 2009, the Court issued an order  
23 consolidating all the petitions for review and granting interventions. Petitioner-intervenors’  
24 briefs, respondent BPA’s brief, respondent-intervenors’ briefs, and parties’ reply briefs have  
25 been filed. The Court granted a motion to stay the consolidated cases while the parties pursue  
26 mediation and settlement.

1 On July 16, 2009, the Commission granted final approval to BPA's WP-07 Wholesale Power  
2 Rates. Within the next 90 days, parties filed petitions for review with the Ninth Circuit  
3 challenging BPA's WP-07 rates, BPA's 2008 Section 7(b)(2) Legal Interpretation, and BPA's  
4 Section 7(b)(2) Implementation Methodology. *See Avista Corp., et al. v. Bonneville Power*  
5 *Admin.*, Nos. 09-73160 *et al.* These petitions involve WP-07 ratemaking issues separate from  
6 the Lookback-related issues raised in *APAC*. The Court granted a motion to stay the  
7 consolidated cases while the parties pursue mediation and settlement.

8  
9 On July 21, 2009, BPA issued a Record of Decision in BPA's 2010 Wholesale Power (WP-10)  
10 and Transmission (TR-10) Rate Proceeding, which incorporated certain decisions from BPA's  
11 WP-07 Supplemental ROD that are under review in *APAC*. Five investor-owned utilities filed  
12 petitions for review of such decisions to the extent the decisions involved non-ratemaking issues  
13 that might be subject to the Ninth Circuit's jurisdiction prior to the Commission's final approval  
14 of BPA's WP-10 power rates. *See Portland General Electric Co. et al. v. Bonneville Power*  
15 *Admin.*, Ninth Circuit Nos. 09-73288 *et al.* The IOU petitioners acknowledged that the  
16 ratemaking issues in the WP-10 rate case would not be timely until the Commission granted final  
17 confirmation and approval to such rates. The Court granted a motion staying the case.

18  
19 On August 6, 2010, the Commission granted final confirmation and approval to BPA's WP-10  
20 power and transmission rates. Certain IOUs, COUs, and a group of industrial consumers served  
21 by COUs filed petitions for review of the ratemaking decisions underlying the WP-10 rates. *See*  
22 *PacifiCorp et al. v. Bonneville Power Admin.*, Nos. 10-73348 *et al.* The petitions for review will  
23 likely be consolidated with the petitions for review in *PGE*, Nos. 09-73288 *et al.* The Court  
24 granted a motion staying the case.

1 In summary, there is currently litigation pending in the Ninth Circuit on issues related to BPA's  
2 establishment of its power rates and BPA's implementation of the REP from FY 2002 to the  
3 present. This litigation creates significant uncertainty for BPA and its customers regarding both  
4 retrospective and prospective wholesale power rate levels and REP benefits.

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1 pool, but defines the rate elements used to recover the costs allocated to the rate pool. This  
2 ratemaking sequence is programmed into a Microsoft Excel spreadsheet model called the Rate  
3 Analysis Model (RAM) for purposes of calculating BPA's requirements power rates.

4  
5 Rate pools are groupings of customer classes for cost allocation purposes. The Northwest Power  
6 Act established three rate pools. The 7(b) rate pool includes public body, cooperative, and  
7 Federal agency sales authorized by section 5(b) of the Northwest Power Act and sales to utilities  
8 participating in the REP, established in section 5(c). The 7(c) rate pool includes sales to BPA's  
9 DSI customers under contracts authorized by section 5(d). The 7(f) rate pool includes all other  
10 power BPA sells in the Pacific Northwest (PNW) and outside of the PNW, including sales  
11 pursuant to section 5(f).

12  
13 The COSA first groups parts of the power revenue requirement into cost pools specified by  
14 section 7 of the Northwest Power Act. The cost pools are associated with resource pools  
15 (Federal base system (FBS) resources, exchange resources, and new resources) and costs  
16 allocated according to section 7(g) of the Northwest Power Act. The COSA then apportions or  
17 "allocates" the cost pools among the rate pools based on the priorities of service from resource  
18 pools to rate pools provided in section 7 and the principle of cost causation when section 7 does  
19 not provide guidance.

20  
21 Rate directive adjustments are made to recognize sections 7(a)(1), 7(c)(2), 7(b)(2), and 7(b)(3) of  
22 the Northwest Power Act. The first adjustment ensures cost recovery for certain surplus sales  
23 whose rates are set by contract by reassigning costs allocated to such sales that are not  
24 recoverable. The second adjustment implements section 7(c)(2) by adjusting the costs allocated  
25 to the Industrial Firm Power (IP) rate pool to ensure the IP rate is set at the level specified in  
26 section 7(c)(2). At this point in the sequence of ratemaking, the PFp rate and the PFx rate are

1 equal except for a transmission wheeling adder to accomplish delivery to the PFX rate purchaser.  
2 In addition, pursuant to section 7(c)(1), the IP rate is equal to the PFP rate plus adjustments for  
3 the typical margin specified in section 7(c)(2) and a section 7(c)(3) adjustment for the value of  
4 power reserves provided by IP rate purchasers pursuant to section 5(d)(1)(A). The final rate  
5 directive adjustments result from the section 7(b)(2) rate test.

### 6 7 **3.2 Description of the Section 7(b)(2) Rate Test**

8 Section 7(b)(2) of the Northwest Power Act directs BPA to conduct a comparison (called the rate  
9 test) of the projected amounts to be charged for general requirements power sold to its public  
10 body, cooperative, and Federal agency customers, over the rate period plus the ensuing four  
11 years with the power costs (as measured by rates) to such customers for the same time period if  
12 certain assumptions are made. The effect of this rate test is to partially protect BPA's preference  
13 and Federal agency customers' wholesale firm power rates from costs resulting from certain  
14 provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from  
15 the rates of PF Public customers to other BPA power rates. BPA has codified the procedures  
16 used to conduct the rate test in the *Implementation Methodology of Section 7(b)(2) of the Pacific*  
17 *Northwest Power Planning and Conservation Act (Implementation Methodology)*, which relies  
18 on BPA's legal interpretation of section 7(b)(2), as set forth in the *Legal Interpretation of*  
19 *Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act (Legal*  
20 *Interpretation)*.

21  
22 The rate test provides partial protection because preference customers' firm power rates applied  
23 to their requirements loads are to be established as no higher than rates calculated using specific  
24 assumptions that may remove certain effects of the Northwest Power Act, but nevertheless  
25 include certain other effects. If the 7(b)(2) rate test indicates that rate protection is due to the  
26 preference customers, the rate test is said to "trigger." Pursuant to section 7(b)(3), the cost of

1 this rate protection is borne by all other BPA power sales. Some PF purchasers, the preference  
2 customers, receive rate protection, while other PF purchasers, the REP participants, pay a portion  
3 of the cost of the rate protection. Thus, to allow the cost reallocations due to the rate protection,  
4 the PF rate is bifurcated into the PFp rate, which receives the rate protection, and the PFx rate,  
5 which does not receive rate protection and which recovers its allocated share of the rate  
6 protection costs. Forecast sales under the IP rate, the New Resources Firm Power (NR) rate, and  
7 the Firm Power Products and Services (FPS) rate also recover a share of the cost of the rate  
8 protection.

9  
10 As noted above, the rate test involves the projection and comparison of two sets of wholesale  
11 power rates for the general requirements of BPA's preference customers. The two sets of rates  
12 are: (1) a set for the rate period and the ensuing four years assuming that section 7(b)(2) is not in  
13 effect (*i.e.*, the "projected amounts to be charged for firm power," known as Program Case  
14 rates); and (2) a set of rates for the same period taking into account the five assumptions listed in  
15 section 7(b)(2) (*i.e.*, the "the power costs for general requirements," known as 7(b)(2) Case  
16 rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are  
17 subtracted from the Program Case rates prior to the rate comparison. Next, each nominal rate is  
18 discounted to the beginning of the test period of the relevant rate case. The discounted Program  
19 Case rates are averaged, as are the discounted 7(b)(2) Case rates. Both averages are rounded to  
20 the nearest hundredth of a mill per kilowatthour for comparison. If the simple average of the  
21 discounted Program Case rates is greater than the simple average of the discounted 7(b)(2) Case  
22 rates, the rate test triggers. The difference between the average of the discounted Program Case  
23 rates and the average of the discounted 7(b)(2) Case rates is used to determine the amount of  
24 costs to be reallocated from the PFp rate to other BPA power rates for the rate period.

1 **3.3 Reallocation of Rate Protection Costs**

2 In the event the section 7(b)(2) rate test triggers, the difference between the average of the  
3 Program Case rates and the average of the 7(b)(2) Case rates is multiplied by the preference  
4 customer loads for the rate period. The resulting dollar amount, the rate protection amount, is  
5 allocated as a credit to the PFp rate pool to reduce the PFp rate to the level allowed by the rate  
6 test.

7  
8 The rate protection amount is allocated as a cost to all other BPA power sales pursuant to  
9 section 7(b)(3). The rate protection amount is allocated on a pro rata energy basis to sales in the  
10 PFx rate pool, the IP rate pool, the NR rate pool, and firm surplus and secondary energy sales  
11 under the FPS rate. As a result of this cost allocation, these other rates, except for the market-  
12 determined FPS rate, will increase as the PFp rate decreases.

13  
14 As a result of the decrease in the PFp rate and the direction by section 7(c)(2) to set the IP rate  
15 equal to the PFp rate, the IP rate (exclusive of its allocation of rate protection costs) is lowered to  
16 the PFp rate. The costs that must be reallocated due to linking the IP rate to the PFp rate are a  
17 direct result of the rate test. Therefore, none the costs of this linking can be allocated to the PFp  
18 rate, as was the case with the linking of the IP rate to the PF rate prior to the rate test. Instead,  
19 the cost of linking the two rates is allocated to the PFx rate pool and the NR rate pool. The rate  
20 protection cost previously allocated to and excluded from the IP rate pool is then reinstated to the  
21 IP rate.

22  
23 In the WP-07 Supplemental proceeding, BPA implemented a new method of allocating rate  
24 protection costs within the PFx rate pool. Prior to the WP-07 Supplemental proceeding, BPA  
25 allocated rate protection costs to the PFx rate pool based on energy loads. This had the effect of  
26 increasing the PFx rate, which could result in disqualifying REP participants whose ASCs would  
27 now be less than the modified PFx rate. In the WP-07 Supplemental proceeding, BPA changed

1 the allocator from energy loads to pre-rate test REP benefits (“Unconstrained Benefits”). This  
2 change in allocation retained all participants that qualified for the REP prior to the rate test.  
3 Therefore, BPA was able to spread the REP benefits more broadly across the region without  
4 increasing the costs of the REP borne by preference customers. The costs of the REP remain the  
5 same under this revised allocation methodology as under the prior allocation methodology, but  
6 the amounts paid to each REP participant are different, and each REP participant has a different  
7 PFX rate.

8  
9 With these final reallocations, rate designs can be applied to each rate pool.  
10

### 11 **3.4 The Effect of the Rate Test**

12 As mentioned above, the inclusion of exchange purchases and sales (MWh) is used to determine  
13 the proper level of REP benefits. The 7(b)(2) rate test changes only one of BPA’s costs, the cost  
14 of the REP. All other BPA costs remain as stated prior to the rate test. In the ratemaking view  
15 of the REP, the level of benefits is determined by changing the amount of revenue requirement  
16 recoverable from the PFX rate pool, which changes the level of the PFX rate and as a result the  
17 amount of revenue from the PFX rates. The cost of exchange purchases included in rates is not  
18 changed by the rate test.

19  
20 The level of REP benefits is determined by comparing each participant’s ASC with its individual  
21 PFX rate and multiplying the difference by each participant’s qualified exchange load. Because  
22 BPA’s rates are set using forecasts of qualified exchange load, the variance between forecast and  
23 actual exchange loads can result in a different amount of REP benefits being paid during a rate  
24 period from the amount forecast in the rate proceeding.  
25

1 Because the REP is the only BPA cost that changes as a result of the rate test, any change in the  
2 outcome of the rate test and the subsequent cost reallocations affects only REP benefits and  
3 which rate pools pay for the REP. Thus, the purpose of the rate test is confined solely to  
4 defining the amount of REP benefits expected to be paid and the sharing of the costs of the REP  
5 by the different rate pools.

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1 Recommendations in rates, time constraints ultimately precluded the parties and Staff from  
2 finalizing a resolution that could be proposed in the WP-07 Supplemental rate proceeding. Staff  
3 subsequently withdrew from the settlement discussions to focus on completing the initial  
4 proposal for the WP-07 Supplemental proceeding. Although some aspects of the  
5 Recommendations were considered in developing the initial proposal, Staff was ultimately  
6 unable to propose the Recommendations as intended by the parties.

7  
8 At the conclusion of the WP-07 Supplemental proceeding in September of 2008, BPA presented  
9 its final findings in the WP-07 Supplemental ROD. In the WP-07 Supplemental ROD, BPA  
10 determined that the COUs had been overcharged by approximately \$1 billion during the  
11 FY 2002–2008 period as a result of the 2000 REP Settlement Agreements. BPA proposed to  
12 return these overcharges to the injured COUs with an initial lump-sum cash payment in 2008 and  
13 then through future reductions in REP benefit payments to the applicable IOUs. In addition to  
14 determining the refunds and overcharges caused by the 2000 REP Settlement Agreements, the  
15 WP-07 Supplemental ROD also addressed the Administrator’s final decisions on the appropriate  
16 amount of REP benefits to pay the IOUs, and include in rates, for FY 2009. To make these  
17 determinations, the Administrator had to address a host of controversial issues related to the  
18 section 7(b)(2) rate test.

19  
20 Both COUs and IOUs vigorously opposed the decisions BPA reached in the WP-07  
21 Supplemental ROD. The COUs and entities supporting the COUs’ positions claimed that BPA  
22 had grossly underestimated the IOUs’ refund obligation and that the actual overcharge to COUs  
23 for the FY 2002–2008 period was at least \$2 billion. The IOUs, public utility commissions, and  
24 ratepayer advocacy groups, in contrast, argued that no refunds were owed at all because the  
25 Court did not direct BPA to provide refunds and because the terms of the 2000 REP Settlement  
26 Agreements specifically prohibited BPA from recouping REP benefits paid under those

1 agreements. The IOUs and COUs also opposed BPA's interpretation and implementation of the  
2 section 7(b)(2) rate test. It appeared inevitable that the parties would challenge in court the  
3 decisions BPA reached in the WP-07 Supplemental ROD. The Administrator, recognizing that  
4 endless litigation over BPA's decisions would only perpetuate uncertainty in the region over  
5 BPA's rates and the REP, appealed to the parties in the WP-07 Supplemental ROD not to give up  
6 on settlement efforts:

7  
8 This has been a very difficult undertaking, fraught with complexity and with large  
9 financial stakes. I believe we have done the best we could do to find a legally  
10 sustainable and politically equitable solution (in that order) to the challenge  
11 provided by the Ninth Circuit. Nevertheless, I would suggest there remains  
12 considerable uncertainty for the parties as to how REP issues may evolve in the  
13 future. For that reason I continue to urge the parties to work towards a lawful  
14 settlement that will provide greater long-term certainty and, because it will be  
15 defined by the parties, greater political equity than what any single Administrator,  
16 acting within the confines of the law, can provide.

17 WP-07 Supplemental ROD, WP-07-A-05, at xx-xxi.

18  
19 Following the publication of the WP-07 Supplemental ROD in 2008, BPA and principals from  
20 various IOU and COU groups continued to explore the possibility of settlement. Settlement  
21 discussions continued through the fall and winter of 2008 and moved into 2009. While these  
22 discussions were ongoing, petitions challenging BPA's implementation of the REP were filed  
23 with the Ninth Circuit Court of Appeals. These challenges were consolidated into four primary  
24 cases: *APAC*, *IPUC*, *Avista*, and *PGE II*. Briefing was set to begin in the *APAC* and *IPUC* cases  
25 in August of 2009. As the briefing in *APAC* and *IPUC* moved forward, BPA and representatives  
26 for the COUs and IOUs met to discuss the possibility of involving a mediator in the REP  
27 settlement discussions. In November of 2009, the parties tentatively agreed to engage a mediator  
28 following the completion of the briefing in the *APAC* and *IPUC* cases. Mediation sessions were  
29 scheduled to begin in mid-April 2010 and continue until late May 2010.

1 **4.2 The REP Mediation Effort**

2 Mediation on the REP litigation commenced on April 15, 2010, in Portland, Oregon. Leading  
3 the mediation sessions was former Federal District Court Judge Layn Phillips, a nationally  
4 renowned mediator. Assisting Judge Phillips was former Magistrate Judge Bernard Schneider.  
5 Because many of the issues in the mediation would affect the prospective implementation of the  
6 REP, the litigants invited regional parties not directly involved in the litigation to participate in  
7 the mediation. In total, more than 50 litigants and other parties participated in the mediation.  
8 The mediation was scheduled to end in May, but discussions between the parties and the  
9 mediator continued through the end of June 2010. Although by the conclusion of these sessions  
10 the litigants and parties had not achieved a global settlement, significant progress had been made  
11 toward reaching a compromise on all existing claims and the future implementation of the REP.  
12 Principals for most of the litigants agreed to continue to work toward a settlement.

13  
14 In early September 2010, with assistance from the mediator, representatives for most of the  
15 litigants and other regional parties agreed to a non-binding Agreement in Principle (AIP). The  
16 AIP committed the negotiating parties to work in good faith on a final settlement of the REP that  
17 adhered to certain terms and conditions outlined in the AIP. *See* FY 2012 REP Settlement  
18 Documentation, REP-12-E-BPA-01B. Drafting of the 2012 REP Settlement began immediately  
19 following the parties' execution of the AIP and continued through February 2011. Participants  
20 in that effort produced a final draft of the Settlement in early March. Once the Settlement was  
21 completed, it was offered to the litigants in the pending cases and to the region's IOUs and  
22 COUs.

23  
24 **4.3 Description of the 2012 REP Settlement Terms**

25 **4.3.1 Basic Elements**

26 The 2012 REP Settlement resolves challenges over BPA's implementation of the REP in return  
27 for a stream of REP benefits to the IOUs for a term of 17 years. IOU-specific Lookback

1 obligations are extinguished. The COUs' obligation to pay REP benefits in rates is limited to the  
2 COUs' share of the stream of REP benefits as set forth in the Settlement. The distribution of  
3 these REP payments to the IOUs will depend on each IOU's respective ASC and exchange load.  
4 The IOUs will continue to file ASCs with BPA pursuant to the 2008 ASCM.

5  
6 In addition to the stream of REP benefits, the IOUs will receive (i) a percentage of any  
7 incremental BPA Renewable Energy Credits (RECs) that might accrue to BPA resources used to  
8 serve BPA Tier 1 loads and (ii) the payment of certain outstanding interim payments due under  
9 the 2008 Residential Exchange Interim Relief and Standstill Agreements between BPA and four  
10 of the IOUs.

11  
12 The Settlement provides for Refund Amounts to COUs through FY 2019 to allocate the benefits  
13 of the Settlement among COUs that paid BPA's rates during FY 2002–2006 and those that did  
14 not. It also requires parties to the Settlement to work together, directly or through associations,  
15 to urge the U.S. Congress to pass legislation that would affirm and direct BPA to implement the  
16 settlement.

17  
18 Under the Settlement, BPA will establish rates consistent with the terms of the Settlement for all  
19 BPA customers, whether or not they signed the Settlement. The settling parties recognize,  
20 however, that parties might challenge BPA's implementation of the Settlement in rates, and that  
21 a court might preclude BPA from setting rates and otherwise treating BPA customers that did not  
22 execute the Settlement in the same manner as parties to the Settlement. Given this possible  
23 outcome, the Settlement includes provisions that address how the Settlement would apply to  
24 parties if a court rules that parties and non-parties should be treated differently.

1 **4.3.2 REP Benefit Payments to the IOUs**

2 Section 3.1 of the Settlement establishes a schedule of annual REP benefits to be paid to the  
3 IOUs in the aggregate (Scheduled Amounts). Scheduled Amounts will increase over time from  
4 \$182.1 million in FY 2012 to \$286.1 million in FY 2028. *See* Table 1. The Scheduled Amounts  
5 constitute the aggregate REP benefits paid to the IOUs, and included in BPA’s rates, under the  
6 Settlement. As described more fully in section 4.3.6, this amount may change if BPA is required  
7 to set rates differently for COUs that did not sign the Settlement. The Settlement permits BPA to  
8 round its rates such that the difference, if any, between the Scheduled Amounts and the amounts  
9 payable to the IOUs is no more than one thousand dollars (\$1000).

10  
11 **4.3.3 Refund Amounts to COUs**

12 Section 3.2 of the Settlement addresses equity issues among the COUs by establishing Refund  
13 Amounts to be provided to COUs during the next eight years of the settlement term. For  
14 FY 2012–2019, \$76.538 million per year will be included in REP costs recovered in BPA rates  
15 in addition to the Scheduled Amounts paid to the IOUs. The \$76.538 million per year will be  
16 returned to BPA customers that purchase power at the PFp rate based on an allocation approach  
17 described in section 4.3.5.

18  
19 **4.3.4 Inclusion of REP Benefit Costs in Rates**

20 Section 3.3 of the Settlement addresses how the REP benefit costs will be recovered in rates,  
21 including the allocation of REP benefit costs to COU parties to the Settlement. BPA will  
22 establish rates to recover the Scheduled Amounts plus the COU Refund Amounts (the sum of  
23 which is defined as the REP Recovery Amounts in the Settlement), plus any COU REP benefits.

24  
25 The Settlement includes a formula that determines an REP Surcharge amount, which is the  
26 amount of rate protection allocated to the IP and NR rates. This formula effectively scales the  
27 rate protection costs allocated to the IP and NR rates for the settlement period to the rate

1 protection costs allocated to the IP and NR rates in the WP-10 rate proceeding. For example, if  
2 the REP Recovery Amounts in a given rate period were 10 percent higher than the REP benefit  
3 costs in the WP-10 rate proceeding, the rate protection costs allocated to the IP and NR rates  
4 would be 10 percent higher (on a mills/kWh basis.)

5  
6 The REP Recovery Amount cost remaining after subtracting the allocation of REP Surcharge  
7 amount to the IP and NR rates is allocated to the IP, NR, and Tier 1 PF rates on a pro rata load  
8 share basis. COU parties to the Settlement agree to pay their Allocated Share of the Scheduled  
9 Amounts based on the sum of COU parties' Tier 1 Cost Allocators (TOCAs) divided by the sum  
10 of all PF customers' TOCAs (TOCA Shares). This TOCA Share approach ensures that the  
11 COUs that sign the Settlement pay in rates only their agreed-upon share of the REP benefits  
12 payable to the IOUs. Non-settling COUs would receive similar treatment in their rates unless  
13 BPA is required to set rates differently for these customers. In that case, the non-settling COUs  
14 would pay their TOCA share of whatever REP benefits were allocated to the PFp rate as  
15 calculated pursuant to the direction of the court.

#### 16 17 **4.3.5 Allocation of Refund Amounts to COUs**

18 Section 3.4 of the Settlement addresses how the Refund Amounts to COUs, described in  
19 section 4.3.3 above, will be calculated. Fifty percent of the amount (\$38.269 million) will be  
20 returned to COUs based on PF-02 customer percentages set forth in the Settlement. *See* Table 2.  
21 These customer percentages are equivalent to the percentages BPA established in the WP-10 rate  
22 proceeding to allocate the FY 2010–2011 Lookback Credits to the COUs.

23  
24 The remainder of the refund amount will be returned to COUs based on each customer's Tier 1  
25 Customer TOCA Share, which is equal to each COU's TOCA divided by the sum of all COUs'  
26 TOCAs. TOCAs are the Tier 1 Cost Allocators established pursuant to BPA's Tiered Rate

1 Methodology (TRM). There are several vintages of TOCAs in the TRM. The Settlement will be  
2 implemented such that the TOCAs used to determine Refund Amounts will be those used to set  
3 rates for a given rate period, not actual TOCAs for Slice/Block customers or adjusted TOCAs for  
4 Load Following customers that might be different from TOCAs used to set rates due to load loss  
5 during the rate period. The Tier 1 Customer TOCA Shares used to determine Refund Amounts  
6 are slightly different from the TOCAs used to set rates because of two adjustments specified in  
7 the Settlement. One adjustment increases Grant PUD's TOCA and reduces the TOCAs of other  
8 customers to address an issue unique to Grant PUD. In addition, Refund Amounts only go to  
9 Existing Customers as that term is defined in BPA's Tiered Rates Methodology, which also  
10 results in slightly different TOCAs from those used to set rates.

11  
12 Once the customer-specific Refund Amounts are established in the final rates proposal for a rate  
13 period, they do not change during the rate period even though the TOCAs used for billing may  
14 change due to the annual net requirements determinations for Slice/Block customers or for other  
15 reasons.

#### 16 17 **4.3.6 Court Determination Related to Allocation of Costs of REP Benefits**

18 Section 3.6 of the Settlement addresses how parties will implement the Settlement if BPA is  
19 precluded from setting rates consistent with sections 3.1–3.5 of the Settlement for all customers,  
20 regardless of whether or not they are parties to the Settlement. Parties to the Settlement will  
21 continue to pay their allocated share of the Scheduled Amounts and Refund Amounts.  
22 Customers that are not parties to the Settlement, if any, would pay the costs of IOU REP benefits  
23 BPA determines consistent with the court's ruling (REP Benefit Costs). The REP benefits that  
24 BPA would pay the IOUs under this situation would be the sum of these two amounts, which  
25 might, in any year, be greater or less than the Scheduled Amounts.



1 For example, assume for illustrative purposes that in the FY 2012–2013 rate period, 85 percent  
2 of REP costs are recoverable from the PFp rate and the remaining 15 percent from other rates  
3 (presumably the IP and NR rates). The COUs in total would be responsible for 85 percent of the  
4 \$182.1 million per year of the Scheduled Amounts, or \$154.4 million per year. If the allocated  
5 share of the COU parties to the settlement was 90 percent, then BPA would recover from these  
6 customers 90 percent of \$154.4 million per year, or \$139.3 million. Further assume that the  
7 court determined that BPA’s recovery of REP costs from rates other than the PFp rate was  
8 appropriate (or alternatively, that all customers paying such other rates are parties to the  
9 settlement), so non-COU customers would be responsible for their 15 percent share, or  
10 \$27.3 million per year. Finally, assume that based on the court ruling, BPA determines that  
11 COUs that are not parties to the settlement are responsible for REP benefit costs of \$20 million  
12 per year rather than the \$15.4 million under the Settlement. Under this example, BPA would  
13 owe the IOUs REP benefits of \$139.3 million plus \$27.3 million plus \$20 million, for a total of  
14 \$186.6 million per year.

#### 16 **4.3.7 Interim Agreement True-Up Payments to the IOUs**

17 Section 4 of the Settlement states that BPA will, consistent with the provisions of the 2008  
18 Residential Exchange Interim Relief and Standstill Agreements (Contract Nos. 08PB-12438,  
19 08PB-12439, 08PB-12441, 08PB-12442) (“Interim Agreements”), pay the IOUs Interim  
20 Agreement True-Up amounts determined by BPA, pursuant to the WP-07 Supplemental ROD  
21 and the 2010 BPA Rate Case Wholesale Power Rate Final Proposal: Lookback Recovery and  
22 Return Study (WP-10-FS-BPA-07).

24 If the Settlement is not challenged, BPA will pay the True-Up amounts 95 calendar days after the  
25 effective date of the Settlement (which is the date the BPA Administrator executes the  
26 Settlement). If the Settlement is challenged, BPA will pay the True-Up amounts 30 days after a

1 final, non-appealable order by the court that dismisses the challenges or that otherwise upholds  
2 the Settlement. If Congress adopts the legislative authorization provided for in section 8 of the  
3 Settlement, any IOU with an Interim Agreement may notify BPA in writing that it wants to be  
4 paid its Interim Agreement True-Up amount. BPA is to pay the True-Up amount within 30 days  
5 of receiving the notice.

6  
7 The IOUs with Interim Agreements and the respective Interim Agreement True-Up principal  
8 amounts are stated in Table 4.5. Simple interest will accrue from April 2, 2008, through the date  
9 the true-up payment is made, with interest of 1.76 percent per year. If all Interim Agreement  
10 True-Up amounts were paid in September 2013, the total interest amount would be  
11 approximately \$6.5 million, and the total principal plus interest amount would be approximately  
12 \$88.1 million.

#### 14 **4.3.8 Treatment of Environmental Attributes**

15 Section 5 and Exhibits C and H of the Settlement address how possible future environmental  
16 attributes associated with the resources used to serve BPA Tier 1 load will be shared with the  
17 IOUs. The Settlement provides that 14 percent of Transferable Renewable Energy Certificates  
18 (RECs) and 14 percent of Carbon Credits will be transferred to or will be valued and the value  
19 paid to the IOUs. Transferable RECs are RECs that may in the future accrue to the resources  
20 used to serve BPA Tier 1 load. Transferable RECs do not include the RECs associated with  
21 existing Tier 1 renewable projects, which are listed in Exhibit C of the Settlement. Carbon  
22 Credits are defined as Environmental Attributes consisting of greenhouse gas emission credits,  
23 certificates, or similar instruments.

24  
25 In order for 14 percent of the RECs and Carbon Credits to be transferred to the IOUs, COU  
26 parties to the Settlement agreed to replace the current Exhibit H of their Contract High Water

1 Mark (CHWM) contracts with the revised Exhibit H in the Settlement. BPA will also offer  
2 Exhibit H of the Settlement to any COU that is not a party to the Settlement. If COUs that are  
3 not parties to the Settlement do not agree to replace their current CHWM Exhibit H with the  
4 Settlement Exhibit H, BPA will use its ratemaking authority as provided in section 9 of the  
5 current Exhibit H to determine and factor in the value or costs of RECs that were transferred to  
6 such COUs.

#### 8 **4.3.9 Allocation of REP Benefits to IOUs**

9 Section 6 of the Settlement addresses the allocation of the Scheduled Amounts among the IOUs.  
10 Section 6.1 describes the calculation that is performed to determine each IOU's respective share  
11 of the Scheduled Amount discussed above. Scheduled Amounts, for the most part, would be  
12 allocated in the same manner as REP benefits under the traditional REP. IOUs' ASCs will be  
13 determined in accordance with the 2008 ASCM. The IOUs' ASCs will also be compared to  
14 BPA-generated utility-specific PFX rates to determine the individual utility REP benefit amounts.  
15 Whether a particular IOU will be eligible to receive REP benefits will continue to depend on the  
16 relationship between the utility's ASC and BPA's rates. Section 6.1.2 of the Settlement  
17 discusses the adjustments that would be made to the formula values in Section 6.1.1 in the  
18 unlikely event not all of the Scheduled Amounts are disbursed to the IOUs.

19  
20 Section 6.2 of the Settlement addresses an equity issue among the IOUs by establishing a  
21 reallocation of rate protection amounts among the IOUs to achieve a particular allocation of REP  
22 benefits. Although the IOUs dispute the existence and level of the Lookback Amounts BPA  
23 established in its WP-07 Supplemental and WP-10 proceedings, they recognize that between  
24 FY 2009 and FY 2011, they have differentially experienced the effects of the setoffs that BPA  
25 has made to their REP benefit payments. In addition, although Idaho Power received no REP  
26 benefits and therefore incurred no Lookback setoffs in FY 2009 through FY 2011, it will realize

1 a substantial benefit under the 2012 REP Settlement because both the disputed deemer obligation  
2 asserted by BPA stemming from its 1981 RPSA and its Lookback obligation established in the  
3 WP-07 Supplemental and WP-10 proceedings are extinguished.

4  
5 In consideration of these equity issues among the IOUs, the Settlement specifies an approach to  
6 reallocate the costs of rate protection among the IOUs and directs BPA to develop PFX rates that  
7 will result in the IOUs receiving REP benefits consistent with the Settlement. Although the  
8 adjustment is included in establishing the PFX rates, each IOU's REP benefits ultimately will be  
9 determined for each rate period based on its ASC, its PFX rate, and its contract exchange load.  
10 Each IOU's PFX rate will be based in part on the IOU-specific adjustment established in the  
11 Settlement. The following describes the IOU reallocation in the Settlement.

12  
13 Step 1 of the reallocation is an initial calculation of the amount of REP benefits each IOU would  
14 receive if the section 7(b)(2) rate test did not trigger (IOU-Specific Unconstrained Benefit  
15 Amounts). These amounts are equal to the difference between each IOU's ASC and the base  
16 PFX rate (the unbifurcated PF rate plus a transmission adder) times its residential load. This step  
17 is equivalent to the ratemaking step BPA currently performs to determine the cost of the REP  
18 prior to the application of the section 7(b)(2) rate test.

19  
20 In step 2, a Constrained Total Benefit Ratio will be calculated for each fiscal year of the  
21 exchange period by dividing the aggregate REP benefits for each year by the sum of all IOU-  
22 Specific Unconstrained Benefit Amounts for the respective year derived in step 1. This ratio will  
23 then be multiplied by each IOU-Specific Unconstrained Benefit Amount to determine IOU-  
24 specific interim REP benefits. In effect, this calculation will proportionally reduce each IOU's  
25 Unconstrained Amount so that the resulting total amount of REP benefits would be equal to the  
26 Scheduled Amounts described in section 4.3.2 above. This step is equivalent to the ratemaking

1 step BPA currently performs to determine the costs of the REP after application of the  
2 section 7(b)(2) rate test.

3  
4 Both steps 1 and 2 capture BPA's current ratesetting methodology for PFX rates using different  
5 terminology. See section 5 of this Study for additional discussion of the ratemaking steps BPA  
6 will perform to implement the Settlement.

7  
8 In step 3, IOU-specific reductions will be made to the IOU-specific interim REP benefits for the  
9 IOUs. These annual adjustment amounts would be determined by establishing initial  
10 adjustment balances and maximum annual reductions for Avista, Idaho Power, PacifiCorp and  
11 PGE. The initial balances (Initial IOU-specific Adjustment Amounts) and the maximum annual  
12 reductions (Maximum IOU Annual Adjustment Amounts) are specified in the Settlement in  
13 Table 3 and Table 4. The IOU-specific Adjustment Amounts will be reduced over time by  
14 annual adjustment amounts until the Initial IOU-specific Adjustment Amounts, plus interest  
15 compounded annually at 3 percent on unpaid balances, are extinguished. The annual reduction  
16 for a given IOU is limited to the least of (i) the outstanding IOU-specific Adjustment Amount  
17 balance, (ii) the Maximum IOU Annual Adjustment Amount in Table 4, or (iii) the amount that  
18 would reduce an IOU's REP benefits for the year to zero. Section 6.2.4 of the Settlement  
19 specifies a separate adjustment for NorthWestern Energy.

20  
21 In step 4, the IOU-specific reductions for each IOU determined in step 3 will be allocated to  
22 other IOUs. Idaho Power's reductions will be allocated to Avista, NorthWestern, PacifiCorp,  
23 PGE, and Puget. Avista and PacifiCorp's reductions will be allocated to NorthWestern, PGE,  
24 and Puget. PGE's reductions will be allocated to NorthWestern and Puget. NorthWestern's  
25 increases will be allocated to Avista, PacifiCorp, PGE, and Puget. In each reallocation, the  
26 receiving IOU will be allocated an amount equal to its IOU-Specific Unconstrained Benefit

1 Amount divided by the sum of the IOU-specific Unconstrained Benefit Amounts for all IOUs  
2 receiving a reallocation from a given IOU. For example, the reduction for Avista will be  
3 allocated to NorthWestern, PGE, and Puget based on each of the receiving IOUs' share of the  
4 sum of the three IOU-Specific Unconstrained Benefit Amounts. At the completion of step 4, the  
5 total REP benefits for all IOUs will remain equal to the REP benefits in section 4.3.2 above.

6  
7 The Settlement specifies that BPA will set rates such that the results of step 4 will be produced  
8 after the application of each IOU's ASC, PFX rate, and exchange load. BPA's implementation  
9 methodology will implement steps 1 and 2 in a similar manner as currently used for PFX rates;  
10 a pro rata allocation of the costs of rate protection among both IOU and COU REP participants  
11 plus a pro rata allocation of Refund Amounts to IOU REP participants. The reallocations of  
12 steps 3 and 4 will take the form of a reallocation of the costs of rate protection to the IOUs in the  
13 development of the utilities' individual PFX rates. Once the allocations of the costs of rate  
14 protection and costs of the Refund Amounts are established, the amounts allocated to each utility  
15 will be specified as a utility-specific REP Surcharge, which will then be added to the utility's  
16 base PFX rate to determine each IOU's utility-specific PFX rate. This will allow the steps  
17 specified in the Settlement to be incorporated into the development of the PFX rate with few  
18 ratemaking modifications.

1           **5.           IMPLEMENTING THE 2012 REP SETTLEMENT IN RATEMAKING**

2  
3           **5.1           Ratesetting Pursuant to the Settlement**

4           As described in section 3.1 above, BPA’s ratesetting consists of three major steps: the COSA  
5           step, the rate directives step, and the rate design step. Ratesetting under the Settlement affects  
6           only a portion of the rate directives step. The ratesetting process is unchanged prior to the  
7           7(b)(2) rate test.

8  
9           As described in sections 3.2 and 3.4 above, the purpose of the rate test is to calculate the level of  
10           rate protection due to preference customers pursuant to section 7(b)(2) of the Northwest Power  
11           Act. At the point in the rate modeling after the section 7(c) rate directive adjustments have been  
12           completed, the Settlement proposes a new set of rate calculations. This new set of rate  
13           calculations effectively implements the section 7(b)(2) rate test through alternative calculations  
14           that provide preference customers with an amount of rate protection based on the amount of IOU  
15           REP benefits specified in the Settlement, any COU REP benefits for qualified REP participants,  
16           and section 7(b)(3) adjustments to the IP and NR rates as specified in the REP Settlement.

17  
18           The Settlement ratesetting begins with total IOU REP benefits as specified in the Settlement,  
19           called Scheduled Amounts. Added to the Scheduled Amount for each year is an additional  
20           amount of REP benefits, also specified in the Settlement, known as the Refund Amount. The  
21           Refund Amounts are considered REP benefits because they are subject to the amount of rate  
22           protection afforded to the PFp rate. The Refund Amounts are not paid to the IOUs, however, but  
23           instead appear as a credit on preference customers’ power bills.

24  
25           The Settlement rate modeling first calculates the Unconstrained Benefits, which are the REP  
26           benefits that would be paid if there was no PFp rate protection. In such circumstance, the REP

1 benefits for each exchanging utility would be equal to that utility's ASC minus its appropriate  
2 Base PFX rate multiplied by its qualified exchange load. These Unconstrained Benefits are then  
3 used to calculate total COU REP benefits pursuant to the COU REP settlements. A ratio is  
4 calculated by dividing (i) the Scheduled Amounts plus the COU Settlement Amounts by (ii) the  
5 total Unconstrained Benefits for IOUs. This ratio is then multiplied by Unconstrained Benefits  
6 for COUs to derive COU REP benefits.

7  
8 The total rate protection provided to preference customers under Settlement ratemaking is  
9 composed of two parts. With the Unconstrained Benefits and the total IOU and COU REP  
10 benefits determined, the first amount of rate protection due to preference customers is calculated  
11 as the sum of Unconstrained Benefits minus the sum of REP benefits. The cost of this first part  
12 of rate protection is allocated entirely to the PFX rate pool. The cost of the second part of rate  
13 protection to be allocated to the IP and NR rate pools is calculated later. Settlement ratemaking  
14 allocates this first amount of rate protection to individual REP participants using the same  
15 process used in non-settlement ratemaking, a pro rata allocation based on each participant's  
16 Unconstrained Benefits. Settlement ratemaking next allocates the cost of providing Refund  
17 Amounts to IOUs using the same pro rata basis. Settlement ratemaking then calculates utility-  
18 specific 7(b)(3) surcharges to be added to the appropriate Base PFX rates to produce utility-  
19 specific PFX rates. After the utility-specific PFX rates are calculated, the utility-specific REP  
20 benefits are calculated and summed. At this point, the total annual utility-specific REP benefits  
21 for IOUs are equal to the Scheduled Amount for each year.

22  
23 The second part of rate protection is calculated and allocated to the IP and NR rate pools. This  
24 second part of rate protection is equal to the REP Surcharge included in the IP and NR rates.  
25 The REP Surcharge is determined by multiplying the total REP benefit costs determined above  
26 (Scheduled Amounts plus COU REP benefits) by a scalar specified in the REP Settlement. The



1 scalar is calculated by dividing the WP-10 7(b)(3) Supplemental Rate Charge included in the IP  
2 and NR rates by the total REP benefit costs included in WP-10 rates. This REP Surcharge, when  
3 multiplied by the expected sales under the IP and NR rate schedules, will produce an amount of  
4 dollars comprising the second amount of rate protection. The second amount of rate protection is  
5 subtracted from the total IOU and COU benefits to yield a residual amount of REP benefits that  
6 are allocated to the PFp, IP, and NR rate pools on a pro rata load basis.

7  
8 After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must again  
9 be adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second  
10 IP-PF Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is set  
11 equal to the flat PFp rate plus the net Industrial Margin plus the REP Surcharge.

12  
13 One further adjustment is made to recognize that the IOUs have differing levels of setoffs in  
14 repaying their Lookback Amounts. See section 4.3.9. This adjustment is accomplished through  
15 reallocations of the cost of rate protection allocated to the IOUs. The Settlement specifies a  
16 maximum annual adjustment amount for three IOUs and separate adjustments for Idaho Power  
17 and NorthWestern Energy. These adjustments change the initial amount of REP benefits that  
18 each IOU would receive and allocate this change to other IOUs. Once all of the adjustments are  
19 allocated, the cost of rate protection initially allocated to each IOU is recomputed to account for  
20 this adjustment. The adjusted allocations of the cost of rate protection are added to the allocation  
21 of the cost of Refund Amounts to compute each IOU's final PFx rate.

22  
23 Once these steps are complete, the ratemaking process continues to the rate design step in the  
24 same manner as with no settlement. The Settlement does not affect the rate design step.

1 **5.2 Comparing the Rate Test with the Settlement**

2 A comparison of the development of rates under the Settlement and without a settlement reveals  
3 only a few changes. Under the Settlement, the amount of rate protection included in the PFp rate  
4 is calculated using specific formulas rather than relying on the disputed rate test. The allocation  
5 of the cost of rate protection is also determined according to specific formulas. In addition, the  
6 allocation of the 7(c)(2) adjustments after the rate protection has been applied is somewhat  
7 different. Other aspects of ratemaking are unchanged by the Settlement.

8  
9 Under the Settlement, rate protection is afforded to preference customers. The amount of rate  
10 protection is calculated in the manner prescribed by the Settlement. In the same manner as with  
11 no settlement, the rate protection reduces the costs allocated to the PFp rate applicable to  
12 preference customers. The cost of this rate protection is reallocated to all other power sales  
13 except surplus sales (the allocation to surplus sales is implicit in the REP Surcharge). Two  
14 PF rates are the result of this reallocation: the PFp rate, which receives the rate protection, and  
15 the PFx rate, which does not receive rate protection and bears its allocated share of the rate  
16 protection reallocation. The cost of rate protection continues to be collected through 7(b)(3)  
17 surcharges applied to non-PFp sales. An additional calculation is performed when determining  
18 utility-specific 7(b)(3) surcharges for IOUs, which assigns the cost of the Refund Amounts in the  
19 rate determination rather than through the current use of separate setoffs to the REP benefits paid  
20 to the IOUs.

21  
22 **5.3 Summarizing the PFp Rate**

23 Under the Settlement, the PFp rate has been lowered from the level prior to the application of  
24 rate protection included in the PFx rates. It has also been lowered by the amount of rate  
25 protection recoverable through the REP Surcharges in the IP and NR rates. It has then been  
26 increased to relink the IP and PFp rates. After these adjustments, the final amount of costs

1 allocated to the PFp rate pool is complete and the ratesetting process proceeds to designing rates  
2 pursuant to the Tiered Rate Methodology.

#### 3 4 **5.4 Summarizing the PFx Rate**

5 Under the Settlement, the PFx rates are set to produce the Scheduled Amounts for the IOUs.  
6 This is accomplished through the allocation of the cost of rate protection provided to the PFp rate  
7 and the cost of providing Refund Amounts. The PFx rates for COUs participating in the REP are  
8 set in the same manner except that the costs of the Refund Amounts are not allocated to the COU  
9 participants. Finally, the rate protection costs allocated to the IOUs are reallocated to provide a  
10 reallocation of REP benefits that recognizes that IOU have differing levels of setoffs in repaying  
11 their Lookback Amounts.

#### 12 13 **5.5 Summarizing the IP and NR Rates**

14 Under the Settlement, the IP and NR rates have been adjusted upward by application of the REP  
15 Surcharge, *i.e.*, section 7(b)(3) recoveries of the cost of rate protection. The IP rate is then  
16 relinked with the PFp rate pursuant to section 7(c)(2).

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1 **PART II ANALYSIS AND EVALUATION OF THE 2012 REP SETTLEMENT**

2  
3 **6. ANALYZING THE SETTLEMENT**

4  
5 **6.1 Introduction**

6 The 2012 REP Settlement reflects a compromise by a substantial majority of BPA’s customers  
7 and most of the participants in the litigation on outstanding REP-related issues. It was developed  
8 after extensive negotiations by representatives of COU customers, IOU customers, public utility  
9 commissions, and ratepayer advocacy groups. Many of these entities signed the AIP. These  
10 parties informed the Administrator of their development of a proposed settlement. The  
11 Administrator requested that BPA Staff analyze and evaluate the Settlement to develop a record  
12 to allow him to determine whether the Settlement is both reasonable and consistent with law and,  
13 if adopted, could be used to set rates consistent with its terms.

14  
15 Although BPA firmly believes that settlement of the existing REP litigation is in the interest of  
16 all BPA ratepayers, the Administrator must ensure that the terms and conditions in the 2012 REP  
17 Settlement are reasonable and comply with all relevant statutory provisions. The purpose of this  
18 part of the Study is to present this analysis and evaluation.

19  
20 **6.2 Overview of Methodology Used to Analyze the 2012 REP Settlement**

21 As noted in section 4 of this Study, the 2012 REP Settlement resolves existing and future  
22 challenges to BPA’s implementation of the REP for a term of 27 years, FY 2002 through  
23 FY 2028. Beginning in FY 2012, BPA will not perform the traditional section 7(b)(2) rate test in  
24 setting its rates. Instead, the Settlement (assessed through the examination of numerous 7(b)(2)  
25 rate test scenarios) determines the amount of REP payments to the IOUs and, concomitantly, the  
26 amount of rate protection afforded to the COUs. REP payments to IOUs under the Settlement

1 will begin in FY 2012 at approximately \$182 million per year and gradually increase over 17  
2 years to about \$286 million by FY 2028. In addition, Refund Amounts of \$76.5 million per year  
3 will start in FY 2012 and run for eight years. COUs may participate in the REP when eligible,  
4 resulting in additional REP payments. To be included in rates, all of these payments under the  
5 Settlement must be allowable under section 7(b)(2).

6  
7 The protection and payments under the Settlement are well defined and can be computed without  
8 much interpretation. The REP payments to the IOUs are defined by a schedule, as are the  
9 Refund Amounts paid to the COUs. However, before the Administrator can make these  
10 payments and perform his obligations in the Settlement, the Settlement must have a clear and  
11 direct connection to the protections and requirements set forth in the Northwest Power Act. To  
12 that end, BPA has approached the analysis of the Settlement by comparing the protections and  
13 requirements set forth in the Settlement with protections and requirements that would be  
14 reasonably expected in absence of the Settlement.

15  
16 To analyze the protections and requirements set forth in the Settlement, BPA develops a set of  
17 potential future streams of results based on an examination of the major variables that would  
18 affect the amount of rate protection and REP payments. In addition, BPA develops a set of  
19 potential future streams of results based on an examination of the issues in litigation that would  
20 affect the amount of rate protection and REP payments. To accomplish this analysis, BPA uses  
21 two separate rate models.

### 22 23 **6.3 Rate Models Used to Analyze the 2012 REP Settlement**

24 BPA modified the existing RAM, RAM2012, to examine the effect of different resolutions of  
25 issues in litigation on the amount of rate protection provided by section 7(b)(2) and the amount  
26 of REP benefits that would be paid after application of the 7(b)(2) alternatives. RAM2012 is the

1 detailed rate model used to calculate the BP-12 rates. RAM2012 has the capability of  
2 developing rates based on either the Settlement or the 7(b)(2) rate test. In fact, RAM2012 is the  
3 model that would be used to set rates using the section 7(b)(2) rate test had the Administrator  
4 decided not to adopt the Settlement. However, RAM2012 in its current state cannot be used as  
5 the sole model for analyzing the Settlement because it calculates rates for only the FY 2012–  
6 2013 rate period.

7  
8 To address the need for a long-term analysis of the Settlement, BPA developed a long-term rate  
9 forecast model (LTRM) to produce estimates of rate protection amounts and REP benefits in the  
10 absence of settlement. LTRM projects rates, including rate protection amounts and REP  
11 benefits, for the full 17-year term of the Settlement. It is a scaled-down version of RAM2012  
12 and performs many of the same functions as RAM2012 in the portions of the ratesetting process  
13 necessary to analyze the Settlement. LTRM develops energy allocation factors in the same  
14 manner as RAM2012 and allocates costs and credits to rate pools in the same manner as  
15 RAM2012. LTRM links the IP rate to the PF rate in a simplified form. That is, it uses annual  
16 data only, so it cannot independently calculate a flat annual PF rate for use in the 7(c)(2) linking  
17 process. Most importantly, LTRM performs the 7(b)(2) rate test, and consequent 7(b)(3)  
18 reallocations, in essentially the same manner as RAM2012.

19  
20 There are a few notable differences between the new long-term model and RAM2012. The long-  
21 term model is an annual model; it does not calculate rates based on a two-year rate period as in  
22 RAM2012. Thus, the rate test in the long-term model is based on each year plus the four  
23 subsequent years. This will create minor differences compared to RAM2012. Also, the long-  
24 term model calculates only average energy rates for different rate classes; RAM2012 can  
25 calculate monthly and diurnal rates and apply the effects of the demand rate to the energy rates.  
26 Finally, the long-term model does not calculate tiered rates, whereas RAM2012 implements the

1 Tiered Rate Methodology. The lack of tiered rates has only one effect on this analysis: the rate  
2 for COUs participating in the REP is based on Tier 1 costs and loads, whereas the long-term  
3 model forecasts the costs and loads associated with expected service at Tier 2 rates and removes  
4 them from the PFx rate for COUs. The assumptions used to develop inputs for the long-term  
5 model, including projected estimates of future ASCs, PF rates, and exchange loads, are discussed  
6 in sections 8 and 9 of this Study.

7  
8 The analysis also incorporates the ability to compute REP benefits and rate protection amounts  
9 under a variety of different litigation scenarios. BPA recognizes that the level of future REP  
10 benefits could be influenced by the outcome of the pending litigation. To model these impacts  
11 on future REP benefits, BPA designed the long-term model to produce rate protection and REP  
12 benefits under differing section 7(b)(2) assumptions in the same manner as in RAM2012.

#### 13 14 **6.4 Overview of the Settlement Analysis**

15 RAM2012 is used in the analysis to produce near-term results and is used as the basis for  
16 calibrating the long-term model. Using both RAM2012 and LTRM, scenarios are developed and  
17 results presented projecting near-term and long-term quantitative impacts on future REP benefits  
18 resulting from a number of different risk and litigation positions. The analysis considers factors  
19 that could affect the future amounts of rate protection and REP benefits, such as changes in costs,  
20 loads, and other revenues. The factors considered can affect the ASCs used as the price of  
21 BPA's purchases from REP participants and the PF rates used as the price of BPA's sales to REP  
22 participants. While any factor that could affect rates could produce a change in rate protection  
23 and REP benefits, the factors can be grouped into those that would cause ASCs to grow faster  
24 than BPA's rates and those that would cause BPA's rates to grow faster than ASCs.



1 If ASCs grow faster than BPA's rates, the increased spread between the two rates produces more  
2 rate protection and mitigates the increase in REP benefits that would otherwise occur as ASCs  
3 increase. If BPA's rates grow faster than ASCs, the decreased spread between the two rates  
4 produces less rate protection and mitigates the decrease in REP benefits that would otherwise  
5 occur as BPA's rates increase. BPA's analysis builds a high-ASC, low-BPA case and a  
6 low-ASC, high-BPA case to be representative of the variety of factors that can affect the two  
7 rates. The factors that affect ASCs are addressed primarily in section 7; the factors that affect  
8 BPA rates are addressed in section 8.

9  
10 Among the litigation scenarios BPA considers in the analysis are a BPA best-case scenario  
11 (Reference Case), single issue analyses, an IOU best-case scenario where IOUs prevail on a  
12 combination of litigated issues (IOU Best Case), and a COU best-case scenario where COUs  
13 prevail on a combination of litigated issues (COU Best Case). The litigated issues BPA  
14 considers in this analysis are discussed in section 9, and the effects these issues have on future  
15 REP benefits are described in section 10.

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## 7. AVERAGE SYSTEM COST FORECASTS

### 7.1 Introduction

This section of the Study presents BPA's FY 2012–2032 forecasts of average system costs (ASCs) and residential and small farm (REP) Exchange Loads for the six investor-owned utilities (IOUs) and two consumer-owned utilities (COUs) currently participating in the REP. The ASCs discussed in this section were determined pursuant to BPA's 2008 Average System Cost Methodology (2008 ASCM), as approved by the Commission in September, 2009.

### 7.2 Overview of Average System Cost Determination Process

In its simplest form, ASC is calculated by dividing a utility's allowable resource costs and credits (referred to as Contract System Cost) by the utility's allowable system load (referred to as Contract System Load). The resulting quotient is the utility's ASC. Whether a cost or credit may be included in Contract System Cost, or a load in Contract System Load, is determined pursuant to the rules in the 2008 ASCM.

Under the 2008 ASCM, ASCs are developed in a two-step process. First, a "Base Period" ASC is calculated for each utility. For the REP-12 exchange period, the Base Period is CY 2009. For all utilities, the Base Period ASC is calculated by populating BPA's 2008 ASC Appendix 1 template, an Excel-based computer model, with financial, load, and resource cost data. For the IOUs, this data is drawn largely from the IOUs' 2009 FERC Form 1 filings. For the COUs, the data is based on each individual utility's 2009 annual financial report. At the end of this first step, all of the utility's costs are functionalized between Production, Transmission, and Distribution/Other to determine the exchangeable Production and Transmission costs. Once the exchangeable costs and loads are determined, a 2009 Base Period ASC (\$/MWh) for each utility is established.

1 In step two, the Base Period ASC is escalated for each utility to the midpoint of the applicable  
2 exchange period. In this case, the applicable exchange period is FY 2012–2013. This escalation  
3 is accomplished by inputting the utility’s Base Period ASC data into the ASC Forecast Model.  
4 The ASC Forecast Model is an Excel-based model that escalates certain categories of costs and  
5 credits in the utility’s Appendix 1 by a set of escalators defined in the 2008 ASCM. The ASC  
6 that is produced following application of the ASC Forecast Model is referred to as the Exchange  
7 Period ASC. The Exchange Period ASC is compared to BPA’s PF Exchange rate to determine  
8 the utility’s REP benefits.

9  
10 The first two steps described above generate forecast ASCs for exchanging utilities up to and  
11 through the Exchange Period (FY 2012–2013). In this Study, however, BPA needs to forecast  
12 ASCs for all utilities for the Long-Term Period (FY 2014–2032). In order to forecast ASCs for  
13 this period, a third step is added to the forecasting of ASCs. In this third step, BPA uses the ASC  
14 Forecast Model described above and makes certain adjustments to the model to project the  
15 utility’s ASC out to FY 2032. The revised ASC Forecast Model is referred to as the Long-Term  
16 ASC Forecast Model or LTAFM. The assumptions BPA uses to develop the LTAFM are  
17 discussed in sections 8.5 through 8.9.

### 18 19 **7.3 Determination of the 2009 Base Period ASC**

20 The Base Period ASCs used in this Study are obtained directly from the Final ASC Reports BPA  
21 issued on July 26, 2011. Table 7.1 shows the 2009 Base Period ASC for each utility.

22  
23 The Appendix 1 workbook used to calculate the Base Year ASC consists of a series of seven  
24 Schedules and other supporting worksheets that present the data necessary to calculate a utility’s  
25 ASC. The Schedules and supporting worksheets are as follows:

- 26 • Schedule 1 – Plant Investment/Rate Base

- 1 • Schedule 1A – Cash Working Capital Calculation (Cash Working Capital)
- 2 • Schedule 2 – Capital Structure and Rate of Return (Rate of Return)
- 3 • Schedule 3 – Expenses
- 4 • Schedule 3A – Taxes
- 5 • Schedule 3B – Other Included Items (Other Items)
- 6 • Schedule 4 – Average System Cost Purchased Power and Sales for Resale (3-Year PP &
- 7 OSS Worksheet)
- 8 • Load Forecast
- 9 • Distribution Loss Calculation (Distribution Loss Calc)
- 10 • Distribution of Salaries and Wages (Salaries)
- 11 • Ratios
- 12 • New Resources – Individual and Grouped
- 13 • Materiality – Individual and Grouped
- 14 • New Large Single Loads (NLSL Base New-Calc)
- 15 • Tiered Rates Above Rate Period High Water Mark (RHWM) ASC Calculation for COUs
- 16 only (Tiered Rates)

17

18 **7.3.1 Schedule 1 – Plant Investment/Rate Base**

19 Schedule 1 of the Appendix 1 establishes the utility’s rate base. The rate base computation

20 begins with a determination of the gross electric plant-in-service for intangible, general,

21 production, transmission, and distribution plant.

22

23 For exchanging IOUs that provide electric and natural gas services, only the portion of common

24 plant allocated to electric service is included. For COUs that provide electric, water, and fiber-

25 optic or other such services, financial statements are reviewed to ensure that only plant and

26 expenses related to electric service are included. These values (and all subsequent values) are

1 entered into the Appendix 1 as line items based on the Commission's Uniform System of  
2 Accounts. Because most financial systems used by COUs have the Commission account  
3 structure built in, the COUs can also prepare plant and expense reports based on the Commission  
4 Uniform System of Accounts. Each line item (generally Account or groups of Accounts) is  
5 functionalized to Production, Transmission, and/or Distribution/Other in accordance with the  
6 2008 ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1.

7  
8 The net electric plant-in-service is determined by subtracting the functionalized depreciation and  
9 amortization reserves from gross plant-in-service.

10  
11 Total Rate Base is determined by incorporating the following adjustments to Net Plant-in-  
12 Service: Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and  
13 Investments, Current and Accrued Assets, Deferred Debits, Current and Accrued Liabilities, and  
14 Deferred Credits.

### 15 16 **7.3.2 Schedule 1A – Cash Working Capital**

17 Cash working capital is an estimate of investor-supplied cash used to finance operating costs  
18 during the time lag before revenues are collected. This approach (cash) ignores the lag in  
19 recovery of non-cash costs of service (depreciation), deferred taxes, and other items. The cash  
20 working capital concept is widely used by state commissions and is the basic premise of the  
21 Commission's proposed working capital formula. The purpose of working capital is to  
22 compensate a utility for funds used in day-to-day operations.<sup>1</sup>

23  
24 Cash working capital is a ratemaking convention that is not included in the Commission's  
25 Uniform System of Accounts but is a part of all electric utility rate filings as a component of rate

---

<sup>1</sup> James C. Bonbright *et al.*, *Principles of Public Utility Rates*, 244 (2d ed. 1988).

1 base. To determine the allowable amount of cash working capital in rate base for a utility, the  
2 2008 ASCM allows into rate base one-eighth of the functionalized costs of total production  
3 expenses, transmission expenses, and administrative and general expenses, less purchased power,  
4 fuel costs, and public purpose charges. Cash working capital is not functionalized *per se*.  
5 Instead, the cash working capital values shown on Schedule 1A are the functionalized value of  
6 each component. *See* 18 C.F.R. § 301, End. f.

### 7 8 **7.3.3 Schedule 2 – Capital Structure and Rate of Return**

9 Schedule 2 calculates the utility’s rate of return, which is applied to the rate base developed in  
10 Schedule 1.

11  
12 The 2008 ASCM requires IOUs to use the weighted cost of capital (WCC) from their most recent  
13 state commission rate orders. The return on equity (ROE) used in the WCC calculation is  
14 grossed up for Federal income taxes at the marginal Federal income tax rate using the formula  
15 described in Endnote b of the 2008 ASCM. *See* 18 C.F.R. § 301, End. b.

16  
17 The 2008 ASCM requires each COU to use a rate of return equal to the COU’s weighted cost of  
18 debt. *Id.*

### 19 20 **7.3.4 Schedule 3 – Expenses**

21 This schedule represents operations and maintenance expenses for the production, transmission,  
22 and distribution functions of the utility. Each line item on Schedule 3 is functionalized as  
23 described in Table 1 of the 2008 ASCM. Also included in Schedule 3 are additional utility  
24 expenses associated with customer accounts, sales, administrative and general expense,  
25 conservation program expense, and depreciation and amortization. The sum of the items in  
26 Schedule 3 is the Total Operating Expenses for the utility.

1 **7.3.5 Schedule 3A – Taxes**

2 This schedule presents the taxes paid by the utility during the Base Period. Federal and state  
3 income taxes, franchise fees, regulatory fees, and city/county taxes are accounted for in this  
4 schedule but are functionalized to Distribution/Other and therefore not included in ASC. Federal  
5 and state employment taxes are functionalized by the Labor ratio, while property taxes are  
6 functionalized by the PTDG ratio. *See* 18 C.F.R. Pt. 301, Tbl. 1. COUs are allowed to include  
7 state taxes paid “in lieu” of property taxes. Taxes and fees for each state listed are grouped  
8 together and entered as “combined” line items for Appendix 1 purposes. *See* 18 C.F.R. § 301,  
9 End. c.

10  
11 Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2,  
12 Capital Structure and Rate of Return. *See* 18 C.F.R. § 301, End. b.

13  
14 **7.3.6 Schedule 3B – Other Included Items**

15 This schedule includes revenues from the disposition of plant, sales for resale, and other  
16 revenues, including electric revenues and revenues from transmission of electricity for others  
17 (wheeling). The revenues in this schedule are deducted from the total costs of each utility in  
18 Schedule 4, Average System Cost.

19  
20 **7.3.7 Schedule 4 – Average System Cost (\$/MWh)**

21 This schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital  
22 Structure and Rate of Return, Expenses, Taxes, and Other Included Items. This schedule also  
23 identifies the Contract System Cost and Contract System Load, as defined below, and calculates  
24 the utility’s Base Period ASC (\$/MWh).



1 **7.3.8 Three-Year Purchased Power and Sales for Resale**

2 This worksheet presents the detailed values by the Commission’s statistical classification code<sup>2</sup>  
3 of the utility’s purchased power and sales for resale for the Base Period and two previous years.  
4 Purchased Power is an Account on Schedule 3, Expenses, and includes all power purchased by  
5 the utility. Sales for Resale is an Account on Schedule 3B, Other Included Items, and includes  
6 power sales to purchasers other than retail consumers. The purpose of this schedule is to  
7 calculate the percentage price spread between the utility’s average cost of short-term purchased  
8 power and sales for resale. *See* 18 C.F.R. § 301.4.(b) The price spread is used in the ASC  
9 Forecast Model and is discussed in Section 7.4.12.

10  
11 **7.3.9 Load Forecast**

12 Each utility is required to provide an eight-year forecast (FY 2010–2017) of its total retail load  
13 and its qualifying residential and small farm retail load, both as measured at the retail meter. The  
14 total retail and residential and small farm load forecasts are adjusted for distribution losses and  
15 New Large Single Loads (NLSLs) when appropriate. The resulting load forecasts are the  
16 Contract System Load forecast and Exchange Load forecast, respectively. The Contract System  
17 Load forecast is used in the ASC Forecast Model to calculate the utility’s ASC; the Exchange  
18 Load forecast is used in the rate case to calculate REP benefits.

19  
20 For the COUs only, the Exchange Period Contract System Load forecasts (FY 2012–2017) are  
21 the load forecasts as determined by BPA under the Tiered Rate Methodology. The COUs  
22 provide their qualifying residential and small farm retail load (Exchange Load) as measured at  
23 the retail meter.

24  

---

<sup>2</sup> Please refer to the FERC Form 1, pages 310-311, for Sales for Resale, and pages 326-327, for Purchased Power, for identification of the classification codes.

1 **7.3.10 Distribution Loss Calculation**

2 Each utility is required to provide a current distribution loss study, as described in Endnote e of  
3 the 2008 ASCM. *See* 18 C.F.R. § 301, End. e. The total retail and residential and small farm  
4 load forecasts are adjusted for distribution losses (and NLSLs when appropriate).

6 **7.3.11 Distribution of Salaries and Wages**

7 This worksheet presents the salary and wage information that is used to determine the Labor  
8 ratio, shown on the Ratios schedule. The data is taken directly from page 354 of the FERC  
9 Form 1, which functionalizes utility total salary and wage costs into the components shown on  
10 the schedule. This worksheet includes salaries and wages from relevant operations and  
11 maintenance of the electric plant. For COUs, comparable information comes from the detailed  
12 salary and wage data of the utility's financial system.

14 **7.3.12 Ratios**

15 This worksheet develops the various ratios used to functionalize costs and revenues on other  
16 Schedules of the Appendix 1 and ASC Forecast Model. Six ratios are calculated on this  
17 worksheet: labor; general plant (GP); production, transmission, distribution (PTD); production,  
18 transmission, distribution and general plant (PTDG); transmission and distribution (TD); and  
19 maintenance of general plant (GPM). Ratios determined in this worksheet are used to allocate  
20 costs on other schedules of the Appendix 1 and ASC Forecast Model. *See* 18 C.F.R. Pt. 301,  
21 Tbl. 1.

23 **7.3.13 Exchange Period Major Resource Additions – Individual and Grouped**

24 The 2008 ASCM allows a utility's ASC to adjust during the Exchange Period to reflect the  
25 addition or loss of a major resource(s), subject to a materiality threshold of 2.5 percent. That is,  
26 in order to be included in the calculation of the utility's Exchange Period ASC, the addition or

1 loss of a major resource must result in a 2.5 percent increase or decrease in the utility's Base  
2 Period ASC. Major resources include production or generating resources, transmission lines,  
3 long-term purchased power contracts, pollution controls and environmental compliance upgrades  
4 related to generating resources, transmission resources or contracts, hydro relicensing costs and  
5 fees, and plant rehabilitation investments. *See* 18 C.F.R. § 301.4(c)(3)(i)-(vii).

6  
7 Utilities are required to provide forecasts of major resource additions, retirements, and sales,  
8 along with the associated costs, with their ASC Filings. In their major resource forecasts,  
9 utilities provide all resources that are planned to begin or cease commercial operation from the  
10 end of the Base Period (December 31, 2009) to the end of the Exchange Period (September 30,  
11 2013). *Id.*

#### 12 13 **7.3.14 Exchange Period Major Resources Materiality – Individual and Grouped**

14 These worksheets determine the effects of major resource additions or reductions on a utility's  
15 Base Period ASC. For major resources that are expected to be on line, sold, or retired prior to  
16 the start of the Exchange Period, BPA projects the costs of the resource forward to the midpoint  
17 of the Exchange Period. For resources that are expected to be on line, sold, or retired during the  
18 Exchange Period, BPA calculates the cost as if the major resource change occurred at the  
19 midpoint of the Exchange Period.

20  
21 Each resource meeting the minimum materiality threshold of 0.5 percent may be entered  
22 individually in the "New Resources – Individual" tab. Resources that do not meet the  
23 2.5 percent materiality requirement independently may be grouped together with other resources  
24 within "New Resources – Grouped" to meet the 2.5 percent materiality requirement. The  
25 grouping and timing of materiality for new resource additions is discussed in section 7.4.2 of this  
26 document.

1 **7.3.15 New Large Single Loads**

2 This worksheet calculates the Base Period cost of resources in an amount sufficient to serve any  
3 New Large Single Loads, which BPA must exclude from the utility’s ASC pursuant to  
4 Northwest Power Act section 5(c)(7). An NLSL is any load associated with a new facility, an  
5 existing facility, or an expansion of an existing facility that was not contracted for or committed  
6 to (CF/CT) prior to September 1, 1979, and which will result in an increase in power  
7 requirements of 10 average megawatts (aMW) or more in any consecutive 12-month period.  
8 16 U.S.C. § 839a(13)(A)-(B). By law, BPA must exclude from a utility’s ASC the load  
9 associated with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See*  
10 16 U.S.C. § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a utility’s  
11 ASC, BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R.  
12 § 301, End. d.

13  
14 The fully allocated cost of resources plus transmission in an amount sufficient to serve NLSLs  
15 that is developed on this worksheet is used in Schedule 4.

16  
17 **7.3.16 Tiered Rates**

18 All exchanging COUs have the right to purchase power at BPA’s Tier 1 rate by executing a  
19 Contract High Water Mark (CHWM) contract with BPA. By signing CHWM contracts, COUs  
20 agree to limit the resources they will exchange in the REP. Under the CHWM contract, the COU  
21 agrees not to include in its ASC the cost of resources necessary to serve the COU’s Above-Rate  
22 Period High Water Mark (RHWM) load. The CHWM contracts require the cost of serving  
23 Above-RHWM loads to be calculated using a methodology similar to that in Endnote d of the  
24 2008 ASCM.

25  
26 This worksheet contains the amount of Tier 1 load purchased from BPA, the amount of Existing  
27 Resources allowed in ASC, and the COU’s Above-RHWM load, and comes from BPA’s Power

1 Rates and Implementation Group (PFR). For background information and details, see Chapter 3  
2 of the Power Rates Study, BP-12-FS-BPA-01.

### 3 4 **7.3.17 Contract System Cost**

5 Contract System Cost is the utility's cost for production and transmission resources, including  
6 power purchases and conservation measures. Contract System Cost is calculated by adding the  
7 functionalized Production and Transmission costs less revenue credits. Contract System Cost  
8 does not include the cost of resources in an amount sufficient to serve any NLSLs of the utility.  
9 Contract System Cost is the numerator in the ASC calculation. Table 7.2 shows the 2009 Base  
10 Period Contract System Cost for each utility.

### 11 12 **7.3.18 Contract System Load**

13 Contract System Load (MWh) is the denominator in the ASC calculation and equals the utility's  
14 total retail sales, minus any NLSLs, plus distribution losses. Distribution loss factors will vary  
15 for each utility due to the size, age, and population density of the system. The 2008 ASCM  
16 includes distribution losses in the Contract System Load. Table 7.3 shows the 2009 Base Period  
17 Contract System Load for each utility.

### 18 19 **7.3.19 PacifiCorp and NorthWestern Jurisdictional Cost Allocation**

20 Calculation of PacifiCorp's and NorthWestern's ASC involves consideration of unique  
21 jurisdictional allocation issues. The 2008 ASCM states that a single ASC will be used for each  
22 utility's entire regional load. Both PacifiCorp and NorthWestern provide retail service to  
23 customers both inside and outside the Pacific Northwest.

24  
25 PacifiCorp's FERC Form 1 is based on its total system costs, and therefore adjustments must be  
26 made to determine the portion of costs used to serve retail load within the region. To perform

1 this adjustment, PacifiCorp's total utility cost data from the FERC Form 1 is entered into the  
2 2008 ASC Appendix 1, and then allocated based on the Inter-Jurisdictional Cost Allocation  
3 Protocol (JCAP) developed jointly by most of PacifiCorp's state commissions. Only the costs  
4 and revenues allocated to the Pacific Northwest are included in PacifiCorp's ASC.

5  
6 NorthWestern's FERC Form 1 contains some data that is specific to its Montana jurisdiction. In  
7 addition, Northwestern also files an annual report to the Montana Public Service Commission  
8 (MPSC) that identifies costs and loads related to its Montana retail electric customers.

9 NorthWestern's FERC Form 1, MPSC annual report, and information from data requests are  
10 used to ensure that only costs and revenues related to NorthWestern's Montana retail electric  
11 service territory are included in its ASC.

#### 12 13 **7.4 Determination of the Exchange Period ASCs for FY 2012–2013**

14 Once the Base Period ASC is calculated, BPA uses the ASC Forecast Model to escalate the Base  
15 Period ASC forward to the midpoint of the Exchange Period, which in this case is October 1,  
16 2012. The ASC Forecast Model uses Global Insight's forecast of cost increases for capital costs  
17 and fuel (except natural gas), operations and maintenance (O&M), and general and  
18 administrative (G&A) expenses; BPA's forecast of market prices for purchases to meet load  
19 growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's  
20 forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other  
21 products. The ASC Forecast process is described in greater detail in the sections that follow.

##### 22 23 **7.4.1 Escalation to Exchange Period (FY 2012–2013)**

24 Table 7.4 shows the annual escalation rates used in the ASC Forecast Model through FY 2013.  
25

1 **7.4.2 Major Resource Additions, Reductions, and Materiality Thresholds**

2 Under the 2008 ASCM, a utility’s ASC is allowed to change during the Exchange Period when  
3 major new power or transmission contracts become effective, major new resource additions  
4 come on line and are used to meet the utility’s retail load, or resources are terminated. These  
5 additions or reductions will affect costs. Additions may include new production resource  
6 investments; new generating resource investments; new transmission investments; long-term  
7 generating contracts; pollution control and environmental compliance investments relating to  
8 generating resources, transmission resources, or contracts; hydro relicensing costs and fees; and  
9 plant rehabilitation investments. *See* 18 C.F.R. § 301.4(c)(4). Changes to an ASC, however, are  
10 limited to instances where the cost impact of the new resource passes a materiality threshold of  
11 an increase in the Base Period ASC of 2.5 percent or greater.

12  
13 All major new resources included in an ASC calculation prior to the start of the Exchange Period  
14 are projected forward to the midpoint of the Exchange Period. For each major new resource  
15 addition forecast to come on line during the Exchange Period, BPA calculates the ASC with the  
16 new resource at the midpoint of the Exchange Period.

17  
18 Under the Settlement, the IOUs agreed not to request a change in ASC for any new resource  
19 additions that come on line during the Exchange Period. Therefore, for the Exchange Period  
20 (FY2012–2013) ASC forecast, BPA assumed that any resource additions or reductions that  
21 parties indicated would be occurring during the Exchange Period would not be included in the  
22 utility’s ASC.

23  
24 **7.4.3 Ratios**

25 To calculate Exchange Period ASCs, functionalization ratios are developed for each year using  
26 the escalated plant and expense values. These functionalization ratios are then applied to the  
27 escalated values to determine costs to include in ASC.

1 **7.4.4 Schedule 1 – Plant Investment/Rate Base Forecast**

2 **7.4.4.1 Production and Transmission Plant**

3 Gross production and transmission plant are held constant through the end of the Exchange  
4 Period, unless there are production plant or transmission plant resource additions. In such case, a  
5 new ASC is calculated including the plant addition, as described above. *See* section 7.4.2.

6  
7 **7.4.4.2 Forecast Distribution Plant-Related Costs**

8 Distribution plant is used to calculate some of the functionalization ratios used in the calculation  
9 of a utility’s ASC. Therefore, BPA escalates the Base Period average per-megawatthour cost of  
10 distribution plant forward to the midpoint of the Exchange Period and uses the escalated average  
11 cost times the megawatthours of load growth to determine the distribution plant-related cost of  
12 meeting load growth since the Base Period. This cost is then included in the ratios used to  
13 forecast the Exchange Period ASCs.

14  
15 **7.4.4.3 Forecast General Plant-Related Costs**

16 To escalate General Plant-related costs, BPA first calculates the ratio of base period general plant  
17 to the sum of base period production, transmission, and distribution plant. BPA then applies this  
18 base period ratio to the sum of the forecast gross costs of production, transmission, and  
19 distribution plant to develop the forecast gross general plant.

20  
21 **7.4.4.4 Forecast Depreciation and Amortization Reserves**

22 The forecast functionalized depreciation and amortization reserves are increased annually by the  
23 amount of annual depreciation and amortization expense.

24  
25 **7.4.5 Schedule 1A – Cash Working Capital Forecast**

26 Forecast cash working capital is calculated using the same method as the 2009 Base Period  
27 value, except that BPA uses the projected component values.



1 **7.4.6 Schedule 2 – Capital Structure and Rate of Return Forecast**

2 The rate of return is held constant at the 2009 Base Period value through the end of the Exchange  
3 Period.

4  
5 **7.4.7 Schedule 3 – Expense Forecast**

6 All expense items in Schedule 3 are escalated using the escalation factors assigned to the  
7 particular expense item as set forth in the 2008 ASCM, with the following exceptions:

- 8 • Short-term purchased power expense is calculated as described in sections 7.4.9,  
9 7.4.11, and 7.4.12.
- 10 • The public purpose charge is escalated at the utility’s rate of load growth.
- 11 • Depreciation and amortization expense is increased for new plant additions, as  
12 described in section 7.4.7.1.
- 13 • Operations and maintenance expense and fuel expense are escalated annually as  
14 described in the ASCM and increased for any additional O&M and fuel associated  
15 with new plant additions.

16  
17 **7.4.7.1 Depreciation and Amortization Expense Forecast**

18 Depreciation and amortization expense for each account is forecast to be constant, except for  
19 additional depreciation expenses associated with the following:

- 20 • new plant additions
- 21 • new distribution plant additions associated with load growth (the amount of the  
22 depreciation expense addition is equal to the additional gross distribution plant  
23 times the ratio of the 2009 distribution depreciation expense to the 2009 gross  
24 distribution plant)
- 25 • new general plant additions (the amount of the depreciation expense addition is  
26 equal to the additional gross general plant times the ratio of the 2009 general plant  
27 depreciation expense to the 2009 gross general plant)

1 **7.4.8 Schedule 3A – Forecast of Taxes**

2 Property-related taxes are held constant throughout the forecast period unless there are property  
3 taxes identified with major resource additions. Labor-related taxes are escalated using the wages  
4 escalator.

5  
6 **7.4.9 Schedule 3B – Forecast of Revenue Credits and Other Items**

7 With the exception of wheeling revenues and Sales for Resale Revenues, all revenue and other  
8 credits are held constant at the Base Period amounts.

9  
10 The ASC Forecast Model distinguishes between long-term and short-term sales for resale and  
11 assumes that the quantity of long-term and intermediate-term firm sales is constant through the  
12 Exchange Period and that revenue from these types of sales escalates at the rate of inflation.

13  
14 The quantity of short-term sales is forecast to be constant into the future unless a utility's  
15 forecast resource additions exceed the utility's forecast load growth requirements and reduce  
16 short-term purchased power to zero. In such case, the surplus energy is sold off-system at the  
17 forecast short-term sales for resale price as determined by BPA. *See* section 7.4.12.

18  
19 Wheeling revenues are held constant unless there are new transmission additions. The increase  
20 in wheeling revenues resulting from new transmission resource additions equals:

21  
22  $(\text{Wheeling revenues (before additions)} / \text{net transmission plant (before additions)}) \times$   
23  $\text{new transmission additions.}$

1 **7.4.10 Load Forecast**

2 **7.4.10.1 Forecast Contract System Load and Exchange Load**

3 Each utility was required to provide with its 2009 ASC Filing a forecast of its Contract System  
4 Load, New Large Single Loads, and Exchange Load, as well as a current distribution loss study  
5 as described in Endnote e of the 2008 ASCM. The load forecast for Contract System Load and  
6 Exchange Load started with the Base Period and extends through FY 2017.

7  
8 For the IOUs, this Study used the Contract System Load forecasts provided by the utilities in  
9 their ASC submittals through the Exchange Period. For the COUs, BPA used the total retail load  
10 forecasts provided by BPA’s load forecasting group.

11  
12 For the Exchange Load forecasts through the end of the Exchange Period, BPA used the  
13 forecasts provided by the utilities. For the COUs, pursuant to the TRM, the total Exchange Load  
14 was reduced each year by each COU’s Tier 1 percentage to determine the forecasts of exchange  
15 load for which the COUs could invoice BPA.

16  
17 **7.4.11 Forecast Methodology for Meeting Load Growth**

18 All forecast load growth will first be met by new resource additions. If the power provided by  
19 the new resources is less than the total forecast load growth, the remaining load growth will be  
20 met with market purchases priced at the utility’s forecast short-term purchased power price. In  
21 the event the power provided by a new resource exceeds the utility’s forecast load growth, the  
22 amount of short-term purchases is reduced by the excess. If short-term purchases are reduced to  
23 zero, any remaining excess power is sold as surplus power into the market and priced at the  
24 utility’s forecast sales for resale price as determined by BPA, as discussed in section 7.4.12.

1 **7.4.12 Treatment of Sales for Resale and Power Purchases**

2 The ASC Forecast Model distinguishes between long-term and short-term purchased power. In  
3 the FERC Form 1, utilities separate purchased power and sales for resale by the type and length  
4 of the purchase and also report any adjustments. The COUs were required to provide detailed  
5 information on their long-term, intermediate-term, and short-term purchased power costs and  
6 sales for resale revenues.

7  
8 BPA escalated the long-term and intermediate-term (as defined by the Commission) firm  
9 purchased power costs and sales for resale revenues at the rate of inflation.

10  
11 For short-term purchases and sales for resale revenues, the Base Period values were used as  
12 starting values. Each utility's ASC was adjusted to reflect new plant additions and used a utility-  
13 specific forecast for the prices of (1) purchased power and (2) sales for resale, to value purchased  
14 power expenses and sales for resale revenue to be included in the Exchange Period ASC.

15  
16 BPA used each utility's historical three-year weighted spread between short-term purchased  
17 power price and sales for resale price (the price spread) to determine that utility's forecast price  
18 spread.

19  
20 To forecast a utility's short-term purchased power and sales for resale price, BPA first calculated  
21 the midpoint of the utility's 2009 average short-term purchased power and sales for resale price.  
22 BPA then escalated the midpoint at the same rate as BPA's market price forecast. The price  
23 spread was then applied to the forecast midpoint to determine the forecast purchased power and  
24 sales for resale prices.

25 Forecast purchase price = Escalated midpoint price  $\times$  (1 + price spread)

26 Forecast sales price = Escalated midpoint price  $\times$  (1 – price spread)

1 **7.4.13 New Large Single Loads**

2 An NLSL is any load associated with a new facility, an existing facility, or an expansion of an  
3 existing facility that was not contracted for or committed to prior to September 1, 1979, and that  
4 will result in an increase in power requirements of 10 average megawatts or more in any  
5 consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

6  
7 Section 5(c)(7)(A) of the Northwest Power Act directs BPA to exclude from ASC the “cost of  
8 additional resources in an amount sufficient to serve any new large single load of the utility ....”

9 16 U.S.C. § 839c(c)(7)(A). To implement this provision, BPA developed Endnote d of the  
10 2008 ASCM. In general, Endnote d identifies three methods for excluding from ASC the cost of  
11 resources sufficient to serve a utility’s NLSL(s). First, the unit cost of any resources dedicated to  
12 serve the NLSL is excluded. Second, if dedicated resources are not used to serve NLSLs, or the  
13 megawatthour amount of dedicated resources is less than the NLSL megawatthour amount, the  
14 unit cost of any purchases of NR power from BPA will be excluded. Finally, to the extent that  
15 the megawatthour amount of dedicated resources plus NR purchases is less than the NLSL  
16 megawatthour amount, the fully allocated unit cost of all resources and long-term purchases that  
17 were not contracted for or committed to load as of September 1, 1979, will be excluded. *See*  
18 18 C.F.R. § 301, Endnote d, for details. To date, no IOU serves NLSLs with dedicated resources  
19 or purchases power from BPA at the NR rate, so all NLSL resource cost exclusions are based on  
20 the fully allocated cost method of Endnote d.

21  
22 NLSL determinations are not made in the ASC review process. Instead, they are identified and  
23 made through a separate process conducted by BPA. Although NLSLs are determined in another  
24 forum, BPA must establish in the Draft and Final ASC Reports the removal of the costs of  
25 serving any potential NLSLs pursuant to the requirements in Endnote d(1)-(3) of the 2008  
26 ASCM. Parties to the ASC Review Processes must also be allowed an opportunity to review and  
27 comment on BPA’s calculation.

1 During review of utilities' ASC Filings for the FY 2012–2013 ASC Exchange Period, several  
2 large utility loads were identified at Idaho Power, PacifiCorp, and Portland General that met the  
3 statutory definition of an NLSL. The Final ASC Reports adjusted the utility's ASC to reflect  
4 BPA's final NLSL determinations.

5  
6 For purposes of the LTAFM, each of the large loads identified as NLSLs for the FY 2012-2013  
7 Final ASC Reports is treated as an NLSL through FY 2032. The megawatt-hours associated with  
8 each NLSL remain constant and are removed from each utility's total retail load. The cost of  
9 resources in an amount sufficient to serve these potential NLSLs is removed from each utility's  
10 allowable production and transmission costs using the NLSL worksheets of the LTAFM  
11 described in section 7.3.15. Costs of resources in an amount sufficient to serve NLSLs are  
12 escalated through FY 2032. When new resources are added for a utility in the LTAFM, they are  
13 also included in the NLSL worksheets to determine NLSL resource costs.

#### 15 **7.4.14 Rate Period High Water Mark ASC Calculation under the Tiered Rate** 16 **Methodology**

17 Exchanging COUs receive power from BPA under CHWM Contracts. By signing the CHWM  
18 Contract, a utility agrees to limit the resources it will exchange in the REP. Under the 2008 ASC  
19 Methodology, COUs that execute CHWM Contracts are not allowed to include in their ASCs the  
20 cost of resources used to meet their Above-RHWM loads.

21  
22 CHWM Contracts require that the cost of resources used to meet Above-RHWM loads be  
23 calculated using a methodology similar to the methodology that determines the cost of resources  
24 used to serve NLSLs. This methodology is contained in Endnote d of the 2008 ASCM.

25  
26 During the FY 2012–2013 ASC Review Process, BPA used the following method to determine  
27 the ASC of a COU that is participating in the REP.

- 1       • RHWMA SC =  $\frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$
- 2
- 3       • NewRes\$ is the forecast cost of resources used to serve a customer's Above-
- 4       RHWMA Load. The costs included in NewRes\$ will be determined using a
- 5       methodology similar to Appendix 1, Endnote d, of BPA's 2008 ASC
- 6       Methodology and as described below.
- 7
- 8       • NewResMWh is the forecast generation from resources used to serve a
- 9       customer's Above-RHWMA Load.
- 10
- 11      • For calculating both NewRes\$ and NewResMWh, Existing Resources for
- 12      CHWMA specified in Attachment C, Column D, of the Tiered Rate Methodology,
- 13      BP-12-A-03, and purchases of power at Tier 1 rates from BPA are excluded.
- 14

15 The following considerations are used in calculating the cost of serving Above-RHWMA Loads

16 using Endnote d of the 2008 ASCM:

- 17      • Types of resources to serve Above-RHWMA Loads may be different from those
- 18      resources used in the NLSL resource cost calculation and will be recognized in
- 19      calculating RHWMA SC.
- 20      • Total output of new resources may exceed Above-RHWMA Load; the RHWMA
- 21      SC does not specify removal of costs associated with this excess.
- 22

23 To calculate RHWMA SC, BPA adjusted Contract System Cost as follows:

- 24      • Set NewResMWh equal to Above-RHWMA Load.
- 25      • NewRes\$ = NewResMWh times Fully Allocated Cost (calculated using
- 26      Endnote d).

- If output of material new resources fails to meet Above-RHWM Load, meet deficit with short-term market purchases at utility-specific market price. Short-term purchases are not allowed in the calculation of the cost to serve NLSLs.
- If output of new resources exceeds Above-RHWM Load, reduce short-term market purchases by the excess to the extent possible in the Contract System Cost calculation.
- Sell any remaining surplus at the utility-specific Sales for Resale price in the Contract System Cost calculation.

#### **7.4.15 Forecast Contract System Cost, Contract System Load, and Average System Cost**

##### **7.4.15.1 Contract System Cost Forecasts**

For the IOUs and COUs, the ASC Forecast Model calculates Contract System Cost as follows:

$$\begin{aligned}
 \text{Exchange Cost}_{2009} = & \Sigma \text{Rate Base Accounts} \times (1 + \text{escalator}_{(\text{by account})}) \times \text{ROR (w/ Federal} \\
 & \text{Income Tax Factor)} \\
 & + (\Sigma \text{Expense Accounts}_{(\text{by account})}) \times (1 + \text{escalator}_{(\text{by account})}) \\
 & + \text{Wholesale Purchase Expense}_{2009} \\
 & - \text{Wholesale Sales for Resale Revenue Credit}_{2009} \\
 & + \text{Cost of Load Growth} \\
 & - \text{New Large Single Load Cost}
 \end{aligned}$$

The COU forecasts do not include the Federal income tax calculation from ROR (Rate of Return).

#### **7.5 Determination of the Forecast ASCs for FY 2014–2032**

To calculate ASCs for the Long-Term Period (FY 2014–2032), BPA used the same methods and ASC Forecast Model as were used to escalate costs and revenues from the Base Period to the Exchange Period, except for the revisions described in the following section.



1 **7.5.1 Escalation from the End of the Exchange Period through the End of the Long-**  
2 **Term Period (FY 2014–2032)**

3 Through CY 2017, the LTAFM uses Global Insight’s forecast of cost increases for capital costs  
4 and fuel (except natural gas), operations and maintenance (O&M), and general and  
5 administrative (G&A) expenses. For CY 2018 through CY 2032, the annual escalation rate for  
6 each Global Insight escalator in the LTAFM is set equal to the CY 2017 escalation rate.

7 Through CY 2017, the LTAFM uses BPA’s forecast of natural gas prices For the CY 2018–  
8 2032 period, natural gas prices are escalated 3 percent annually. Through FY 2017, the LTAFM  
9 uses BPA’s forecast of market prices for purchases to meet load growth and to estimate short-  
10 term and non-firm power purchase costs and sales revenues. For the FY 2018–2032 period,  
11 electric market prices are escalated 3 percent annually. Through FY 2032, the LTAFM uses  
12 BPA’s estimates of the rates it will charge for its PF and other products.

13  
14 Table 7.5 in the Documentation shows the escalation rates through FY 2032.  
15

16 **7.5.2 Plant Investment/Rate Base Forecast**

17 New resource additions for the FY 2014–2028 period are based on each utility’s most recent  
18 Integrated Resource Plan (IRP) or similar document, the Northwest Power and Conservation  
19 Council’s Sixth Power Plan, and other sources. The analysis is described in greater detail in  
20 sections 7.7, 7.8, and 7.9. All resource additions are included at the midpoint of the fiscal year  
21 they are projected to come on line. Depreciation and amortization reserves are held constant at  
22 the FY 2014 level for the Long-Term Period. BPA assumes that the utilities will refurbish or  
23 replace existing resources. Most of the utilities did not identify in the IRPs the cost of  
24 maintaining or replacing existing resources. BPA chose to represent the cost of refurbishing or  
25 replacing existing resources as equal to the annual depreciation and amortization costs. In effect,  
26 this holds the depreciation and amortization reserves constant.  
27

1 **7.5.3 Load Forecast**

2 **7.5.3.1 Forecast Contract System Load and REP Exchange Load**

3 The IOUs' FY 2018–2032 Contract System Load forecasts are based on the load information  
4 provided in each IOU's IRP. This load forecast is described in greater detail in section 7.8.3.

5  
6 For the COUs, BPA used the total retail load forecast through FY 2029 provided by BPA's Load  
7 Forecast group. For FY 2030–2032, COU loads were escalated at the rate of growth from  
8 FY 2028–2029.

9  
10 To develop the FY 2018–2032 REP Exchange Load forecast for the IOUs, BPA calculated the  
11 ratio of Exchange Load to total retail load for FY 2017. These ratios were then applied to the  
12 individual IOU's total retail load forecast for FY 2018–2032.

13  
14 For the COU REP Exchange Load forecast, BPA used the same method to forecast exchange  
15 loads that was used for the IOUs, with one additional step. For the COUs, Total REP Exchange  
16 Load was reduced each year by each COU's Tier 1 percentage to determine the forecast of  
17 exchange load for which the COUs could invoice BPA, as required by the TRM.

18  
19 **7.6 ASC Inputs into the Long-Term Rate Model**

20 The cost, revenue, and load values from the Long-Term ASC Forecast Model are used to provide  
21 the ASC inputs for the Long-Term Rate Model (LTRM). The LTRM uses these inputs to  
22 generate ASCs and REP benefits under the various scenarios.

23  
24 The first step in generating the ASC inputs is to run the ASC Forecast Model, including all new  
25 resources scheduled to come on line prior to the start of the Exchange Period. The resulting cost,  
26 revenue, and load data are then used to generate the inputs used in the LTRM. The costs and

1 revenues are selected for the Base Period (CY 2009), and for FY 2012 through FY 2032 at the  
2 midpoint (April 1) of each fiscal year.

### 4 **7.6.1 Escalators**

5 Once the input data has been calculated, escalators are calculated using the input values. The  
6 escalators for FY 2012 equal the FY 2012 values divided by the CY 2009 values. The escalators  
7 for FY 2013–2032 equal the values for the current fiscal year divided by the values for the  
8 previous fiscal year.

9  
10 For example, the FY 2013 escalator for Production Rate Base equals the Production Rate Base  
11 value for FY 2013 divided by the Production Rate Base value for FY 2012.

### 13 **7.6.2 Forecast Values**

14 With the exception of short-term purchases and sales, Tier 1 purchases, and the NLSL and  
15 Above-RHWM items discussed below, the forecast revenue and expense items are calculated as:

$$16 \quad \text{Current FY Value} = [\text{Previous FY Value} \times (1 + \text{escalator})] +$$
$$17 \quad \text{Current FY New Resource Addition}$$

### 19 **7.6.3 Short-Term Purchases and Sales**

20 Short-term purchases quantity and expense and short-term sales quantity and revenue are  
21 calculated in the same way as they are in the ASC Forecast Model used to calculate Exchange  
22 Period ASCs. Any forecast load growth not met with new resources is met with market  
23 purchases priced at the utility's forecast short-term purchased power price. In the event the  
24 power provided by a new resource exceeds the utility's forecast load growth, the amount of  
25 short-term purchases is reduced by the excess. If short-term purchases are reduced to zero, any

1 remaining excess power is sold as surplus power into the market, priced at the utility's forecast  
2 sales for resale price as discussed in section 7.4.12.

#### 3 4 **7.6.4 Tier 1 Purchases**

5 For FY 2012 and FY 2013, Tier 1 purchase expense is calculated using tiered rate estimates that  
6 assume no IOU settlement.

7  
8 For FY 2014–2032, the tiered rates are escalated at the same rate as the average PF rate changes.  
9 These escalated tiered rates are then used to calculate the Tier 1 purchase expense in each fiscal  
10 year.

11  
12 The annual Lookback credit equals Initial Proposal values. For all fiscal years, net Tier 1  
13 purchase expense equals Tier 1 purchase expense less the Lookback credit.

#### 14 15 **7.6.5 NLSL and Above-RHWM Cost Components**

16 For each fiscal year, the NLSL and Above-RHWM production rate base equals the CY 2009  
17 Base Period ASC input value plus the cumulative new resource rate base additions up to that  
18 fiscal year. As in the LTAFM, if the output of material new resources fails to meet Above-  
19 RHWM Load, the deficit is met with short-term market purchases at utility-specific market  
20 prices. Above-RHWM ASC is calculated as discussed in section 7.4.14. Contract System Cost  
21 is calculated as discussed in section 7.4.15.1.

#### 22 23 **7.7 New Resource Additions for FY 2014–2032**

24 New resource additions used in the Long-Term ASC Forecast Model are based on review and  
25 analysis of each utility's Integrated Resource Plan. The individual IRPs guided the timing,  
26 quantity, and resource type added for each utility. However, for the resources added in the

1 LTAFM, a set of 14 “generic” resources was developed and used when a utility IRP indicated  
2 that a new resource was added. Cost and operating characteristics for the 14 generic new  
3 resources were based largely on Appendix I of the Council’s Sixth Power Plan, except as noted  
4 in the following paragraph.

5  
6 First, Appendix I calculates resource costs in real, levelized 2006 dollars. Because the LTAFM  
7 calculates ASCs in nominal dollars for each year of the Long-Term Period, the data was  
8 converted using the Council’s MicroFin model (used by the Council to develop the real,  
9 levelized values) so that the first-year costs for each resource could be calculated in nominal  
10 dollars. Appendix I of the Council’s Sixth Power Plan also reports transmission costs and losses  
11 as a single value, also in real, levelized dollars per megawatthour. The LTAFM separates  
12 transmission costs and losses and requires transmission costs in nominal dollars per kilowatt per  
13 year. MicroFin was also used to convert transmission costs. For resource capacity factors, BPA  
14 relied on the Appendix I values except for combined and single-cycle combustion turbines. For  
15 these resources, BPA relied on the capacity factors from the California Energy Commission.<sup>3</sup>  
16 The cost and heat content of coal were based on the weighted average of those values for 19 coal  
17 plants owned by exchanging utilities. See Table 7.9 of the Documentation.

## 19 **7.7.1 Global Parameters and Definitions Used in Determining Reference Plant Costs**

### 20 **7.7.1.1 Conventions**

21 **Price Year:** The price year from which future changes in costs are calculated is 2009.

23 **Year Dollars:** Costs are expressed in nominal dollars.

24  

---

<sup>3</sup> California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies, December 2007, at 19.

1 **Technology Base Year:** The technology base year from which future changes in technology are  
2 calculated is 2009.

3  
4 **Project Scope:** The scope of resource cost estimates includes the cost of project development;  
5 construction, operation, and integration costs for variable resources; and the cost and losses of  
6 transmission to the wholesale receiving point of a load-serving entity.

7  
8 **Total Plant Cost:** Capital costs<sup>4</sup> are expressed in overnight (instantaneous) Total Plant Costs.  
9 Total Plant Costs are the sum of direct and indirect engineering, procurement, and construction  
10 (EPC) costs, plus owner's costs. Owner's costs include non-EPC costs incurred by the project  
11 developer, such as permits and licenses; land and right-of-way acquisition; project development  
12 costs; legal fees; owner's engineering, project, and construction management staff; startup costs;  
13 site infrastructure (*e.g.*, transmission, road, water, rail, waste water disposal); taxes; spares;  
14 furnishings; and working capital. Not included in Total Plant Cost are financing costs, escalation  
15 incurred during construction, and interest incurred during construction (IDC).

#### 16 17 **7.7.1.2 Project Financing**

18 Power plants are assumed to be constructed by investor-owned utilities and consumer-owned  
19 utilities. Each of these entities uses different project financing mechanisms.

20  
21 Plant investment costs are calculated using the spreadsheet model used to calculate resource  
22 capital cost and the annual revenue requirements for the various resources. Depreciation is  
23 assumed to be straight-line over the life of the plant.

24  

---

<sup>4</sup> The capital cost estimates for the reference power plants are based on the Northwest Power and Conservation Council's Sixth Power Plan (except where noted).

1 The financing parameter values used are shown in Table 7.5.  
2

### 3 **7.7.1.3 Project Costs**

- 4 • All costs are escalated from the nominal Base Period 2009 dollars to the  
5 resource's on-line date.
- 6 • Total project investment is calculated for the selected year of construction using  
7 the estimated total plant cost, plant capacity, cost escalation factors, construction  
8 cash flow estimates, and construction financing of the selected type of project  
9 developer.
- 10 • Annual capital-related costs (debt interest, debt principal, return on equity,  
11 recovery of equity, and state and Federal taxes) are calculated for the total project  
12 investment using the long-term financing characteristics and tax obligations of the  
13 selected type of developer.
- 14 • Annual property tax and insurance payments are calculated based on the plant  
15 value.
- 16 • Annual energy production is calculated based on plant capacity and capacity  
17 factor.
- 18 • Annual fixed fuel costs are calculated based on escalated fixed fuel costs and  
19 plant capacity. Annual variable fuel costs are based on escalated variable fuel  
20 costs, heat rate, and energy production.
- 21 • Annual fixed O&M costs are calculated based on escalated fixed O&M costs and  
22 plant capacity. Annual variable O&M costs are based on escalated variable O&M  
23 costs and energy production.
- 24 • Annual transmission costs are calculated based on plant capacity and escalated  
25 unit transmission costs. Integration costs are calculated based on forecast  
26 integration costs and energy production.

- The value of transmission losses is calculated based on total annual costs and the transmission loss factor.

#### **7.7.1.4 Escalation Rates**

For calculating the capital costs of the new resource additions included in the LTAFM, BPA uses Global Insight’s CY 2014–2019 forecast of capital cost increases. For the CY 2020–2032 period, the capital cost escalation rates are set equal to the CY 2019 escalation rates. For calculating the operating costs of the new resource additions included in the LTAFM, BPA uses Global Insight’s CY 2014–2017 forecast of cost increases for fuel (except natural gas), O&M, and G&A expenses. To escalate these items for the CY 2018–2032 period, the escalation rates are set equal to the CY 2017 escalation rates. Through CY 2017, the LTAFM also uses BPA’s forecast of natural gas prices to calculate the natural gas fuel costs for new gas-fired resources. For CY 2018-2032, the natural gas fuel price is increased 3 percent annually. The escalators are shown in Table 7.6.

#### **7.7.1.5 General Forecasts**

##### **Transmission**

The common point of reference for the costs of generating resources and energy efficiency measures is the wholesale delivery point to local load-serving entities (*e.g.*, the substations connecting local utilities to the regional transmission network). The costs and losses of transmission from the point of generating project interconnection to the wholesale point of delivery are included in estimated generating resource cost.

The cost of resources serving local loads (*e.g.*, Oregon and Washington resources serving Oregon and Washington loads) includes local (in-region) transmission costs and losses. The cost of resources serving remote loads (*e.g.*, Wyoming resources serving Idaho, Oregon, and Washington loads) includes the estimated cost and losses of needed long-distance transmission.



1 **Local Transmission Costs and Losses**

2 Local transmission costs are based on the 2010 Bonneville Power Administration Transmission  
3 and Ancillary Service Rate Schedules. The representative local transmission cost is an  
4 approximation of the long-term firm point-to-point service (PTP) rate plus required Ancillary  
5 Services and Control Area Services (ACS) rates (scheduling system control and dispatch,  
6 reactive supply and voltage control, regulation and frequency response, spinning reserve, and  
7 supplemental reserve). The estimated fixed component is \$17/kW/yr, and the variable  
8 component is \$1.00/MWh (2009 dollars). The estimated cost of regulation and load-following  
9 required to integrate variable generation is separately included, as described in the following  
10 section. Local transmission losses are assumed to be 1.9 percent (BPA OATT, Schedule 9 *see*  
11 [http://transmission.bpa.gov/business/ts\\_tariff/default.cfm?page=oatt](http://transmission.bpa.gov/business/ts_tariff/default.cfm?page=oatt) ) ).

12  
13 **Transmission to Access Remote Resources**

14 PacifiCorp is the only utility that specifically identified long-haul wind resources in its IRP.  
15 PacifiCorp did not identify the points of delivery or points of receipt for long-haul resources in  
16 its IRP, so the assumption used in this Study is that the long-haul wind resources are located in  
17 Wyoming and the power is received by PacifiCorp in Southern Idaho. The cost and losses  
18 associated with long-distance transmission to access remote resources are based upon the  
19 Council's Sixth Power Plan estimates of actual proposed new long-distance transmission  
20 alignments serving the resource areas of interest (Council Plan, Appendix I, Table I-3).  
21 Table I-24 of Appendix I shows the estimated transmission cost and losses in real, levelized  
22 dollars per megawatthour for the Wyoming-Southern Idaho route. Table I-3 is the source for the  
23 2.5 percent transmission loss factor for the Wyoming-to-Southern Idaho route used in the  
24 LTAFM for long-haul wind. To develop the \$126.56/kW/year used for transmission costs, the  
25 Council's MicroFin model (Version 15.01 with Scenario AddIn) was used to develop the  
26 estimated first-year costs of the line, \$119.64/kW/year in 2006 dollars. This value was escalated

1 to 2009 dollars using the GDP escalator of 1.0578 for 2006 to 2009 to arrive at \$126.56/kW/year  
2 cost of transmission used in the ASC Forecast Model. See Table 1.1.a of the Council Plan  
3 Documentation for results of the MicroFin model for this calculation. See Appendix I of the  
4 Council's Plan for a greater discussion of transmission costs and the MicroFin model.  
5

#### 6 **Integration Cost for Variable Resources**

7 The cost of providing balancing services for wind resources is based on Table I-5 of Appendix I  
8 of the Council's Plan, which shows balancing costs of \$8.85/MWh for 2010. The 2010  
9 balancing cost was reduced to 2009 dollars using the GDP escalator to arrive at the \$8.67/MWh  
10 used in the LTAFM.  
11

#### 12 **7.7.1.6 Capacity Factors**

13 The capacity factor of a power plant is the ratio of the actual output of a power plant over a  
14 period of time to its output if it had operated at full nameplate capacity the entire time. Table 7.8  
15 provides the plant capacity factor for each of the reference resources, and Table 7.9 provides the  
16 adjusted plant capacity factor for each of the reference resources to reflect the transmission  
17 losses of energy delivered to the utilities' systems.  
18

#### 19 **7.7.1.7 Fuel Costs, Purchase Power Expenses, and REC Costs**

##### 20 **Coal**

21 Coal costs (\$/ton) and heat content values (Btu/lb) are based on the 2009 weighted average for  
22 the 19 coal-fired power plants operated by exchanging utilities (individual coal plant data from  
23 2009 FERC Form 1). Support for this calculation is shown in Table 7.9 of the documentation.  
24

1 **Natural Gas**

2 Natural gas price (\$/MMBtu) is the same gas price used to calculate BP-12 rates. This study  
3 assumes the inclusion of incremental transportation costs of \$0.73/MMBtu (\$2006).<sup>5</sup>  
4

5 **7.7.2 Assumptions for Reference Plants**

6 The descriptions below are taken largely from, or are direct quotes from, Appendix I of the  
7 Council’s Sixth Power Plan. Tables for each reference plant are included in the Council’s Sixth  
8 Power Plan Documentation, Appendix B, pages 6-9.  
9

10 **7.7.2.1 Landfill Gas Energy Recovery**

11 A landfill gas energy recovery plant uses the methane content of the gas produced as a result of  
12 the decomposition of landfill contents to generate electric power. The complete recovery system  
13 includes an array of collection wells, collection piping, gas cleanup equipment, and one or more  
14 generator sets, usually using reciprocating engines. Typically, the gas collection system is  
15 installed as a requirement of landfill operation, and the raw gas is sold to the operator of the  
16 power plant.  
17

18 **Reference Plant**

19 The reference plant consists of two 1.6 MW reciprocating-engine generating units fueled by  
20 landfill gas. The scope includes gas processing equipment, engine-generator sets, powerhouse  
21 and maintenance structure, and power generation site infrastructure.  
22

---

<sup>5</sup> Fuel Price Forecasting Model – West-Side Firm Utility Gas Price, Sixth Power Plan Appendix A: Fuel Price Forecast, Table A6-71a.

1 **Fuel**

2 A typical business arrangement is for the power plant operator to purchase the raw landfill gas  
3 from the landfill operator. The landfill operator is responsible for installing and operating the  
4 well field and collection system.

5  
6 **Heat rate**

7 The heat rate of the reference plant is 10,060 Btu/kWh. The assumed heat content of the gas is  
8 841,000 Btu/Mcf.<sup>6</sup>

9  
10 **Unit Commitment Parameters**

11 Landfill gas energy recovery plants operate as must-run units at an annual capacity factor of  
12 85 percent.

13  
14 **Total Plant Cost**

15 The “overnight” total plant cost of the reference plant is \$2,350/kW installed capacity (2008  
16 price year). This estimate is based on reported as-built costs for three landfill gas energy  
17 recovery plants and four generic estimates of plant development costs. Three of the latter were  
18 range estimates consisting of low and high bound costs. These cost observations, normalized as  
19 described in the Capital Cost Estimates subsection of Appendix I of the Council’s Plan, are  
20 plotted by vintage in Figure I-4 of the Council’s Plan. The increase in capital costs from 2004 to  
21 2008 observed for most power generation technologies is not clearly evident here, particularly  
22 for the as-built costs. A reason may be that the built projects were of substantially different  
23 scopes (*e.g.*, with or without the gas collection system). For this reason, the representative  
24 project cost estimate was based on a projection of the 2005 and 2007 generic cost estimates,

---

<sup>6</sup> Energy Information Agency – Average Heat Content of Selected Biomass Fuels, August 2010.

1 which together with the 2006 actual project cost seem to reasonably track observed power plant  
2 cost escalation during this period. Because landfill gas energy recovery projects were not  
3 modeled in the Regional Portfolio Model, capital cost uncertainty was not estimated.

4  
5 Construction costs are forecast to decline by 8 percent (real) in 2009, and then continue to  
6 decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by  
7 2011. Construction costs are assumed to remain constant in real terms thereafter.

### 8 9 **Development and Construction Schedule, Cash Flows**

10 Development and construction schedule and cash flow assumptions for a landfill gas energy  
11 recovery plant are those assumed for reciprocating-engine power plants:

12 **Development** (feasibility study, permitting, geophysical assessment, preliminary engineering):  
13 18 months, 3 percent of total plant cost.

14  
15 **Early Construction** (final engineering, major equipment order, site preparation): 9 months,  
16 9 percent of total plant cost.

17  
18 **Committed Construction** (delivery of major equipment, completion of construction and  
19 testing): 6 months, 88 percent of total plant cost.

### 20 21 **Operating and Maintenance Costs**

22 Fixed O&M cost for landfill gas energy recovery is \$26/kW/yr., and variable O&M cost is  
23 \$19/MWh.

1 **Economic Life**

2 The economic life of a landfill gas energy recovery plant is assumed to be 20 years, limited by  
3 the operating life of a reciprocating-engine generator and the productive life of a typical landfill.

4  
5 **7.7.2.2 Biomass (Woody Residue Power Plants)**

6 Woody residue includes mill residues, logging slash, urban construction and demolition debris,  
7 urban forest and landscaping debris, unmerchantable products of commercial forest management  
8 and ecosystem restoration, and woody energy crops. Conventional steam-electric plants with or  
9 without combined heat and power (CHP) will in the near term be the chief technology for  
10 electricity generation using woody residue.

11  
12 **Reference Plant**

13 The reference Greenfield plant is a 25 MW (nominal) fluidized-bed steam-electric plant with a  
14 full condensing steam turbine-generator. The plant is provided with mechanical draft condenser  
15 cooling. Selective non-catalytic nitrogen oxide (NOx) reduction, cyclones, and fabric filters are  
16 employed for air emission control. The plant consists largely of new equipment.

17  
18 **Fuel**

19 The fuel supply consists largely of forest thinning and restoration residues within a 50- to  
20 75-mile radius, augmented by mill, logging, forest thinning, and urban wood residues.

21  
22 The fuel supply of the Greenfield plant consists largely of forest thinning residues, supplemented  
23 with limited quantities of mill residue, logging slash, and urban wood residues with an average  
24 net cost of \$3.00/MMBtu.

1 **Heat rate**

2 The heat rate of the standalone plant is 15,500 Btu/kWh.

4 **Unit Commitment Parameters**

5 Woody residue steam-electric plants are assumed to operate as must-run units at an annual  
6 capacity factor of 80 percent.

8 **Total Plant Cost**

9 The Greenfield plant representing longer-term marginal development conditions is estimated to  
10 cost \$4,000/kW (net) installed capacity.

12 **Development and Construction Schedule, Cash Flows**

13 Development and construction schedule and cash flow assumptions are as follows:

15 **Development** (feasibility study, permitting, geophysical assessment, preliminary engineering):  
16 24 months, 2 percent of total plant cost.

18 **Early Construction** (final engineering, major equipment order, site preparation): 12 months,  
19 45 percent of total plant cost.

21 **Committed Construction** (delivery of major equipment, completion of construction and  
22 testing): 12 months, 53 percent of total plant cost.

24 **Operating and Maintenance Costs**

25 The estimated O&M costs for the reference Greenfield plant are \$180/kW/yr fixed and  
26 \$3.70/MWh variable.

1 **Value of Steam Sales**

2 Extracted 150-psi saturated steam is assumed to be valued at \$5.00/1000 lb, based on the Port of  
3 Port Angeles (2009) plant characteristics and costs.

4  
5 **Economic Life**

6 A new steam-electric plant can operate for 30 years or more.

7  
8 **7.7.2.3 Geothermal**

9 Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies  
10 could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest.

11 **Reference Plant**

12 The reference plant is a 40 MW (nominal) binary-cycle plant comprised of three 13 MW (net)  
13 units. The plant is assumed to use closed-loop organic Rankine-cycle technology suitable for  
14 low geothermal fluid temperatures. The plant includes production and injection wells;  
15 geothermal fluid piping; power block; cooling towers; step-up transformers; switchgear and  
16 interconnection facilities; and security, control, and maintenance facilities. Wet cooling,  
17 resulting in higher plant efficiency, greater productivity, and lower cost, would likely be used at  
18 sites with sufficient water. Dry cooling could be employed at sites with insufficient cooling  
19 water availability, at additional cost and some sacrifice in efficiency and productivity.

20  
21 **Unit Commitment Parameters**

22 Geothermal plants are assumed to operate as must-run units.

23  
24 **Capacity Factor:** The average capacity factor over the life of the facility is assumed to be  
25 90 percent.



1 **Heat Rate:** The average annual full load heat rate is 28,500 Btu/kWh, typical of an Organic  
2 Rankine Cycle (ORC) binary plant operating on 300°F geothermal fluid.

3  
4 **Total Plant Cost**

5 The total plant cost of the reference geothermal plant is \$4,800/kW installed capacity. This  
6 estimate is based on a sample of one reported as-built plant cost and 12 preconstruction  
7 estimates, including one estimate consisting of low and high bound costs.

8  
9 **Operating and Maintenance Cost**

10 Estimated O&M costs for the reference plant are \$175/kW/yr fixed plus \$4.50/MWh variable.

11 **Economic Life**

12 The economic life of a geothermal plant is assumed to be 30 years, limited by well field viability  
13 and equipment life.

14  
15 **7.7.2.4 Hydropower**

16 **Reference Plant**

17 Because of the diversity of remaining hydropower development opportunities, no single plant  
18 configuration is representative. Cost and performance assumptions were based on the  
19 characteristics of recently developed proposed hydropower plants in the Western Electricity  
20 Coordinating Council (WECC).

21  
22 **Unit Commitment Parameters**

23 Hydropower plants are assumed to operate as must-run units.  
24

1 **Capacity Factor:** The average capacity factor over the life of the facility is assumed to be  
2 50 percent, based on the average of the reported energy production of a sample of 15 recently  
3 developed and proposed hydropower plants in the WECC (49.4 percent), rounded to 50 percent.  
4

#### 5 **Total Plant Cost**

6 The representative cost of \$3,000/kW is the rounded capacity-weighted, escalation-adjusted  
7 average cost of eight “committed” (recently completed or under construction) projects.  
8

#### 9 **Development and Construction Schedule, Cash Flows**

10 The development and construction schedule and cash flow assumptions for a typical small  
11 hydropower plant are as follows:  
12

13 **Development** (issuance of preliminary permit to receipt of FERC license and selection of EPC  
14 contractor): 48 months, 12 percent of total plant cost.  
15

16 **Construction** (site preparation, construction, and commissioning): 24 months, 88 percent of  
17 total plant cost.  
18

#### 19 **Operating and Maintenance Cost**

20 O&M costs are assumed to be 3 percent of overnight capital cost. The variable component is  
21 small and is included in the fixed O&M estimate.  
22

#### 23 **Economic Life**

24 The economic life of a small hydropower plant is assumed to be 30 years, limited by major  
25 equipment life.  
26

1 **7.7.2.5 Concentrating Solar Thermal Power Plant**

2 Parabolic-trough concentrating solar thermal power plants are a commercially proven technology  
3 with over 20 years of operating history. Existing plants use a synthetic oil primary heat transfer  
4 fluid and a supplementary natural gas boiler in the secondary water heat transfer loop for output  
5 stabilization and extended operation into the evening hours. Future plants are expected to benefit  
6 from higher collector efficiencies, higher operating temperatures (providing higher thermal  
7 efficiency and more economical storage), and economies of production.

8  
9 **Reference Plant**

10 The reference plant is a 100-MW dry-cooled parabolic-trough concentrating solar thermal plant  
11 located in east-central Nevada near Ely. Power would be delivered to southern Idaho by the  
12 north segment of the proposed Southwest Intertie Project and then to the Boardman area by  
13 portions of the proposed Gateway West and Boardman-to-Hemingway transmission projects.  
14 Higher-temperature heat transfer fluids such as molten salt are expected to be available by the  
15 earliest feasible date for energization of the necessary transmission (ca. 2015). The reference  
16 plant is assumed to be equipped with a 2.5 solar multiplier collector field and thermal storage  
17 sufficient to support six to eight hours of full-power operation. This storage would allow output  
18 to be shifted to non-daylight hours, improve winter capacity factor, levelize output on  
19 intermittently cloudy days, and impart some firm capacity value. No natural gas backup is  
20 provided, because natural gas service is not available in the vicinity of the reference site.

21  
22 **Capacity Factors and Temporal Output**

23 Annual capacity factor and seasonal, daily, and hourly output was 35.5 percent for the Ely site.  
24 Output is highly seasonal, even with a collector field solar multiplier of 2.5.

1 **Unit Commitment Parameters**

2 Concentrating solar thermal plants are assumed to operate as must-run units.

3  
4 **Total Plant Cost**

5 The total plant cost of a representative parabolic-trough concentrating solar plant is estimated to  
6 be \$4,700/kW. Publicly available cost information was located for three proposed or recently  
7 constructed parabolic-trough concentrating solar plants, ranging in size from 64 to 250 MW.

8  
9 **Operating and Maintenance Cost**

10 Fixed O&M cost is \$60/kW/yr, and variable O&M is \$1.00/MWh.

11  
12 **Integration Cost**

13 The thermal storage capacity of the representative solar thermal plant is assumed to eliminate the  
14 need for incremental regulation and load following.

15  
16 **Economic Life**

17 The economic life of a parabolic-trough concentrating solar thermal plant is assumed to be  
18 30 years.

19  
20 **Transmission**

21 New long-distance transmission would be required to deliver power to Northwest load centers  
22 from a solar thermal power plant near Ely, Nevada. Estimated costs and losses appear in  
23 Table 7.9.

1 **7.7.2.6 Wind Power Plants**

2 Wind power is modeled by defining a reference wind plant and then applying transmission costs  
3 and losses appropriate to the location of the wind resource and the load center served. Plant  
4 capacity factors are adjusted to reflect the quality of the various wind resource areas. Five wind  
5 resource areas were assessed, including the Columbia basin (eastern Washington and Oregon),  
6 southern Idaho, central Montana, southern Alberta, and eastern Wyoming. The combinations of  
7 wind resource areas, transmission, and points of delivery considered are shown in Table I-3 of  
8 the Council's Plan in the Transmission section.

9  
10 **Reference Plant**

11 The 100 MW reference plant consists of arrays of conventional three-blade wind turbine  
12 generators, in-plant electrical and control systems, interconnection facilities and on-site roads,  
13 meteorological towers, and support facilities.

14 **Capacity Factors and Temporal Output**

15 The annual average capacity factors used for the five resource areas are shown in Table 7.10.

16  
17 **Unit Commitment Parameters**

18 Wind power plants are assumed to operate as must-run units.

19  
20 **Total Plant Cost**

21 The total plant cost of the reference wind plant is \$2,100/kW installed capacity.

22  
23 **Operating and Maintenance Cost**

24 Fixed O&M cost is \$40/kW/yr and escalates with total plant cost. The variable O&M cost of  
25 \$2.00/MWh is intended to represent land rent. Land rent is estimated to be between 2 and  
26 4 percent of the gross revenue from wind turbine generation.

1 **Economic Life**

2 The economic life of a wind plant is assumed to be 20 years.

3  
4 **7.7.2.7 Coal-Fired Steam-Electric Plants**

5 The pulverized coal-fired power plant is the established technology for producing electricity  
6 from coal. The basic components of a steam-electric pulverized coal-fired power plant include a  
7 coal storage, handling, and preparation facility; a furnace and steam generator; and a steam  
8 turbine-generator. Coal is ground (*i.e.*, pulverized) to dust-like consistency, blown into the  
9 furnace, and burned in suspension. The energy from the burning coal generates steam that is  
10 used to drive the steam turbine-generator. Ancillary equipment and systems include flue gas  
11 treatment equipment and stack, an ash handling system, a condenser cooling system, and a  
12 switchyard and transmission interconnection. Newer units are typically equipped with low-NOx  
13 burners, sulfur dioxide removal equipment, and electrostatic precipitators or baghouses for  
14 particulate removal. Selective catalytic reduction of NOx and carbon monoxide (CO) emission  
15 is becoming increasingly common, and post-combustion mercury control is expected to be  
16 required in the future. Often, several units of similar design will be co-located to take advantage  
17 of economies of design, infrastructure, construction, and operation. Most western coal-fired  
18 plants are sited near the mine mouth, though some plants are supplied with coal by rail at  
19 intermediate locations between mine mouth and load centers.

20  
21 Most existing North American coal steam-electric plants operate at sub-critical steam conditions.  
22 Supercritical steam cycles operate at higher temperature and pressure conditions, at which the  
23 liquid and gas phases of water are indistinguishable. This results in higher thermal efficiency,  
24 with corresponding reductions in fuel cost, carbon dioxide production, air emissions, and water  
25 consumption. Supercritical units are widely used in Europe and Japan. Several supercritical  
26 units were installed in North America in the 1960s and 1970s, but the technology was not widely

1 adopted because of low coal costs and the poor reliability of some early units. The majority of  
2 new North American coal capacity is now supercritical technology.

#### 4 **Reference Plant**

5 The reference plant is a single 450 MW net supercritical pulverized coal-fired power plant at a  
6 Greenfield site. This plant is equipped with low-NOx burners, overfire air, and selective  
7 catalytic reduction for control of nitrogen oxides. The plant would be provided with flue gas  
8 desulfurization, fabric filter particulate control, and activated charcoal injection for reduction of  
9 mercury emissions. The capital costs include a switchyard and transmission interconnection.

10  
11 The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and  
12 might be more suitable for arid areas of the West. But dry cooling reduces the thermal efficiency  
13 of a steam-electric plant by about 10 percent and proportionally increases per-kilowatt air  
14 emissions and carbon dioxide production. The effect is about three times greater for steam-  
15 electric plants than for gas turbine combined-cycle power plants, where recent proposals have  
16 trended toward dry condenser cooling. For this reason, BPA assumes the majority of new coal-  
17 fired power plants would be located in areas where water availability is not critical and would  
18 use evaporative cooling.

#### 20 **Fuel**

21 The reference plant is assumed to be fueled by western subbituminous coal.

#### 23 **Total Plant Cost**

24 The “overnight” total plant cost of the reference pulverized coal-fired plant is estimated to be  
25 \$3,500/kW installed capacity.

1 **Operating and Maintenance Costs**

2 The fixed O&M cost for the reference plant is estimated to be \$60/kW/yr (exclusive of property  
3 tax and insurance). The variable O&M cost for the reference plant is estimated to \$2.75/MWh.  
4

5 **Economic Life**

6 The economic life of a coal-fired steam-electric plant is assumed to be 30 years.  
7

8 **7.7.2.8 Natural Gas Simple-Cycle Intercooled Gas Turbine Plant**

9 **Reference Plant**

10 The reference intercooled simple-cycle gas turbine plant consists of a single gas turbine  
11 generator set of 99 MW nominal capacity, an external intercooler, an evaporative mechanical  
12 draft cooling system for the intercooler, lube oil, fuel forwarding and other ancillary equipment,  
13 a control building, and switchyard. Cost and performance characteristics are based on the  
14 General Electric LMS100PB (dry low-NOx combustors). Auxiliary loads for external  
15 intercooler technology will be greater than a conventional simple-cycle unit, and the net “new  
16 and clean” capacity of the plant under ISO conditions is 96 MW. The new and clean heat rate is  
17 degraded a further 2.2 percent for maintenance-adjusted lifecycle aging effects, to yield a  
18 lifecycle average baseload capacity of 94 MW (ISO conditions). The gas turbine generator is  
19 enclosed for weather protection and acoustic control and is provided with inlet air filters and  
20 exhaust silencers.  
21

22 **Fuel**

23 Natural gas is supplied on a firm transportation contract with capacity release capability. No  
24 backup fuel is provided.  
25



1 **Heat Rate**

2 The full-load, higher heating value (HHV) heat rate under “new and clean” conditions is  
3 estimated to be 8,810 Btu/kWh. This rate is based on the nominal lower heating value heat rate  
4 reported for a General Electric LMS100PB in Gas Turbine World (2009), converted to HHV and  
5 derated 3.1 percent for inlet, exhaust, auxiliary load, and transformer losses. The lifecycle  
6 average HHV full-load heat rate is estimated to be 8,870 Btu/kWh. This is based on the new and  
7 clean heat rate degraded 0.8 percent for maintenance-adjusted lifecycle aging effects.

8  
9 **Total Plant Cost**

10 The overnight total plant cost of the reference plant is estimated to be \$1,130/kW. This estimate  
11 is based on a sample of one reported as-built plant cost, three “as-committed” cost estimates,  
12 seven preconstruction cost estimates (including one range estimate), and five generic cost  
13 estimates including two range estimates.

14 **Economic Life**

15 The economic life of an intercooled hybrid simple-cycle gas turbine power plant is assumed to  
16 be 30 years.

17  
18 **Operating and Maintenance Cost**

19 Fixed O&M cost is estimated to be \$8/kW/yr, and variable O&M is estimated to be \$5.00/MWh.

20  
21 **7.7.2.9 Natural Gas Combined-Cycle Plant – Duct Firing**

22 Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided  
23 with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a  
24 steam-turbine generator. Capture of the energy of the gas turbine exhaust increases the overall  
25 thermal efficiency of a combined-cycle plant compared to a simple-cycle gas turbine generator.

1 The reference combined-cycle unit, for example, has a base load efficiency of 48 percent  
2 compared to a full-load efficiency of 38 percent for the reference hybrid intercooled gas turbine.

3  
4 Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production)  
5 by extracting steam at the needed pressure from the heat-recovery steam generator or steam  
6 turbine. Additional generating capacity (power augmentation) can be obtained at low cost by  
7 oversizing the steam turbine generator and providing the heat recovery steam generator with  
8 natural gas burners (duct firing). The resulting capacity increment operates at somewhat lower  
9 electrical efficiency than the base plant and is usually reserved for peaking operation. The  
10 incremental efficiency, however, is comparable to that of simple-cycle gas turbines.

11  
12 Because they often operate at or near market clearing prices, combined-cycle plants can be an  
13 economical source of system balancing reserves. With high reliability, high efficiency, low  
14 capital cost, short lead time, operating flexibility, and low air emissions, gas-fired combined-  
15 cycle plants have been the bulk power generation resource of choice since the early 1990s.

### 16 17 **Reference Plant**

18 The reference plant is a single-train (1x1) natural gas-fired combined-cycle plant consisting of a  
19 “G-class” gas turbine generator, a fired heat recovery steam generator, and a steam turbine  
20 generator. The “new and clean” net base load capacity under ISO conditions is 395 MW, with  
21 25 MW of peaking power augmentation. The net baseload capacity is based on the nominal  
22 capacity of a 1x1 Mitsubishi 501G combined-cycle unit (Gas Turbine World, 2009), derated  
23 0.9 percent for Selective Catalytic Reduction (SCR) and main transformer losses. The new and  
24 clean heat rate is degraded a further 2.7 percent for maintenance-adjusted lifecycle aging effects  
25 to yield a lifecycle average baseload capacity of 385 MW. Air emission controls include dry  
26 low-NOx combustors and selective catalytic reduction for NOx control, and an oxidation catalyst

1 for CO and volatile organic compound (VOC) control. Condenser cooling is wet mechanical  
2 draft.

#### 4 **Fuel**

5 Fuel for the plant is natural gas supplied on a firm transportation contract with capacity release  
6 capability. No backup fuel is provided.

#### 8 **Heat Rate**

9 The HHV heat rate at full baseload under “new and clean” conditions is estimated to be  
10 6,790 Btu/kWh. This is the reported heat rate for the Port Westward plant (Mitsubishi MHI  
11 501G). The lifecycle average HHV heat rate at full baseload is estimated to be 6,930 Btu/kWh.  
12 This is based on the new and clean heat rate degraded 2.1 percent for maintenance-adjusted  
13 lifecycle aging effects. The incremental heat rate of supplemental (duct-fired) capacity is  
14 estimated to be 9,500 Btu/kWh (Fifth Power Plan assumption).

#### 16 **Economic Life**

17 The economic life of a combined-cycle plant is assumed to be 30 years.

#### 19 **Total Plant Cost**

20 The overnight total plant cost of the reference plant is estimated to be \$1,120/kW, based on an  
21 estimated cost of baseload capacity of \$1,160/kW and an estimated cost of supplementary (fired  
22 HSRG) capacity of \$465/kW. These estimates were derived from six reported as-built plant  
23 costs, 16 preconstruction cost estimates (one with low and high bound estimates), and four  
24 generic cost estimates (one including low and high bound costs) from 2004 or later.

1 **Operating and Maintenance Cost**

2 Fixed O&M cost is \$14/kW/yr. Variable O&M is \$1.70/MWh.

3

4 **7.8 Renewable Portfolio Standards**

5 A Renewable Portfolio Standard (RPS) is a regulation that requires the increased production of  
6 energy from renewable energy sources, such as wind, solar, biomass, and geothermal. The RPS  
7 mechanism generally places an obligation on electricity supply companies to produce a specified  
8 fraction of their electricity from renewable energy sources. Renewable energy sources may  
9 include:

- 10 • Biofuels
- 11 • Biomass
- 12 • Fuel cells
- 13 • Geothermal
- 14 • Hydro
- 15 • Landfill gas
- 16 • Ocean thermal
- 17 • Photovoltaic
- 18 • Solar thermal electric
- 19 • Tidal
- 20 • Waste tire
- 21 • Wave
- 22 • Wind

23 Following is a summary of RPS requirements by state for the Pacific Northwest.

1 **7.8.1 Overview of State Renewable Portfolio Standards**

2 **Oregon**

3 In June 2007, Oregon adopted RPS standards in Senate Bill 838 (ORS 469A). The bill directs  
4 Oregon utilities to meet a percentage of their retail electricity needs with qualified renewable  
5 resources. For Portland General Electric and PacifiCorp the standard starts at 5 percent in 2011  
6 and increases to 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025.

7  
8 The legislation also provides that Renewable Energy Credits (RECs) may be used to fulfill RPS  
9 targets. Utilities may bank unused RECs from one year to apply to future RPS requirements.

10  
11 An Oregon utility may comply with the RPS using any combination of the following options:

- 12 • Build an eligible facility (or continue to operate an existing one) and retain REC  
13 output from these facilities.
- 14 • Buy power and REC output (a bundled REC) from another eligible facility.
- 15 • Buy unbundled REC output.
- 16 • Make “alternative compliance payments” with options to use these funds for  
17 construction of an eligible facility in the future.

18  
19 **Washington**

20 In November 2006, Washington voters approved Initiative Measure No. 937, which established  
21 renewable energy targets starting at 3 percent of a qualifying utility’s load by 2012, 9 percent in  
22 2015, and 15 percent by 2020. Qualifying utilities are public and private utilities that serve more  
23 than 25,000 customers in the state of Washington. Electricity produced from an eligible  
24 renewable resource must be generated in a facility that started operating after March 31, 1999.  
25 Either the facility must be located in the Pacific Northwest, or the electricity from the facility  
26 must be delivered into the state on a real-time basis. Incremental electricity produced from

1 efficiency improvements at hydropower facilities owned by qualifying utilities is also an eligible  
2 renewable resource, if the improvements were completed after March 31, 1999.

3  
4 Initiative 937 allows utilities to use RECs to meet their acquisition targets. RECs can be bought  
5 and sold in the marketplace, and they may be used during the year they are acquired, the  
6 previous year, or the subsequent year.

7  
8 **Idaho**

9 There are currently no RPS requirements in Idaho.

10  
11 **Montana**

12 In April 2005, Montana enacted its RPS as part of the Montana Renewable Power Production  
13 and Rural Economic Development Act, which requires public utilities and competitive electricity  
14 suppliers to obtain a percentage of their retail electricity sales from eligible renewable resources  
15 according to the following schedule:

- 16 • 5 percent for compliance years 2008–2009 (1/1/2008–12/31/2009)
- 17 • 10 percent for compliance years 2010–2014 (1/1/2010–12/31/2014)
- 18 • 15 percent for compliance year 2015 (1/1/2015–12/31/2015) and for each year  
19 thereafter

20  
21 Eligible facilities must begin operation after January 1, 2005, and must be either located in  
22 Montana or located in another state and be delivering electricity into Montana.

23  
24 Utilities and competitive suppliers can meet the standard by entering into long-term purchase  
25 contracts for electricity bundled with RECs, by purchasing the RECs separately, or a  
26 combination of both.

1 The relationship between each exchanging utility’s annual RPS requirement and the amount of  
2 renewable resource megawatthours and RECs is shown in Table 7.10 of the Documentation.

### 3 4 **7.8.2 Treatment of RPS Requirements in ASC Forecast Model**

5 For certain utilities, additional renewable resources not specifically included in the individual  
6 IRPs were added so that each utility met RPS requirements through 2028. Avista fell slightly  
7 below RPS requirements in a few years, because the model did not include several small  
8 upgrades to existing hydro resources. When the upgrades are included, Avista meets RPS  
9 requirements in all years through 2028. Wind resources were also added to NorthWestern to  
10 meet its RPS requirements. For PGE and Snohomish, additional wind resources were added  
11 after 2021, the end of their IRP planning window. Clark’s IRP stated that it would purchase  
12 RECs to meet RPS targets in certain years. Clark estimated that the price of a REC is \$20/MWh  
13 in 2012.

### 14 15 **7.8.3 Load Forecasts**

16 The load forecast portion of this Study shows the loads for FY 2009–2032. For FY 2009–2017,  
17 BPA used the loads that were filed in each IOU’s 2009 Base Year Appendix 1. BPA used its  
18 own COU load forecasts as was agreed upon in the TRM. For the Long-Term Period for IOUs,  
19 BPA escalated the utility’s ending year FY 2017 load forecast out to FY 2032, using the  
20 percentage load growth forecast published in the utility’s IRP, if available. Tables 7.8.1 through  
21 7.8.8 present each utility’s long-term load forecast for FY 2009–2032.

#### 22 23 **7.8.3.1 Avista Corporation**

24 This Study used Avista’s retail load forecast from the 2009 Base Year Appendix 1 Final ASC  
25 Report for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the  
26 following:

- 1 1. Avista reported in its 2009 IRP that retail load would grow by 1.8 percent from 2009 to  
2 2029. See Avista’s 2009 Electric Integrated Resource Plan, August 31, 2009, at 2–11.  
3 Avista did not report the level of load in 2029. BPA forecast Avista’s FY 2029 Total  
4 Retail Sales based on this growth rate to be 12,794,413 MWh.

5 
$$FY\ 2029\ Total\ Retail\ Sales = FY\ 2009\ Total\ Retail\ Sales \times (1 + .018)^{20}$$

6 
$$FY\ 2029\ Total\ Retail\ Sales = 12,794,413\ MWh$$

- 7  
8 2. BPA then calculated the growth rate from the Final ASC Report FY 2017 Total Retail  
9 Sales that would result in the forecast FY 2029 Total Retail Sales.

10 
$$Growth\ Rate\ FY\ 2017-2029 = ((FY\ 2029\ Total\ Retail\ Sales / FY\ 2017\ Total$$
  
11 
$$Retail\ Sales)^{(1/12)} - 1$$

- 12  
13 3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 1.74 percent  
14 load growth percentage.

15  
16 Table 7.8.1 in the Documentation shows the load forecast from Avista’s 2009 Base Year  
17 Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads for  
18 the years FY 2018–2032 as determined from Avista’s IRP load growth percentage.

19  
20 **7.8.3.2 Clark County PUD**

21 The load forecast used in the LTAFM for Clark is shown in Table 7.8.2 of the Documentation.

22  
23 **7.8.3.3 Idaho Power Company**

24 This Study used Idaho Power’s retail load forecast from the 2009 Base Year Appendix 1 Final  
25 ASC Report for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the  
26 following:



1 1. Idaho Power reported in its 2009 IRP that retail load would grow by 0.70 percent from  
2 2009 to 2029. See Idaho Power’s 2009 Electric Integrated Resource Plan, Appendix C,  
3 December 2009, at 35. Idaho Power did not report the level of load in 2029. BPA  
4 forecast Idaho Power’s FY 2029 Total Retail Sales based on this growth rate to be  
5 16,116,331 MWh.

$$6 \quad \text{FY 2029 Total Retail Sales} = \text{FY 2009 Total Retail Sales} \times (1 + .725) ^ {20}$$

$$7 \quad \text{FY 2029 Total Retail Sales} = 16,116,331 \text{ MWh}$$

8  
9 2. BPA then calculated the growth rate from the Final ASC Report FY 2017 Total Retail  
10 Sales that would result in the forecast FY 2029 Total Retail Sales.

$$11 \quad \text{Growth Rate FY 2017–2029} = ((\text{FY 2029 Total Retail Sales} / \text{FY 2017 Total}$$
$$12 \quad \text{Retail Sales}) ^ {(1/ 12)}) - 1$$

13  
14 3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 0.16 percent  
15 load growth percentage.

16 Table 7.8.3 in the Documentation shows the load forecast from Idaho Power’s 2009 Base Year  
17 Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads for  
18 the years FY 2018–2032 as determined from Idaho Power’s IRP load growth percentage.

#### 19 20 **7.8.3.4 NorthWestern Corporation**

21 This Study used NorthWestern’s retail load forecast from the 2009 Base Year Appendix 1 Final  
22 ASC Report for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the  
23 following:

24 1. NorthWestern reported in its 2009 IRP that retail load would grow by 0.80 percent from  
25 2009 to 2029. See NorthWestern’s 2009 Electric Default Supply Procurement Plan,  
26 June 2010, at 112. NorthWestern did not report the level of load in 2029. BPA forecast

1 NorthWestern's FY 2029 Total Retail Sales based on this growth rate to be  
2 6,811,234 MWh.

$$3 \quad \text{FY 2029 Total Retail Sales} = \text{FY 2009 Total Retail Sales} \times (1 + .008)^{20}$$

$$4 \quad \text{FY 2029 Total Retail Sales} = 6,811,234 \text{ MWh}$$

- 5
- 6 2. BPA then calculated the growth rate from the Final ASC Report FY 2017 Total Retail  
7 Sales that would result in the forecast FY 2029 Total Retail Sales.

$$8 \quad \text{Growth Rate FY 2017-2029} = ((\text{FY 2029 Total Retail Sales} / \text{FY 2017 Total}$$
$$9 \quad \text{Retail Sales})^{(1/12)}) - 1$$

- 10
- 11 3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 0.72 percent  
12 load growth percentage.

13

14 Table 7.8.4 in the Documentation shows the load forecast from NorthWestern's 2009 Base Year  
15 Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads for  
16 the years FY 2018–2032 as determined from NorthWestern's IRP load growth percentage.

### 17

#### 18 **7.8.3.5 PacifiCorp**

19 This Study used PacifiCorp's retail load forecast from the 2009 Base Year Appendix 1 Final  
20 ASC Report for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the  
21 following:

- 22 1. PacifiCorp reported in its 2009 IRP that its regional retail load would grow by  
23 approximately 1.13 percent annually from 2009 to 2028. *See* PacifiCorp's 2009 Electric  
24 Integrated Resource Plan, May 28, 2009, at 71. PacifiCorp did not report the level of  
25 load in 2028. BPA escalated PacifiCorp's total regional retail Sales by the annual growth  
26 rate of 1.13 percent for the FY 2018-2032 period.

1 Table 7.8.5 in the Documentation shows the load forecast from PacifiCorp’s 2009 Base Year  
2 Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads for  
3 the years FY 2018–2032 as determined from PacifiCorp’s IRP load growth percentage.

#### 4 5 **7.8.3.6 Portland General Electric**

6 This Study used Portland General’s retail load forecast from the 2009 Base Year Appendix 1  
7 Final ASC Report for the years FY 2009–2017. For the FY 2018–2032 period, the Study used  
8 the following:

- 9 1. Portland General reported in its 2009 IRP that retail load would grow by 1.91 percent  
10 from 2009 to 2030. *See* Portland General’s 2009 Electric Integrated Resource Plan,  
11 2009, at 37. Portland General did not report the level of load in 2030. Therefore, BPA  
12 forecast Portland General’s FY 2030 Total Retail Sales based on this growth rate to be  
13 23,797,064 MWh.

$$14 \quad \text{FY 2030 Total Retail Sales} = \text{FY 2009 Total Retail Sales} \times (1 + .0191)^{21}$$

$$15 \quad \text{FY 2030 Total Retail Sales} = 23,797,064 \text{ MWh}$$

- 16  
17 2. BPA then calculated the growth rate from the Final ASC Report FY 2017 Total Retail  
18 Sales that would result in the forecast FY 2030 Total Retail Sales.

$$19 \quad \text{Growth Rate FY 2017–2030} = ((\text{FY 2030 Total Retail Sales} / \text{FY 2017 Total} \\ 20 \quad \text{Retail Sales})^{(1/13)}) - 1$$

- 21  
22 3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 1.75 percent  
23 load growth percentage.

1 Table 7.8.6 in the Documentation shows the load forecast from Portland General’s 2009 Base  
2 Year Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads  
3 for the years FY 2018–2032 as determined from Portland General’s IRP load growth percentage.  
4

### 5 **7.8.3.7 Puget Sound Energy**

6 This Study used Puget’s retail load forecast from the 2009 Base Year Appendix 1 Final ASC  
7 Report for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the  
8 following:

- 9 1. Puget reported in its 2009 IRP that retail load would grow by 1.95 percent from 2009 to  
10 2027. *See* Puget’s 2009 Electric Integrated Resource Plan, July 2009, at 4–14. Puget did  
11 not report the level of load in 2027. Therefore, BPA forecast Puget’s FY 2027 Total  
12 Retail Sales based on this growth rate to be 30,984,120 MWh prior to adjustments for  
13 conservation or demand side resources.

$$14 \quad \text{FY 2027 Total Retail Sales} = \text{FY 2009 Total Retail Sales} * (1 + .0195)^{18}$$

$$15 \quad \text{FY 2027 Total Retail Sales} = 30,984,120 \text{ MWh}$$

- 16  
17 2. In its 2009 IRP, Puget reported that 533 aMW (or 4,669,080 MWh) of load growth would  
18 be met with demand side resources. *See* Puget’s 2009 Electric Integrated Resource Plan,  
19 July 2009, at 8–7. BPA subtracted the 4,669,080 MWh from the FY 2027 total retail  
20 sales before conservation to get Total Retail Sales after conversation of 26,315,040  
21 MWh.

- 22  
23 3. BPA then calculated the growth rate from the Final ASC Report FY 2017 Total Retail  
24 Sales that would result in the forecast FY 2027 Total Retail Sales.

$$25 \quad \text{Growth Rate FY2017–2027} = ((\text{FY 2027 Total Retail Sales} / \text{FY 2017 Total}$$
$$26 \quad \text{Retail Sales})^{(1/10)}) - 1$$

1 3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 1.72 percent  
2 load growth percentage.

3  
4 Table 7.8.7 in the Documentation shows the load forecast from Puget's 2009 Base Year  
5 Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads for  
6 the years FY 2018–2032 as determined from Puget's IRP load growth percentage.

### 7 8 **7.8.3.8 Snohomish County PUD**

9 The load forecast used in the LTAFM for Snohomish PUD is shown in Table 7.8.8 of the  
10 Documentation.

## 11 12 **7.9 Resource Additions**

13 This section includes the forecast new resource additions through 2028. This Study assumes the  
14 following:

- 15 • The new resources for 2010 through FY 2012–2013 are the same as the resources  
16 filed in each utility's ASC filing for FY 2012–2013.
- 17 • BPA used the utility's most recent IRP for the basis for new resource additions  
18 through the 2028 forecast period.
- 19 • Resources identified in the IRP as becoming operational during the Exchange  
20 Period, but not identified in the utility's ASC filing, were assumed to be delayed  
21 and brought on in FY 2014.
- 22 • If the utility's IRP did not extend through 2028, BPA did not add new resource  
23 additions for the outyears not covered in the IRP except for RPS Compliance.  
24 Instead, BPA assumed load growth was met with market purchases.
- 25 • BPA tested for RPS compliance. If a utility did not comply with the RPS  
26 requirements, BPA met the requirements with regional wind additions.

1 **7.9.1 Avista Corporation**

2 New resources for Avista are shown in Table 7.11. Table 7.11 is consistent with Avista’s 2009  
3 Preferred Resource Strategy with the exception of 150 MW of wind coming online in 2014.  
4 Because this wind resource was not included in Avista’s 2009 ASC filing, the on-line date was  
5 delayed in the LTAFM until 2014. *See* Avista’s 2009 Electric Integrated Resource Plan,  
6 August 31, 2009.

7  
8 **7.9.2 Clark County PUD**

9 New resources for Clark PUD are shown in Table 7.12. Table 7.12 is consistent with Clark’s  
10 2010 preferred Portfolio 1 from its IRP. *See* Clark Public Utilities Final Integrated Resource  
11 Plan, August 2010, at C-1. The REC purchases in 2015 and 2020 are also based on Clark’s 2010  
12 Portfolio 2 analysis of RPS Requirements versus Renewable Purchases. *See* Clark’s Final  
13 Integrated Resource Plan at 70.

14  
15 **7.9.3 Idaho Power Company**

16 New resources for Idaho Power are shown in Table 7.13. Table 7.13 is consistent with Idaho  
17 Power’s 2009 Action Plan in its IRP with the exception of the 20 MW of geothermal, which is  
18 shown in the table as coming on line in 2014. Because the geothermal resource was not included  
19 in Idaho Power Company’s 2009 ASC filing, the on-line date was delayed until 2014 in the ASC  
20 Forecast Model. *See* Idaho Power Company’s 2009 Integrated Resource Plan, December 2009,  
21 at 123-124.

22  
23 **7.9.4 NorthWestern Corporation**

24 New resources for NorthWestern are shown in Table 7.14. Table 7.14 is consistent with  
25 NorthWestern’s 2009 Action Plan in its IRP (Electric Default Supply Procurement Plan). *See*  
26 NorthWestern’s 2009 Electric Default Supply Procurement Plan, June 2010, at 157.

1 **7.9.5 PacifiCorp**

2 New resources for PacifiCorp are shown in Table 7.15. Table 7.15 is based on PacifiCorp's  
3 2008 IRP preferred portfolio, with a few exceptions. First, because PacifiCorp's IRP was  
4 published in 2008, the wind resources projected to come on line in 2009 were already reflected  
5 in PacifiCorp's 2009 FERC Form 1 filing and thus are contained in PacifiCorp's existing  
6 resources. See PacifiCorp's 2008 Integrated Resource Plan, Volume I, May 28, 2009, at 245,  
7 and PacifiCorp's 2009 FERC Form 1, pages 410-411. Second, the Blundell Geothermal  
8 resource, projected to come on line in 2013, was delayed until 2014 in the LTAFM because it  
9 was not included in PacifiCorp's 2009 ASC filing. Third, the values for "Long Haul Wind" and  
10 "Wind" shown in 2014 represent the sum of individual wind plants projected to come on line  
11 between 2010 and 2014 but not included in PacifiCorp's 2009 ASC filing. Fourth, the values  
12 shown for PacifiCorp's new resource additions in the LTAFM represent the Oregon,  
13 Washington, and Idaho share, or 40.98 percent of the actual values. This factor is the same one  
14 used by PacifiCorp to allocate total system generation to Oregon, Washington, and Idaho in its  
15 ASC filings. Finally, after 2021, PacifiCorp's IRP assumed that load growth would be met with  
16 front-office (purchased power) transactions. Because the ASC Forecast Model already contains  
17 logic to cover load/resource deficits with purchased power, the front-office transactions were not  
18 included.

19  
20 **7.9.6 Portland General Electric**

21 New resources for Portland General are shown in Table 7.15. Table 7.16 is consistent with  
22 Portland General's 2009 IRP with the exception of the four wind resources added after 2021.  
23 Because PGE's IRP did not extend beyond 2021, the wind resources were added to meet RPS  
24 requirements. See Portland General Electric's 2009 Integrated Resource Plan Addendum,  
25 April 9, 2010, at 119.

1 **7.9.7 Puget Sound Energy**

2 New resources for Puget are shown on Table 7.17. Table 7.17 is consistent with Puget’s 2009  
3 IRP, with two exceptions. Puget included in its IRP 300 MW of wind resources projected to  
4 come on line 2011 and 2012 but did not include them in its 2009 ASC filing. However, Puget’s  
5 ASC filing did include a new wind resource (LSR) with a nameplate capacity of 343 MW,  
6 projected to come on line in 2012. The LFAFM used the LSR wind resource in place of the  
7 2011 and 2012 wind resources contained in Puget’s IRP.

8  
9 **7.9.8 Snohomish County PUD**

10 New resources for Snohomish PUD are shown in Table 7.18. Table 7.18 agrees with  
11 Snohomish’s preferred plan as contained in its 2010 IRP with the exception of wind resources,  
12 which in the above table are added beginning in 2020 in order to comply with RPS requirements.  
13 *See* Snohomish County PUD’s 2010 Integrated Resource Plan, August 17, 2010, at 4.



## 8. RISK FACTORS

### 8.1 Risk Factors Affecting BPA Rates and ASCs

BPA and REP participants face numerous risks that can impact the level of future REP benefits, since they ultimately impact the costs and/or the revenues of BPA and the REP utilities. Some of these risks impact both the PF rate and ASCs, while other risks primarily impact one or the other. Because COU REP participants purchase much of their power from BPA and the cost of BPA purchases is included in ASCs, risks to BPA can directly translate into ASC risk for COU REP participants. Some of these risks are in existence now and impact current financial conditions, some are currently foreseeable but lack specificity, and some are unforeseen but will likely occur over the course of a 17-year period.

In this section, the words “risk” and “uncertainty” are used interchangeably. Generally, each can have both up-side (beneficial) and down-side (harmful) possibilities, and thus a reference to “risk” in this discussion signifies the possibility of events occurring that can impact expected future outcomes, generally future rate levels.

#### 8.1.1 Gas and Electric Market

Natural gas market conditions are important for two reasons. First, natural gas prices affect the overall cost of generation for utilities with gas-fired generation in their portfolios. Second, when natural gas-fired resources are the marginal unit dispatched, the price of natural gas determines the variable cost for that marginal generator and hence, the market-clearing price of electricity. Higher natural gas prices increase the cost of producing electricity and thus the ASCs of the utilities that rely on gas-fired generation. Lower natural gas prices reduce the cost of producing electricity and thus the ASCs of the utilities that rely on gas-fired generation. Natural gas prices have historically been very volatile and can materially change the level of an ASC.

1 Changes in electricity market prices can impact the cost of producing power and the prices paid  
2 and received for buying and selling energy on the wholesale power market. Two changes in the  
3 electricity market that are of particular importance to the calculation of ASCs are state or federal  
4 Renewable Portfolio Standards and the potential impact of carbon dioxide (CO<sub>2</sub>) costs being  
5 reflected in the cost of producing electricity from fossil fuels. Because BPA does not currently  
6 have gas-fired generation in its resource portfolio, BPA-related risks stemming from market  
7 prices are generally confined to the effects of wholesale electricity prices.

## 8 9 **8.1.2 Operating Cost Risk: Hydro (Including Fish), Columbia Generating Station** 10 **(CGS), Wind**

### 11 **8.1.2.1 Hydro Generation Risk Impacts**

12 The amount of Federal hydro generation impacts the amount of surplus energy BPA can sell, the  
13 amount of power BPA needs to purchase, and the level of the revenue credits used when  
14 calculating rates for PF customers. BPA faces not only the financial risk of reductions in the  
15 amount of hydro generation, but also higher capital and expense costs associated with meeting  
16 fish-related operational requirements. That is, hydro generation can be reduced due to additional  
17 hydro spill requirements, and monthly and hourly hydro generation can be reshaped into less  
18 valuable time periods, due to hydro operation changes specified in current and future fish-related  
19 requirements for the Columbia and Willamette dams. Litigation of such operational  
20 requirements also may result in additional generation loss or reshaping.

21  
22 Future fish mitigation requirements may result in higher capital costs and expenses, especially if  
23 additional fish passage is required at the Columbia and Willamette dams. It is likely that  
24 additional outlays will be required for the dams and fish passage structures associated with  
25 mussel control measures. An additional risk is the impact that global climate change may have  
26 on the amount and monthly shape of future hydro generation. Capital investments and O&M  
27 expenses associated with maintaining the capability of the Federal dams in the future also are

1 unknown and may exceed current forecasts. The risks enumerated above are primarily focused  
2 on BPA's rates and COU ASCs.

#### 3 4 **8.1.2.2 CGS Generation Risk Impacts**

5 The level of output from the Columbia Generation Station impacts the amount of energy BPA  
6 can sell and the amount of power BPA needs to purchase to meet its sales obligations. CGS  
7 generation risks include the amount of output produced and the level of capital expenditures and  
8 O&M costs to maintain the plant's output as it ages. The prices paid for nuclear fuel on the spot  
9 and forward markets are volatile and represent a sizable cost risk. CGS risks could lead to higher  
10 BPA rate levels in the future and higher COU ASCs.

#### 11 12 **8.1.2.3 Wind Generation Risk Impacts**

13 The financial impacts of increasing amounts of wind generation in BPA's Balancing Authority  
14 Area are most likely to impact BPA in terms of reduced surplus energy revenues, resulting in  
15 higher BPA rates. BPA seeks to recover the costs associated with higher wind penetration levels  
16 from those benefiting from BPA providing interconnection services. However, such may not be  
17 possible to the extent that surplus energy revenues are reduced by the impact that increased  
18 quantities of low variable cost (but high fixed cost) wind generation can have on electricity  
19 prices. As wind penetration levels continue to rise, passing additional costs to the beneficiaries  
20 of this service may lag until there is adequate data to support such cost recovery. These wind  
21 generation risks could lead to higher BPA rate levels and higher ASCs due to higher charges for  
22 wind integration services for utilities that own or purchase wind generation.

#### 23 24 **8.1.3 RPS, Carbon, and Other Environmental Mandates**

25 Renewable resource additions to meet RPS requirements are likely to increase BPA's rates  
26 (primarily due to reduced net secondary revenues) and increase ASCs. The impact on REP

1 benefits under such conditions is not clear, but rather is dependent on the relative magnitude of  
2 the change in BPA's rate levels compared to ASC levels. The change in BPA rates will depend  
3 on the amount of wind generation that is built in the PNW to serve the PNW or California and  
4 how much of the wind generation built for California is physically delivered to California, rather  
5 than left in the PNW with the environmental attributes of the wind generation being claimed by  
6 California utilities. The cost of wind resources in ASCs will be impacted by whether Federal  
7 production/investment tax credits remain available. These tax credits reduce the prices that wind  
8 generators need to receive in their contracts with utilities, which can reduce the costs of these  
9 resources in ASCs.

10  
11 There is currently much uncertainty in terms of whether, when, where, and how CO<sub>2</sub> markets  
12 will be implemented. BPA rate levels are more likely to benefit from the reflection of CO<sub>2</sub> costs  
13 in electricity market prices relative to ASC levels, because the generation that BPA sells is  
14 almost entirely hydro and nuclear generation (which emits almost no CO<sub>2</sub>). In contrast, both  
15 IOU and COU REP participants' generation is mostly from coal and natural gas-fired resources  
16 that emit substantial amounts of CO<sub>2</sub>. For this reason, BPA generation will likely be assigned  
17 very little CO<sub>2</sub> costs and would benefit from higher electricity prices for its net secondary  
18 revenues (which lower BPA rates). Depending on the resource mix of each utility (which can  
19 vary considerably), the IOUs and COUs would pay the CO<sub>2</sub> costs, but they may also benefit from  
20 higher electricity prices. The net impact is that ASCs will likely increase for all the IOUs and  
21 COUs; although likely to a lesser extent for COUs with substantial purchases at lower BPA rates.

#### 22 23 **8.1.4 Measuring the High and Low BPA Rate Effects**

24 Risk analysis scenarios are performed to assess the potential impact that high, medium, and low  
25 BPA resource costs and high, medium, and low CO<sub>2</sub> costs might have on REP benefits under  
26 high, medium, and low natural gas prices. Other than the probabilities associated with the high

1 and low natural gas prices, no probabilities are assigned to each of the risk analysis scenarios  
2 developed to assess the range of possible rate levels and REP benefits under plausible potential  
3 outcomes. The financial impacts of the changes in the risk analysis scenarios are accounted for  
4 in the Long Term Rate Model in terms of changes in surplus energy revenues, balancing power  
5 purchase expenses, augmentation purchase expenses, and the BPA revenue requirement. The  
6 risk analysis scenarios assume that the risks occur during the FY 2012–2017 period, with the  
7 impact carried through 2032 using common escalation assumptions. Uncertainty in the timing of  
8 when the risks might occur is not included in this analysis.

9  
10 Annual average energy prices for BPA’s surplus energy sales are derived by dividing median  
11 annual surplus energy revenues by average annual surplus energy sales, reported in Table 23 of  
12 the Power Risk and Market Price Study Documentation, BP-12-FS-BPA-04A. These annual  
13 average surplus energy prices reflect the overall impact of when and how much surplus energy  
14 BPA sells each month. Annual average implied heat rates for BPA’s surplus energy sales are  
15 then derived by dividing the annual average surplus energy prices by the forecast annual natural  
16 gas prices at Stanfield, Oregon. Given these annual average implied heat rates, changes in  
17 annual surplus energy revenues are computed under different natural gas price levels by  
18 multiplying the alternative natural gas prices by the implied heat rates and the number of  
19 megawatthours of annual surplus energy sales.

20  
21 High and low trajectories of natural gas prices are derived from simulated annual FY 2012–2017  
22 natural gas price data for 3,500 games developed for the BP-12 final proposal. The methodology  
23 used for simulating the natural gas prices is documented in the Power Risk and Market Price  
24 Study, BP-12-FS-BPA-04. The first step in the process of developing these natural gas price  
25 trajectories involves calculating average annual natural gas prices from FY 2012–2017 for each  
26 of the 3,500 games, developing a cumulative probability of these values by sorting them from

1 lowest to highest, and determining what the values are at the 5th and 95th percentiles. The  
2 second step in the process is to develop a cumulative probability distribution of natural gas prices  
3 for each fiscal year from FY 2012 to FY 2017 by sorting results for the 3,500 games from lowest  
4 to highest and calculating the average price for each cumulative probability value over FY 2012–  
5 2017. The final step in the process is to identify the set of sorted FY 2012–2017 prices at a given  
6 cumulative probability level that average the natural gas prices determined at the 5 percent and  
7 95 percent values in the first step.

8  
9 Table 8.1 of the Documentation reports the FY 2012–2017 high, median, and low natural gas  
10 prices used in this analysis, the derived annual average surplus energy prices, the derived implied  
11 heat rates, and the median surplus energy revenues under high, median, and low natural gas  
12 prices. The Long Term Rate Model uses these results to calculate the BPA rate impacts  
13 associated with changes in surplus energy revenues and the ASC impacts associated with  
14 changes in the natural gas prices.

15  
16 Low, medium, and high CO<sub>2</sub> costs are accounted for in the risk analysis scenarios assuming no  
17 CO<sub>2</sub> prices and initial CO<sub>2</sub> prices of \$20.00/ton and \$40.00/ton in FY 2012 that escalate at a real  
18 annual rate of 5.0 percent and at an inflation rate of 2.5 percent through FY 2017. In order to  
19 convert these CO<sub>2</sub> prices into the impact on electricity prices (\$/MWh), it is assumed in this  
20 analysis that 40 percent of the price of CO<sub>2</sub> per ton is reflected in the electricity prices. This  
21 value assumes the marginal resource is a gas-fired resource with a heat rate of 8,000 Btu/kWh.

22  
23 FY 2012–2017 surplus energy revenues under the \$20/ton and \$40/ton alternatives under high,  
24 median, and low natural gas prices are calculated and input into the Long Term Rate Model to  
25 determine the impact that these changes have on PF rates. The carbon prices for the high and  
26 medium CO<sub>2</sub> scenarios are input into the Long Term Rate Model as \$/MWh deltas to the BP-12

1 market price curve and are accounted for in the model in two ways. First, these prices are used  
2 in the computation of ASCs through adjusting the assumed market value for each exchanging  
3 utility's open position on market purchases and sales. Second, for the reference case, these  
4 prices are used to meet 50 percent of load growth through market purchases. The results from  
5 the risk analysis scenarios (which produce deltas to the secondary energy credit) are converted  
6 into ratios that are applied to the secondary energy and balancing purchase prices, such that the  
7 resulting secondary energy revenues and balancing purchase expenses incorporate an equivalent  
8 dollar delta. Individual ratios of the high and medium CO<sub>2</sub> price to the base market price are  
9 computed. These ratios are then applied to the augmentation price, increasing the augmentation  
10 price in the same proportion for each of the high and medium CO<sub>2</sub> price scenarios. Tables 8.2.1  
11 and 8.2.2 of the Documentation report the results of these risk analysis scenarios.

12  
13 High and low resource cost scenarios are computed by evaluating the rate impact of high and low  
14 nuclear fuel costs and potential future reductions in resource output from existing resources (for  
15 the high resource cost scenario). The medium resource cost scenario reflects base case values  
16 used in the BP-12 final proposal. The impact of changes in nuclear fuel costs is reflected in the  
17 Long Term Rate Model in terms of the amounts of dollars in the revenue requirement. The  
18 impact of potential future reductions in resource output is reflected in the Long Term Rate Model  
19 in terms of reductions in surplus energy revenues.

20  
21 The high resource cost scenario evaluates the rate impact of high nuclear fuel costs and potential  
22 future reductions in annual resource output from existing resources of 250 aMW. The low  
23 resource cost scenario assumes no future reductions in annual resource output and evaluates the  
24 impact that low nuclear fuel costs might have on reducing BPA's rates. The assumed future  
25 reduction in annual resource output was subjectively determined and is meant to account for the  
26 potential impact of a variety of both currently known and unknown factors. Such factors could,

1 over the course of the 17-year contract period, reduce generation and/or increase capital  
2 investment or O&M costs from the values reflected in current generation output estimates and  
3 expenses accounted for in the revenue requirement during FY 2012–2017.

4  
5 The costs of converting uranium into the nuclear fuel used in reactors include the costs of the  
6 raw uranium (referred to as yellow cake or U308), conversion services, and enrichment services.  
7 The quantity of product produced at each step decreases throughout the process. In this analysis,  
8 the changes in costs of nuclear fuel for CGS are computed by multiplying the annual reactor  
9 requirements (specified in terms of quantity) at each of these steps times the associated costs.  
10 The annual reactor requirements are based on values reported by Energy Northwest. The  
11 FY 2012–2015 forward market prices for raw uranium used in the base case scenario, and from  
12 which the revisions in nuclear fuel costs are computed for the high and low scenarios, are based  
13 on prices quoted on 06/30/2011 at the following Web site:

14 [http://www.cmegroup.com/trading/metals/other/uranium\\_quotes\\_globex.html](http://www.cmegroup.com/trading/metals/other/uranium_quotes_globex.html)

15  
16 Because forward price quotes were not available for FY 2016–2017, the FY 2015 price quotes  
17 are used for these years. The base case cost for enrichment services per Separative Work Unit is  
18 based on a value reported by Energy Northwest. The base case cost for conversion services per  
19 kilogram of uranium (kgU) is based on making a modest increase in this cost (\$.025 per kgU)  
20 from the historical data reported from January 2002 through December 2007 by Ux Consulting  
21 Company, LLC. See Web site at [http://www.uxc.com/review/uxc\\_PriceTable.aspx](http://www.uxc.com/review/uxc_PriceTable.aspx).

22  
23 Assumptions regarding the potential variability in nuclear fuel cost risk, which are reflected in  
24 terms of high and low multiplier factors in this analysis, were not explicitly derived from the  
25 historical data from Ux Consulting, but values reported in the Ux data were considered when  
26 determining those assumptions.



1 Values used in deriving the nuclear fuel cost scenarios and the resource cost scenarios are  
2 reported in Tables 8.3.1 through 8.3.4 of the Documentation.

## 3 4 **8.2 Summary**

5 Uncertainty is one thing that is certain when considering future rate levels. The risks discussed  
6 in this section will affect future BPA rates and utilities' ASCs. What is unknown is the timing of  
7 the risks and the magnitude of the risks. As discussed above, some risks affect both BPA's rates  
8 and utilities' ASCs, while others have differential effects on BPA's rates and utilities' ASCs.

9 This section presents a qualitative discussion of future risks and their effects on rate levels and a  
10 limited quantitative analysis of the effect of the risks on rate levels. The quantitative analysis is  
11 used in forming the effect of rate level differentials from a base case projection of future rate  
12 levels. These rate level differentials are aggregated into scenarios in the Settlement analysis, as  
13 discussed in the next section.

14  
15 Impacts of this risk analysis on REP benefits are shown in Figure 1 of this Study. Section 8 of  
16 the Documentation includes tables that show the complete impact of this risk analysis on rates  
17 and REP benefits.

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1 would have received under the traditional implementation of the REP pursuant to sections 5(c)  
2 and 7(b) of the Northwest Power Act. IOUs that received more in REP benefits under the 2000  
3 REP Settlement Agreement than allowed by sections 5(c) and 7(b)(2) of the Act were assessed a  
4 refund obligation known as a “Lookback Amount.” BPA decided to recover the Lookback  
5 Amounts from the IOUs by withholding future benefits owed to the IOUs under the REP and  
6 issuing refunds to the injured COUs. WP-07 Supplemental ROD, WP-07-A-05, at 253-294.

7  
8 In the WP-07 Supplemental ROD, BPA determined that the COUs had been overcharged by  
9 approximately \$1.003 billion during the FY 2002–2008 period. This amount was subsequently  
10 revised to \$985.2 million as a result of the settlement of the Avista deemer account. Lookback  
11 Recovery and Return, WP-10-BPA-FS-07, at 3. To return these overcharges to the injured  
12 COUs, BPA proposed to provide the COUs with an initial lump-sum cash payment in 2008 and  
13 then return the remaining overcharges through future reductions to REP benefit payments of  
14 applicable IOUs. By the end of FY 2011, a total of \$587 million in Lookback Amount  
15 payments, including interest, will have been paid back to COUs. FY 2012–2013 Lookback  
16 Recovery and Return Study, REP-12-E-BPA-03 at 6; Table 2.

17  
18 Parties to the WP-07 Supplemental rate proceeding disputed many of BPA’s Lookback-related  
19 decisions. BPA’s decisions were appealed to the Ninth Circuit Court of Appeals and have been  
20 fully briefed in the *APAC* and *IPUC* cases. The following subsections summarize the parties’  
21 respective litigation positions regarding BPA’s Lookback-related determinations. These  
22 descriptions are not intended to be legal evaluations of the parties’ positions and should be read  
23 as BPA’s understanding of the relevant issues for purposes of analyzing the Settlement. For a  
24 comprehensive review of the parties’ legal positions, please refer to the litigants’ briefs, which  
25 are included in the Study Documentation for the Initial Proposal, REP-12-E-BPA-01A.

26

1 **9.2.1 No Lookback Proposition**

2 **9.2.1.1 Invalidity Clause**

3 The IOUs argue that no Lookback Amounts are owed to COUs because the 2000 REP  
4 Settlement Agreements included an “Invalidity Clause.” In describing the Invalidity Clause, the  
5 IOUs allege that BPA agreed to forgo recovery of past settlement payments if the settlement  
6 agreements were deemed “unlawful, void, or unenforceable” by the Court. IOU *IPUC* Br. at 1.  
7 The IOUs allege that BPA’s Lookback construct violates the Invalidity Clause because it  
8 recovers past payments made under the 2000 REP Settlement Agreement through prospective  
9 reductions in REP benefit payments made under Northwest Power Act section 5(c). The IOUs  
10 also contend that enforcing the Invalidity Clause is consistent with the Court’s opinions in *PGE*  
11 and *Golden NW* because neither decision declared the 2000 REP Settlement Agreements to be  
12 void in their entirety. *Id.* at 32–39. The IOUs believe the Invalidity Clause was severable from  
13 the illegal portions of the 2000 REP Settlement and should be enforced in accordance with its  
14 terms. *Id.* at 29–32; *see also* IOU *APAC* Br. at 32, OPUC *APAC* Br. at 34; CUB *IPUC* Br. at 12.

15  
16 If the IOUs were to prevail on their argument that the Invalidity Clause is enforceable as of the  
17 date of the Court’s ruling (May 4, 2007), BPA assumes that the \$237.6 million in FY 2002–2006  
18 Lookback Amounts recovered from the IOUs in FY 2009–2011, and paid to the COUs, would  
19 have to be returned to the IOUs. BPA also assumes that the remaining portions of the Lookback  
20 Amount would not be recoverable.

21  
22 **9.2.1.2 Retroactive Rulemaking and Ratemaking**

23 The OPUC argues that BPA’s Lookback proposal is faulty because it comprises retroactive  
24 rulemaking. OPUC *APAC* Br. at 12–15. The OPUC contends that the Lookback is a retroactive  
25 rule because it revises BPA’s previously established rulemaking (in this case, the WP-02 rates).  
26 *Id.* at 15–16. The OPUC contends that because BPA does not have express statutory authority to

1 engage in retroactive rulemaking, the Lookback proposal is unlawful. *Id.* at 19; *see also* OPUC  
2 *APAC* Reply Br. at 7.

3  
4 The IPUC similarly argues that BPA’s Lookback proposal violates the general prohibition  
5 against retroactive ratemaking. IPUC *APAC* Br. at 21–24. The IPUC contends that BPA does  
6 not have express statutory authority to engage in retroactive ratemaking, and therefore, there is  
7 no basis for BPA to conduct the Lookback. *Id.* at 24–31; *see also* IPUC *APAC* Reply Br. at 2.

8  
9 If either the OPUC or IPUC were to prevail on its argument, it is assumed that the \$237.6 million  
10 in Lookback Amounts that BPA has already collected from the IOUs, and paid to the COUs,  
11 would have to be returned to the IOUs. It is also assumed that the remaining portions of the  
12 Lookback Amount would not be recoverable.

13  
14 If refunds to the IOUs were required, BPA would need to decide how to fund those refunds.  
15 They could be paid for by simply raising rates to the COUs, or perhaps by recovering the credits  
16 that the COUs have received on their power bills in FY 2009–2011.

17  
18 In this case, because the WP-07 power rates had not yet received final approval from the  
19 Commission, they would not be affected by a ruling in favor of retroactive ratemaking. Hence,  
20 while the Lookback Amount up to that point in time would be extinguished, and the  
21 \$237.6 million of REP benefits recovered from the IOUs would need to be returned, a small  
22 Lookback Amount of \$55 million for FY 2007–2008 would remain. This amount results from  
23 the settlement payments paid to Avista and PacifiCorp that exceeded their reconstructed REP  
24 benefits. *See* FY 2002–2008 Lookback Study, WP-07-FS-BPA-08, at 282.

1 **9.2.1.3 Load Reduction Agreements (LRAs) Separate and Unchallenged**

2 Under the 2000 REP Settlement Agreements, BPA provided the IOUs access to approximately  
3 1900 aMW of benefits for the FY 2002–2006 period. Of this amount, 900 aMW of benefits were  
4 to be provided as financial payments and 1,000 aMW were to be provided as power, which  
5 could, however, be converted to financial payments by election of the customer. The  
6 1,000 aMW of power sales were to be provided through actual power deliveries under the terms  
7 of a Block Firm Power Sale Agreement, which was attached to the 2000 REP Settlement  
8 Agreements as Exhibit A.

9  
10 In 2001, extremely low water in the Federal hydrosystem, an extremely tight power supply on  
11 the West Coast, and extremely high and volatile wholesale market prices for power combined to  
12 portend a 250 percent or higher increase in BPA’s power rates for FY 2002–2006. BPA  
13 concluded that the most effective response to these circumstances was to reduce its costs by  
14 reducing its reliance on the high-priced electricity market. BPA therefore developed a three-  
15 pronged Load Reduction Program that involved conservation by consumers, reductions in power  
16 purchases from BPA by utilities, and load curtailments by the DSIs. One element of the Load  
17 Reduction Program involved BPA purchasing back approximately 620 aMW of power it was  
18 contractually obligated to provide to PacifiCorp and Puget for five years (the “Load Reduction  
19 Agreements” or “LRAs”). The Load Reduction Program proved tremendously successful,  
20 reducing a potential 250 percent (or higher) rate increase to only 46 percent. The LRAs with  
21 PacifiCorp and Puget were not challenged within 90 days, as required by the jurisdictional  
22 provisions of the Northwest Power Act.

23  
24 Because no timely challenges were filed against the LRAs, BPA proposed to allow PacifiCorp  
25 and Puget to retain the value of the LRAs when constructing the Lookback in the WP-07  
26 Supplemental rate proceeding. *See* BPA *APAC* Br. at 78. However, BPA did not entirely

1 exclude the LRAs from the Lookback calculation. Instead, BPA allowed PacifiCorp and Puget  
2 to retain the greater of their LRA payments or their revised REP benefits as determined in the  
3 Lookback (but not both). *Id.* at 78–80. This treatment of the LRA payments in BPA’s Lookback  
4 proposal, referred to as “protecting” the LRA payments, had the effect of increasing PacifiCorp’s  
5 and Puget’s respective Lookback Amounts.

6  
7 PacifiCorp and Puget oppose BPA’s decision to include the LRA payments in the Lookback  
8 calculation. IOU *APAC* Br. at 46–47. They contend that BPA should not have adopted the  
9 “greater than, but not both” methodology but instead should have completely removed the LRA  
10 payments from the Lookback calculation. *Id.*

11  
12 If PacifiCorp and Puget were to prevail on this argument, it is assumed that BPA would have to  
13 remove the LRA payments from BPA’s Lookback calculations. This adjustment would have the  
14 effect of reducing PacifiCorp’s Lookback Amount by approximately \$15.7 million and Puget’s  
15 Lookback Amount by approximately \$262 million. *See IOU APAC* Br. at 47. *See* Table 6.

#### 16 17 **9.2.1.4 Exclusion of Power Sales**

18 As noted above, the 2000 REP Settlement Agreements provided the IOUs with both cash  
19 payments and a firm power sale. When considering the amount of REP benefits the IOUs  
20 received under the 2000 REP Settlement Agreements, BPA included the market value of the  
21 power sold to PGE and the actual financial payments to Avista and Idaho Power that monetized  
22 what would have been a power sale.

23  
24 The IOUs allege that BPA improperly included in the Lookback calculation the value of the  
25 power BPA sold to the IOUs under the 2000 REP Settlement Agreements. *See IOU APAC* Br.  
26 at 37-45. The IOUs contend that the power sales made under the 2000 REP Settlement



1 Agreements were separate power sales made under section 5(b) of the Northwest Power Act and,  
2 therefore, were not invalidated by the Court’s decisions in *PGE* and *Golden NW*. *Id.* at 42–45.  
3 The IOUs also argue that the COUs’ rates were not adversely impacted by these sales because  
4 BPA would have sold the power to other parties at the same rate regardless of the settlement.  
5 *Id.* at 41, 44–45.

6  
7 If the IOUs were to prevail on this argument, it is assumed that BPA would have to remove the  
8 value of the power sales from the Lookback calculation for Avista, PGE, and Idaho Power. This  
9 adjustment would have the effect of reducing Avista’s, Idaho Power’s, and PGE’s FY 2002–  
10 2006 Lookback Amounts by the value attributed to the power sales and used in the calculation of  
11 these utilities’ Lookback Amounts, or approximately \$26.3 million, \$33.3 million, and  
12 \$144.2 million, respectively, prior to bringing the Lookback Amounts to 2009 dollars. *See IOU*  
13 *APAC Br.* at 40, 45.

#### 15 **9.2.1.5 Combined Effect of IOU Positions**

16 The combined effect of the IOU and related party positions is to reduce the initial FY 2002–2006  
17 Lookback Amounts established for each IOU to zero. To analyze the REP Settlement, in one  
18 scenario it is assumed that the \$237.6 million in Lookback Amount refunds that BPA has already  
19 collected from the IOUs, and paid to the COUs, would have to be returned to the IOUs. It is also  
20 assumed that the remaining portions of the Lookback Amount would not be recoverable. *See*  
21 section 10.4.1.

#### 23 **9.2.2 Large Lookback Proposition**

##### 24 **9.2.2.1 Use WP-02 Determinations**

25 In *Golden NW*, the Court remanded BPA’s WP-02 power rates to BPA with instructions “to set  
26 rates in accordance with this opinion.” Upon remand, BPA had to determine whether the

1 existing record was sufficient to reset rates. In order to correct overcharges to the COUs' rates,  
2 BPA determined to, in simple terms, compare the benefits the IOUs received under the 2000  
3 REP Settlement Agreements with the REP benefits the IOUs would have received in the absence  
4 of the settlement and under the traditional implementation of the REP, referred to as  
5 reconstructed REP benefits. The difference would be recovered from the IOUs and refunded to  
6 the injured COUs. REP benefits are determined by comparing an IOU's ASC with BPA's PFX  
7 rate, and then multiplying the difference by the utility's exchange load. The WP-02 record,  
8 however, included IOUs' ASCs and exchange loads that were not reviewed for accuracy and  
9 appropriateness, and included a PFX rate that relied on faulty market price and load data.  
10 Consequently, BPA reopened the WP-02 record to correct known errors and supply adequate  
11 ASC and exchange load information.

12  
13 APAC argues that, in reopening the WP-02 record, BPA violated the rule against retroactive  
14 ratemaking, violated the rule prohibiting retroactive rulemaking, and exceeded the scope of the  
15 Court's mandate. APAC claims that BPA should have simply relied on the existing WP-02  
16 record to determine the reconstructed REP benefits due the IOUs in the absence of the 2000 REP  
17 Settlements. APAC claims that BPA exceeded the scope of the Court's mandate and violated the  
18 rules prohibiting retroactive ratemaking and rulemaking when BPA reopened the final rate  
19 determinations made in the WP-02 ROD, updated the rates with different load and market price  
20 assumptions, and revised the section 7(b)(2) Implementation Methodology and Legal  
21 Interpretation retroactively. *See APAC APAC Br. at 38-39.*

22  
23 If APAC were to prevail on this argument, it is assumed that BPA would have to determine the  
24 IOUs' reconstructed REP benefits using the PFX rate developed in the original WP-02 rate  
25 proceeding. Under this scenario, the IOUs' reconstructed REP benefits for FY 2002–2006  
26 would average \$48 million per year, an \$86 million reduction from the reconstructed average of

1 \$134 million. The IOUs' Lookback Amounts would then be \$929.3 million, if calculated the  
2 same way as in the WP-07 Supplemental proceeding, an increase of \$183.1 million. *See* Table 7.

3  
4 Similarly, the total Lookback Amount would be \$1,933 million under the WP-02 determinations  
5 of REP benefits when combined with the assumption of void LRAs, and \$764 million if the  
6 WP-02 determinations are combined with the assumption that the LRAs are valid and separate.  
7 All of these amounts are larger than the original Lookback Amount of \$746 million.

#### 9 **9.2.2.2 LRAs Voided**

10 This issue is related to the issue discussed in section 7.2.1.3. In the WP-07 Supplemental  
11 proceeding, BPA treated the LRAs as valid and binding contracts. As a result, BPA concluded  
12 that the LRA payments to PacifiCorp and Puget would be “protected” payments that were not  
13 subject to recovery as part of their Lookback Amounts. BPA explained that the LRAs were  
14 contracts with PacifiCorp and Puget under which BPA purchased power back from these utilities  
15 to limit BPA's exposure to volatile energy prices during the West Coast energy crisis of 2001.  
16 BPA further explained that petitions to review the LRAs, which only challenged the reduction of  
17 risk provision of the LRAs, were dismissed as moot.

18  
19 APAC and Tillamook argue that the LRAs simply amended the 2000 REP Settlement  
20 Agreements to monetize as cash payments certain physical power deliveries required only by the  
21 2000 REP Settlement Agreements. They state that despite the fact that the physical power  
22 deliveries required under the 2000 REP Settlement Agreements were later found by the Court to  
23 be unlawful, BPA elected to treat the cash payments required by the LRAs as binding obligations  
24 in the WP-07 Supplemental proceeding. They note that BPA further determined that the LRA  
25 payments would be “protected” against the section 7(b)(2) rate test and, ultimately, exempted  
26 from repayment to preference customers. APAC and Tillamook assert that BPA's refusal to

1 include the LRA payments in the amount to be refunded to its preference customers is unlawful  
2 both because the LRAs were part and parcel of the 2000 REP Settlement Agreements held to be  
3 illegal and void, and because the LRA payments were charged to the preference customers in  
4 violation of the section 7(b)(2) rate test. *APAC APAC Br.* at 25, 28; *APAC APAC Reply Br.* at  
5 28; *Tillamook APAC Br.* at 28; *Tillamook APAC Reply Br.* at 10.

6  
7 If APAC and Tillamook were to prevail on this argument, it is assumed that BPA would have to  
8 include the value of the LRAs in the Lookback Amount calculation. As a result of this  
9 adjustment, PacifiCorp's Lookback Amount would increase from \$203.5 million to  
10 \$660.3 million, and Puget's Lookback Amount would increase from \$262.2 million to  
11 \$562.6 million. *See* Table 8.

### 12 13 **9.2.2.3 Certainty of Repayment of Lookback**

14 Under the Lookback Approach, BPA determined that as a result of the 2000 REP Settlement  
15 Agreements the COUs had been overcharged approximately \$1.002 billion in rates, subsequently  
16 revised to \$985.2 million due to the Avista deemer settlement. To refund this amount to the  
17 injured COUs, BPA developed a comprehensive Lookback Recovery and Return Proposal  
18 (Lookback Recovery Proposal) in the WP-07 Supplemental rate proceeding. Under the  
19 Lookback Recovery Proposal, BPA provided COUs an initial cash payment of approximately  
20 \$256 million, which refunded all overcharges to COUs in the PF-07 rates charged in FY 2007–  
21 2008. It was further decided that the remaining \$767 million in outstanding refunds, referred to  
22 as the Lookback Amount, would be recovered from the IOUs through reductions in prospective  
23 IOU REP benefits and provided to the COUs as credits on their power bills. A goal was  
24 established to recover the overpayments from the IOUs and return all overcharges to the COUs  
25 within seven years (by FY 2015). Interest is paid on the outstanding Lookback Amount  
26 balances.

1 BPA's Lookback recovery method is not a rigid formula. Instead, in each rate proceeding BPA  
2 balances the interests of the COUs, which are entitled to refunds, with the interests of the  
3 residential and small farm consumers of the IOUs, who are the beneficiaries of the REP.  
4 Whether and to what extent refunds are provided in a given rate period are determined by the  
5 Administrator based on the facts in the given case. For FY 2009, the Administrator decided to  
6 withhold from the IOUs sufficient REP benefits to meet the seven-year goal, provided that no  
7 IOU received less than 50 percent of the utility's lawfully due REP benefits. For FY 2010–2011,  
8 the Administrator determined that sufficient progress had been made in returning the Lookback  
9 Amounts and that it would be reasonable to retain the 50 percent threshold for the WP-10 rate  
10 period.

11  
12 APAC and Tillamook argue that BPA acted unlawfully in the WP-07 Supplemental rate  
13 proceeding by adopting a repayment scheme that defers repayment of the Lookback Amounts to  
14 the COUs far into the future in order to allow BPA to maintain substantial and additional REP  
15 payments to the IOUs. They claim BPA has failed to respond to this Court's order in  
16 *Golden NW* and to fulfill its statutory duties to recoup and repay monies unlawfully paid to the  
17 IOUs and illegally charged preference customers. Specifically, Tillamook and APAC argue that  
18 BPA's establishment of a seven-year goal for repayment and recoupment of costs from the  
19 IOUs' prospective REP benefits does not provide sufficient certainty of repayment; that one IOU  
20 may not participate in the REP and thus would not have REP benefits to offset for its share of the  
21 Lookback Amount; that BPA's approach does not guarantee that the customers who paid the  
22 illegal rates will receive refunds; and that higher interest should be applied to the Lookback  
23 Amounts. APAC APAC Br. at 32; APAC APAC Reply Br. at 22; Tillamook APAC Br. at 46.

24  
25 If APAC and Tillamook were to prevail on this argument, it is assumed that BPA would have to  
26 accelerate the recovery and return of the Lookback Amounts to the affected COUs. The effect of

1 this outcome on future REP benefits depends on the remaining level of Lookback Amount and  
2 the projected amount of future REP benefits.

#### 3 4 **9.2.2.4 Combined Effect of COU Positions**

5 The combined effect of the COU and related party positions is to increase the total Lookback  
6 Amount to \$1,941 million. *See* Table 7. To analyze the Settlement, there are two different  
7 assumptions on how quickly the Lookback Amounts would be recovered from the IOUs. One  
8 analysis assumes BPA continues the 50 percent rule established in the WP-07 Supplemental  
9 ROD, which limits the Lookback Amount recovered in any year to no more than 50 percent of  
10 the REP benefits for that year. The second analysis assumes that the Lookback Amounts would  
11 be recovered from the IOUs, and paid to the COUs, as much as necessary to effect repayment of  
12 the IOUs' outstanding Lookback Amount balances by the end of FY 2015, or as soon thereafter  
13 as possible. The 50 percent rule is removed and REP benefits are allowed to fall to zero if  
14 necessary to accomplish repayment to COUs. *See* section 10.4.3.

### 15 16 **9.3 7(b)(2) Issues**

#### 17 **9.3.1 Treatment of Conservation**

##### 18 **9.3.1.1 General Requirements Same in Both Cases**

19 In the WP-07 Supplemental proceeding, BPA described its treatment of conservation in the  
20 7(b)(2) rate test. BPA initially included all of its conservation costs in the Program Case revenue  
21 requirement. BPA's acquired conservation reduces preference customers' requirements. Next,  
22 BPA excluded all conservation costs from the Program Case, because section 7(b)(2) prescribes  
23 the Program Case as "exclusive of amounts charged such customers under subsection (g) for the  
24 costs of conservation ...." 16 U.S.C. § 839e(b)(2). There is no similar requirement to remove  
25 such costs from the 7(b)(2) Case. In the 7(b)(2) Case, "[t]he initial loads that will be used in the  
26 7(b)(2) case will be the same as those used in the program case, except they will not include

1 estimates of programmatic conservation savings.” 1984 section 7(b)(2) Implementation  
2 Methodology, section V.1. Because conservation resources are included in the resource stack  
3 used to serve remaining loads if needed, these resources could not have already reduced loads in  
4 the 7(b)(2) Case. To remove the effects of conservation from the 7(b)(2) Case, the 7(b)(2)  
5 Customer loads were increased by an amount of load equal to the conservation savings BPA  
6 assumed in the Program Case. This adjustment ensured that conservation resources were given  
7 their full and intended effect when selected from the resource stack under section 7(b)(2)(D)(i).  
8  
9 Cowlitz and APAC argue that increasing preference customers’ general requirements by BPA’s  
10 estimate of conservation savings conflicts with the Northwest Power Act because it is contrary to  
11 the definition of “general requirements” in the Act. Cowlitz *APAC* Br. at 32–46; APAC *APAC*  
12 Br. at 52–54. They state that the definition, in section 7(b)(4), specifically defines the term  
13 “general requirements” as preference customers’ “electric power purchased from [BPA] under  
14 § 5(b), exclusive of any new large single load.” They argue that power *not purchased* because of  
15 conservation is *not* “power purchased.” Cowlitz and APAC note that section 3(9) of the Act  
16 defines “electric power” as “electric peaking capacity, electric energy, or both.” They argue that  
17 BPA’s approach is inconsistent with the definition of “general requirements” in BPA’s Legal  
18 Interpretation. They claim that Congress addressed the one and only change BPA should make  
19 to “general requirements” between the Program Case and 7(b)(2) Case, and the only permissible  
20 difference is set forth in the first assumption, which requires BPA to add to the general  
21 requirements only DSI loads. In summary, Cowlitz and APAC argue that had Congress wanted  
22 load-changing assumptions in the 7(b)(2) Case other than the required addition of certain DSI  
23 loads, it would have specified them. They argue that Congress did not, and BPA had no  
24 authority to modify the section 7(b)(2) assumptions adopted by Congress so as to increase  
25 preference customers’ “general requirements.”  
26

1 The IOUs argue that BPA must not increase the combined general requirements of PF Preference  
2 rate customers in the 7(b)(2) Case by an amount equal to conservation load reduction, but rather  
3 must include all conservation costs in the section 7(b)(2) Case. IOU Br., WP-07-B-JP6-01,  
4 at 27. The IOUs argue that BPA’s proposed 7(b)(2) Legal Interpretation must be revised to  
5 exclude conservation as an available resource in the 7(b)(2)(D) resource stack. *Id.* at 97. The  
6 IOUs argue that BPA’s proposed treatment of conservation is contrary to five provisions of the  
7 Northwest Power Act. *Id.* at 51. The IOUs contend that BPA must adopt an interpretation that  
8 comports with the five statutory provisions they describe. *Id.*

9  
10 If APAC and the PPC were to prevail on this argument, it is assumed that the conservation  
11 adjustment to 7(b)(2) Customers’ loads in the 7(b)(2) Case would be removed and loads would  
12 be consistent with Program Case preference customer plus DSI loads. *See* section 10.4.5. If the  
13 IOUs were to prevail on this argument, it is assumed that the conservation adjustment to  
14 7(b)(2) Customers’ loads in the 7(b)(2) Case would be removed and loads would be consistent  
15 with the total of Program Case preference customer and DSI loads; plus the Program Case  
16 conservation costs would be included in the 7(b)(2) Case revenue requirement. *See*  
17 section 10.4.6.

### 18 19 **9.3.2 7(b)(2) Repayment Study**

20 BPA develops different revenue requirements, based on different repayment studies, for the  
21 Program Case and the 7(b)(2) Case. One is incorporated into the total Program Case revenue  
22 requirement, and the other is incorporated into the total revenue requirement developed  
23 specifically for the 7(b)(2) Case, based on the relevant assumptions that guide the two respective  
24 Cases. In each Case, BPA’s outstanding debt and appropriation repayment obligations are  
25 considered; however, for the 7(b)(2) Case repayment study, conservation repayment obligations  
26 are removed because the resources are considered not to have been acquired. Instead, the



1 conservation is included in the resource stack, and the cost of the repayment obligation is  
2 included in the cost of the resource specified in the stack.

3  
4 BPA’s preference customers argue that an alternative repayment study is contrary to the 1984  
5 Legal Interpretation and the 1984 Implementation Methodology, which provide that only  
6 changes required by the five 7(b)(2) assumptions may be reflected in the 7(b)(2) Case. Cowlitz  
7 *APAC Br.* at 47–49. Assuming that BPA might lawfully create an alternative 7(b)(2) repayment  
8 study, Cowlitz states that BPA cannot as a matter of law base that study on an arbitrarily  
9 truncated set of revenue requirements. Cowlitz argues that BPA must base any alternative  
10 repayment study on the full revenue requirements of the 7(b)(2) Case, including the revenue  
11 requirements of all resources necessary to meet the general requirements of preference  
12 customers.

13  
14 If Cowlitz were to prevail on this argument, BPA it is assumed that BPA would have to remove  
15 the effects of the separate repayment study from the 7(b)(2) Case COSA and replace those costs  
16 with the equivalent costs from the Program Case COSA. *See* section 10.4.7.

### 18 **9.3.3 Treatment of Mid-Columbia Resources**

19 Section 7(b)(2)(D) of the Act requires BPA to assume that Federal base system (“FBS”)  
20 resources are used first to meet the COUs’ requirements loads in the 7(b)(2) Case. If there are  
21 “remaining” COU requirements loads, BPA must assume that all resources that would have been  
22 required to meet these loads were (i) purchased from such COU customers by the Administrator  
23 under section 6 of the Northwest Power Act, or (ii) not committed to load under section 5(b) of  
24 the Northwest Power Act. In addition, these must be the least expensive resources owned or  
25 purchased by COUs. Therefore, these two types of resources are stacked in order of cost, and the  
26 least-expensive resources are acquired from the resource stack to meet COU loads in the 7(b)(2)

1 Case as needed. If the resource stack is insufficient to meet COU loads, any additional needed  
2 resources are obtained at the average cost of all other new resources acquired by the  
3 Administrator.

4  
5 Section 7(b)(2)(D)(ii) of the Act provides that resources owned or purchased by COUs but “not  
6 committed to load pursuant to section 839c(b) [Northwest Power Act section 5(b)]” can be used  
7 to meet remaining COU requirements in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2)(D)(ii). Non-  
8 committed resources are eligible to meet COU loads in the 7(b)(2) Case; committed resources  
9 are not eligible to meet COU loads in the 7(b)(2) Case. Thus, first, only resources “not  
10 committed to load pursuant to [Northwest Power Act section 5(b)]” can be used to meet  
11 remaining COU requirements in the 7(b)(2) Case. Second, resources can be committed to load  
12 pursuant to section 5(b) only by COUs or IOUs. Therefore, only resources not committed to  
13 load by COUs and IOUs pursuant to section 5(b) can be used to meet COU requirements in the  
14 7(b)(2) Case.

15  
16 BPA’s preference customers note that under section 7(b)(2)(D), “resources owned or purchased  
17 by public bodies or cooperatives” are available in the 7(b)(2) Case if they are “not committed to  
18 load pursuant to section 5(b).” 16 U.S.C. § 839e(b)(2)(D). Cowlitz *APAC* Br. at 49–58.

19 Cowlitz notes that the Act defines “resources” as “electric power, including the actual or planned  
20 electric power *capability* of generating facilities.” 16 U.S.C. § 839e(b)(2)(D) (emphasis added).

21 Cowlitz states that therefore a generator’s capability is a “resource” for purposes of  
22 section 7(b)(2)(D). Cowlitz then argues that under section 5(b)(1)(A), a generator’s *capability*  
23 can be committed to serve only the load of the generator’s owner (*i.e.*, “the capability of such  
24 entity’s firm ... resources used ... to serve its firm load in the region.”). 16 U.S.C.

25 § 839c(b)(1)(A). Cowlitz concludes that under these statutory provisions, the capability of non-  
26 Federal resources, including the capability of the Mid-Columbia resources, cannot be

1 “committed to load pursuant to section 5(b)” unless their capability is committed to the load of  
2 the resource owner.

3  
4 If the preference customers were to prevail on this argument, it is assumed that BPA would have  
5 to include Mid-Columbia resources in the resource stack to the extent that such resources are not  
6 committed to serving COU loads. *See* section 10.4.8.

#### 7 8 **9.4 7(b)(3) Issues**

9 Section 7(b)(2) of the Northwest Power Act directs BPA to conduct, after July 1, 1985, a  
10 comparison of the projected amounts to be charged its preference and Federal agency customers  
11 for their general requirements with the costs of power for the general requirements of those  
12 customers if certain assumptions are made. 16 U.S.C. § 839e(b)(2). The effect of this  
13 comparison is to protect BPA’s preference and Federal agency customers’ wholesale firm power  
14 rates from certain costs resulting from the provisions of the Northwest Power Act. The rate test  
15 can result in a reallocation of costs from the general requirements loads of preference and  
16 Federal agency customers to other BPA loads.

17  
18 Section 7(b)(3) of the Northwest Power Act governs the reallocation of costs in the event the  
19 section 7(b)(2) rate test triggers. Section 7(b)(3) provides that “[a]ny amounts not charged to  
20 public body, cooperative, and Federal agency customers by reason of paragraph (2) of this  
21 subsection shall be recovered through supplemental rate charges for all other power sold by the  
22 Administrator to all customers.” 16 U.S.C. § 839e(b)(3). In other words, if the rate test triggers,  
23 the trigger amount must be allocated away from preference customers’ power sales priced under  
24 section 7(b) and reallocated to other power sales, including sales to utilities participating in the  
25 REP. These costs increase the PFx rate, which is the rate at which BPA sells power to utilities

1 participating in the REP. When the PFX rate increases, the difference between that rate and the  
2 utility's ASC rate decreases, resulting in a reduction of REP benefits paid to the utility.

#### 3 4 **9.4.1 Allocation of Rate Protection to Surplus Power Sales**

5 In the section 7(b)(2) rate test, if the average of the discounted Program Case rates exceeds the  
6 average of the discounted 7(b)(2) Case rates, the rate test is said to "trigger." The difference  
7 between the rates in the two cases is called the "trigger amount" and is multiplied by the  
8 preference customer loads for the rate period to yield the "7(b)(3) allocation amount."

9 Section 7(b)(3) of the Northwest Power Act prescribes the manner in which the 7(b)(3)  
10 allocation amount is allocated. Section 7(b)(3) provides, in pertinent part, that "[a]ny amounts  
11 not charged to public body, cooperative, and Federal agency customers by reason of paragraph 2  
12 of this subsection shall be recovered *through supplemental rate charges for all other power sold*  
13 *by the Administrator to all customers.*" 16 U.S.C. § 839e(b)(3) (emphasis added). The trigger  
14 amount is to be recovered from "*all other power sold by the Administrator to all customers,*" *id.*  
15 (emphasis added), which includes secondary power sales at the FPS rate.

16  
17 Section 7(b)(3) appears unambiguous to BPA. In its WP-07 ROD, BPA decided to recover part  
18 of the 7(b)(3) allocation amount from BPA's forecast surplus power sales on a prospective basis,  
19 beginning with rates being established for FY 2009. Such recovery is accomplished by  
20 incorporating a 7(b)(3) Supplemental Rate Charge in the FPS rate schedule. BPA decided that  
21 no 7(b)(3) supplemental rate charge was necessary to accomplish such recovery from the surplus  
22 sales to Slice customers. The 7(b)(3) Supplemental Rate Charge is separately stated in the PF  
23 Exchange, IP, NR, and FPS rate schedules.

24  
25 The preference customers argue that a 7(b)(3) allocation to surplus power sales would offset  
26 revenues that would have otherwise been credited to the wholesale power rates charged to BPA's

1 preference customers. They claim that the result will be, in economic terms, placing back into  
2 preference customers' wholesale power rates the costs that were supposedly removed by  
3 operation of section 7(b)(2). Cowlitz WP-07 Br., WP-07-B-CO-01, at 43–47. They state that  
4 section 7(b)(3) does not direct BPA to “allocate” the trigger amount to other power rates, but to  
5 “recover” the amounts from “other” power sales. They criticize an “allocation,” wherein the  
6 rates would remain the same but the allocation would only cause the surplus revenue credit to  
7 decrease or a surplus revenue deficit to increase. They assert that allocating the trigger amount  
8 to the FPS rates, with the “net effect” of shrinking the secondary revenues credit and raising the  
9 PFp rate, is contrary to the section 7(b)(2) statutory guarantee.

10  
11 If the preference customers were to prevail on this argument, it is assumed that BPA would  
12 remove the 7(b)(3) allocation to surplus sales in the ratesetting process. *See* section 10.4.9.

#### 14 **9.4.2 Treatment of Secondary Energy Credit**

15 BPA believes that all surplus sales should be reflected in the cost reallocations pursuant to  
16 section 7(b)(3). There is no difference in the section 7(b)(3) reallocations regardless of whether  
17 BPA assumes the sale of surplus power is to the market or to the Slice customers. BPA receives  
18 the same amount of forecast revenue whether the surplus is sold in the market and credited to  
19 rates or sold to the Slice customers at the Slice rate. BPA properly reflects sales of surplus  
20 power associated with the Slice product in the section 7(b)(3) cost reallocations. BPA does not  
21 add an explicit 7(b)(3) Supplemental Rate Charge on the Slice sale of surplus power because the  
22 effect of the 7(b)(3) allocation to the sale is incorporated into the PFp rate paid by Slice  
23 customers. In calculating the amount included in the PFp rate, BPA reduces the secondary  
24 revenue credit in the Program Case for the 7(b)(3) allocation, but does not reduce the secondary  
25 credit in the 7(b)(2) Case.

1 The IOUs state that BPA, in performing the section 7(b)(3) reallocations, does not assess a  
2 7(b)(3) Supplemental Rate Charge on the surplus power associated with the Slice product sold to  
3 Slice customers under the Slice rate and understates the 7(b)(3) allocation to the Slice surplus  
4 power.

5  
6 If the IOUs were to prevail on this argument, it is assumed that BPA would have to adjust the  
7 secondary revenue credit in the 7(b)(2) Case to use the same reduced secondary revenue credit as  
8 used in the Program Case. *See* section 10.4.10.

## 9 10 **9.5 Additional Issues Subject to Litigation**

### 11 **9.5.1 7(b)(2) Accounting and Financing Treatment of Conservation Costs**

12 In the WP-07 Supplemental ROD, historical and projected capitalized conservation costs were  
13 amortized and financed over a 15-year period for the 7(b)(2) Case resource stack. The first-year  
14 historically expensed costs were treated as deferred charges amortized and financed over a  
15 one-year to useful-life period. In the WP-07 Supplemental ROD, the first-year expense cost was  
16 deferred over seven years. This approach mitigated the first-year rate shock associated with the  
17 large number of programmatic conservation resources being selected from the resource stack in  
18 the first year of the five-year period. The financing parameters will be assessed in each BPA rate  
19 case depending on the number of conservation resources drawn from the stack and the  
20 then-current accounting practices for conservation costs. Conservation investments that have  
21 been fully amortized (FY 1998 and prior years) are considered obsolete resources that are not  
22 available to serve 7(b)(2) Customer loads in the 7(b)(2) Case.

23  
24 PPC disagrees with BPA's treatment of financing conservation resources available to serve  
25 preference customer load in the 7(b)(2) Case. PPC contends that the manner in which  
26 conservation is acquired in the 7(b)(2) Case is fundamentally different from that in the Program

1 Case. PPC states that BPA must determine how the Joint Operating Agency in the 7(b)(2) Case  
2 would finance a very large resource brought on to meet load, and argues that standard industry  
3 practice for financing such a resource is to capitalize all costs of such a resource and amortize  
4 those costs over the useful life of the resource.

5  
6 The OPUC argues that BPA's approach of deferring the historical expensed portions of BPA's  
7 conservation programs and financing these costs over five years should be rejected. The OPUC  
8 believes that proposals that avoid the front-loading of costs are contrary to current utility  
9 practice.

10  
11 The IOUs argue that BPA's financing and accounting treatment for conservation costs in the  
12 7(b)(2) rate test is incorrect. The IOUs' primary argument is that BPA should not have increased  
13 the 7(b)(2) Case loads for conservation savings that did not occur. However, if conservation  
14 should be in the resource stack and there should be a load adjustment, the IOUs argue that  
15 conservation costs should be expensed in the year the costs are incurred.

16  
17 If the PPC were to prevail on this argument, it is assumed that BPA would have to capitalize all  
18 costs of the conservation resources included in the resource stack and recover the costs over the  
19 useful life of the resources. If the OPUC were to prevail on this argument, and the IOUs were to  
20 prevail on their alternative argument, it is assumed that BPA would have to expense all costs of  
21 the conservation resources in the resource stack and recover costs in the first year the resource is  
22 selected from the stack.

### 23 24 **9.5.2 Discounting of the Stream of 7(b)(2) Rate Projections**

25 In the 1984 7(b)(2) Implementation Methodology, BPA decided that after calculating the stream  
26 of annual rates in the Program and 7(b)(2) Cases, it would be appropriate to discount the rates to

1 the beginning of the rate test period before averaging the rate streams to perform the 7(b)(2) rate  
2 test. The purpose of the statutory directive to include four years beyond the rate period is to  
3 ensure that the rate period 7(b)(2) rate test trigger in one rate case is similar to the rate test  
4 triggers in later rate cases, all else being equal, by discounting rate period anomalies through the  
5 inclusion of more normalized forecast years. This process has the effect of reducing the  
6 weighting of an anomalous rate period difference between the Program Case and the  
7 7(b)(2) Case. BPA uses the forecast long-term interest rate on Federal debt for this discounting.  
8 In establishing the discounting methodology and use of the long-term interest rate, BPA stated  
9 “[i]t is logical to use BPA’s borrowing rate, since BPA could theoretically borrow the money in  
10 the test year to reimburse the 7(b)(2) customers for the five-year section 7(b)(2) rate test  
11 differential. The value to BPA of money over time is thus the economically correct value for the  
12 rate differential over time.” Melton and Armstrong, b2-84-E-BPA-01, at 35-36. Also,  
13 smoothing the within-rate-case annual data is not necessarily a meaningful criterion; nor is  
14 minimizing the differences between the rate test period average difference and the annual  
15 differences between the Program Case and 7(b)(2) Case rates.

16  
17 APAC argues that the methodology BPA uses to perform the present value calculation and the  
18 averaging in the 7(b)(2) rate test distorts the rate test results in future years. APAC WP-10 Br.,  
19 WP-10-B-AP-01, at 13. APAC further argues that the trigger calculation should be based on an  
20 inflation adjustment internal to the data for BPA costs and ASC levels. APAC claims that this  
21 methodology better smoothes the annual trigger data while minimizing the difference between  
22 the annual values and the combined trigger.

23  
24 The IOUs support BPA’s position, but offer an alternative if a change in discount rates is  
25 warranted. The IOUs argue that if any change is to be made from using the long-term interest  
26 rates, it should be to use BPA’s capital investment decision rate.



1 If APAC were to prevail on this argument, it is assumed that BPA would use the current inflation  
2 rate forecast as discount factors in the rate discounting. If the IOUs were to prevail on this  
3 argument, it is assumed that BPA would use its current investment decision rate forecast for the  
4 rate discounting. *See* sections 10.5.3 and 10.5.4.  
5

### 6 **9.5.3 Including All Acquired Conservation in the Resource Stack**

7 Section 7(b)(2)(D) of the Northwest Power Act directs that any additional resources necessary to  
8 serve 7(b)(2) Customer load after FBS resources have been completely used should be the least-  
9 expensive resources owned or purchased by public bodies or cooperatives if such resources  
10 (i) have been acquired by BPA pursuant to section 6 of the Act, or (ii) not committed to load  
11 pursuant to section 5(b) of the Act. To model this provision, a resource stack is established for  
12 the 7(b)(2) Case that contains resources meeting the requirements of section 7(b)(2)(D). In  
13 BPA's construction of this resource stack, certain conservation acquisitions are excluded because  
14 some acquisitions of conservation have not already reduced customers' general requirements in  
15 the Program Case and therefore should not adjust customers' general requirements in the  
16 7(b)(2) Case. *See* section 7.3.1.1 for additional discussion on the interaction between  
17 conservation and general requirements.  
18

19 The IOUs argue that the exclusion of the conservation acquisitions from the resource stack is  
20 inappropriate. Notwithstanding their primary argument regarding the treatment of conservation  
21 in the 7(b)(2) Case, they argue that if conservation is included in the resource stack, all of the  
22 conservation acquisitions should be included because all of the conservation resources meet the  
23 7(b)(2)(D) definition.  
24

25 If the IOUs were to prevail on this argument, it is assumed that all of the conservation  
26 acquisitions, including the amount currently excluded, would be included in the 7(b)(2) Case

1 resource stack, and 7(b)(2) Customer loads would be adjusted for the full amount of the  
2 acquisitions.

## 3 4 **9.6 RPSA Issues**

### 5 **9.6.1 Deemer Treatment**

6 Section 5(c) of the Northwest Power Act established the REP as a “purchase and exchange sale”  
7 by and between BPA and an exchanging utility. See 16 U.S.C. §§ 839c(c)(1) and (2). Although  
8 the language and structure of section 5(c) is couched in terms of an actual power exchange (with  
9 BPA selling power to the exchanging utility at the applicable PF rate and purchasing an  
10 equivalent amount of power from the exchanging utility at the utility’s ASC), BPA has  
11 implemented the REP as a monetary transaction since its inception in 1981. In this monetary  
12 transaction, BPA pays the exchanging utility based on the difference between the PF rate and the  
13 utility’s ASC.

14  
15 Nevertheless, because REP benefits are derived by comparing the rate levels charged by each  
16 party for its hypothetical sale of power to the other, the benefits (or economic value of the  
17 exchange) could flow from an exchanging utility to BPA in the event the utility’s ASC (the rate  
18 “paid” by BPA) is lower than BPA’s PF rate. However, Congress appears to have contemplated  
19 such a circumstance and provided exchanging utilities with a limited statutory right to terminate  
20 their RPSAs in the event a utility’s ASC falls below the PF rate due to application of  
21 section 7(b)(3) of the Act. 16 U.S.C. §§ 839c(c)(4), 839e(b)(3).

#### 22 23 **9.6.1.1 Past Deemer Treatment**

24 The 1981 RPSAs, in addition to providing for termination or suspension of the Agreement  
25 consistent with the above-referenced statutory right, included a provision that gave an  
26 exchanging utility the option, in lieu of invoking its termination or suspension right, to have its

1 ASC “deemed equal” to the PF rate. This allowed the exchanging utility to avoid paying money  
2 to BPA. Notwithstanding this deemed equalization of the two rates, the provision also provided  
3 that during the period any such election was in effect, BPA would “debit to a separate account  
4 the net exchange payment to Bonneville, if any, that would have been required of the Utility if  
5 the Utility had not made such election and shall credit to that account any exchange payments  
6 that would have been made.” The debit calculated by this provision of the 1981 RPSA  
7 accumulated whenever the utility’s ASC was less than BPA’s applicable PF rate. These debits  
8 would accrue in a “deemer account” maintained by BPA. Under the terms of the 1981 RPSA,  
9 the utility was required to extinguish its deemer account balance before it could receive any REP  
10 payments from BPA. A utility could pay off its deemer balance either by making cash payments  
11 to BPA or by allowing BPA to reduce the utility’s REP benefit payments when its ASC rose  
12 above the PF rate.

13  
14 Between 1984 and 1993, Idaho Power accrued a deemer balance of approximately \$91 million.  
15 Idaho Power subsequently terminated its participation in the REP. Upon termination, Idaho  
16 Power agreed that its outstanding deemer balance would accrue interest. Between 1993 and  
17 October 2000, Idaho Power’s deemer balance grew to approximately \$158 million. Idaho Power  
18 and BPA then entered the 2000 REP Settlement Agreement, wherein BPA and Idaho Power  
19 agreed to hold the deemer balance “in abeyance” during the term of that agreement.

20  
21 Idaho Power and the Idaho Public Utilities Commission (IPUC) vigorously oppose BPA’s  
22 decision to recover the outstanding deemer balances accrued under the 1981 RPSA. Idaho  
23 Power and the IPUC argue that BPA has not articulated a “cost or power planning purpose” for  
24 recovering the outstanding deemer balance against future ratepayers of Idaho Power. IPUC  
25 *IPUC Br. at 43.*

1 If Idaho Power and the IPUC were to prevail on this argument, it is assumed that BPA would  
2 have to cease collecting deemer balances from Idaho Power. Because Idaho Power was not  
3 eligible to receive REP benefits in the Lookback period (FY 2002–2006), the WP-07 rate period  
4 (FY 2007–2009), or the WP-10 rate period (FY 2010–2011), no retroactive adjustments to Idaho  
5 Power’s REP benefits would be necessary if Idaho Power were to succeed in its challenge.  
6 Prospectively, however, BPA expects Idaho Power to become eligible to receive REP benefits  
7 beginning in FY 2012. If Idaho Power’s historical deemer balance is extinguished or otherwise  
8 unrecoverable, it is assumed that Idaho Power would receive its full allocation of REP benefits  
9 beginning in FY 2012, subject to setoffs to recover Idaho Power’s Lookback Amount, and  
10 continuing through the end of the evaluation period (FY 2028).

#### 11 12 **9.6.1.2 Existing Provision**

13 The “deemer” account concept was carried forward by BPA in the 2008 and subsequent RPSAs  
14 in the form of a Payment Balancing Account. Whenever a utility’s ASC is less than BPA’s then-  
15 current PFX rate during the term of the 2008 and subsequent RPSA, the payment that would  
16 otherwise be owed BPA is tracked by BPA and added to the balancing account. If there is a  
17 balance in the balancing account and the ASC is greater than the applicable PFX rate, BPA  
18 makes no cash payments but applies the amount that would have been paid in order to reduce the  
19 account balance. The utility resumes the receipt of exchange payments from BPA when there is  
20 no longer an amount in the balancing account, or the utility makes payments to BPA to bring the  
21 balance in the balancing account to zero.

22  
23 The IPUC and Idaho Power argue that Congress enacted the REP for the purpose of providing  
24 rate relief to residential and small farm consumers of the IOUs by providing IOUs access to  
25 lower-cost Federal power, thereby promoting wholesale rate parity between BPA’s preference  
26 customers and eligible IOU customers. IPUC *IPUC* Br. at 21–28. The IPUC and Idaho Power

1 argue that the REP should be implemented in a manner that allows benefits to be provided only  
2 to utilities' residential consumers, not through a deemer mechanism that effectively allows  
3 payments to be made to BPA. *Id.* at 31. The IPUC and Idaho Power propose that the deemer  
4 provision should be stricken in its entirety, and replaced with provisions that permit an  
5 exchanging utility to suspend participation in the REP when the utility's ASC is lower than the  
6 PFX rate, and to resume participation when the circumstances reverse. *Id.*

7  
8 If the IPUC and Idaho Power were to prevail on this argument, it is assumed that BPA would  
9 remove the Payment Balancing Account provision from the 2008 and subsequent RPSAs. Under  
10 this scenario, an exchanging utility would have no risk of losing future REP benefits if its ASC  
11 fell below BPA's PFX rate.

### 13 **9.6.2 Exit/Reentry of REP Participants**

14 Section 5(c)(1) of the Northwest Power Act provides that BPA shall enter into an exchange  
15 transaction whenever an exchanging utility offers to sell power to BPA at the utility's average  
16 system cost. 16 U.S.C. § 839c(c)(1). The Act further provides that an exchanging utility may  
17 terminate an exchange transaction "upon reasonable terms and conditions agreed to by the  
18 Administrator and such utility prior to such termination" in the event that the 7(b)(2) rate test  
19 triggers and additional costs are allocated to the PFX rate, causing that rate to exceed the average  
20 system cost of power sold by an exchanging utility to BPA. 16 U.S.C. § 839c(c)(4). The effect  
21 of this termination provision is to relieve the exchanging utility from buying higher-priced BPA  
22 power and selling to BPA its own lower-cost power, but only in the case where the 7(b)(2) rate  
23 test trigger is the cause of PFX rate exceeding the utility's ASC. The statute does not expressly  
24 provide for termination of an exchange transaction in the event the PFX rate exceeds a utility's  
25 ASC due to an increase in the PFX rate caused by something other than the 7(b)(2) rate test  
26 triggering.

1 The IPUC and OPUC allege that sections 1 and 11 of the 2008 RPSAs are unlawful in requiring  
2 utilities to agree to a single long-term contract as a condition for participating in the REP, which  
3 impermissibly and unreasonably restricts utilities' rights to enter and exit residential exchange  
4 transactions and make new offers for new residential exchange transactions. IPUC *IPUC* Br.  
5 at 34–37; OPUC *IPUC* Br. at 10–16. The IPUC and OPUC argue that because the Northwest  
6 Power Act allows utilities to offer to sell power to BPA to begin the exchange, utilities should be  
7 able to determine the period of time the exchange will exist. IPUC *IPUC* Br. at 34; OPUC *IPUC*  
8 Br. at 7.

9  
10 If the IPUC and OPUC were to prevail on this argument, it is assumed that BPA would revise the  
11 terms of the 2008 RPSA to permit exchanging utilities to exit and enter the exchange. If the  
12 provision restricting exiting and reentry into the REP is removed, an exchanging utility would  
13 have the ability to exit the exchange whenever its ASC fell below BPA's PFx rate, thereby  
14 avoiding an assessment of a Payment Balance Account obligation (deemer balance). The impact  
15 on REP benefits of this outcome is similar to the result discussed in section 7.6.1.

1           **10. ANALYSIS OF THE SETTLEMENT: SCENARIO DEVELOPMENT**

2  
3           **10.1 Analysis of the 2012 REP Settlement**

4           This section of the Study presents BPA’s technical analysis of the 2012 REP Settlement. The  
5           technical analysis examines the ratemaking provisions of the Settlement by constructing a variety  
6           of scenarios resulting in potential future streams of REP benefits based on differing  
7           implementations of the section 7(b)(2) rate test or other major drivers of REP benefits.  
8           Constructing these alternative results using the 7(b)(2) rate test allows evaluation of the  
9           Settlement through the comparison of the results specified in the Settlement with the results of  
10          the scenarios developed in this analysis. The analysis is divided into two major groups of  
11          scenarios: (1) those that examine forecasting risk and uncertainty around BPA’s base forecast in  
12          the Reference Case, and (2) those that examine litigation risks related to Lookback, conservation  
13          treatment and other statutory implementations currently under dispute.

14  
15          **10.2 Rate Models Used in the Analysis**

16          The analysis employs two rate models to measure the impact of changing inputs and assumptions  
17          on REP benefits: RAM2012 and the new Long-Term Rate Model (LTRM). RAM2012 is the  
18          model used when establishing rates for two-year rate periods and is used to calculate BP-12  
19          rates. RAM2012 is limited to calculating rates for the two-year rate period. The LTRM was  
20          developed for this proceeding to extend rate analysis through the end of the Settlement, 2028.

21  
22          The LTRM employs the same ratemaking logic as RAM2012 but in a scaled down form. It  
23          performs the same calculations as the COSA Step in RAM2012. See section 2 of the Power  
24          Rates Study, BP-12-FS-BPA-01. LTRM uses the same input data used in RAM2012 whenever  
25          possible. LTRM is calibrated to RAM2012 for the FY 2012–2013 period, and the results are  
26          reasonably similar.

1  
2 **10.3 Reference Case: Base Case Forecasts and BPA’s Position on Issues**

3 The Reference Case (or Scenario 0) employs BPA’s current 7(b)(2) implementation  
4 methodology and a base case, or best forecast, of inputs used in ratemaking. The Reference Case  
5 is built upon the updated results to uection 7(b)(2) Rate Test Study, REP-12-E-BPA-02. *See*  
6 Documentation, Tables 10.2 and 10.3. Performing Scenario 0 in RAM2012 produces the results  
7 shown for FY 2012-13 in Table 10.6 of this Study, and are consistent with the methodology from  
8 the uection 7(b)(2) Rate Test Study from the Initial Proposal, updated to the latest available data.  
9 Performing Scenario 0 in the LTRM produces 17 years of results consistent with RAM2012, as  
10 updated to the latest available data. Reference Case projected benefits for FY 2014-2028 rely on  
11 LTRM.

12  
13 As discussed in section 6.3, LTRM is a long term model with several simplifying assumptions.  
14 Documentation is presented for FY 2012–2013 for data inputs used in RAM2012. (REP-12-FS-  
15 BPA-01A, Tables 10.2 through 10.3). However, given the term of forecasts necessary to  
16 complete 7(b)(2) rate tests for each of 17 years for 2012 through 2028, 6 year forecasts used in  
17 RAM were expanded for use in LTRM. Input data assumptions for LTRM include:

- 18 • **BPA Loads:** BPA load inputs build from loads presented in the Power Loads and  
19 Resource Study, BP-12-FS-BPA-03, as used in the uection 7(b)(2) Rate Test Study  
20 through 2017, and are consistent with BPA’s 20-year load forecasts.
- 21 • **BPA Resources:** BPA resource inputs build from resources presented in the Power  
22 Loads and Resource Study, BP-12-FS-BPA-03, as used in the Section 7(b)(2) Rate Test  
23 Study through 2017, and are consistent with BPA’s 20-year resource forecasts.
- 24 • **ASCs:** ASC inputs are described in Chapter 7.
- 25 • **Exchange Load:** Exchange load inputs are described in Chapter 7.



- 1 • **Costs:** BPA cost inputs build from costs developed in the Power Revenue Requirement  
2 Study, BP-12-FS-BPA-02, as used in the section 7(b)(2) Rate Test Study through 2017;  
3 starting with 2018, costs are escalated at 3.75 percent per year (2 percent real growth).  
4 For debt financing forecast assumptions, values from the full 20-year Repayment Study  
5 in BP-12-FS-BPA-02 are used.
- 6 • **Revenue Credits:** BPA revenue credit inputs build from costs developed in the Power  
7 Rates Study, BP-12-FS-BPA-01, as used in the updated results to section 7(b)(2) Rate  
8 Test Study through 2017; starting with 2018, costs are escalated at 3.75 percent per year  
9 (2 percent real growth).
- 10 • **Market Electric Prices:** Market electric price inputs build from the Aurora forecasts  
11 developed in the Power Risk and Market Price Study, BP-12-FS-BPA-04, through 2017  
12 and escalate at 3 percent per year thereafter.
- 13 • **7(b)(2) Resource Stack Costs:** Resource costs are consistent with the costs developed in  
14 the section 7(b)(2) Rate Test Study, REP-12-E-BPA-02, with updated data for the Final  
15 Proposal. *See* Documentation Table 10.3.2.2.
- 16 • **Miscellaneous Inputs:**
  - 17 • BPA's transmission rates escalate after FY 2017 at the assumed annual inflation  
18 rate of 1.75 percent.
  - 19 • The IP rate net margin remains constant at the -0.255 mills/kWh used in  
20 RAM2012.
  - 21 • Low density discount and irrigation rate discount costs are RAM2012 values  
22 through FY 2017 and are escalated to 3.75 percent thereafter.
  - 23 • The PF flat load rate conversion factor is set at a constant 96.5 percent for all  
24 years.

- The 30-year Treasury borrowing interest rate is consistent with the forecast in the Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, Table 1.

#### **10.4 Analyzing Effect of Forecasting Risk and Uncertainty**

The analysis does not rely on a single static forecast of future costs. Recognizing inherent hurdles with forecasting, the analysis is stressed against a wide degree of future variation in the two “natural” drivers of REP benefits and associated rate protection: exchanging utility ASCs and BPA costs.

Base ASC forecasts used in the Reference Case are adjusted in these risk scenarios to reflect a wide range of outcomes throughout the 17-year period. As with the ASCs forecast for the Reference Case, these adjustments rely on resource cost expectations expressed in individual IOU integrated resource plans (IRPs), but are increased (or decreased) by high (or low) cost estimates for resource additions. High ASC cost scenarios assume that the full gamut of new resource needs identified in each exchanging utility’s IRP are met through new resource additions, while low ASC cost scenarios assume that these resource needs are met solely through market purchases using BPA’s current (and relatively low) market price forecast. These cost assumptions are an adequate proxy for the many cost variations that can be reasonably expected to occur through the next 17 years. Additional variation around high and low ASCs is modeled by further adjusting the natural gas and electricity market price assumptions as discussed in section 7.

BPA cost forecasts used in the Reference Case are adjusted in these risk scenarios to reflect a wide range of outcomes throughout the 17-year period. Variance around the Reference Case is implemented through adjustment to the escalation rates assumed for BPA costs through the

1 future. While the Reference Case assumes inflation plus 2 percent, the high BPA cost scenario  
2 assumes inflation plus 4 percent, while the low BPA cost scenario assumes costs grow solely at  
3 the rate of inflation. Additional variation around high and low BPA costs is modeled by further  
4 adjusting uranium resource costs, the quantity of secondary energy available in future rate cases,  
5 as well as natural gas and electricity market prices.

6  
7 Both high and low BPA revenue requirement scenarios are combined with the low and high ASC  
8 scenarios to produce a reasonable set of projections with upper and lower REP benefit bounds  
9 around the base ASC and BPA rates from the Reference Case. The pairing of “Low ASCs” with  
10 “High PF costs,” by the nature of the arithmetic workings of the REP benefit calculations, results  
11 in a cautious while reasonable lower bound for benefits expected over the 17-year period.  
12 Conversely, the pairing of “High ASCs” with “Low PF costs” results in a generous while  
13 reasonable upper bound for benefits expected over the 17-year period.

14  
15 This pairing is deliberate: one would expect some positive degree of correlation between costs  
16 faced by BPA and costs faced by IOUs (regardless of the price scenario). The specific design of  
17 risk scenarios to test divergence between BPA and IOU costs (which therefore posits a negative  
18 correlation between costs faced by BPA and costs faced by IOUs) stresses the lower and upper  
19 bounds of REP benefits. This intentional design in the scenario development acknowledges  
20 inherent uncertainty in forecasting and compensates for such uncertainty by expanding the  
21 “jaws” of foreseeable benefits, upon which the analysis and evaluation is based.

22  
23 Figure 1 summarizes post-Lookback IOU REP Benefits under alternative risk scenarios.  
24  
25  
26

1 **10.4.1 High ASCs, Low BPA Rates**

2 High ASCs are represented by assuming that 100 percent of IOU load growth is met by new  
3 resources as specified in the respective IOUs' Integrated Resource Plans. Low BPA rates are  
4 represented by assuming that BPA's costs and revenue credits increase at the rate of inflation for  
5 2018 onward. All other assumptions are consistent with the Reference Case.

6  
7 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
8 adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013,  
9 results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

10  
11 **10.4.2 Low ASCs, High BPA Rates**

12 Low ASCs are represented by assuming that 100 percent of IOU load growth is met by market  
13 purchases, using the Reference Case market forecast. High BPA rates are represented by  
14 assuming that BPA's costs and revenue credits increase at the rate of inflation plus 4 percent real  
15 growth for 2018 onward. All other assumptions are consistent with the Reference Case.

16  
17 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
18 adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013,  
19 results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

20  
21 **10.4.3 High Benefits Risk Scenario**

22 As discussed in section 8, several scenarios are constructed by varying natural gas and electricity  
23 market prices. In addition, scenarios with varying BPA resource costs are developed, comprising  
24 both high and low nuclear fuel scenarios, as well as potentially reduced available generation for  
25 secondary sales. The High Benefits Risk Scenario builds upon the “High ASC, Low BPA Rates”  
26 scenario in section 10.7.1 and assumes *high* carbon costs, *high* gas prices, *low* nuclear fuel, and

1 *no loss* in BPA generation. This, in general, causes IOUs' ASCs to rise at a rate faster than  
2 BPA's rates, which generally raises REP benefits.

3  
4 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
5 adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013,  
6 results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

#### 8 **10.4.4 Low Benefits Risk Scenario**

9 The Low Benefits Risk scenario builds upon the “Low ASC, High BPA Rates” scenario in  
10 section 10.7.2, and assumes *no* carbon costs, *low* gas prices, *high* nuclear fuel, and a *loss* in BPA  
11 generation. This, in general, causes IOUs' ASCs to rise at a rate slower than BPA's rates, which,  
12 places downward pressure on REP benefits.

13  
14 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
15 adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013,  
16 results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

#### 18 **10.5 Analysis of Issues in Litigation**

19 BPA's analysis of the Settlement further stresses forecast REP benefits (and implied 7(b)(2) rate  
20 protection) through acknowledging that certain aspects of the 7(b)(2) Implementation  
21 Methodology are currently under dispute. Ongoing litigation could potentially have material  
22 ratemaking effects on projections of REP benefits (and associated 7(b)(2) rate protection).  
23 Scenarios are therefore developed and modeled to analyze the impact of each of the issues in  
24 litigation discussed in Chapter 9 of this Study. A scenario is developed for each issue, followed  
25 by several scenarios that combine several issues to represent the aggregate position of the COU  
26 parties or the IOU parties. A discussion of each of the scenarios follows.

1 See Figures 2-4 for a graphical summary of post-Lookback IOU REP benefits under alternative  
2 litigation scenarios.

### 3 4 **10.5.1 Scenario 1: No Lookback (an IOU position)**

5 Scenario 1 models the impacts of a successful challenge by the IOUs to BPA’s decision to  
6 recover Lookback Amounts from the IOUs. *See* section 9.2.1. The Lookback Amounts  
7 generally reflect the amount by which the IOUs were overpaid for FY 2002–2007 or the amount  
8 by which the COUs were overcharged due to the 2000 REP Settlement Agreements. This  
9 scenario models likely prospective REP benefits to the IOUs if the Invalidity Clause in the 2000  
10 REP Settlement Agreements is found to be enforceable. *See* section 9.2.1.1 regarding the IOUs’  
11 Invalidity Clause argument. Under this scenario, not only would the Lookback Amount of  
12 \$767 million be reduced to zero, but BPA would likely return to the IOUs those amounts  
13 recovered during FY 2009–2011, about \$237.6 million.

14  
15 Table 10.1 presents the stream of annual Lookback Amounts recovered from the IOUs in  
16 FY 2009–2011 and assumed to be returned to them in FY 2012–2014. One plausible means to  
17 raise the funds needed to return these amounts to the IOUs would be for BPA to include the costs  
18 in the PF Public rates. Alternatively, BPA could raise funds through surcharges on the COUs’  
19 power bills. Staff is not proposing or modeling the source of these funds at this time. Reference  
20 Case stream of benefits is adjusted for the Scenario 1, and results are presented Tables 10.3.1-2.

### 21 22 **10.5.2 Scenario 2: Large Lookback without LRAs (a COU position)**

23 Scenario 2 models the arguments by the COUs that BPA should limit its determinations of  
24 reconstructed REP benefits to the analysis, data, assumptions, and methodologies BPA  
25 established in the WP-02 case. *See* section 9.2.2. This approach results in average annual REP  
26 benefits for FY 2002–2006 of approximately \$48 million. Section 7(b)(2) Rate Test Study,

1 WP-02-FS-BPA-05A, at 166. This scenario is combined with the base case approach from  
2 BPA’s WP-07 Supplemental ROD, in which the LRA payments to PacifiCorp and Puget are  
3 “protected.” This means that PacifiCorp and Puget are allowed to keep the greater of their LRA  
4 payments or their reconstructed REP benefits.

5  
6 Recovery of the revised Lookback Amounts under this scenario is presented in two payback  
7 alternatives. The first assumes BPA continues its application of the “50-percent” rule adopted in  
8 the WP-07 Supplemental ROD. The second assumes that the 50-percent rule is abandoned and  
9 future REP benefits owed to an IOU are reduced until the Lookback Amounts are paid off over a  
10 seven-year period, or as soon as possible thereafter if there are not sufficient REP benefits  
11 available to recover the full Lookback Amount in seven years.

12  
13 Table 10.1 presents the two resulting streams of total annual Lookback Amounts recovered from  
14 the IOUs. Tables 9.1 and 9.2 in the Documentation show the full results of the Lookback  
15 Lookforward Model (Documentation, REP-12-E-BPA-01A). Reference Case stream of benefits  
16 is adjusted for the Scenario 2, and results are presented Tables 10.3.1-2.

### 17 18 **10.5.3 Scenario 3: Large Lookback with LRAs (a COU position)**

19 Scenario 3 models a combination of the COUs’ argument that BPA should limit reconstructed  
20 REP benefits to the WP-02 rate record assumptions (\$48 million) and the COUs’ argument that  
21 the LRAs are invalid and therefore not protectable in the Lookback Amount calculation. *See*  
22 section 7.2.2.2. As in Scenario 2, two payback alternatives are shown, one with the “50-percent”  
23 rule and one without the rule.

24  
25 Table 10.1 presents the two streams of annual Lookback amounts recovered from the IOUs in  
26 total. Tables 9.2 and 9.4 in the Documentation show the full results of the Lookback

1 Lookforward Model (Documentation, REP-12-E-BPA-01A). Reference Case stream of benefits  
2 is adjusted for the Scenario 3, and results are presented Tables 10.3.1-2.

#### 3 4 **10.5.4 Scenario 4: Idaho Deemer Balance**

5 In this scenario, it is assumed that Idaho Power and IPUC prevail in their arguments, described in  
6 section 9.6.1, such that Idaho Power's deemer balance would be zero. However, all of Idaho's  
7 REP benefits would go toward its relatively large Lookback balance until it is extinguished.

8 Reference Case stream of benefits is adjusted for the Scenario 4, and results are presented Tables  
9 10.3.1-2.

#### 10 11 **10.5.5 Scenario 5: Conservation = General Requirements without Conservation Costs** 12 **(a COU position)**

13 Scenario 5 models the COUs' contention that the loads in the 7(b)(2) Case should not be adjusted  
14 for acquired conservation. *See* section 9.3.1.1. This scenario is a combination of two issues in  
15 litigation: 1) that conservation savings are general requirements under the Northwest Power Act,  
16 and 2) that conservation savings should be included in the 7(b)(2) Case at zero cost. To model  
17 this scenario, the load adjustment in the 7(b)(2) Case is set to zero, as are the conservation  
18 resources in the 7(b)(2) resource stack. This modification results in the 7(b)(2) Case starting  
19 with the same COU loads as used in the Program Case and adding the within-or-adjacent DSI  
20 loads to develop the 7(b)(2) Customer loads. The costs of the acquired conservation are not  
21 added to the 7(b)(2) Case revenue requirement.

22  
23 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
24 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.



1 **10.5.6 Scenario 6: Conservation = General Requirements with Conservation Costs**  
2 **(an IOU position)**

3 Scenario 6 models the IOU exchange customers' contention that the loads in the 7(b)(2) Case  
4 should not be adjusted for acquired conservation, as in Scenario 5, but also that Program Case  
5 conservation costs should be included in the 7(b)(2) Case. *See* section 9.3.1.1. To model this  
6 scenario, the load adjustment in the 7(b)(2) Case is set to zero, the conservation resources in the  
7 7(b)(2) resource stack are also set to zero, Program Case conservation costs are included in the  
8 7(b)(2) Case revenue requirement, and the 7(b)(2) Case repayment study results are replaced  
9 with the Program Case repayment study results.

10  
11 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
12 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

13  
14 **10.5.7 Scenario 7: Same Repayment Study in Both Cases (a COU position)**

15 Scenario 7 models the contention that inclusion of different repayment costs from the Program  
16 Case revenue requirement is not allowed in the 7(b)(2) Case. *See* section 9.3.2. To model this  
17 scenario, the 7(b)(2) Case repayment study results are replaced with the Program Case  
18 repayment study results.

19  
20 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
21 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

22  
23 **10.5.8 Scenario 8: Mid-C Resources Included in 7(b)(2)(D) Resource Stack (a COU**  
24 **position)**

25 Scenario 8 models the COUs' contention that Mid-Columbia resources should be included in the  
26 resource stack pursuant to section 7(b)(2)(D) of the Northwest Power Act. *See* section 9.3.3. To  
27 model this scenario, the Mid-C resources are included in the resource stack, with the available

1 power equal to the energy capability of each plant less the amount of energy used to serve COU  
2 load.

3  
4 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
5 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

#### 6 7 **10.5.9 Scenario 9: No 7(b)(3) Allocation to Surplus (a COU position)**

8 Scenario 9 models the COUs' contention that the costs of rate protection should not be allocated  
9 to surplus and secondary sales. *See* section 9.4.1. To model this scenario, the reallocation of rate  
10 protection to the secondary energy credit is removed and rate protection costs are allocated to  
11 only the PFx, IP, and NR rate pools.

12  
13 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
14 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

#### 15 16 **10.5.10 Scenario 10: Same Secondary Credit in 7(b)(2) Case (an IOU position)**

17 Scenario 10 models the IOUs' contention that the surplus sales to Slice customers should include  
18 a 7(b)(3) Supplemental Rate Charge and that BPA has not properly accounted for this allocation  
19 in the 7(b)(3) reallocations. *See* section 9.4.2. To model this scenario, the post-7(b)(3)  
20 allocation of rate protection to the secondary credit is assumed in both the Program Case and the  
21 7(b)(2) Case. This modification results in more costs of providing REP benefits being conveyed  
22 through the PFp rate.

23  
24 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
25 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

1 **10.5.11 Scenario 11: Conservation Resource Costs Are Expensed (an IOU position)**

2 Scenario 11 models the IOUs' contention that the conservation resources included in the  
3 resource stack should be expensed and the cost of such resources recovered in the year that the  
4 resource is called upon. *See* section 9.3.1.2. To model this scenario, the cost of each  
5 conservation resource is set equal to BPA's cost of acquiring the conservation and is recovered  
6 as an O&M expense, resulting in the acquisition cost being recovered in the year the resource is  
7 selected from the resource stack. This scenario is meaningless if considered in conjunction with  
8 either Scenario 5 or Scenario 6, where conservation resources are excluded from the resource  
9 stack.

10  
11 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
12 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

13  
14 **10.5.12 Scenario 12: Conservation Resource Costs Are Capitalized (a COU position)**

15 Scenario 12 models the COUs' contention that the conservation resources included in the  
16 resource stack should be capitalized over the useful life of the resource. *See* section 9.3.1.2. To  
17 model this scenario, the cost of each conservation resource is set equal to BPA's cost of  
18 acquiring the conservation and is recovered as a capitalized expense, resulting in the acquisition  
19 cost being amortized over the number of years of useful life of the resource. This scenario is  
20 meaningless if considered in conjunction with either Scenario 5 or Scenario 6, where  
21 conservation resources are excluded from the resource stack.

22  
23 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
24 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

1 **10.6 Analyzing the Effects of Issues That Are Expected to be Litigated in**  
2 **Challenges to WP-07 Supplemental Rates and WP-10 Rates**

3 Section 7 identifies several issues that are expected to be raised before the Ninth Circuit if  
4 briefing proceeds on BPA’s WP-07 Supplemental rates and WP-10 rates. These issues are  
5 described in the following sections.

6  
7 **10.6.1 Scenario 13: Excluded Conservation Added to Resource Stack (an IOU position)**

8 Scenario 13 models the IOUs’ contention that all acquired conservation should be included in the  
9 resource stack rather than the smaller portion used in the Reference Case. *See* section 9.5.2. To  
10 model this scenario, the amounts of excluded conservation are added to the amounts already  
11 included in the resource stack, such that the conservation resource capability is the full amount  
12 acquired under each year’s resource program. The full capability of the conservation resources  
13 is also used in the load adjustment to determine the general requirements of 7(b)(2) Customers in  
14 the 7(b)(2) Case.

15  
16 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
17 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

18  
19 **10.6.2 Scenario 14: Placeholder**

20 Scenario 14 was reserved for possible other analysis and is not used.

21  
22 **10.6.3 Scenario 15: Inflation Rate Used for Discount Rate (a COU position)**

23 Scenario 15 models APAC’s contention that the projected rate of inflation should be used to  
24 discount projected rate streams for the Program Case and the 7(b)(2) Case rather than the  
25 forecast BPA borrowing rate. *See* section 9.5.1. To model this scenario, the 30-year Treasury  
26 borrowing rate forecast is replaced with the forecast inflation rate for purposes of discounting the  
27 rate streams.

1 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
2 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

3  
4 **10.6.4 Scenario 16: Investment Rate Used for Discount Rate (an IOU position)**

5 Scenario 16 models the IOUs' alternative contention that the projected investment decision  
6 discount rate should be used to discount projected rate streams for the Program Case and the  
7 7(b)(2) Case rather than the forecast BPA borrowing rate. *See* section 9.5.1. To model this  
8 scenario, the 30-year Treasury borrowing rate forecast is replaced with an investment decision  
9 discount rate of 13 percent for purposes of discounting the rate streams.

10  
11 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
12 adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

13  
14 **10.6.5 Scenario 17: Placeholder**

15 Scenario 17 was reserved for possible other analysis and is not used.

16  
17 **10.7 Combined COU/IOU Scenarios**

18 To further analyze the Settlement, several additional scenarios combine those described above to  
19 define upper and lower bounds of litigation risk across the 17-year stream of REP benefits.

20 Scenarios 18 and 19 combine all of the positions asserted by the COUs and IOUs, respectively,  
21 into two best-case scenarios. An alternative IOU best-case scenario, Scenario 20, is included to  
22 represent a combination of IOU positions that produces superior results for the IOUs than the  
23 scenario that assumes the IOUs' positions on all issues. Scenarios 21 and 22 combine all of the  
24 positions asserted by the COUs and IOUs, respectively, that have already been briefed to the  
25 court; these scenarios exclude the positions on issues not yet briefed.

1 **10.7.1 Scenario 18: COU Best Case**

2 Scenario 18 is modeled by combining the COUs' position on the treatment of conservation from  
3 Scenario 5, their position on the 7(b)(2) Case repayment study from Scenario 7, their position on  
4 the inclusion of Mid-C resources in the resource stack from Scenario 8, their position on  
5 allocating 7(b)(3) rate protection costs to surplus sales from Scenario 9, their position on the  
6 capitalization of conservation resources from Scenario 12, and their position on discounting rate  
7 streams from Scenario 16.

8  
9 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
10 adjusted for Scenario 3 Lookback (without 50 percent rule) Amounts as shown in Table 10.1.

11  
12 **10.7.2 Scenario 19: IOU Best Case**

13 Scenario 19 is modeled by combining the IOUs' position on the treatment of conservation from  
14 Scenario 6, their position on allocating 7(b)(3) rate protection costs to Slice surplus sales from  
15 Scenario 10, their position on the expensing of conservation resources from Scenario 13, and  
16 their position on discounting rate streams from Scenario 15.

17  
18 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
19 adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

20  
21 **10.7.3 Scenario 20: IOU Alternative Case**

22 Scenario 20 is modeled by combining the IOUs' position on allocating 7(b)(3) rate protection  
23 costs to Slice surplus sales from Scenario 10, their position on the expensing of conservation  
24 resources from Scenario 13, and their position on discounting rate streams from Scenario 15. It  
25 omits their position on the treatment of conservation from Scenario 6 to allow their position on  
26 expensing conservation resources to affect the combined results of the IOUs' positions.

1 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
2 adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

#### 3 4 **10.7.4 Scenario 21: COU Brief Case**

5 Scenario 21 is modeled by combining the COUs' position on the treatment of conservation from  
6 Scenario 5, their position on the 7(b)(2) Case repayment study from Scenario 7, their position on  
7 the inclusion of Mid-C resources in the resource stack from Scenario 8, their position on  
8 allocating 7(b)(3) rate protection costs to surplus sales from Scenario 9, and their position on the  
9 capitalization of conservation resources from Scenario 12. It omits their position on discounting  
10 rate streams from Scenario 16 because it has not yet been briefed.

11  
12 Tables 10.2 and 10.3.1-2 present presents the stream of REP benefits resulting from this  
13 modification, adjusted for Scenario 3 Lookback (without 50 percent rule) Amounts as shown in  
14 Table 10.1.

#### 15 16 **10.7.5 Scenario 22: IOU Brief Case**

17 Scenario 22 is modeled by combining the IOUs' position on the treatment of conservation from  
18 Scenario 6 and their position on allocating 7(b)(3) rate protection costs to Slice surplus sales  
19 from Scenario 10. Scenario 22 excludes their position on the expensing of conservation  
20 resources from Scenario 13 and their position on discounting rate streams from Scenario 15  
21 because these have not yet been briefed.

22  
23 Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification,  
24 adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

25  
26 Figure 5 summarizes post-Lookback IOU REP Benefits under alternative brief scenarios.

1 **10.8 Summary: Presenting Model Results**

2 RAM2012 computation of REP benefits for the Reference Case and the litigation scenarios for  
3 the FY 2012–2013 period are included in Table 10.2. These results utilize scenario analysis in  
4 RAM2012. As presented in Tables 10.3.1-2, computed REP benefits for the Reference Case and  
5 all risk scenarios rely on RAM2012 for FY 2012–2013 and LTRM for FY 2014–2028.  
6 Computed REP benefits in Tables 10.3.1-2 for litigation and combined scenarios rely on LTRM  
7 analysis for the full FY 2012–2028 period, to provide consistency with associated  
8 Documentation.

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1 **Secondary criteria**

- 2       • The Settlement would recognize that not all COUs were equally harmed by the  
3       costs of the 2000 REP Settlement Agreements and that IOUs were differentially  
4       affected by BPA’s setting off REP benefits for Lookback Amounts.
- 5       • The Settlement would provide reasonable rates for non-settling parties and other  
6       classes of BPA’s customers.

7

8 Although more criteria could have been added to this list, BPA believes that a settlement that  
9 satisfies the aforementioned criteria would be, from an analytical perspective, reasonable and  
10 consistent with the protections and requirements of the Northwest Power Act. Most  
11 significantly, in BPA’s view, a settlement that meets the foregoing criteria would also avoid the  
12 key concerns expressed over previous settlements of the REP.

13

14 To test whether the Settlement satisfies the above criteria, BPA compares the projected rate  
15 protection amounts and REP benefits developed by the various litigation scenarios with the  
16 amounts provided under the Settlement. Based on this comparison, BPA provides an assessment  
17 of whether the Settlement satisfies the criteria set forth above.

18

19 **11.3 Evaluation of the 2012 REP Settlement**

20 Under almost all outcomes of the analysis, the Settlement provides superior rate protection  
21 compared to the 7(b)(2) rate test scenarios. The analysis performs the rate test under a variety of  
22 potential future rate scenarios and litigation results and shows that except in the instance that  
23 COUs prevail on every contested issue, the rate protection is greater and REP benefits smaller  
24 under the Settlement. The conclusion is that under most possible future results of the rate test,  
25 rates for COUs would be higher than the rates under the Settlement, all other factors being the  
26 same in both futures.

1 The Settlement continues to provide REP benefits to the settling IOUs in conformance with  
2 section 5(c) of the Northwest Power Act. The determination of REP benefits is unchanged under  
3 the Settlement. BPA continues to “purchase” power pursuant to section 5(c) at the average  
4 system cost of the IOU. BPA continues to “sell” power pursuant to section 5(c) at rates  
5 established pursuant to sections 7(b)(1), 7(b)(3), and 7(g) of the Northwest Power Act. The  
6 amount of REP benefits BPA pays to the settling IOU continues to be the difference between the  
7 amount BPA pays for the purchase and the amount BPA receives for the sale.

8  
9 The Settlement continues to distribute the REP benefits among the settling IOUs in a manner  
10 consistent with ASCs established under BPA’s current ASC Methodology and rates established  
11 under section 7 of the Northwest Power Act. The Settlement requires no changes to the ASC  
12 Methodology, and no changes have been proposed. Rates continue to be established using a  
13 method very similar to that used to establish rates without the Settlement. The majority of the  
14 cost of rate protection continues to be allocated to the PFX rate, thereby reducing REP benefits  
15 below the Unconstrained Benefits. If a utility’s ASC is less than the PFX rate, it will not receive  
16 any REP benefits under the Settlement, just as it would not receive any REP benefits in absence  
17 of the Settlement. The cost of rate protection is allocated among the eligible REP participants in  
18 the same manner as would be done without the Settlement.

19  
20 The Settlement resolves, in a fair and equitable manner, all of the outstanding issues with BPA’s  
21 development and implementation of the Lookback for the FY 2002–2011 period. Lookback  
22 Amounts are discharged as an individual obligation of each settling IOU. All of the settling  
23 parties, by signing the Settlement, would agree that the stream of Scheduled Benefits  
24 appropriately captures the disputed obligations and benefits arising from the past rate  
25 overcharges.

1 The COU reallocation of Refund Amounts takes into account the differential impacts of the past  
2 overcharges on the individual COUs. The COUs have negotiated among themselves to resolve  
3 these concerns.

4  
5 The IOU reallocation of REP benefits seeks to equalize the IOUs' exposure to differential  
6 impacts of REP benefit setoffs between FY 2008 and FY 2011. The IOUs' reallocations have  
7 been agreed to among them and can be implemented in a way that does not introduce any change  
8 to the section 5(c) procedures or any change in the section 7 ratemaking directives. It does not  
9 change the costs borne by any other customer group.

10  
11 The Settlement provides rate protection superior to that provided by the 7(b)(2) rate test in  
12 almost all instances. To achieve higher rate protection, the non-settling COUs would have to  
13 prevail on five litigated issues. Although it is always risky to lay odds on the possible decisions  
14 of the Court, simply affixing a 50/50 probability to the outcome of each COU issue (and zero  
15 probability to countervailing IOU positions) would mean that the likelihood of receiving greater  
16 rate protection is  $(\frac{1}{2})^5$ , or about 3 percent. Given the unlikely probability of complete success  
17 before the Court, the Settlement would provide superior rate protection for non-settling COUs.

18  
19 COUs participating in the REP bear the same exposure as the IOUs to deleterious outcomes of  
20 7(b)(2)-related issues before the Court. While the COUs do not bear any exposure to an adverse  
21 outcome regarding Lookback issues, the Settlement methodology does not assign any Lookback  
22 consequence to the COUs' REP benefit level. Thus, the Settlement puts COU REP participants  
23 in the same position as IOU REP participants with regard to the outcome of 7(b)(2)-related  
24 litigation. By settling this litigation, the COU REP participants gain the same certainty that the  
25 IOUs gain. The COUs are in no worse or better position than the IOUs.

1 Furthermore, the Settlement provides direct benefits for the FY 2012–2013 rate period. IOU  
2 REP benefits under BPA’s traditional 7(b)(2) Implementation Methodology (Reference Case  
3 from RAM Final Proposal results, Table 10.2) would, absent Settlement, result in an annual  
4 average for FY 2012–2013 of \$271 million. This amount is exclusive of REP benefits which  
5 would otherwise accrue to Idaho, but for Idaho’s outstanding deemer balance, and is before  
6 accounting for Lookback Amounts. The equivalent amount of REP Benefits under Settlement,  
7 including the Refund Amounts, is \$258.6 million. Therefore, the Settlement provides a benefit  
8 to Public and DSI customers of roughly \$12 million per year, for a total of \$24 million of known  
9 savings for FY 2012–2013.

10  
11 The IP rate under the traditional 7(b)(2) Implementation Methodology would result in an IP rate  
12 of \$37.63 mills/kWh, compared to the IP-12 final rate of \$36.32 mills/kWh under Settlement, as  
13 shown in Tables 10.5 and 10.6. Applied to Alcoa’s flat annual load of 320 aMW, Settlement  
14 results in a direct savings to Alcoa of \$7.4 million for FY 2012–2013.

15  
16 Moreover, the IP rate is not protected from REP costs. Although the IP rate does receive a  
17 benefit by being linked to the PFp rate after the PFp rate has reduced by rate protection, the  
18 7(b)(3) Supplemental Rate Charge is excluded from the 7(c)(2) linking. The analysis of the  
19 Settlement shows that as ASCs increase faster than BPA’s rates (the more likely future), the  
20 IP rate increases, because the 7(b)(3) Supplemental Rate Charge increases with ASCs faster than  
21 the underlying PFp rates.

22  
23 Figure 6 compares the IP rate for FY 2012–2028 under Settlement relative to BPA’s traditional  
24 Implementation methodology. Because ASCs are forecast to grow faster than the PF rate, the  
25 7(b)(3) Surcharge under the traditional Implementation Methodology is expected to grow faster

1 than under the REP Surcharge methodology under Settlement. The IP rate is therefore forecast  
2 to remain substantially lower under the Settlement than would otherwise be the case.

3  
4 **11.4 Conclusion**

5 This Study forms the analytical basis supporting the findings in the REP-12 Final Record of  
6 Decision, REP-12-A-02. The analysis demonstrates that the conclusions reached by the  
7 Administrator in the Final ROD have a basis in fact and are supported by substantial evidence.

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## **TABLES**

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**Table 4.1: Schedule of REP Benefit Payments to IOUs**

<b>Rate Period</b>	<b>Fiscal Year</b>	<b>Scheduled Amounts</b>
FY 2012–2013	2012	\$182,100,000
FY 2012–2013	2013	\$182,100,000
FY 2014–2015	2014	\$197,500,000
FY 2014–2015	2015	\$197,500,000
FY 2016–2017	2016	\$214,100,000
FY 2016–2017	2017	\$214,100,000
FY 2018–2019	2018	\$232,200,000
FY 2018–2019	2019	\$232,200,000
FY 2020–2021	2020	\$245,200,000
FY 2020–2021	2021	\$245,200,000
FY 2022–2023	2022	\$259,000,000
FY 2022–2023	2023	\$259,000,000
FY 2024–2025	2024	\$273,600,000
FY 2024–2025	2025	\$273,600,000
FY 2026–2028	2026	\$286,100,000
FY 2026–2028	2027	\$286,100,000
FY 2026–2028	2028	\$286,100,000

**Table 4.2: Refund Amounts to COUs**

<b>Rate Period</b>	<b>Fiscal Year</b>	<b>Refund Amounts</b>
FY 2012–2013	2012	\$76,537,617
FY 2012–2013	2013	\$76,537,617
FY 2014–2015	2014	\$76,537,617
FY 2014–2015	2015	\$76,537,617
FY 2016–2017	2016	\$76,537,617
FY 2016–2017	2017	\$76,537,617
FY 2018–2019	2018	\$76,537,617
FY 2018–2019	2019	\$76,537,617
all years thereafter		\$0

**Table 4.3: Initial IOU Adjustment Amount**

<b>IOU</b>	<b>Initial IOU Adjustment Amount</b>
Avista	\$22,986,000
NorthWestern	\$0
Idaho Power	\$45,140,170
PacifiCorp	\$66,721,315
PGE	\$4,699,222
Puget	\$0

**Table 4.4: Maximum IOU Annual Adjustment Amount**

<b>IOU</b>	<b>Maximum IOU Annual Adjustment Amount</b>
Avista	\$2,004,778
NorthWestern	\$0
Idaho Power	50 percent of Idaho Power's interim REP benefits
PacifiCorp	\$8,442,636
PGE	\$1,237,583
Puget Sound	\$0

**Table 4.5: Interim True-Up Payment Principal Amounts**

<b>IOU</b>	<b>Interim True-up Payment Principal Amounts</b>
Avista	\$ 2,410,000
NorthWestern	\$10,199,000
PGE	\$12,007,000
Puget	\$56,994,000
Total	\$81,610,000

**Table 7.1: 2009 Base Period Average System Cost**  
(Dollars per megawatt hour)

Avista	56.04
Idaho Power	47.77
NorthWestern	58.10
PacifiCorp	58.70
Portland General	68.97
Puget Sound Energy	69.11
Clark	53.87
Snohomish	47.99

See REP-12-FS-BPA-01A, Section 7, and FY 2012–2013 Final ASC Reports for each of the exchanging utilities.

**Table 7.2: 2009 Base Year Contract System Cost**  
(Dollars)

Avista	525,768,148
Idaho Power	679,834,891
Northwestern	353,188,004
PacifiCorp	1,239,331,429
Portland General	1,242,122,673
Puget Sound Energy	1,588,027,729
Clark	254,099,355
Snohomish	341,468,092

See REP-12-FS-BPA-01A, Section 7, and FY 2012–2013 Final ASC Reports for each of the exchanging utilities.

**Table 7.3: 2009 Base Year Contract System Load  
(MWh)**

Avista	9,382,688
Idaho Power	14,230,732
Northwestern	6,078,493
PacifiCorp	21,112,995
Portland General	18,009,327
Puget Sound Energy	22,979,451
Clark	4,716,985
Snohomish	7,115,588

*See REP-12-FS-BPA-01A, Section 7, and FY 2012–2013 Final ASC Reports for each of the exchanging utilities.*

**Table 7.4: Escalation Rates and Price Forecasts**

<b>Cost Item</b>	<b>Escalation</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>
No Escalation	CONSTANT	0.00%	0.00%	0.00%	0.00%
Distribution Plant	CD	0.90%	1.70%	2.10%	2.70%
Inflation	INF	1.07%	1.48%	1.50%	1.65%
Wages	WAGES	1.70%	2.00%	2.50%	2.70%
Steam Fuel (Coal)	COAL	-12.10%	0.60%	1.00%	1.90%
Steam Operations	SOPS	2.30%	2.90%	2.90%	2.50%
Steam Maintenance	SMN	0.40%	1.60%	2.40%	2.60%
Nuclear Fuel	NFUEL	0.00%	0.00%	0.00%	0.00%
Nuclear Operations	NOPS	1.70%	2.50%	2.50%	2.30%
Nuclear Maintenance	NMN	1.50%	2.10%	2.30%	2.30%
Hydro Operations	HOPS	2.70%	3.20%	2.70%	2.20%
Hydro Maintenance	HMN	0.20%	1.60%	2.50%	2.60%
Natural Gas	NATGAS	9.42%	-11.95%	10.56%	13.42%
Other Operations	OOPS	3.00%	3.70%	3.30%	2.80%
Other Maintenance	OMN	0.10%	1.30%	2.20%	2.30%
Transmission Operations	TOPS	1.90%	2.60%	2.60%	2.50%
Transmission Maintenance	TMN	0.60%	1.80%	2.30%	2.20%
Distribution Operations	DOPS	1.50%	2.10%	2.40%	2.30%
Distributions Maintenance	DMN	1.10%	2.00%	2.30%	2.20%
Customer Accounts	CACNT	1.50%	1.80%	2.30%	2.20%
Customer Service	CSERV	1.40%	2.10%	2.20%	2.00%
Customer Sales	CSALES	1.40%	2.10%	2.50%	2.40%
Administrative and General	A&G	2.30%	2.50%	2.90%	3.00%
Blank	ADDER	0.00%	0.00%	0.00%	0.00%
FY Market Price		19.19%	-3.98%	-8.75%	13.21%
FY Market Price (\$/MWh)		38.19	36.67	33.46	37.88

**Table 7.5: Financing and Other Common Parameter Assumptions  
(Values are nominal unless stated)**

	<b>Municipal/ PUD</b>	<b>Investor-Owned Utility</b>
Federal Income Tax Rate		35%
State Income Tax Rate		5.0%
Property Tax	1.4%	1.4%
Insurance	0.25%	0.25%
Development	100%	50%
Construction	100%	50%
Term	100%	50%
Debt interest – Development	5.1%	7.1%
Debt interest – Construction	5.1%	7.1%
Debt interest – Term	5.1%	7.1%
Return on Equity – Development		10.2%
Return on Equity – Construction		10.2%
Return on Equity – Term		10.2%

**Table 7.6: Escalation Rates for Various ASC Forecast Model Components**

	<b>CY 10</b>	<b>CY 11</b>	<b>CY 12</b>	<b>CY 13</b>	<b>CY 14</b>	<b>CY 15</b>	<b>CY 16</b>	<b>CY 17</b>	<b>CY 18</b>	<b>CY 19–28</b>
<b>Capital</b>	1.3%	1.6%	1.7%	2.3%	2.7%	3.0%	2.1%	1.9%	2.1%	2.3%
<b>Variable O&amp;M</b>	1.6%	2.5%	2.8%	2.6%	3.1%	2.5%	1.8%	1.4%	1.4%	1.4%
<b>Fixed O&amp;M</b>	1.6%	2.5%	2.8%	2.6%	3.1%	2.5%	1.8%	1.4%	1.4%	1.4%
<b>Natural Gas</b>	9.4%	-11.9%	10.6%	13.4%	2.7%	4.6%	3.1%	4.4%	3.0%	3.0%
<b>Inflation</b>	1.1%	1.5%	1.5%	1.7%	1.8%	1.7%	1.7%	1.8%	1.8%	1.8%
<b>Transmission</b>	1.0%	1.8%	2.4%	3.0%	3.3%	3.1%	1.9%	1.8%	2.0%	2.3%
<b>Steam Fuel</b>	-12.1%	0.6%	1.0%	1.9%	1.9%	1.8%	1.8%	1.7%	1.7%	1.7%

**Table 7.7: Plant Capacity Factor**

<b>Resource Type</b>	<b>Capacity Factor</b>	<b>Source</b>
Coal Supercritical PC	93.0%	Council Plan
CCCT	60.0%	CEC (2007)
Biomass	80.0%	Council Plan
Wind	32.0%	Council Plan
Long-Haul wind	38.0%	Council Plan
Peaker Heavy-duty (Frame)	46.0%	CEC (2007)
Landfill gas	85.0%	Council Plan
Geothermal	90.0%	Council Plan
Solar CST	35.5%	Council Plan
Waste Heat Energy Recovery Cogeneration	80.0%	Council Plan
CCCT – Duct Firing	60.0%	CEC (2007)
SCCT – LMS100	5.0%	CEC (2007)
Purchased Power	100.0%	N/A
Hydro	50.0%	Council Plan

**Table 7.8: Capacity Factor (less losses)**

<b>Resource Type</b>	<b>Capacity Factor</b>	<b>Trans Loss Factor</b>	<b>Capacity Factor (less losses)</b>
Coal Supercritical PC	93.0%	1.9%	85.6%
CCCT	60.0%	1.9%	58.9%
Biomass	80.0%	1.9%	78.5%
Wind	32.0%	1.9%	31.4%
Long-Haul wind	38.0%	2.5%	36.1%
Peaker Heavy-duty (Frame)	46.0%	1.9%	45.1%
Landfill gas	85.0%	1.9%	83.4%
Geothermal	90.0%	1.9%	88.3%
Solar CST	35.5%	1.9%	34.8%
Waste Heat Energy Recovery Cogeneration	80.0%	1.9%	78.5%
CCCT – Duct Firing	60.0%	1.9%	58.9%
SCCT – LMS100	5.0%	1.9%	4.9%
Purchased Power	100.0%	1.9%	98.1%
Hydro	50.0%	1.9%	49.1%

**Table 7.9: Transmission Costs and Losses (Ely location)**

<b>Load Center</b>	<b>Fixed Transmission Costs</b>	<b>Variable Transmission Costs (\$/MWh)</b>	<b>Transmission Losses</b>
Southern Idaho	\$102	\$1.00	4.0%
Oregon & Washington	\$189	\$1.00	6.5%

**Table 7.10: Wind Average Annual Capacity Factors**

<b>Wind Resource Area &gt;</b>	<b>Columbia Basin</b>	<b>Southern Idaho</b>	<b>Central Montana</b>	<b>Southern Alberta</b>	<b>Eastern Wyoming</b>
Average annual capacity factor (net plant output)	32%	30%	38%	38%	38%

**Table 7.11: Avista Corporation New Resources**

<b>MW Capacity</b>																
<b>Resource</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>Total</b>
<b>SCCT – LMS100</b>																
<b>CCCT</b>						250					250			250		<b>750</b>
<b>Biomass</b>																
<b>Geothermal</b>																
<b>Landfill Gas</b>																
<b>Long-Haul Wind</b>																
<b>Solar</b>																
<b>Wind</b>	150					150			50							<b>350</b>
<b>Purchased Power</b>																
<b>REC</b>																

**Table 7.12: Clark County PUD New Resources**

<b>MW Capacity</b>																
<b>Resource</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>Total</b>
<b>SCCT – LMS100</b>	70															<b>70</b>
<b>CCCT</b>																
<b>Biomass</b>																
<b>Geothermal</b>																
<b>Landfill Gas</b>											22					<b>22</b>
<b>Long-Haul Wind</b>																
<b>Solar</b>																
<b>Wind</b>									20					10		<b>30</b>
<b>Purchased Power</b>																
<b>REC</b>		30					40									<b>70</b>



**Table 7.13: Idaho Power Company New Resources**

<b>MW Capacity</b>																
<b>Resource</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>Total</b>
<b>SCCT – LMS100</b>							100				200		200		400	<b>900</b>
<b>CCCT</b>																
<b>Biomass</b>																
<b>Geothermal</b>	20		20													<b>40</b>
<b>Landfill Gas</b>																
<b>Long-Haul Wind</b>																
<b>Solar</b>																
<b>Wind</b>									100					400		<b>500</b>
<b>Purchased Power</b>																
<b>REC</b>																

**Table 7.14: NorthWestern Corporation New Resources**

<b>MW Capacity</b>																
<b>Resource</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>Total</b>
<b>SCCT – LMS100</b>																
<b>CCCT</b>		200														<b>200</b>
<b>Biomass</b>							25									<b>25</b>
<b>Geothermal</b>																
<b>Landfill Gas</b>																
<b>Long-Haul Wind</b>																
<b>Solar</b>																
<b>Wind</b>	50		75	25												<b>150</b>
<b>Purchased Power</b>	-287															<b>-287</b>
<b>REC</b>																

**Table 7.15: PacifiCorp New Resources**

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT – LMS100			261													261
CCCT	570															570
Biomass												25		25		50
Geothermal	35															35
Landfill Gas																
Long-Haul Wind	549	150	100	100	50	200	200	150								1499
Solar																
Wind	220															220
Purchased Power																
REC																

**Table 7.16: Portland General Electric New Resources**

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT – LMS100	200															200
CCCT		441						440								881
Biomass				29		29										58
Geothermal						58										58
Landfill Gas																
Long-Haul Wind																
Solar						27										27
Wind							200		100		200	200	200			900
Purchased Power																
REC																

**Table 7.17: Puget Sound Energy New Resources**

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
<b>SCCT – LMS100</b>	160			160			160	160	160	160	160	160	160	160	160	<b>1760</b>
<b>CCCT</b>	275			275			275									<b>825</b>
<b>Biomass</b>							20					20				<b>40</b>
<b>Geothermal</b>																
<b>Landfill Gas</b>																
<b>Long-Haul Wind</b>																
<b>Solar</b>																
<b>Wind</b>	100		200		200		200									<b>700</b>
<b>Purchased Power</b>																
<b>REC</b>																

**Table 7.18: Snohomish County PUD New Resources**

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
<b>SCCT – LMS100</b>																
<b>CCCT</b>																
<b>Biomass</b>			1.25													<b>1.25</b>
<b>Geothermal</b>			5.56		5.56		44.44									<b>55.56</b>
<b>Landfill Gas</b>			3.53													<b>3.53</b>
<b>Long-Haul Wind</b>																
<b>Solar</b>																
<b>Wind</b>							50	20		20		20				<b>110</b>
<b>Purchased Power</b>																
<b>Hydro</b>					4		4									<b>8</b>

**Table 9.1: FY 2002–2006 Lookback Amounts**  
 WP-07 Supplemental Lookback Calculations  
 2009\$ in millions

	<b>LRAs Valid and Protected 1/</b>	<b>LRAs Valid but Separate and Unchallenged</b>
PacifiCorp	\$203.5M	\$187.8M
Puget Sound Energy	\$262.2M	\$0
Total for all IOUs	\$746.2M	\$468.2M

1/ FY 2002-2008 Lookback Study, WP-07-FS-08, at 282-284. These three amounts are the FY 2002-2006 totals for lines 39, 57, and 69 of Table 15.9.

**Table 9.2: FY 2002-2006 Lookback Amounts**  
 Large Lookback Calculations based on WP-02 Determinations of REP Benefits  
 2009\$ in millions

	<b>Base Case 1/</b>	<b>Large Lookback with LRAs Valid and Protected</b>	<b>Large Lookback with LRAs Invalid</b>	<b>Large Lookback with LRAs Valid, but Separate and Unchallenged</b>
Avista	\$64.6	\$64.6	\$64.6	\$64.6
Idaho Power	\$85.0	\$85.0	\$85.0	\$85.0
Northwestern	\$5.7	\$17.1	\$17.1	\$17.1
PacifiCorp	\$203.5	\$203.5	\$669.6	\$197.1
Portland General Electric	\$125.1	\$267.7	\$267.7	\$267.7
Puget Sound Energy	\$262.2	\$289.3	\$828.6	\$132.5
Total	\$746.2	\$927.3	\$1,932.7	\$764.0

**Table 9.3: FY 2002–2006 Lookback Amounts**  
 WP-07 Supplemental Lookback Calculations  
 2009\$ in millions

	<b>LRAs Valid and Protected</b>	<b>LRAs Invalid</b>
PacifiCorp	\$203.5	\$660.3
Puget Sound Energy	\$262.2	\$562.6
Total for all IOUs	\$746.2	\$1,503.3

**Table 9.4: REP Benefits, Lookback Amounts to be Recovered,  
and REP Benefits Paid – FY 2012–2013**  
(\$ in million)

	A	B	C		D	E	F
	REP Benefits Due		Lookback Amount Recovered		REP Benefits Paid		
	FY 2012	FY 2013	FY 2012	FY 2013	FY 2012	FY 2013	
Avista	\$20.18	\$19.07	\$10.09	\$9.54	\$10.09	\$9.54	
Idaho Power	\$ 6.51	\$10.42 1/	\$ 0	\$ 0	\$0	\$0	
Northwestern	\$ 2.67	\$ 2.52	n/a	n/a	\$2.67	\$2.52	
PacifiCorp	\$58.44	\$60.87	\$29.22	\$30.44	\$29.22	\$30.44	
PGE	\$83.46	\$78.86	\$15.93	\$15.05	\$67.52	\$63.80	
Puget	\$106.89	\$108.26	\$23.10	\$23.39	\$83.79	\$84.87	
Total	\$278.15	\$280.00					
Total w/o IP	\$271.64	\$269.58	\$78.34	\$78.42	\$193.30	\$191.16	

1/ Note that Idaho Power’s REP benefits will be applied to its deemer balance and not its Lookback Amount until the deemer balance is extinguished.

**Table 10.1: Lookback Amounts Recovered in each Year**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
<b>No Settlement Base Case</b>											
Total Payments toward the Lookback Amount	\$78.34	\$78.42	\$95.44	\$97.13	\$58.15	\$29.37	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Payments toward Deemer balances	\$6.51	\$10.42	\$4.59	\$1.70	\$3.89	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments	\$84.85	\$88.84	\$100.03	\$98.83	\$62.03	\$29.37	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
<b>Scenarios</b>											
<b>10.4.1 No Lookback - Return the Amounts Recovered from the IOUs in FY 12-14</b>	(\$77.49)	(\$82.06)	(\$81.06)								
<b>10.4.2 Large Lookback with Protected LRAs</b>											
Lookback Payments w/ 50% rule	\$100.73	\$100.02	\$128.49	\$136.78	\$114.50	\$28.87	\$14.72	\$12.78	\$1.55	\$0.92	\$0.69
Lookback Payments w/o 50% rule	\$126.99	\$126.24	\$169.64	\$165.53	\$23.89	\$3.48	\$3.64	\$3.29	\$3.11	\$1.84	\$1.39
Total Payments toward Deemer balances	\$29.36	\$32.01	\$13.95	\$5.46	\$8.75	\$0.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	\$130.08	\$132.04	\$142.44	\$142.24	\$123.25	\$29.52	\$14.72	\$12.78	\$1.55	\$0.92	\$0.69
Total of Lookback and Deemer balance payments w/o 50% rule	\$156.35	\$158.26	\$183.59	\$170.98	\$32.63	\$4.14	\$3.64	\$3.29	\$3.11	\$1.84	\$1.39
<b>10.4.3 Large Lookback with Invalid LRAs</b>											
Lookback Payments w/ 50% rule	\$124.39	\$123.99	\$155.97	\$165.02	\$189.56	\$135.30	\$143.73	\$157.28	\$151.48	\$144.21	\$133.17
Lookback Payments w/o 50% rule	\$218.81	\$219.66	\$278.59	\$293.44	\$263.59	\$220.91	\$89.74	\$100.98	\$97.41	\$78.78	\$1.39
Total Payments toward Deemer balances	\$29.36	\$32.01	\$13.95	\$5.46	\$8.75	\$0.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	\$153.75	\$156.00	\$169.92	\$170.48	\$198.30	\$135.95	\$143.73	\$157.28	\$151.48	\$144.21	\$133.17
Total of Lookback and Deemer balance payments w/o 50% rule	\$248.16	\$251.67	\$292.54	\$298.90	\$272.34	\$221.57	\$89.74	\$100.98	\$97.41	\$78.78	\$1.39

**Table 10.1: Lookback Amounts Recovered in each Year**

	2023	2024	2025	2026	2027	2028
<b><u>No Settlement Base Case</u></b>						
Total Payments toward the Lookback Amount	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Payments toward Deemer balances	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
<b><u>Scenarios</u></b>						
<b>10.4.1 No Lookback - Return the Amounts Recovered from the IOUs in FY 12-14</b>						
<b>10.4.2 Large Lookback with Protected LRAs</b>						
Lookback Payments w/ 50% rule	\$0.12	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Lookback Payments w/o 50% rule	\$0.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Payments toward Deemer balances	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	\$0.12	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments w/o 50% rule	\$0.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
<b>10.4.3 Large Lookback with Invalid LRAs</b>						
Lookback Payments w/ 50% rule	\$39.88	\$44.15	\$46.87	\$47.30	\$42.74	\$43.64
Lookback Payments w/o 50% rule	\$0.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Payments toward Deemer balances	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	\$39.88	\$44.15	\$46.87	\$47.30	\$42.74	\$43.64
Total of Lookback and Deemer balance payments w/o 50% rule	\$0.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

**Table 10.2: RAM2012 REP Benchmarks for FY 2012-2013 under Alternative Scenarios /1**

	<b>Unconstrained REP Benefits</b>	<b>Rate Protection</b>	<b>7(b)(3) PFx Alloc</b>	<b>7(b)(3) IP Alloc</b>	<b>7(b)(3) NR Alloc</b>	<b>REP Benefits</b>	<b>REP paid by PFp</b>
Settlement Case	861,413	607,161	584,211	22,950	0.0675	277,202	242,589
Reference Case	785,151	660,448	432,088	28,444	0.0837	306,235	265,126
Scenario 5 - Conservation = Gen. Req. w/o Costs.	765,278	809,702	529,735	34,872	0.1026	187,912	146,065
Scenario 6 - Conservation = Gen. Req. w/ Costs	781,586	686,567	449,176	29,569	0.0870	285,492	244,256
Scenario 7 - Single Repayment Study	782,886	677,861	443,480	29,194	0.0859	292,509	251,311
Scenario 8 - Mid-C in Stack	765,731	806,592	527,701	34,739	0.1022	190,419	148,585
Scenario 9 - No 7(b)(3) to Surplus	868,112	573,383	537,968	35,415	0.1042	285,693	238,869
Scenario 10 - Identical Secondary Credits	803,331	524,254	342,985	22,579	0.0664	413,771	373,357
Scenario 11 - Conservation Res. Expensed	796,023	580,224	379,603	24,989	0.0735	369,779	329,071
Scenario 12 - Conservation Res. Capitalized	779,774	700,249	458,127	30,159	0.0887	274,669	233,363
Scenario 13 - No Exclusions	789,681	627,488	410,524	27,025	0.0795	332,419	291,471
Scenario 15 - Discount Rate = Inflation	766,124	803,483	525,666	34,605	0.1018	192,868	151,051
Scenario 16 - Discount Rate = Investment	801,972	533,582	349,088	22,980	0.0676	406,319	365,861
Scenario 18 - COU Best Case	864,941	851,990	799,367	52,623	0.1548	23,338	(27,946)
Scenario 19 - IOU Best Case	829,152	333,333	218,078	14,356	0.0422	564,102	524,680
Scenario 20 - IOU Alternative Case	835,042	290,423	190,005	12,508	0.0368	597,857	558,658
Scenario 21 - COU Brief Case	866,694	720,149	675,669	44,480	0.1308	147,743	98,560
Scenario 22 - IOU Brief Case	800,613	544,154	356,005	23,436	0.0689	398,029	357,514

/1 These results assume both IOU and COU participation in the REP.



**Table 10.3.1: Estimated IOU REP Payments for FY 2012 - 2020 under Litigated Scenarios (\$1000s, nominal)**

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	193,295	191,156	225,862	236,676	326,002	356,096	404,996	474,341	485,213
High ASC; Low PF	193,295	191,156	253,136	264,743	361,840	395,724	460,683	528,781	553,637
Low ASC; High PF	193,295	191,156	199,171	208,098	290,399	303,470	349,254	407,116	402,219
High ASC; Low PF - Risk	193,295	191,156	318,262	343,796	434,402	453,375	507,498	594,343	626,408
Low ASC; High PF - Risk	193,295	191,156	209,276	227,767	262,432	276,372	306,124	350,395	348,800
Scenario 1 - No Lookback	380,453	385,719	406,954	335,503	388,036	385,462	404,996	474,341	485,213
Scenario 2 - Large Lookback w/ Protected LRAs (50% rule)	172,880	171,621	183,451	193,265	264,791	355,941	390,271	461,560	483,659
Scenario 2 - Large Lookback w/ Protected LRAs (no 50% rule)	146,617	145,401	142,304	164,520	355,402	381,324	401,355	471,050	482,105
Scenario 3 - Large Lookback w/ LRAs Invalid (50% rule)	149,218	147,656	155,974	165,028	189,734	249,512	261,263	317,060	333,736
Scenario 3 - Large Lookback w/ LRAs Invalid (no 50% rule)	54,801	51,987	33,353	36,607	115,695	163,894	315,255	373,362	387,804
Scenario 4 - Idaho Deemer Relief	193,295	191,156	225,862	236,676	326,002	356,096	404,996	474,341	485,213
Scenario 5 - Conservation = Gen. Req. w/o Costs.	96,602	89,053	99,268	86,519	160,177	184,805	232,505	265,919	297,521
Scenario 6 - Conservation = Gen. Req. w/ Costs	199,297	198,300	211,926	212,359	298,150	331,438	394,854	443,356	489,797
Scenario 7 - Single Repayment Study	205,141	206,674	216,111	219,017	302,533	333,967	384,252	452,630	472,131
Scenario 8 - Mid-C in Stack	112,219	98,214	102,316	95,964	168,133	200,221	249,548	304,469	322,142
Scenario 9 - No 7(b)(3) to Surplus	197,549	196,949	205,490	222,376	308,696	327,366	373,038	448,876	454,559
Scenario 10 - Identical Secondary Credits	310,966	307,022	323,790	335,415	423,743	455,931	508,529	584,961	607,662
Scenario 11 - Conservation Res. Expensed	289,454	287,869	315,906	355,983	444,745	478,893	569,170	618,536	583,068
Scenario 12 - Conservation Res. Capitalized	178,418	173,535	186,579	193,938	285,573	312,263	363,044	428,444	449,571
Scenario 13 - No Exclusions	263,389	264,890	246,231	273,042	338,415	390,131	429,772	496,162	529,183
Scenario 15 - Discount Rate = Inflation	145,757	139,203	147,151	146,414	231,983	262,961	306,554	376,770	368,751
Scenario 16 - Discount Rate = Investment	298,469	295,036	310,749	316,854	408,389	436,619	490,998	559,879	585,851
Scenario 18 - COU Best Case	-	-	-	-	-	-	-	-	-
Scenario 19 - IOU Best Case	527,344	532,236	562,995	478,855	535,769	529,750	569,823	627,374	684,979
Scenario 20 - IOU Alternative Case	662,653	699,704	712,145	659,449	718,337	729,559	767,079	858,676	916,255
Scenario 21 - COU Brief Case	-	-	-	-	-	-	56,687	87,318	134,677
Scenario 22 - IOU Brief Case	445,998	450,198	479,837	399,204	458,380	450,380	485,010	537,266	586,458
Settlement	182,100	182,100	197,500	197,500	214,100	214,100	232,200	232,200	245,200

**Table 10.3.2: Estimated IOU REP Payments for FY 2021 - 2028 under Litigated Scenarios (\$1000s, nominal) cont.**

	2021	2022	2023	2024	2025	2026	2027	2028
Reference Case	468,204	515,352	490,364	573,660	642,054	682,466	695,563	751,988
High ASC; Low PF	542,434	610,389	572,168	657,309	727,096	799,195	815,761	872,919
Low ASC; High PF	387,618	430,692	405,467	478,562	537,397	587,274	585,187	639,937
High ASC; Low PF - Risk	613,091	673,855	645,038	753,549	833,429	904,795	929,917	992,230
Low ASC; High PF - Risk	325,860	344,667	338,061	391,687	479,787	501,539	505,889	503,721
Scenario 1 - No Lookback	468,204	515,352	490,364	573,660	642,054	682,466	695,563	751,988
Scenario 2 - Large Lookback w/ Protected LRAs (50% rule)	467,285	514,658	490,243	573,660	642,054	682,466	695,563	751,988
Scenario 2 - Large Lookback w/ Protected LRAs (no 50% rule)	466,366	513,965	490,121	573,660	642,054	682,466	695,563	751,988
Scenario 3 - Large Lookback w/ LRAs Invalid (50% rule)	323,999	382,179	450,482	529,510	595,180	635,168	652,825	708,351
Scenario 3 - Large Lookback w/ LRAs Invalid (no 50% rule)	389,429	513,965	490,121	573,660	642,054	682,466	695,563	751,988
Scenario 4 - Idaho Deemer Relief	468,204	515,352	490,364	573,660	642,054	682,466	695,563	751,988
Scenario 5 - Conservation = Gen. Req. w/o Costs.	264,453	297,533	271,718	350,119	416,394	471,219	444,137	495,343
Scenario 6 - Conservation = Gen. Req. w/ Costs	470,650	514,496	498,384	583,991	659,441	708,413	710,421	771,854
Scenario 7 - Single Repayment Study	447,146	476,895	433,974	498,556	546,059	582,718	595,223	647,924
Scenario 8 - Mid-C in Stack	301,483	337,937	318,530	391,111	464,715	479,059	486,094	536,385
Scenario 9 - No 7(b)(3) to Surplus	442,867	482,554	465,282	535,090	610,458	665,818	676,497	727,486
Scenario 10 - Identical Secondary Credits	591,261	639,606	613,673	696,753	769,628	809,304	816,364	868,593
Scenario 11 - Conservation Res. Expensed	600,782	667,511	632,645	711,435	784,556	852,558	880,111	939,197
Scenario 12 - Conservation Res. Capitalized	422,305	472,364	444,380	530,253	596,739	637,465	648,205	704,737
Scenario 13 - No Exclusions	531,501	565,603	576,869	643,186	749,797	780,172	817,754	859,740
Scenario 15 - Discount Rate = Inflation	352,083	398,995	373,330	453,961	519,584	555,307	571,295	627,265
Scenario 16 - Discount Rate = Investment	567,015	613,912	589,320	675,156	745,352	790,088	801,302	859,794
Scenario 18 - COU Best Case	-	29,800	-	25,589	75,350	131,322	112,976	158,815
Scenario 19 - IOU Best Case	663,906	712,927	692,140	780,940	856,229	910,722	906,246	972,917
Scenario 20 - IOU Alternative Case	941,130	984,189	1,010,800	1,078,060	1,214,226	1,265,347	1,332,375	1,385,817
Scenario 21 - COU Brief Case	120,009	189,898	149,211	197,535	246,370	304,007	289,441	339,174
Scenario 22 - IOU Brief Case	567,012	616,355	597,470	682,295	759,620	810,399	805,666	872,895
Settlement	245,200	259,000	259,000	273,600	273,600	286,100	286,100	286,100

**Table 10.4: Net Present Value of IOU REP Payments FY 2007 - 2028 /1**

	Reference	Scenario	Settlement
High ASC; Low PF	3,070,189	3,383,042	2,050,628
Low ASC; High PF	3,070,189	2,743,230	2,050,628
High ASC; Low PF - Risk	3,070,189	3,760,079	2,050,628
Low ASC; High PF - Risk	3,070,189	2,520,694	2,050,628
Scenario 1 - No Lookback	3,070,189	3,490,261	2,050,628
Scenario 2 - Large Lookback w/ Protected LRAs (50% rule)	3,070,189	2,961,276	2,050,628
Scenario 2 - Large Lookback w/ Protected LRAs (no 50% rule)	3,070,189	2,952,509	2,050,628
Scenario 3 - Large Lookback w/ LRAs Invalid (50% rule)	3,070,189	2,524,433	2,050,628
Scenario 3 - Large Lookback w/ LRAs Invalid (no 50% rule)	3,070,189	2,386,540	2,050,628
Scenario 4 - Idaho Deemer Relief	3,070,189	3,070,189	2,050,628
Scenario 5 - Conservation = Gen. Req. w/o Costs.	3,070,189	2,009,250	2,050,628
Scenario 6 - Conservation = Gen. Req. w/ Costs	3,070,189	3,042,585	2,050,628
Scenario 7 - Single Repayment Study	3,070,189	2,896,953	2,050,628
Scenario 8 - Mid-C in Stack	3,070,189	2,145,570	2,050,628
Scenario 9 - No 7(b)(3) to Surplus	3,070,189	2,952,082	2,050,628
Scenario 10 - Identical Secondary Credits	3,070,189	3,767,230	2,050,628
Scenario 11 - Conservation Res. Expensed	3,070,189	3,854,496	2,050,628
Scenario 12 - Conservation Res. Capitalized	3,070,189	2,836,170	2,050,628
Scenario 13 - No Exclusions	3,070,189	3,405,181	2,050,628
Scenario 15 - Discount Rate = Inflation	3,070,189	2,488,684	2,050,628
Scenario 16 - Discount Rate = Investment	3,070,189	3,655,538	2,050,628
Scenario 18 - COU Best Case	3,070,189	758,842	2,050,628
Scenario 19 - IOU Best Case	3,070,189	4,551,241	2,050,628
Scenario 20 - IOU Alternative Case	3,070,189	5,964,218	2,050,628
Scenario 21 - COU Brief Case	3,070,189	1,172,139	2,050,628
Scenario 22 - IOU Brief Case	3,070,189	4,005,802	2,050,628

/1 For FY2012-2028, NPV uses payment values presented in Tables 10.3.1 and 10.3.2. The following payments for FY2007-2011 are used: 2007=168,377,396; 2008=110,408,668; 2009=190,010,000; 2010=170,260,000; and 2011=176,180,000. NPVs assume a discount rate of 8%.

**Table 10.5: Final Rates Under Settlement**

		% above WP-10	
Unbifurcated PF	\$ 38.88	7.1%	
PF Public	\$ 30.27	5.2%	
PF Exchange	\$ 54.30	11.5%	
IP	\$ 36.31	4.9%	
NR	\$ 69.50	1.2%	
<b>Residential Exchange Benefits</b>			
	<b>FY 2012</b>	<b>FY 2013</b>	
Avista	\$ 11,838	\$ 11,838	
Idaho Power	\$ 2,524	\$ 2,524	
Northwestern	\$ 2,907	\$ 2,907	
PacifiCorp	\$ 31,455	\$ 31,455	
PGE	\$ 58,257	\$ 58,257	
Puget Sound Energy	\$ 75,119	\$ 75,119	
Net IOU Exchange	\$ 182,101	\$ 182,101	<b>\$ 182,101</b>
Refund Amt	\$ 76,538	\$ 76,538	<b>\$ 76,538</b>
<b>Net COU Exchange</b>			
Clark	\$ 14,874	\$ 15,029	
Franklin	\$ -	\$ -	
Snohomish	\$ 4,587	\$ 4,631	
Net COU Exchange	\$ 19,461	\$ 19,660	<b>\$ 19,560</b>
		<b>Total</b>	<b>\$ 278,199</b>
<b>Annual Average \$ (1000s).....</b>	<b>WP-10</b>	<b>WP-12</b>	<b>Change</b>
<b>Composite Revenues.....</b>	\$ 2,321,998	\$ 2,262,417	-2.6%
<b>Non-Slice Revenues.....</b>	\$ (514,761)	\$ (325,256)	36.8%
<b>Slice Revenues.....</b>	\$ 2,422	\$ -	
<b>Load Shaping Revenues.....</b>	\$ 32,200	\$ (14,083)	-143.7%
<b>Demand Revenues .....</b>	\$ 53,303	\$ 60,101	12.8%
<b>Tier 1 Revenue Requirement</b>	<b>\$ 1,895,163</b>	<b>\$ 1,983,179</b>	<b>4.6%</b>
<b>Tier 2 Revenue Requirement</b>		\$ 16,363	
<b>Lookback Return (credit).....</b>	\$ (81,575)	\$ (76,538)	
<b>Value of Slice Secondary.....</b>	\$ (166,495)	\$ (162,043)	2.7%
<b>Net Power Cost to All PF.....</b>	\$ 1,647,093	\$ 1,760,961	6.9%
<b>Total PF Load w/Slice (GWh)/yr.....</b>	61,408	60,702	-1.2%
<b>Average Net Cost \$/MWh.....</b>	26.82	29.01	8.2%
<b>Tier 1 Average Net Cost (\$/MWh).....</b>		28.90	7.8%
<b>Tier 2 (\$/MWh).....</b>	-	47.59	

**Table 10.6: Final Rates Under No Settlement**

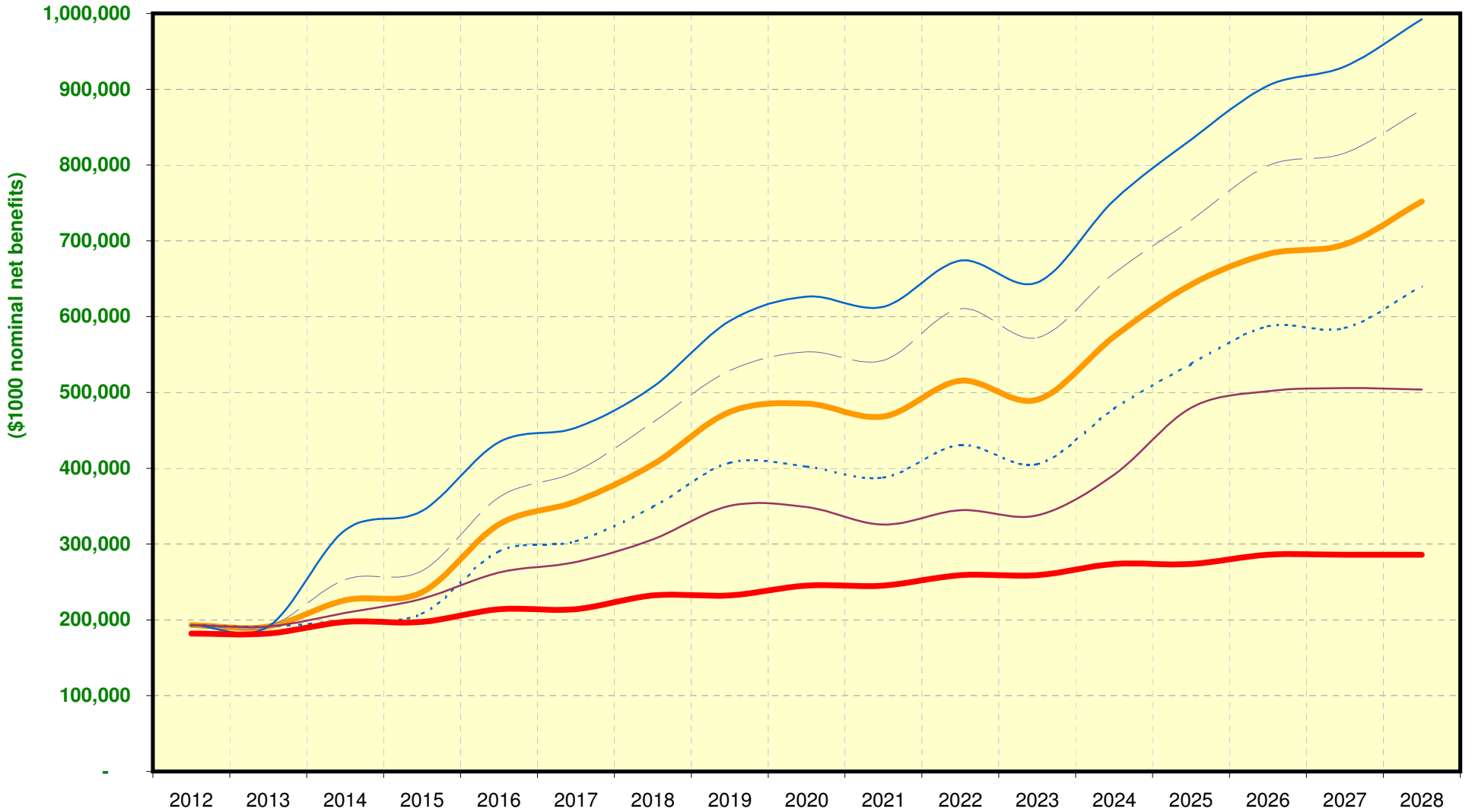
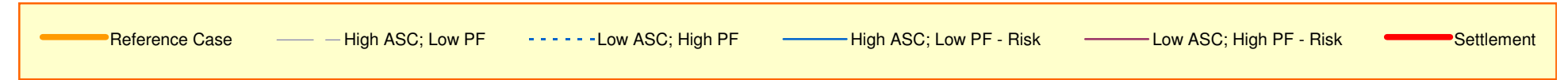
		% above WP-10	
Unbifurcated PF	\$ 40.84	12.4%	
PF Public	\$ 30.37	5.6%	
PF Exchange	\$ 54.61	12.2%	
IP	\$ 37.63	8.8%	
NR	\$ 72.38	5.4%	
<b>Residential Exchange Benefits</b>			
	<b>FY 2012</b>	<b>FY 2013</b>	
Avista	\$ 20,181	\$ 19,072	
Idaho Power	\$ 6,509	\$ 10,424	Deemer Amount
Northwestern	\$ 2,667	\$ 2,517	
PacifiCorp	\$ 58,438	\$ 60,873	
PGE	\$ 83,457	\$ 78,856	
Puget Sound Energy	\$ 106,890	\$ 108,256	w/o Deemer \$s
Net IOU Exchange	\$ 271,632	\$ 269,573	\$ 270,603
Refund Amt	\$ -	\$ -	\$ -
<b>Clark</b>			
Clark	\$ 15,246	\$ 14,447	
Franklin	\$ -	\$ -	
Snohomish	\$ 2,550	\$ 2,415	
Net COU Exchange	\$ 17,796	\$ 16,862	\$ 17,329
		<b>Total</b>	<b>\$ 287,932</b>
<b>Annual Average \$ (1000s).....</b>	<b>WP-10</b>	<b>WP-12</b>	<b>Change</b>
Composite Revenues.....	\$ 2,321,998	\$ 2,268,352	-2.3%
Non-Slice Revenues.....	\$ (514,761)	\$ (325,173)	36.8%
Slice Revenues.....	\$ 2,422	\$ -	
Load Shaping Revenues.....	\$ 32,200	\$ (14,083)	-143.7%
Demand Revenues .....	\$ 53,303	\$ 60,101	12.8%
<b>Tier 1 Revenue Requirement</b>	<b>\$ 1,895,163</b>	<b>\$ 1,989,196</b>	<b>5.0%</b>
<b>Tier 2 Revenue Requirement</b>		\$ 16,363	
Lookback Return (credit).....	\$ (81,575)	\$ (78,377)	
Value of Slice Secondary.....	\$ (166,495)	\$ (162,043)	2.7%
Net Power Cost to All PF.....	\$ 1,647,093	\$ 1,765,140	7.2%
Total PF Load w/Slice (GWh)/yr.....	61,408	60,702	-1.2%
Average Net Cost \$/MWh.....	26.82	29.08	8.4%
<b>Tier 1 Average Net Cost (\$/MWh).....</b>		<b>28.97</b>	<b>8.0%</b>
<b>Tier 2 (\$/MWh).....</b>	<b>-</b>	<b>47.59</b>	

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## **FIGURES**

**Figure 1: IOU REP Payments Risk Scenarios**

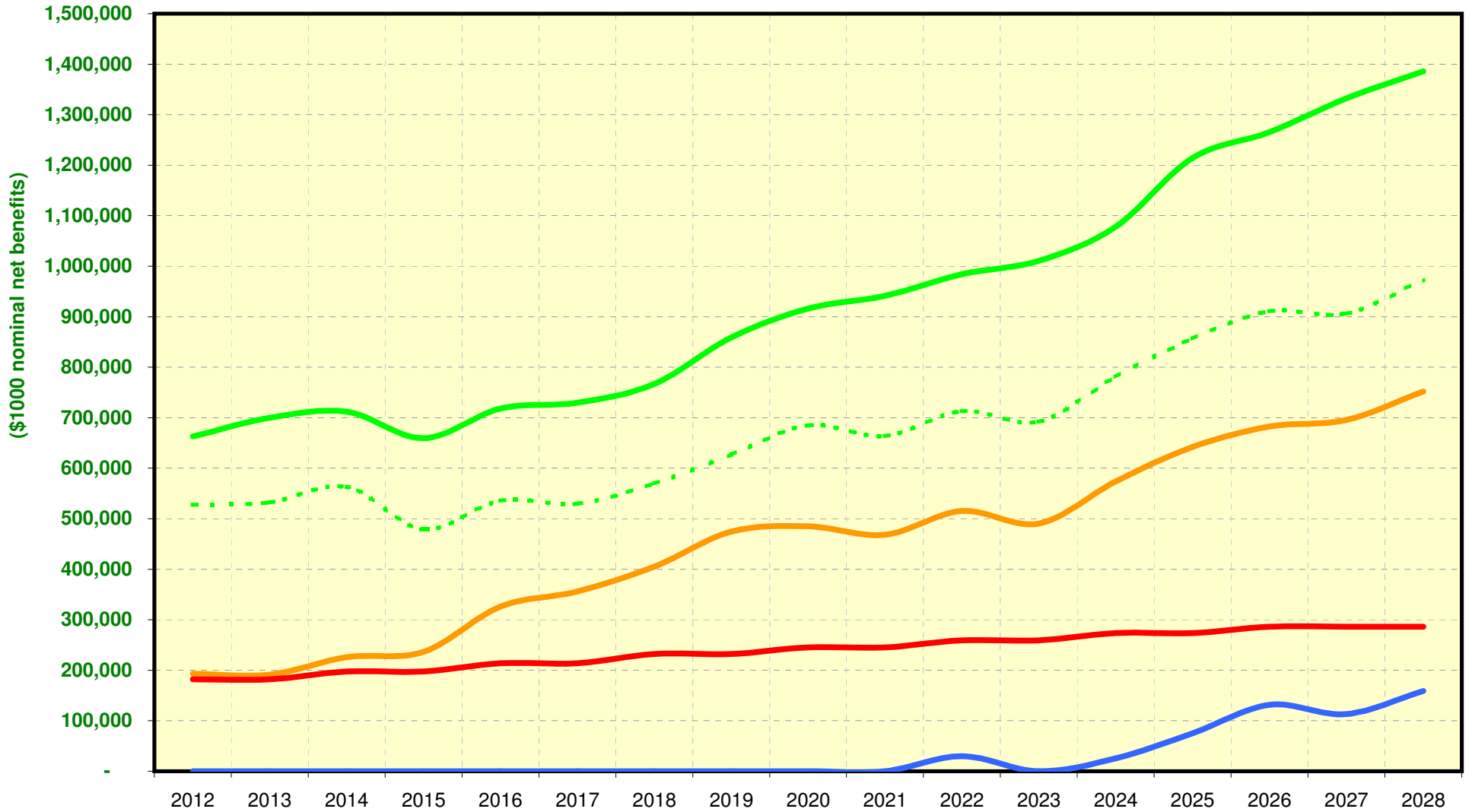
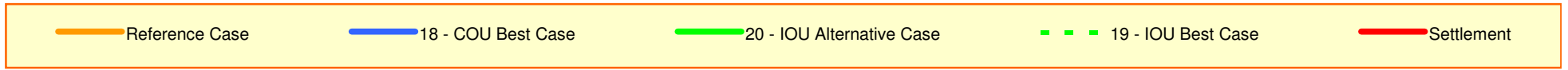
Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction  
 IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.





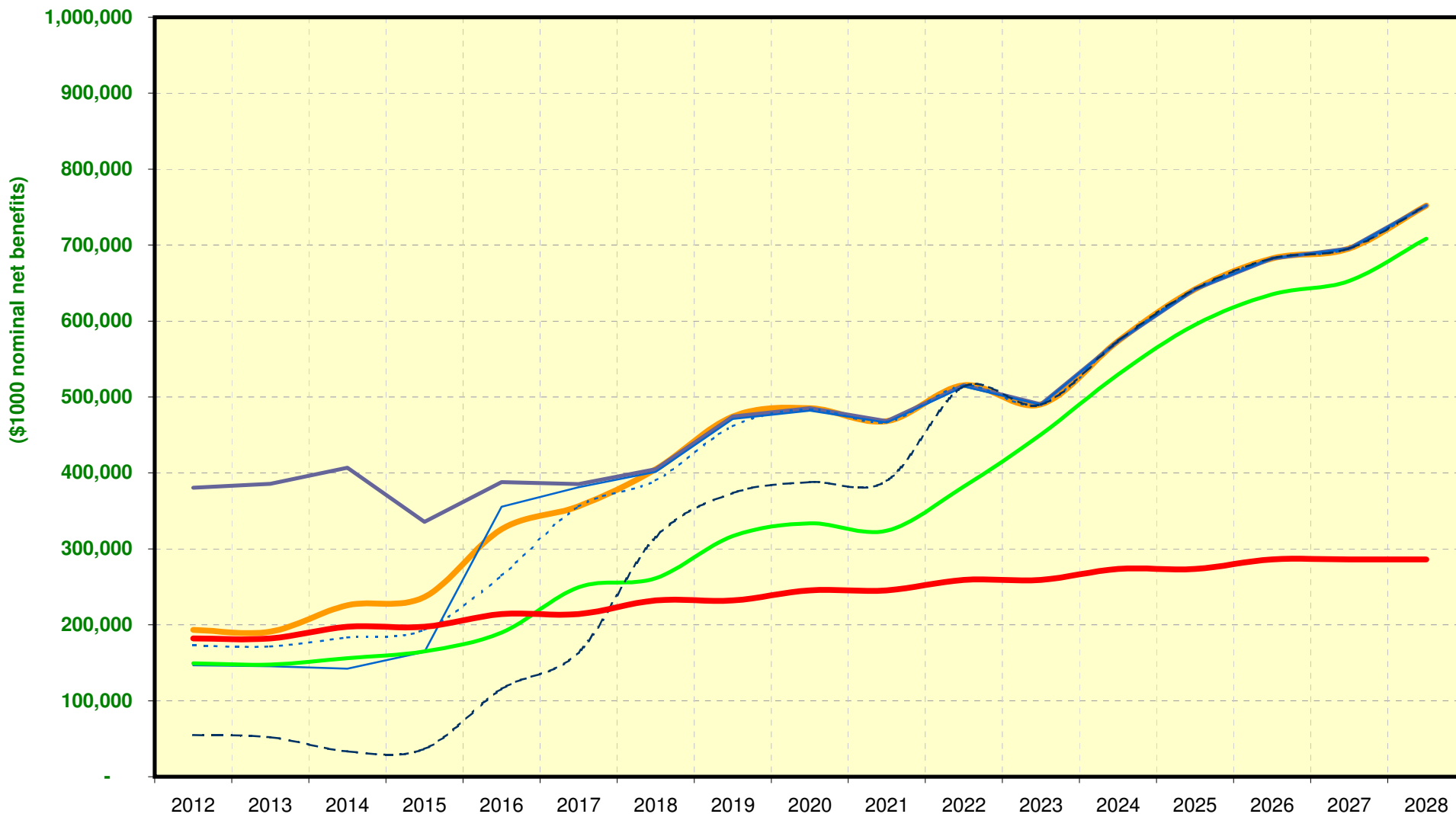
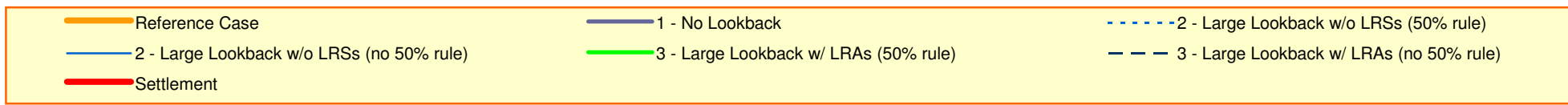
### Figure 2: IOU REP Payments Extreme Scenarios

Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction (Except COU/IOU Best/Alternative)  
 IOU Load growth met 50% IRP, 50% Market; COSA Escalated at Inflation + 2%



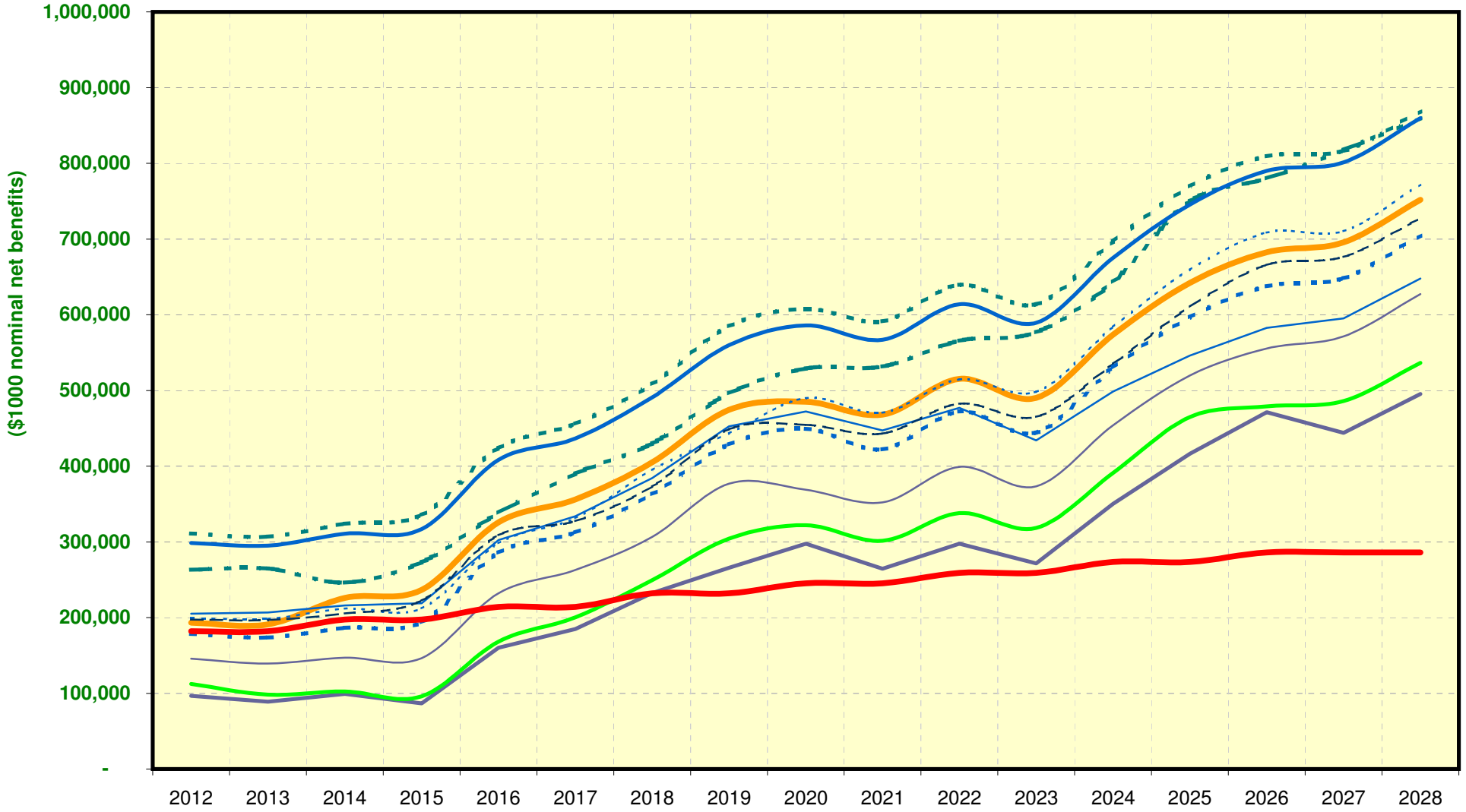
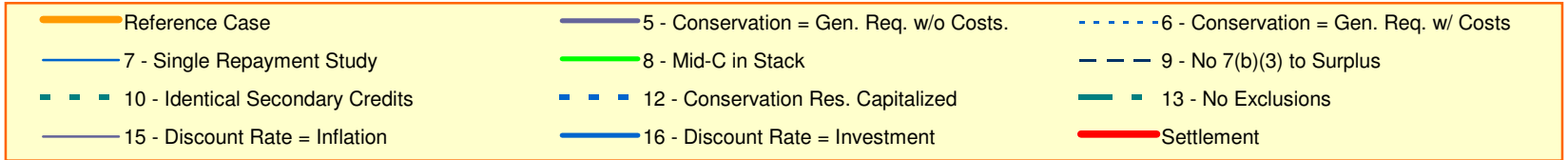
### Figure 3: IOU REP Payments Lookback Scenarios

Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction  
 IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.



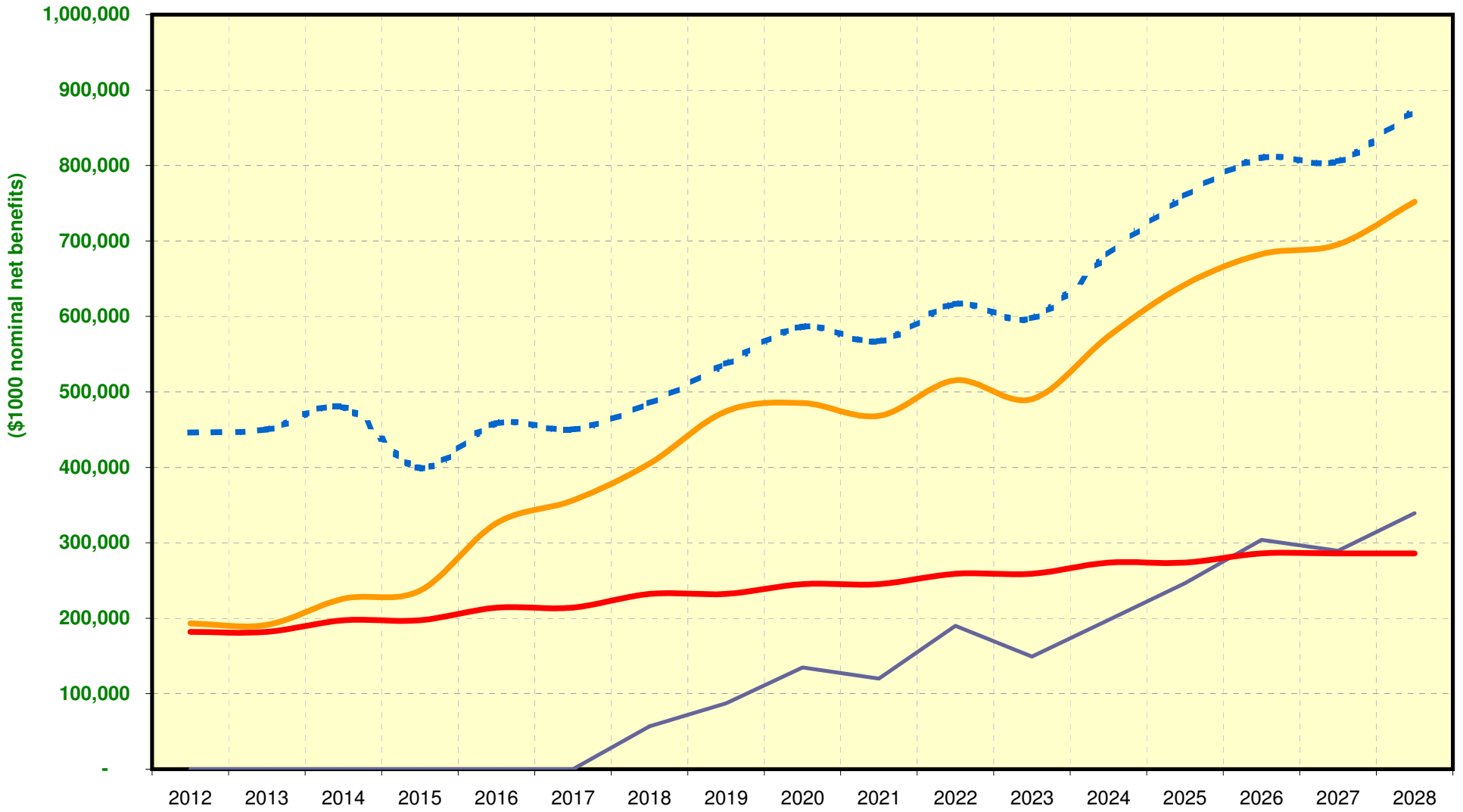
**Figure 4: IOU REP Payments Other Scenarios**

Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction  
 IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%



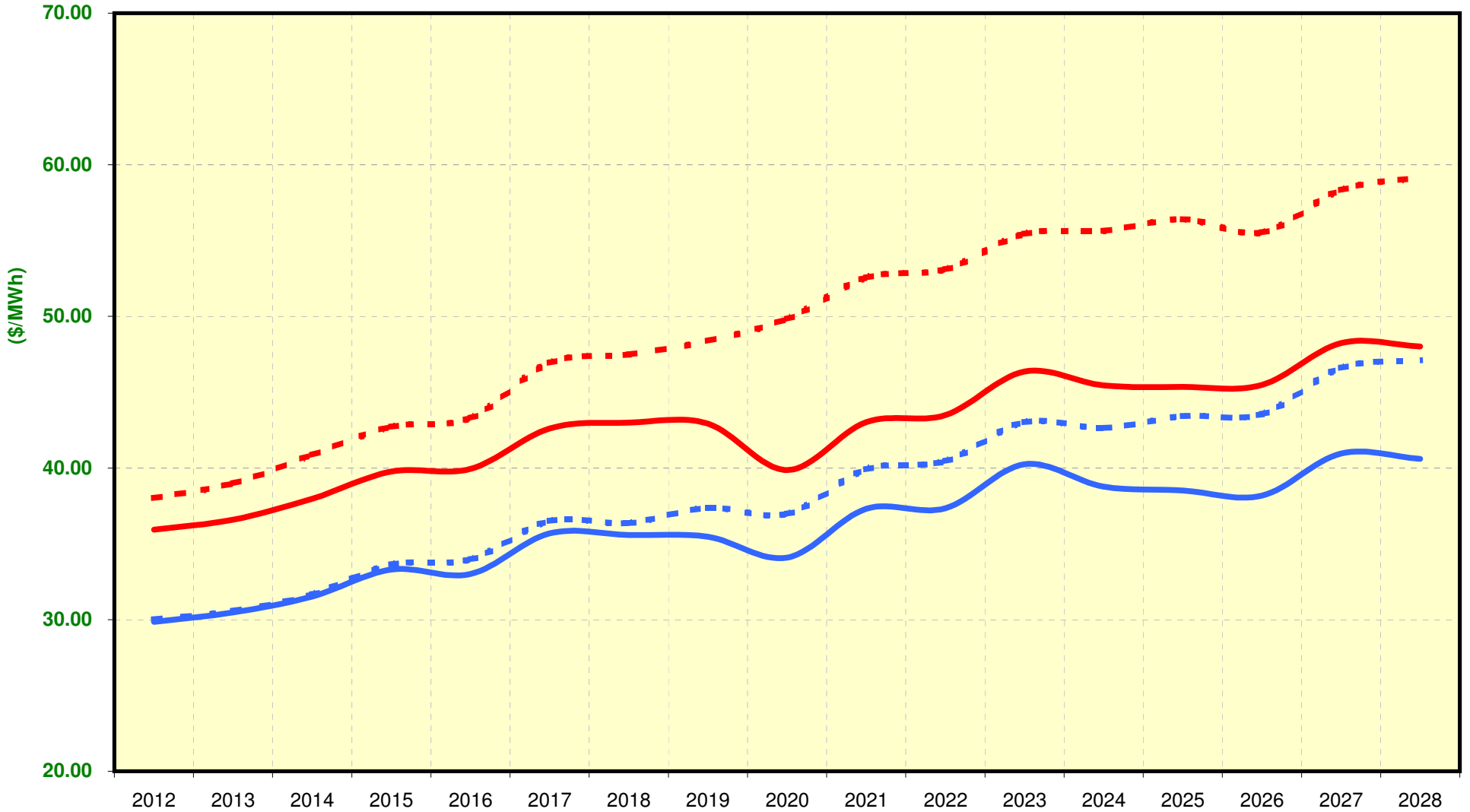
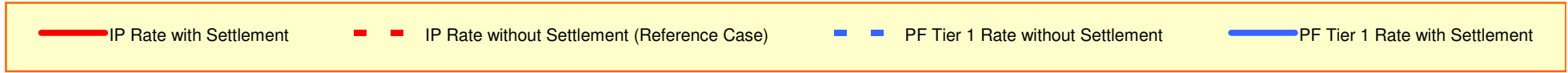
**Figure 5: IOU REP Payments Brief Scenarios**

Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction (Except COU/IOU Brief)  
IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.



**Figure 6: Comparison of Public and Industrial Priority Firm Rate Under Settlement vs. No Settlement**

Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction.  
IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.



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