POWER SALE TO ALCOA INC.
COMMENCING DECEMBER 22, 2009

ADMINISTRATOR'S RECORD OF DECISION

December 21, 2009

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I. INTRODUCTION

On December 14, 2009, BPA made a contingent offer of a block power sales contract to Alcoa, Inc. ("Alcoa") commencing December 22, 2009, (the "Block Contract") pending the Administrator's final decision regarding whether to sign the Block Contract. Under the Block Contract, BPA proposed to sell to Alcoa up to 320 aMW of power over approximately 17 months on a firm basis, and for an additional 5 years if certain specified conditions are met. Service will be provided at the Industrial Firm (IP) power rate. BPA made the draft contract available for public review on October 30, 2009. This record of decision addresses the comments received, and provides the rationale supporting BPA's decision to enter into the Block Contract, in light of the comments received and the opinions of the United States Court of Appeals for the Ninth Circuit ("Court") in *Pacific Northwest Generating Coop. v. Dep't of Energy*, 580 F.3d 792 (9th Cir. 2009) ("*PNGC I*") and *Pacific Northwest Generating Coop. v. BPA*, 580 F.3d 828 (9th Cir. 2009) ("*PNGC II*"). Prior to issuance of those opinions, BPA provided service to Alcoa by means of a monetized sale of surplus power pursuant to section 5(f) of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "NPA"), 16 U.S.C. § 839c(f). In response to the Court's opinions, BPA is no longer monetizing the sale, nor is BPA selling surplus power to Alcoa. Instead, pursuant to the new power sales contract that is the subject of this record of decision, BPA is making a sale of physically delivered industrial firm power pursuant to authority provided under section 5(d) of the NPA, which authorizes the Administrator "to sell in accordance with this subsection electric power to existing direct service industrial customers." 16 U.S.C. § 839c(d)(a)(A).

The sale is priced at the Industrial Firm power ("IP") rate, described at section 7(c) of the Northwest Power Act, which is the applicable rate for sales of non-surplus firm power to BPA's direct service industrial ("DSI") customers. 16 U.S.C § 839e(c). The Court found that the IP rate is the statutorily required rate for such sales. See *PNGC I,* 580 F.3d at 812.

The Court required in *PNGC II* that any offer of power to a DSI must be "consistent with sound business principles." See *PNGC II* at 842.. More particularly, careful review of the Court's opinion in *PNGC II* has led BPA to conclude that, in order to offer a sale of power to a DSI, BPA must conclude based on evidence in the record that the proposed transaction will result in benefits that equal or exceed the costs to BPA of the transaction. In response, BPA has developed an "Equivalent Benefits Test". BPA has determined with respect to the power sales contract with Alcoa that, for a period approximately equal to the first seventeen months of the contract term, service can be provided in a manner that meets the test.

BPA is obligated to adhere to the Court's opinions. However, as discussed later in this Record of Decision, BPA does not believe that imposition of an equal or net benefits standard, as embodied by the Equivalent Benefits Test, is consistent with BPA's enabling statutes. Such a standard misreads explicit statutory language, and is fundamentally inconsistent with BPA's dual roles as a business enterprise and a governmental entity. In those roles, the Administrator has traditionally had, and should continue to have, flexibility to weigh the financial benefits of any given transaction or final action against other considerations related to BPA's statutory responsibilities. BPA should not be confined, as the Court seems to have done, to consideration of only the "bottom line."

II. POLICY DISCUSSION

The Block Contract will supply firm power to Alcoa's Intalco Works ("Intalco Plant"), a long-standing directly-served aluminum smelter in Ferndale, Washington. The contract provides for the sale of firm power by BPA to Alcoa, at the applicable industrial firm power (IP) rate, during an initial period and potentially a subsequent 5-year period.

While BPA's enabling statutes contain a great number of sometimes competing policies, one in particular warrants attention here: the purpose of the Northwest Power Act to "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply . . ." 16 U.S.C. § 839(2). As the language makes clear, the purpose is not directed specifically at preference customers, or any other single customer class or interest group, but to assure "the Pacific Northwest" of an "adequate, efficient, economical, and reliable power supply." The Administrator does not act with a view to operating as a profit-making enterprise. In broadest terms, BPA's statutorily defined mission is to dispose of low-cost federal power at cost. Many of BPA's statutory responsibilities evince social policies that might be viewed as inimical to acting purely like a "business." In the context of insuring an adequate, efficient, economical and reliable power supply, it is certainly reasonable for BPA to consider the impact of its actions on the continued viability of its customer base, including the DSIs.

BPA believes the sale:

- provides a balanced approach to supplying Federal power to Alcoa,
- limits BPA's financial exposure, and
- conforms with *PNGC I* and *PNGC II*.

BPA's approach is balanced. BPA's current approach to DSI service recognizes that DSIs have historically been an integral part of the Federal system virtually since its inception. Because DSIs have been directly served and are statutorily defined as "direct service industrial customers," DSIs do not receive retail electricity service from any of BPA's retail distribution utility customers, or from any of the regional investor-owned utilities. DSIs have therefore relied on BPA or the wholesale power market to meet their operational needs. In the case of aluminum smelter load, power requirements account for one-third of total operating costs, which makes it essential for such operations to have a dependable and low-cost power provider, so that a solid basis exists for long term planning and marketing. Likewise, the sale to Alcoa will assure BPA of a fixed load and a steady revenue stream to help BPA meet its repayment obligations to the United States Treasury. *See, e.g.,* Northwest Power Act, 16 U.S.C. 839e(a)(1) (rates must be established and revised to recover costs, including "the amortization of the Federal investment in the Federal Columbia River Power System.")

BPA's financial exposure is limited. BPA has determined that during the so-called "Initial Period" (comprising a sale of power for approximately 17-months from December 22, 2009, through May 26, 2011 under the Block Contract) application of the Equivalent Benefits Test shows the forecast benefits to BPA during that period exceed the forecast cost. A so-called "Second Period" of power sales could be available under the Block Contract, but only if service can be provided in a manner that is consistent with an opinion or ruling by the Court that holds, or can reasonably be interpreted to mean, that the Equivalent Benefits Test does not apply to BPA sales. In that case, service will still be conditioned upon and subject to cost caps that will limit BPA's financial risk, and mitigate rate impacts on other customers. All sales will also be made at the applicable IP rate, which insures that BPA will obtain revenues in excess of revenues obtained through sales at the PF rate, while avoiding the variability and volatility associated with making market sales. Additionally, BPA can impose assurance payment provisions for power sold, and BPA will retain any gains from reselling power not taken while Alcoa retains a take-or-pay obligation in most situations. Taken together, these risk provisions support BPA's ability to meet its Treasury payment obligations and mitigate rate impacts on BPA's other power customers.

In its comments, the Industrial Consumers of Northwest Utilities ("ICNU") object to BPA's approach on the basis that "BPA's own analysis shows that the Block Contract is only profitable for the first eight months and BPA loses money on the contract in each of the next eleven months." ICNU at 3.[1] PPC states that it "opposes any service to the Direct Service Industries (DSIs) that comes at the expense of preference customers" and that "BPA has once again failed to demonstrate that sound business reasons underlie its proposal." PPC at 1. PPC argues that *PNGC II* requires that the "agency may only engage in a transaction with the DSIs if it is expected to result in a benefit to the federal system." PPC at 2. BPA does not interpret *PNGC II*, as ICNU does, to require that the Block Contract be profitable for each month of the entire term of the Initial Period, but instead reads the opinion to allow that, in the aggregate, the Block Contract provide benefits that equal or exceed the cost over its term. If BPA sold an equivalent amount of power on the market, at a fixed price over a similar period of time, there would be no

[1] Comment cites are to comments filed regarding the proposed Block Contract on November 9, 2009, unless otherwise noted.

guarantee that the fixed price would meet or exceed the prevailing market price in each and every month of the period. In fact, it would be likely that the fixed price would be below market during some periods; thus, in that situation, BPA could be accused of not maximizing its revenues. Yet, such an agreement could, in fact be justified on the grounds that it mitigated the risk of fluctuating prices over the term of the contract and therefore supported BPA's obligations to recover its costs consistent with sound business principles. Similarly, the Block Contract with Alcoa, as shown in more detail below, provides mitigation of market risk and provides BPA with a valuable fixed revenue stream in a manner that has no adverse rate impacts on other customers during the Initial Period and limited impacts in the Second Period, if any.

It is not clear what PPC means by a "benefit to the federal system." BPA interprets the Court's discussion of a proposed transaction being "consistent with sound business principles" to mean that benefits to BPA of the transaction must equal or exceed costs. As the Court clearly recognized, benefits can take many forms, whether quantifiable in financial terms or not. If service to a DSI promotes one or more of BPA's statutory missions, such a benefit might be reducible to a monetary value, or it might not. Other benefits might not be reducible to a dollar amount. Or, benefits might benefit a non-DSI customer group or public interest but not another, again making it difficult to assess the value of the benefit in relation to the detriment to another group. Also, there could be potential future benefits that might turn out to be of significant value or minimal value depending on how circumstances developed. Nonetheless, even a benefit not readily reducible to a dollar amount is real and should be accounted for, if not in strict economic terms, then in some fashion. In this particular instance, BPA did not attempt to account for such benefits because the tangible benefits that can be measured in economic terms were sufficient to support the Initial Period of approximately seventeen months.

Moreover, trying to determine if something is a "benefit to the federal system" is a questionable proposition because the term is so vague and amorphous. Without additional definition of the term, it does not provide a meaningful standard. On the one hand, it can be inferred from the comments from BPA's public body and cooperative utility customers that they interpret it to mean a benefit to them through lower power rates, *i.e.*, BPA ought to sell the power as surplus into the market (or at least reap market prices if sold to DSI customers) so resulting surplus revenue can be credited to the PF rate. On the other hand, a benefit could be almost anything that promotes any of BPA's statutory mandates, whether marketing low-cost federal power to promote widespread use, selling power to supply the needs of all of BPA's regional power customers, advancing fish and wildlife mitigation, insuring a reliable power system, advancing the purposes of the Northwest Power Act, or other BPA mandates.

The Block Contract is consistent with law. *PNGC I* and *PNGC II* upheld BPA's discretion to serve the DSIs at the IP rate. *PNGC I*, 580 F.3d, 792, 807 (Section 5(d) of the NPA "authorizes but does not obligate the agency to sell power to the DSIs") and *PNGC II*, 580 F.3d 828, 835 (BPA "authorized to sell power to the DSIs at the IP rate") However, BPA believes there is still some uncertainty in the Court's opinions with respect to what the law requires when assessing whether a DSI sale is consistent with sound business principles. BPA has taken a cautious approach, applying the Equivalent Benefits Test to the Initial Period. As noted above, pursuant to application of that test, the Initial Period of service under the Block Contract will provide BPA with benefits that exceed BPA's cost. In taking this approach, BPA has deferred consideration of other aspects of the Court's rulings, which suggest that decisions regarding DSI service can include consideration of factors that cannot readily be reduced to a monetary amount. For example, in *PNGC II*, the court pointed to "non-financial" benefits that might be provided. 580 F.3d at 835. As noted above, BPA has not developed an analytical framework for consideration of non-financial benefits. BPA will, however, continue to consider how such benefits may be applied consistent with the Court's opinions. This could be particularly important when BPA considers service for the contingent Second Period of the Block Contract, which encompasses five years of service following the Initial Period. BPA's approach is entirely appropriate at this time, in that it provides a significant period of service based on its view of the Court's opinions, while leaving room for additional flexibility at a later date in the event that the Court determines that an equivalent benefits test need not apply to sales under this contract and further clarifies what it means for BPA to enter into a transaction consistent with sound business principles.

III. BACKGROUND

a. Original Contract

The Block Contract represents BPA's attempt to structure a power sales contract for service to Alcoa that responds to the Court's opinions in *PNGC I* and *PNGC II*, issued in connection with petitions for review challenging the five-year power sales agreement (the subject of the *PNGC I* challenge), and an amendment thereto (the subject of the *PNGC II* challenge) by and between BPA, the Public Utility District No. 1 of Whatcom County, Washington, and Alcoa, whereby BPA agreed to sell to Whatcom, and Whatcom agreed to sell to Alcoa, 320 aMW for the period October 1, 2006, through September 30, 2011 ("Original Contract").

The Original Contract was structured so that BPA, at its option, could monetize the value of the contract pursuant to a formula contained in the contract, and make financial payments to Alcoa in lieu of physically delivering power. By monetizing the contract and capping the amount of benefits it would pay to Alcoa, BPA was able to mitigate any purchase power risk it may have in the event it needed to make market purchases in order to serve Alcoa's load, and thereby meet its twin goals of allocating some benefits of the federal power system to its long-time customer Alcoa, but at a known and capped cost. Payments were calculated and paid (up to the cap) based on the difference between BPA's lowest-cost base rate available to its public preference customers (the PF rate), and market prices. Alcoa therefore was responsible for procuring its own power supply in the market, using the payments by BPA to lower its actual power purchase cost. In its opinion issued December 17, 2008, the Court in *PNGC I* held, among other things, the monetization formula, and the payments made pursuant that formula, invalid inasmuch as it was based on a rate that was below both the IP rate and market prices. 580 F.3d at 820. Prior to the Court's opinion, pursuant to certain reallocation provisions in the Original Contract, BPA agreed to provide Alcoa an additional 70 aMW in benefits, raising Alcoa's demand entitlement to 390 aMW for the period October 1, 2007 through September 30, 2011.

b. Amendment to the Original Contract

In response to *PNGC I*, BPA and Alcoa entered into a ten -month amendment to the Original Contract, which was intended to conform the Original Contract to the Court's opinion, allowing BPA to continue service to Alcoa under an IP equivalent rate, until such time as the parties could fashion a new contract to replace the Original Contract. Pursuant to the amendment, BPA continued to monetize the value of the transaction in lieu of physically delivering power to Alcoa, but calculated these payments (again limited by the caps established in the Original Contract) based on the difference between the IP rate (rather than the lower PF rate) and BPA's forecast of market prices. BPA believed this approach was consistent with the Court's central holding in *PNGC I* that service to BPA's direct service industrial customers must be based on the IP rate. 580 F.3d at 812 ("BPA, when entering into contracts for the sale of firm power to a DSI, must initially offer the IP rate") Petitions for review challenging the amendment were filed, and in *PNGC II* dated August 28, 2009, the Court held, among other things, that BPA had failed to demonstrate how entering into the amendment was consistent with sound business principles. 580 F.3d at 842.

c. December Draft Contract

In connection with its goal of negotiating new long-term contracts with all its public, investor-owned utility, and DSI customers, and prior to the Court's opinion in *PNGC I* in October 2008, BPA commenced a public process (including workshops and public review/ comment) to fashion a contract for Alcoa to be effective upon expiration of the Original Contract in September 2011. BPA proposed a set of principles that, if adopted, could have led to a power sales contract in which BPA would have provided Alcoa 240 aMW of power (150 aMW less than the maximum amount available to Alcoa under the Original Contract) for a period of ten years at the IP rate, beginning in 2012, and 160 aMW (or 230 aMW less than under the Original Contract) for an additional seven years in the event BPA determined it could provide such service within predefined price caps.

BPA submitted a proposed contract for public review and comment in December 2008 (December Draft Contract). Pursuant to the December Draft Contract, BPA's obligation to serve Alcoa was contingent on BPA's ability to purchase market power within predefined price caps, but BPA agreed to pay certain of Alcoa's shutdown costs in the eventuality it could not purchase power at or below the caps, which averaged $65 million per year. A later contract draft would have obligated BPA to provide Alcoa up to 240 aMW of power, beginning in 2012 for 17 years, within a predefined 240 aMW price cap starting at $72 per MWh for FY 2012 through FY 2016 and rising to $90 per MWh in FY 2021.

However, as time passed, aluminum prices continued to plummet, as they had been for several months prior, and Alcoa was forced to reassess whether it could continue operations and perform its obligations under the proposed contract with BPA, given the dire aluminum market conditions. On January 22, 2009, BPA and Alcoa issued a joint letter to the region indicating that Alcoa had concluded it could not sign the contract. BPA posted the contract on its website on January 23.

d. *PNGC I*

In the meantime, on December 17, 2008, the Ninth Circuit issued *PNGC I* responding to petitions challenging the legality of the Original Contract. In *PNGC I*, the Court conducted an extensive analysis of BPA's statutory authority to serve the DSIs and the appropriate rate under which to provide such service. The Court resolved some issues in a manner adverse to BPA and some in BPA's favor, and on the basis of such rulings, the Court granted in part, denied in part, and dismissed in part the petitions for review. Most notably, the Court found that:

- BPA has the statutory authority, but not the obligation, to sell power to the DSIs (580 F.3d at 807);
- BPA, when entering into contracts for the sale of firm power to a DSI, must initially offer power at the Industrial Firm Power ("IP") rate prior to offering power at any other rate (*id*. at 817);
- BPA erred in the Agreements under review in *PNGC I* because BPA provided financial benefits to the DSIs "at a rate that was below both the market rate *and* the statutorily authorized IP rate . . . " (*id*. at 823) (emphasis in original);
- the challenged Agreements were not void: "[w]e do not hold that the contracts are void . . . Instead, we *affirm* the authority of BPA to sell physical power to the DSIs, § 839c(d), at a valid rate." (*id.* at 827) (emphasis in original); and
- BPA may lawfully provide monetary benefits to a DSI rather than provide a physical supply of power as long as BPA does so under appropriate circumstances consistent with BPA's specific statutory obligations (*id.* at 821, fn 35).

e. August Draft Contract

In a May 29, 2009 letter to the region, BPA convened a new public process to consider whether the unsigned December Draft Contract "should be changed, and what changes are needed for the term of future contracts".[2] A workshop was held on June 8, 2009. Alcoa also made a presentation during the workshop that detailed their operating costs and how the Intalco Plant compared to other U.S. aluminum smelters. The materials indicated that Alcoa's Intalco Plant was cost efficient and energy efficient but had suffered from relatively high power costs. In summary, Alcoa stated that a "mid to long-

[2] Letter to region, Bonneville Power Administration, May 29, 2009 at 1.

term contract is desirable" and continued operations at the Intalco Plant "need cost-based power to operate at 2 -3 lines of production to survive and plan for the future".[3]

In a July 17, 2009 letter to the region, BPA proposed term sheets for a firm power sale at the IP rate that would be sufficient to meet a portion of the smelter's load for up to seven years. BPA also provided its "Summary of BPA's Use of the Regional Economic Study to Contemplate the Service Concept" which is BPA's update to the results of the "2006 Regional Employment and Economic Study". BPA's summary demonstrated there would be a small net gain in jobs from offering the new service constructs to the DSIs compared to the proposal that was under consideration earlier in January 2009. BPA accepted public comments on the proposed term sheets through August 3, 2009, and received 221 comments.

In an August 19, 2009, letter to the region, BPA proposed a seven year (October 1, 2009, through Sept. 30, 2016) block power sales contract ("August Draft Contract") of up to 320 average megawatts at the IP rate sufficient to meet a portion of Alcoa's load at its Intalco Plant. As an attachment to the August 19th letter, BPA provided it's "Summary of Changes BPA has Made in the Draft Contract in Response to the Public Comment Process on the Alcoa Term Sheet." The contract was contingent on BPA determining it could provide service within the cost caps established therein.

While the August Draft Contract provided more flexibility than the earlier unsigned draft contract, BPA believed that the changes above, taken together, better met the objectives outlined for DSI service than the term sheet. The August Draft provided a balanced approach, limited BPA's financial exposure, and appeared to be legally sustainable. However, the issuance of a second Ninth Circuit opinion, *PNGC II*, altered BPA's assessment of its objectives. In particular, the August Draft Contract no longer appeared to be legally sustainable.

f. *PNGC II*

On August 28, 2009, the Ninth Circuit issued its opinion in the case challenging the Alcoa amendment in *PNGC II*. The opinion raised additional issues regarding service to DSI customers, and BPA concluded it could not reach a final decision whether to offer the August Draft Contract prior to October 1, 2009. BPA determined it needed additional time to evaluate *PNGC II*, and make a determination, in light of that opinion, whether offering a multi-year contract to the DSIs, including Alcoa, would be consistent with "sound business principles" as BPA believes that standard was described in *PNGC II*.

While BPA's reading of *PNGC II* is addressed at length in Part VI below, it is pertinent to restate here that BPA interprets *PNGC II* as requiring that if the Administrator exercises his discretion to serve a DSI customer, the decision to serve must be consistent with "sound business principles." As described by the Court, a decision to serve a DSI customer is consistent with sound business principles when it can be shown that the benefits to BPA of serving the DSI load would equal or exceed BPA's cost of serving the

[3] See Public workshop presentation, Alcoa, June 8, 2009.

load during the period of service. If they do not, then the Administrator must demonstrate that there is a reasonable prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service. BPA has responded to the *PNGC II* requirement by applying, at the outset, the Equivalent Benefits Test, a test that comports with the Court's ruling.

In the meantime, BPA concluded that *PNGC II* did not support the agency making the remaining payments to Alcoa under the Original Contract, as amended, which (as noted earlier) was being implemented by monetizing the power sale, *i.e.*, providing the financial equivalent of the costs that BPA believed it would have otherwise incurred through a physical sale of Federal power at the IP rate. Therefore, in its September 17, 2009, letter to the region, BPA announced it would not make the scheduled payments for August and September. These payments would have been made September 11 and October 13, 2009.[4] Taken together, the payments to Alcoa would have amounted to approximately $6 million.

g. November Draft Contract

BPA endeavored to address *PNGC II* consistent with its objectives for DSI service. This led to BPA's October 17, 2009 letter to the region proposing revisions to the August Draft Contract (the "November Draft Contract") to comport with "sound business principles," as that standard was described in *PNGC II*, the key feature being the incorporation of an the Equivalent Benefits Test that requires that benefits that are forecast to accrue to BPA as a result of providing firm power service to Alcoa equal or exceed the forecast cost of providing such service at the Industrial Firm Power (IP) rate.[5]

BPA's application of the test showed it would be able to offer Alcoa a contract with an Initial Period of 19 months on a non-contingent basis, during a period commencing on December 1, 2009 and ending on June 30, 2011. The November Draft Contract also provides for a Second Period after the Initial Period, but this follow-on period is contingent on an opinion or ruling by the Court that holds, or can be reasonably interpreted to mean, that the Equivalent Benefits Test does not apply to BPA sales, BPA's determination that the Second Period sale would satisfy the Court's rulings, and BPA's determination that the Second Period cost caps can be met. In most other material respects, the November Draft Contract reflects the terms of the August Draft Contract.

In the meantime, Alcoa continued to operate in October and November by providing for its own power needs, and will continue to do so through December 21, 2009. BPA indicated in mid-November that it would need additional time beyond the proposed December 1, 2009, start date to allow for its evaluation of the comments filed by parties with respect to modifications made in the November Draft Contract (referred to herein as the "Block Contract" as described immediately below), and to draft this record of decision detailing its final decisions with respect to that contract.

[4] Letter to the region, Bonneville Power Administration, September 17, 2009.
[5] Letter to the region, Bonneville Power administration, October 17, 2009.

IV. BLOCK CONTRACT

a. Summary of Block Contract

Pursuant to the Block Contract, BPA has agreed (subject to certain conditions described below) to make available to Alcoa, and Alcoa has agreed to purchase from BPA (on a take-or-pay basis) up to 320 aMW for potentially a period of up to approximately seven years, at the Industrial Firm (IP) power rate.

The term of the Block Contract is divided into two main periods, the Initial Period and the Second Period, with the Initial Period encompassing the approximately 17 month period December 22, 2009, through May 26, 2011, and the Second Period encompassing the five-year period following expiration of the Initial Period. However, the Block Contract provides that the Initial Period may be extended (subject to certain conditions precedent) for a minimum of three months and a maximum of one year (the Extended Initial Period). Therefore, the Initial Period, as extended, could have a maximum term of 29 months, through May 26, 2012. See Block Contract, section 5.

As of the effective date, BPA would have made available 285 aMW to Alcoa, but Alcoa has requested that BPA increase such amount to 320 aMW, pursuant to applicable contract provisions. See Block Contract section 5.2. As described more fully below, BPA has concluded that it will achieve Equivalent Benefits from the sale of 320 aMW to Alcoa during the Initial Period, and has granted Alcoa's request. Pursuant to contractual provisions, BPA's determination is conclusive and binding on Alcoa, and may not be challenged by Alcoa in any forum. *See* Block Contract section 5.1.1.

The Second Period will commence, if at all, as specified in section 6 of the Block Contract, which provides for a Second Period only if following execution of this Block Contract, (i) the Ninth Circuit holds that the Equivalent Benefits standard does not apply to sales under the Block Contract, (ii) BPA determines that selling 320 aMW to Alcoa under the Block Contract during a Second Period would be consistent with the Court's rulings with respect to service to the DSIs, and (iii) BPA determines that the cost of selling 320 aMW to Alcoa under the Block Contract during a Second Period would not exceed the cost caps specified in Exhibit B of the Block Contract.

The period between the date of the foregoing Ninth Circuit holding and BPA's subsequent decisions regarding continued service to Alcoa under the Block Contract is referred to in the Block Contract as the "Transition Period", and may have a term of up to one year. See Block Contract section 6.1. The Transition Period will, depending on the disposition of any petitions for review challenging the Block Contract by the Court, fall completely or only partially within the Initial Period or any Extended Initial Period; but any Second Period will commence no earlier than the expiration of the Initial Period or Extended Initial Period. To the extent the Transition Period extends beyond the term of the Initial or Extended Initial Period, then as specified in section 6.1.2, BPA may serve Alcoa under the Block Contract pending its determinations regarding service to Alcoa in a Second Period. In the event there is no Second Period, then the Block Contract will terminate as specified in section 5.3 or section 6.2.

The Block Contract contains cost caps. See Block Contract section 7. The level of the cost caps, and the manner in which BPA will evaluate whether the cost of service to Alcoa is equal to or less than the applicable cost caps, are specified in Exhibit B of the Block Contract. The cost caps will apply only to BPA's evaluation of whether it will provide service under the Block Contract during a Second Period. By contrast, service to Alcoa under the Block Contract during the Initial Period (as well as any increase in the level of service from 285 aMW to 320 aMW, or any extension of the term of the Initial Period) is contingent on BPA determining that it will achieve Equivalent Benefits from such service. Therefore, the cost caps are unnecessary and would provide no meaningful additional risk mitigation to BPA during the Initial Period or Extended Initial Period.

While Alcoa's obligation under the Block Contract is take-or-pay, it may curtail its load pursuant to the terms and conditions specified in section 9 of the Block Contract. During such periods of curtailment Alcoa's take-or-pay obligation is excused. During such periods of allowable curtailment, Alcoa is not liable for any losses BPA may incur in remarketing such curtailed power, nor is it entitled to the benefits BPA is more likely to receive. Several parties in comments questioned why Alcoa is not obligated to pay BPA damages in the event that BPA accrues less revenues from remarketing curtailed power than it would have received from selling such power to Alcoa under the Block Contract. See e.g., WPAG at 6; Snohomish at 5. The rationale for excusing Alcoa's take-or-pay obligation, and not requiring Alcoa to pay BPA damages, if any, associated with a curtailment under the Block Contract is discussed more fully elsewhere in this record of decision.

Alcoa is obligated, at BPA's request, to arrange for BPA to be provided with a $30 million standby letter of credit, issued in a form and by a bank acceptable to BPA, and to have issued, at BPA's request, replacement standby letters equal to the value of 103 days of power service, calculated using the highest monthly average IP rate, so that a letter of credit is in place for the term of the Block Contract. See Block Contract section 21.8. BPA may seek additional performance assurance from Alcoa to the extent Alcoa's financial responsibility or performance viability become unsatisfactory to BPA. See Block Contract section 21.8.3.

In addition to the standard termination for default provisions, each party has the right to terminate the Block Contract under certain additional circumstances. BPA's additional termination rights primarily relate to cases where it has made a determination that it cannot serve Alcoa consistent with the Court's rulings or opinions, or at a cost that is at or below the cost caps. See Block Contract section 6.2. For its part, Alcoa may terminate the Block Contract at any time during the Initial, Extended Initial, or Transition Periods, on six months notice, and during any Second Period on 12 months notice. See Block Contract sections 22.1.1.1 and 22.1.1.2. In each case, Alcoa retains some (in the case of termination during the Initial, Extended Initial, of Transition Periods) or all (in the case of a termination during a Second Period) of its take-or-pay obligation.

Alcoa may terminate at any time, and on one day written notice, in the event BPA has made a determination pursuant to section 6.2 that it cannot serve Alcoa during a Second Period. See Block Contract section 22.1.2. Alcoa also may terminate in the event it has been billed directly, and paid to BPA, in excess of $2 million for certain environmental or regulatory costs. See Block Contract section 22.1.4. In each of the foregoing terminations, Alcoa has agreed (except in the case of a termination following a determination by BPA under section 6.2) that it will not restart the Intalco Plant until after the time when a Second Period would have otherwise ended. See Block Contract section 22.1.5.

Alcoa has made certain covenants, including agreeing not to challenge the validity of the Block Contract, any determinations by BPA regarding Equivalent Benefits, or any BPA determination under Exhibit B. See Block Contract section 25.1. In addition, Alcoa has agreed not to request any surplus power from BPA during the term of the Block Contract, and not to challenge any proposed or actual sale of surplus power by BPA, or to challenge any rate adopted by BPA for the sale of surplus power. See Block Contract section 25.2. Finally, Alcoa agreed that it will waive any claims it may have under Contract No. 06PB-11744, as amended, in the event BPA determines on remand in *PNGC I* and *PNGC II* that no payments are owing to or from either party under such contract, but that such waiver will be of no force or effect in the event that the Ninth Circuit grants a petition for review challenging BPA's determination.

b. Contract Demand

As noted, pursuant to the Block Contract, BPA has agreed (subject to certain conditions precedent) to make available to Alcoa, and Alcoa has agreed to purchase from BPA (on a take-or-pay basis) up to 320 aMW for a period of up to approximately seven years, at the IP rate.

Alcoa is currently operating at 285 aMW with power purchased from the wholesale power market. BPA has previously offered Alcoa service benefit levels equal to or in excess of that needed to operate two of the three potlines at the Intalco Plant, or approximately 320 aMW.[6] Alcoa has also indicated that 320 aMW is sufficient to provide a reasonable chance for continued operation of the Intalco Plant, preserving jobs that are dependent upon Alcoa operating that facility.[7]

[6] The 320 aMW amount is equal to the service benefit level established in the BPA/Alcoa contract for the FY 2007 through FY 2011 period. The amount provided in the BPA/Alcoa contract for the FY 2002 through FY 2006 period was 718 aMW. Historically, BPA has contracted with Alcoa for all of its delivery points under one contract. As such, the 718 aMW refers to the contract demand in the Subscription contract for the FY 2002 through FY 2006 period covering the following points of delivery: Ferndale, Longview, Troutdale, and potentially Wenatchee.

[7] See letter re *7-year power sale agreement*, Alcoa, Inc., submitted to BPA September 9, 2009, in public comment on the Draft Contract, at 1: "While Alcoa would much prefer to receive a sufficient amount of power to serve the entire electric power load that BPA has traditionally served, we believe that the offer of 320 average megawatts of power (enough to serve two of three of Alcoa's potlines) will permit the Intalco

Purchases for the Intalco Plant from BPA have been greater than the 320 aMW in the past. The historic contract demand for the Alcoa Intalco plant is 468 MW, as provided by section 5(d) of the NPA, as implemented and established in the Intalco Aluminum Corporation's 1981 power sales contract. Section 5(d)(1)(B) of the NPA directed BPA to offer each DSI an initial long-term contract in an amount, referred to generally as its "contract demand," equivalent to the amount of power each DSI was entitled to under its then existing BPA power sales contract. For the Intalco Aluminum Corporation, this amount was 445.6 MW. The resulting 1981 DSI power sales contracts provided that a company's contract demand could be increased for certain efficiency improvements and modifications to plant equipment, including the addition of certain environmental protection equipment. These increases were referred to in the 1981 DSI contracts as "technological allowances," and in 1987 the Intalco Aluminum Corporation applied to BPA for such an increase. BPA approved the request in September 1987, thereby increasing the Intalco Aluminum Corporation's contract demand (*i.e.*, the maximum amount of IP power BPA may legally provide to Alcoa) to 468 MW. See Attachment A. The Intalco Aluminum Corporation was later acquired by Alcoa Inc.

Under the BPA/Whatcom/Alcoa Contract, Alcoa's service benefit was initially 320 aMW for the period October 1, 2006, through September 30, 2011. Subsequently, pursuant to certain provisions of that contract, and upon expiration of another aluminum smelter's right to service benefits, BPA agreed to sell and Alcoa accepted the purchase of an additional 70 aMW of service benefits, raising their demand entitlement to 390 aMW for the period October 1, 2007 through September 30, 2011. This changed the allocation of service benefits amongst the DSIs, but did not increase the collective load of the DSIs.

In fact, DSI loads served by BPA, in total, continue to decline because Golden Northwest Aluminum has not been operating and does not qualify for a contract in the Regional Dialogue period, Alcoa's maximum demand in the Block Contract is 320 aMW and an equivalent maximum demand for CFAC is 140 aMW – also equivalent to two pot lines.[8] BPA determined that it could offer Alcoa an opportunity to ramp up to 320 aMW because Alcoa agreed to a cost cap for the Second Period that was actually lower than the one proposed in the December Contract Draft. For the Initial Period, BPA will still achieve equal or equivalent benefits even if serving 320 aMW.

c. Rate Charged for Power Deliveries

In past comments, particularly comments related to the CFAC Amendment, some of BPA's preference customers have expressed a belief that, even if BPA offers to sell power to DSIs at the IP rate, that rate must recover the full incremental costs of any resources obtained to support DSI contracts. *See e.g.,* NRU, CFA090001 at 2 (arguing

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smelter to survive and to preserve the more than 500 smelter jobs and 1,500 other jobs that are dependent upon Intalco receiving BPA's cost-based power."

[8] See section 4.1.3 of the Block Contract limiting GNA's access to a contract offer. See BPA's Block Contract offered to CFAC on December 14, 2009 and posted on BPA's external website.

that "DSIs have no right to continued BPA service" and a discretionary sale must be consistent with "establishing rates at the lowest possible cost consistent with sound business principles"); SUB, CFA090003; and Canby, CFA09002.[9] Even in the most recent round of comments, preference customer groups have continued to suggest that service to Alcoa would constitute a "subsidy." See e.g., PPC at 9; ICNU at 5; SUB at 18; WPAG at 9.

A central holding of the Court's opinion in *PNGC I* is that, if the Administrator exercises his discretion to offer to sell power to the DSIs, any initial offer must be at the IP rate. 580 F.3d 817. In support of its conclusion that any initial offer of DSI service must be at the IP rate, the Court observed that the legislative history of the Northwest Power Act "contains extensive evidence that Congress intended the IP rate to be the default price for sales of power to the DSIs." *Id.* 814 In this connection, the Court noted that legislative history states that "Section 7(c) prescribes the rates applicable to direct service industrial customers" (H.R. Rep. No. 96-976, pt. 1, at 69) and is the rate which "applies to all 'Industrial Firm' sales to BPA's direct-service industries . . . [for] 1985-86 and all future [sales]." (S. Rep. No. 96-272 at 59) (emphasis added in Opinion). The Court adds that, to the extent BPA decides to exercise its discretion to offer power to the DSIs, the *Kaiser* case "supports . . . our understanding is that BPA does have an obligation to offer the DSIs a cost-based rate—namely, the IP rate—before declaring energy as surplus under § 839c(f) and selling it to the DSIs at a market-based—or other—FPS rate." *Id.* at 817 (emphasis added).

The "cost-based rate" referred to is not, as some preference customers have suggested, one that reflects the prevailing prices for power available on the open market, but is rather the IP rate, a rate that is statutorily tied to the PF rate, 16 U.S.C. § 839e(c)(2). Thus, the Court recognized that the IP rate is a cost based rate, *i.e.*, a rate that together with BPA's other rates are based on and established to recover BPA's total system costs, and not a rate targeted to recover the incremental costs of resources, as some commenters have argued, that might be needed to replace system capability in order to support all of BPA's contractual obligations.

In addition, the Court set out the applicable rate directive, which supports the view that the IP rate is not an incremental cost rate. See, *id.*, at 16556, citing 16 U.S.C. § 839e(c) (Section 7(c) of the NPA). The general statutory command is that the section 7(c) rate directive requires that the IP rate be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." 16 U.S.C. § 839e(c)(1)(B). The determination of equitability is required to be based upon the rate BPA charges its preference customers, with certain adjustments. 16 U.S.C. § 839e(c)(2). Those adjustments include the inclusion of an "industrial margin" which reflects the "overhead" that preference customers charge their own industrial customers. Also included in the IP rate is a credit for reserves that DSIs provide in connection with

[9] Comments appearing in this format, with an alphabetical prefix "CFA," refer to the comment period closing on February 20, 2009, which received comments on an amendment to the CFAC's contract which provided for service through the balance of FY 2009.

the Administrator's right to interrupt or curtail sales under the IP rate. 16 U.S.C. § 839e(c)(3).

It is difficult to understand, as PPC and other commenters apparently contend, how the IP rate established pursuant to section 7(c), which provides very explicit and detailed requirements for developing the rate, could recover from the DSIs the incremental cost of any acquisitions required to replace system capacity in support of DSI service and still be "equitable" in relation to the rates of industrial customers of BPA's public customers, who purchase power to serve their industrial loads at the PF (preference) rates. As the language of section 7(c) shows, it was not Congress's intent to have BPA charge the DSI customers rates that are inequitable as compared to the retail rates charged by preference customers to their industrial consumers. Rather, Congress intended to closely link the IP rate to the PF rate.

This issue of whether BPA should establish the IP rate on the basis of cost causation was fully aired in BPA's WP-10 rate proceeding. See 2010 Wholesale Power and Transmission Rate Adjustment Proceeding (BPA-10) Administrator's Final Record of Decision, (July 2009), Section 12.2, Section 7(c) Rate Directive, at pages 200-212, where BPA concluded that BPA is required to set the IP rate, as it has since 1985, consistent with the relevant provisions of section 7(c) of the Northwest Power Act. BPA has never interpreted these provisions to mean that the IP rate can be set based on principles of cost causation and sees no reason to deviate from its historical practices.

In short, the section 7(c) statutory rate directive specifically mandates the criteria by which the IP rate will be developed and there is no legal basis to conclude that it must be set to recover the incremental cost of any acquisitions made by BPA to replace resources if needed to support DSI sales. The Court in *PNGC* understood the nature of the IP rate when it held that any initial offer of service must be at the IP rate. 830 F.3d at 817. Thus, if the comments are taken at face value, some commenting parties would require the Administrator to ignore the rate-setting directive, which would be contrary to law, or make an initial offer at a rate other than the IP rate, which is prohibited by the *PNGC* opinion. Accepting such an argument would be in direct contravention of the Court's holding in the very case being relied upon by the parties who are raising it.

Even though BPA projects no need to do so during the Initial Period of the Block Contract, the Court recognized further that BPA may make market purchases to support DSI sales: "Congress also vested BPA with the authority to acquire power, including purchasing energy on the open market, if needed to meet its contractual obligations... [and] BPA has the statutory authority to sell power to DSIs at valid contract rates and to purchase at market rates the power to serve those contracts." 830 F.3d at 819. Additionally, in a separate Ninth Circuit opinion, the Court did not agree with the preference customers' assertion, now apparently recast in response to *PNGC II*, that no costs associated with DSI service can be allocated to the preference rate:

> According to petitioners, "Entering contracts to sell power to the DSIs when BPA has none to sell them is unlawful.... The only way the post-2001 contracts with the

> DSIs can be lawfully performed is to require the DSIs to pay the full costs of service." In other words, petitioners asserted that BPA could not allocate to its preference customers any of the costs of purchasing power at market prices to serve the DSIs.

Golden Northwest Aluminum, Inc. v. Bonneville Power Admin., 501 F.3d 1037, 1044 (9th Cir. 2007). The Court rejected petitioners' arguments. Instead, the Court in GNA concluded that BPA can "use any remaining FBS resources—including FBS replacement resources—to supply its DSI customers" and BPA "is entitled to charge preference customers a rate that reflects the total cost of all FBS resources, including resources acquired to replace losses in the generation capabilities of BPA's primary resources." *Id*.

The *PNGC* Court recognized that providing such service at the IP rate, as mandated by Congress, might itself provide some level of subsidy. The Court refers to the IP rate as the rate that BPA "is statutorily required to offer" and reflects "the primary benefit that the class of DSI customers receives under the NPA . . ." *PNGC I* 580 F.3d 792, 825. Further, the *PNGC* Court invalidated the monetized FPS surplus sale, at least in part, because BPA was "subsidizing the DSIs' smelter operations beyond what it is obligated to do," *i.e*., beyond what is provided for by Congress through the IP rate directive. *Id*. at 822 (emphasis added). Thus, if proper application of the IP rate directives results in a benefit to the DSIs, that is simply a consequence of the NPA, and not an illegal subsidy. By the same token, if BPA acquires expensive resources to serve preference customer load growth, and those resource costs increase the PF rate, this in turn results in an increase in the IP rate due to the workings of section 7(c), which means essentially that the DSIs would share some of those expensive resource costs. That too is the way the NPA works and is not an illegal subsidy. Finally, mindful that DSI and certain other features of the proposed Northwest Power Act could substantially increase the PF rate, Congress provided limited cost protection for preference customers in the form of Northwest Power Act section 7(b)(2), 16 U.S.C. § 839e(b)(2). Section 7(b)(2) requires, as one of a series of assumptions in comparing costs under the Act with costs under an alternative case, that the Administrator assume the preference customer load would have included the DSI loads. *Id.* § 839e(b)(2)(A). In other words, in the absence of the Act, BPA would still be serving the load, but indirectly through its preference customers rather than directly. Given that and section 7(c)'s link of the DSI rate to the PF rate, any protection Congress intended to provide preference customers against costs incurred to serve the DSIs is afforded by section 7(b)(2).

Prior to *PNGC I*, BPA's rates were set based on a monetized power sale to DSI aluminum smelters capped at $59 million per year. Subsequent to *PNGC I*, in the WP-10 rate adjustment proceeding, BPA abandoned the monetized power sale assumption and assumed a direct power sale to both aluminum DSIs and Port Townsend Paper. All such DSI power sales were assumed to be sold at the IP rate established in the WP-10 proceeding. WP-10 established the IP rate pursuant to section 7(c) of the NPA and existing BPA ratesetting methodologies and rate design. Issues were raised by parties regarding the IP ratesetting process and its compliance with *PNGC I* and these issues were dealt with in the WP-10 Final ROD.

In the WP-10 ratesetting process, BPA assumed that it would have a contractual obligation to serve the DSIs at a level of 402 aMW, which included an amount of service to Alcoa. In accord with the *Golden NW* decision, BPA assumed that it would augment the Federal Base System (FBS) resources as needed to meet its expected total obligations, including all PF requirements service to its public customers plus DSI IP service. While BPA did not attribute specific power purchases to specific loads, it can be ascertained from the rate case models that the then-forecasted power purchase expenses, net of additional revenues at the IP rate, increased an average of $37 million in the two-year rate period ($32 million for FY 2010 and $42 million for FY 2011) when compared to power purchase expenses without the assumed power sale to the DSIs. In addition, the risk of both power purchase prices and loads being higher or lower than the level assumed in establishing the amount of power purchases in the revenue requirement was assessed in the risk analysis performed for the rates being established.

The costs of purchased power, including the $37 million average increase, were allocated based on rate directives set forth in section 7 of the NPA. Because these purchased power costs were included in the FBS, section 7(b)(1) specifies that these costs are allocated to the loads of preference customers and the section 5(c) loads of utilities participating in the REP, otherwise known as the PF rate pool. By allocating all of the power purchase costs to the PF rate pool, the DSIs were allocated the costs of more expensive power from section 5(c) exchange resources and new resources. After these power costs are allocated, BPA then adjusts the IP rate to conform to section 7(c) of the NPA by reallocating costs among the rate pools, including the PF rate pool. This reallocation is supported by the legislative history of the NPA, as explained in the WP-10 Final ROD. And, as indicated above, these allocations are further subject to the section 7(b)(2) rate test.

Once established, BPA's rates are set for a two-year period subject, however, to adjustment clauses if BPA's financial reserves are above or below rate case determined thresholds. As such, as long as BPA's financial reserves are between these thresholds, rates will not be adjusted if there are cost overruns or shortfalls. If BPA sells fewer than 402 aMW of power to the DSIs during FY 2010-2011, or if the actual purchase power cost is less than forecasted in the WP-10 rate proceeding, as anticipated, then BPA's financial reserves will be better than expected when setting rates, all else being equal. BPA's latest forecast, discussed in Section V, indicates that BPA now expects that costs and benefits in the Initial Period will be approximately equal. These savings would accrue to BPA's financial reserves and, lacking an FY 2011 adjustment due to other cost and revenue changes, would be available to offset risks in future years, thus reducing upward pressure on BPA's future rates.

Beginning in FY 2012, BPA has established a completely new rate design for the Priority Firm Preference rate. This new rate design was codified in the Tiered Rate Methodology, adopted by the Administrator in the TRM ROD of November 2008. The first rate adjustment proceeding to establish rates pursuant to the TRM will be the WP-12 rate proceeding which is expected to commence in November 2010. As such, no decisions have yet been made about how the IP rate will be established after FY 2011. However, the TRM does not in any way remove or modify any ratesetting instructions contained in section 7 of the NPA, including section 7(c) regarding the IP rate, and the Block Contract is explicit that all rate determinations will be made in BPA rate cases.

For all the reasons outlined above, a sale to Alcoa at the IP rate is consistent with statutory requirements and is consistent with sound business principles.

d. Term of the Block Contract

The December Draft Contract developed for Alcoa (but not executed) had a proposed term of 17 years beginning October 1, 2011, and ending September 30, 2028, the same duration as BPA's other long-term power sales contracts that were executed in 2008 with BPA's public preference and other customers.

During subsequent negotiations between BPA and Alcoa, and after considering comments received, BPA has decided to reduce the 17-year term to seven years. BPA's primary interest with respect to the length of the new contract was that it not be so long that it exceeded BPA's risk tolerance for insuring adequate inventory to serve the load within a specified cost. For its part, Alcoa's primary concern was that the term be of sufficient duration to give Alcoa an opportunity to recover losses it has incurred at the Intalco Plant and to justify making capital investment in the Intalco Plant. Under the appropriate market conditions, Alcoa feels it should be able to recover losses incurred, within the latter years of a seven year agreement. Alcoa also indicated that a contract term of 10 years or more would allow it to make capital investment at the Intalco Plant. Alcoa encouraged BPA to offer at least a seven-contract and to consider what steps it could take to put in place a 10-year contract.[10] BPA has decided to offer a contract with a seven year term.

NRU commented that the structure of the contract makes it difficult to determine if sales under the Block Contract will be "in the money." NRU at 1. Canby requested BPA to conduct an economic analysis prior to the end of the 19-month period to assess whether BPA made money on the contract and whether BPA's public power customers subsidized BPA sales to Alcoa, and that the results of the economic analysis could be used in establishing service for the subsequent 5-year contract period. Canby at 10. Nearly all of BPA's rate setting is based on forecasts without specifically adjusting for what actually happens relative to each specific forecast. Rather, what actually happens collectively is covered by negative and positive adjustments to BPA's financial reserves, as well as rate adjustments, if needed. Depending on whether BPA is worse off or better off, relative to the forecast, at the end of the rate period, the results will be reflected in BPA's financial reserves and become an issue for treatment in subsequent rate cases.

WP-10 rate case models were used to establish the term of the Initial Period of the Block Contract with only a gas forecast update. BPA is satisfied the rate case models and the updated gas forecast used in the Equivalent Benefits Test sufficiently establishes the

[10] See letter to Allen Burns from Mike F. Rousseau, dated June 22, 2009, at.2.

Initial Period term of the contract without going back and making retroactive adjustments. BPA has decided not to conduct an economic analysis prior to the end of the Initial Period.

Snohomish commented that a Transition Period of a full year “is far too long” and stated that “BPA should already have the economic models in place to make this determination, and therefore should be able to do so in a matter of months, not a full year.” Snohomish at 6. The contract enables BPA to establish the Transition Period from as short of a duration as six months and as long as 12 months. This provides BPA the flexibility to establish the duration needed to accomplish what might be required in the event there is a Transition Period. In the event there is a Transition Period BPA may have to do more than run economic models. BPA will need to evaluate future IP rates, forward power market prices and then finally determine if it can provide service to Alcoa within the Cost Caps negotiated within the Block Contract. BPA has decided to include a Transition Period not to exceed 12 months.

Snohomish also commented that language in the Block Contract suggests “the contract could terminate after the end of the Initial Period, and be revived after the passage of some unspecified period of time.” Snohomish at 6. The provision commented on refers to a Transition Period that begins during the Initial or Extended Initial Period and extends beyond the end of those periods. If the Block Contract terminates because the Initial or Extended Initial Period ends without the Transition Period starting before or at the end of the Initial or Extended Initial Period, the terminated contract cannot be “revived” by a Ninth Circuit Opinion.

Snohomish urged BPA not to sign the Block Contract, and stated that “given BPA’s derived benefit and the contingent nature of the Second Period, BPA has assumed a much higher level of risk with no demonstrated benefit by signing the DSI contracts at this time.” Snohomish at 2. Snohomish is correct that the five-year Second Period is contingent, and is dependent on a future Ninth Circuit opinion that the Equivalent Benefits Test is not necessary and that BPA can provide service to Alcoa during the Second Period within the Cost Caps established in the Block Contract. For reasons stated elsewhere in this ROD, BPA believes the cost caps and other provisions of a Second Period are justified and adequately balance risks and benefits.

e. Cost Caps

The Block Contract contains cost caps applicable to any Transition Period and Second Period. See Block Contract section 7. The level of the cost caps, and the manner in which BPA will evaluate whether the cost of service to Alcoa is equal to or less than the applicable cost caps, are specified in Exhibit B of the Block Contract. The cost caps will apply only to BPA’s evaluation of whether it will provide service under the Block Contract during the Transition and Second Periods. This is because service to Alcoa under the Block Contract during the Initial Period, any increase in the level of service from 285 aMW to 320 aMW, or any extension of the term of the Initial Period, is contingent on BPA determining that it will achieve Equivalent Benefits from such service. Therefore, the cost caps are unnecessary during the Initial Period or any Extended Initial Period and would provide no additional risk mitigation to BPA.[11]

Comments raised a number of objections to the Cost Cap provision. PPC stated that it is not clear "whether BPA intended the cost caps to be an alternative to, or backstop to the Equivalent Benefits test," adding that in multiple places the contract "refers to instances where both the Equivalent Benefits test and the Cost Caps could be met," which implies that the Equivalent Benefits test could be complied with even if BPA were losing up to $330 million on the transaction." PPC at 7. ICNU made a similar point, stating that "[I]t is entirely inappropriate to include in the contract the 'Second Period' with the associated 'cost caps' that by their terms impose as cost on BPA's customers for service to the DSIs—a plain and admitted violation of the 9th circuit's decision." ICNU at 5.

BPA agrees that the draft sent out for public comment was unclear on this point. The final version has been changed to clarify that Cost Caps are not applicable to the Initial Period, or Extended Initial Period, if any, because BPA has determined that the benefits of the transaction exceed the cost. The Cost Caps could apply in the Transition and Second Periods of the Block Contract, but only if the Ninth Circuit clarifies its earlier opinions in a manner that would permit or require BPA to apply a test less stringent than the Equivalent Benefits Test. In that eventuality, BPA believes service to Alcoa of 320 aMW during a Transition and Second Period, at a cost that is within the Cost Caps, is in accordance with BPA's policy objectives of providing a reasonable level of service to an historical customer class without placing undue upward pressure on the rates of other customers.

WPAG argues that there is no limit on potential monetary losses during the Initial Period, and that neither the Equivalent Benefits Test nor the Cost Caps limit BPA's actual monetary losses since they are based on forecasts. WPAG at 5. PPC makes a similar argument. The consequence of WPAG's argument is either that (1) BPA may never serve DSI load because it can never know with absolute certainty that its forecast of the costs and benefits associated with a DSI transaction will, in fact, match actual costs and benefits, or (2) BPA may only serve the DSIs if it recovers its actual costs of service. The latter argument, essentially a rates argument, has already been addressed above. Regarding the former, nothing in *PNGC I* or *PNGC II*, or in the Northwest Power Act, prohibits BPA from entering into a transaction with a DSI customer (or with any other customer) unless the costs and benefits of the transaction can be locked-in with absolute certainty. Such a requirement does not comport with a commodities business, which by definition requires buyers and sellers to forecast, as part of any transaction, both availability and market price for the commodity in question. In simplest terms, this is what BPA does every time it establishes its rates, with risk mitigation tools established and deployed as necessary to assure total overall cost recovery, including repayment to the U.S. Treasury.

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[11] As explained in Part V herein, BPA has determined that it will achieve Equivalent Benefits from the sale of 285 aMW to Alcoa, increasing to 320 aMW, during the term of the Initial Period.

It is true, as WPAG and PPC argue, that once BPA makes a determination based on a forecast basis, and then executes the Alcoa contract, there is no contract provision that allows BPA to terminate the contract if the actual cost to provide service to Alcoa in the Initial Period exceeds the forecast. However, it is also the case that if actual costs are less than forecast, then BPA (and not Alcoa) receives that benefit. As indicated before, service to the DSIs during FY 2011-2012 was modeled in the WP-10 rate setting process at a level close to the amount offered in the Block Contract. Results from the rate case models forecast that the power purchases expenses, net of additional revenues at the IP rate, increased an average of $37 million in the two-year rate period ($32 million for FY 2010 and $42 million for FY 2011) when compared to power purchase expenses without the assumed power sale to the DSIs. In addition, the risk of both power purchase prices and loads being higher or lower than the level assumed in establishing the amount of power purchases in the revenue requirement was assessed in the risk analysis performed for the rates being established. All BPA rates are based on forecasts modeled in BPA's 7(i) ratesetting process. Therefore, for the Initial Period, BPA's rates (including the IP rate) have already accounted for the risk of actual costs exceeding the forecast amount.

Canby commented that section 2.2 of the draft Block Contract, which contemplated increasing the Cost Caps for Alcoa under certain circumstances, should be eliminated. Canby at 10. BPA decided the contingency for increasing the Cost Caps was a cumbersome concept, added unnecessary complexity, and removed this provision from Exhibit B. This concept was replaced with a simple, straightforward fixed benefit of $50.2 million per year for 320 aMW during the Transition period. The basis for the increase from $41 million per year is that during FY 2010 Alcoa self supplied power for 82 days prior to the start of the Block Contract, from October 1, 2009 through December 21, 2009. The portion of FY 2010's $41 million Cost Cap (also included in the August Draft and the November Draft contracts) associated with those 82 days was added to the Transition Period Cost Cap. The $50.2 million is equal to $41 million, plus the product of $41 million multiplied by 82 days divided by 365 days ($41,000,000 + [$41,000,000 * 82 / 365] = $50.2 million)

f. Termination and Take-or-Pay

In addition to the standard termination for default provisions, each party has the right to terminate the Block Contract under certain additional circumstances. BPA's additional termination rights primarily relate to cases where it has made a determination that it cannot serve Alcoa consistent with the Court's rulings or opinions, or at a cost that is at or below the cost caps. *See* Block Contract section 6.2. For its part, Alcoa may terminate the Block Contract at any time during the Initial, Extended Initial, or Transition Periods, on six months notice, and during any Second Period on 12 months' notice. *See* Block Contract sections 22.1.1.1 and 22.1.1.2. In each case, Alcoa retains some (in the case of termination during the Initial, Extended Initial, or Transition Periods) or all (in the case of a termination during a Second Period) of its take-or-pay obligation before the date of termination.

During the first three months of the 6 month notice period of a termination during the Initial, Extended Initial, or Transition Periods the take-or-pay obligation is 90 percent of Alcoa's then current firm power consumption. For the remaining 3 months of the 6 month notice period Alcoa is obligated to pay for only the firm power that it actually consumes during the ramp-down of plant operations. If Alcoa terminates the Block Contract during the Second Period, its take-or-pay obligation is for 12 months following such notice. Following the effective date of termination Alcoa has no further take-or-pay obligation and BPA has no further obligation to serve Alcoa during what would have been the remaining term of the contract. However, during the Second Period, BPA's forecast market prices for surplus sales are expected to exceed the IP rate. So while BPA bears some risk that prices could be lower, this is offset by BPA getting the more likely upside benefit.

Alcoa may terminate at any time, and on one day written notice, in the event BPA has made a determination pursuant to section 6.2 that it cannot serve Alcoa during a Second Period. See Block Contract section 22.1.2. Alcoa also may terminate in the event it has been billed directly, and paid to BPA, in excess of $2 million for certain environmental or regulatory costs. *See* Block Contract section 22.1.4. In each of the foregoing terminations, Alcoa has agreed (except in the case of a termination following a determination by BPA under section 6.2) that it will not restart the Intalco Plant until after the time when a Second Period would have otherwise ended. See Block Contract section 22.1.5.

WPAG commented objecting to the termination provisions, arguing that BPA has given Alcoa an unfettered termination right, which could expose BPA and its public utility customers to significant financial risk if such a termination were to occur during a period of low market prices. WPAG at 8. WPAG recognized BPA's assertion that protection is provided by a provision that prohibits re-start of operations until the end of the Second Period if the termination right is exercised, but insists that BPA's argument is flawed in that the prohibition would apparently not apply if the smelter is operating at the time Alcoa exercises its termination right (i.e., no "restart" is required). BPA believes the intent of the Block Contract is clear. If Alcoa terminates, except for terminations pursuant to section 6.2 of the Block Contract, Alcoa cannot operate the Intalco Plant for what would have been the remainder of the term of the Block Contract. *See* Block Contract section 22.1.5.

WPAG also argues there is no survivability language, which means that "when Alcoa terminates the Block Contract section 22.1.5 will be terminated along with the rest of the Block Contract." WPAG at 8. In fact, the term section of the Block Contract does contain survivability language, and an additional survivability provision was added at section 22.1.6. in response to the concerns expressed by WPAG.

BPA is confident that it can manage the risks associated with periods following termination of the Block Contract by using the same strategies outlined in the Curtailments and Liquidated Damages section below.

g. Curtailment and Liquidated Damages

While Alcoa's obligation under the Block Contract is generally take-or-pay, but Alcoa may curtail its load pursuant to the terms and conditions specified in section 9 of the Block Contract. During such periods of curtailment Alcoa's take-or-pay obligation is excused, and Alcoa is not liable for any losses (liquidated damages) BPA may incur in remarketing such curtailed power, nor is Alcoa entitled to share in any gains that BPA may receive as a result of remarketing.

Several parties in comments questioned why Alcoa is not obligated to pay BPA damages in the event BPA accrues less revenue from remarketing power during a curtailment of DSI load than it would have received from selling such power to Alcoa under the Block Contract.

PPC commented that the Block Contract contains no take-or-pay provisions. PPC at 7. The Block Contract is clearly structured as take-or-pay, but BPA has modified its earlier version of the Block Contract to clarify that, except for periods of curtailment, the sale and purchase is subject to take-or-pay requirements. Additionally, PPC objected to the inclusion of curtailment rights, stating the inclusion of curtailment rights in the contract essentially excludes any obligation for DSIs to pay BPA during times they do not operate their plants, and that in such instances BPA would be left unloading power in the market instead of selling it to the DSIs. PPC at 2. Furthermore, PPC argues that BPA's forecasts show prices for both aluminum and power prices as being low, "there may be a correlation between a DSI's decision to curtail and a low market in which BPA would have to resell such power." *Id*.

Other comments similarly argue the curtailment provisions create an unacceptable level of risk to BPA, and that, according to its own forecast of market prices, BPA will always suffer a financial loss on occasions of curtailment. E.g., WPAG at 6 (BPA's analysis shows that sales of power on the market will generate less revenue than if such power were sold to Alcoa, based on BPA's analysis any curtailment by Alcoa of BPA power deliveries are virtually assured to generate losses).

In addition, several parties commented that waiving Alcoa's take-or-pay obligation during periods or curtailment and not charging Alcoa any damages in the event BPA remarkets curtailed power at a loss, is inconsistent with how BPA addressed this issue in the recently executed contract with DSI customer Port Townsend. It is true Alcoa does not pay damages during periods of curtailments while Port Townsend does. A key reason for this difference in service concepts is that Port Townsend has unlimited curtailment rights while Alcoa's curtailment rights are limited. Alcoa can curtail for only a maximum of 24 months and under certain circumstances for a maximum of just 18 months.

BPA also agreed to include curtailment flexibility and waive Alcoa's take-or-pay obligation and not impose a liquidated damage obligation (i.e., an obligation to pay damages to BPA equal to any negative difference between IP revenues and the revenues BPA receives from remarketing curtailed power) during a curtailment on the basis that

Alcoa cannot replace BPA's power with power from another source and that during any curtailment period Alcoa must maintain certain employment levels. *See* Agreement section 9.2. On average, during the Initial Period, BPA would be in no worse position with regard to reselling the power into the market than had BPA not entered into the Block Contract to begin with. The contract provides Alcoa with the right to curtail its purchases for a maximum of 24 months. This 24 month maximum is limited further during the Second Period. Alcoa may only curtail purchases for 18 months during the Second Period, provided the 24 month overall limit is not exceeded. Without exercising its curtailment rights under the Block Contract Alcoa must pay for the full contract amount.

BPA is confident that it can manage the risks associated with periods of curtailment. Curtailments are limited to 24 months overall and 18 months within the Second Period. During the Initial and Extended Initial Period, if any, BPA plans to serve this load from existing inventory and does not expect to make long-term purchases. For this reason, BPA will not be in a position of having to dispose of significant amounts of power it had specifically acquired to serve Alcoa. Thus, during a curtailment BPA will market its remaining inventory as though the Block Contract was never executed, meeting its other firm contractual load obligations and then selling into the market. Therefore there is no additional risk resulting from this contract as compared to a scenario where BPA had not entered into this contract.

During the Transition Period or Second Period, while BPA may need to acquire some power, and such acquisitions are anticipated to be short-term purchases and BPA probably will not acquire power equal to the full contract amount since, again, BPA's existing system is expected to partially supply the load. Therefore, during a curtailment any power acquired to provide service to Alcoa is expected to be less than the full contract amount and for durations less than the Second Period reducing the risk of BPA being in a position of having to dispose of amounts of power equal to 320 aMW. BPA's forecast market price for power is expected to exceed the IP rate after the Initial Period and any Extended Initial Period. Therefore, even if BPA has purchased power in this timeframe to support the Alcoa sale, and Alcoa were to curtail or terminate deliveries, BPA has a greater probability of having a benefit by increasing revenues from reselling the power in the market at prices above the IP rate, rather than incurring costs from remarketing at a lower rate. While there is a low probability that market prices in this timeframe could be below the IP rate, resulting in a loss of revenues, the probability is greater that market prices and revenues will be higher, resulting in a net benefit.

h. Credit Support

Alcoa is obligated, at BPA's request, to arrange for BPA to be provided with a $30 million standby letter of credit, issued in a form and by a bank acceptable to BPA, and to have issued, at BPA's request, replacement standby letters so that a letter of credit will be in place if BPA determines such protection is necessary.

WPAG argues that, in spite of being able to call upon Alcoa to provide a letter of credit, BPA has assumed risks of non-payment, and that several of BPA's DSI customers have defaulted on their payment obligations to BPA and filed for bankruptcy protection. WPAG at 7. WPAG correctly points out that Alcoa is obligated, at BPA's request, to arrange for BPA to be provided with a $30 million standby letter of credit, equal to 103 days of power, calculated using the highest monthly average IP rate, so that a letter of credit is in place if BPA determines such protection is necessary. *See* Agreement section 21.8.1. BPA may seek additional performance assurance from Alcoa to the extent Alcoa's financial responsibility or performance viability become unsatisfactory to BPA. See Agreement section 21.8.3.

Some parties commented that BPA required more credit assurances from Port Townsend. BPA agrees that its payment assurance approach is different with Alcoa than is with Port Townsend. Port Townsend's parent company recently came out of Bankruptcy in 2007, whereas, Alcoa Inc. has maintained an investment grade rating since 1989. Even prior to Port Townsend's bankruptcy filing, Port Townsend was rated multiple notches below investment grade. For these reasons, Port Townsend is required to prepay monthly for its minimum take-or-pay purchase amount (13 aMW) and to post an additional deposit with BPA. The deposit is equal to the product of the difference of it maximum monthly purchase amount (20.5 aMW) minus the minimum take-or-pay amount times the highest monthly IP rate. The sum of the prepayment and the deposit is equal to or greater than the payment for power before it is delivered, mitigating account receivable risk of full payment prior to the start of deliveries. Alcoa is a publicly traded company with a bond ratings from Standard & Poor's, Moody's, and Fitch of BBB- rating. According to default rates published in the 2008 Corporate Default and Recovery Rates, 1920-2008 by Moody's and a similar issued by Standard & Poor's, Alcoa Inc. has a lower estimated default probability than the other DSIs. For this reason, Alcoa in not required to make a prepayment. But to help assure payment, BPA may request, and Alcoa is then obligated to post a $30 million letter of credit. These different payment assurance provisions are appropriate and provide the right balance for payment assurance.

It is not clear what risk WPAG believes BPA is taking in this respect, unless WPAG is arguing that there is a risk that Alcoa would owe BPA more than $30 million. A standby letter of credit represents an irrevocable and unconditional promise by the issuing bank to pay on demand to a beneficiary, in this case BPA, that is independent of the underlying Block Contract by and between BPA and Alcoa. BPA's right to draw on such a letter of credit is not dependent on Alcoa's financial condition. In the event Alcoa defaults on any payment obligation to BPA when due, BPA can, and will, draw on the letter of credit in the amount of such payment default. In addition, to the extent that WPAG is suggesting the amount of the letter of credit is insufficient and should cover all conceivable BPA exposure, it is not standard industry practice to require that a counterparty post security equal to the full notional value of the underlying transaction, which in the case of the Block Contract would equal approximately $700 million dollars, as this would require companies to post unreasonable amounts of collateral.[12] The letter of credit provisions in

[12] In the case of a power sales contract, the notional value would be calculated by multiplying the maximum number of megawatts sold (in this case 320 MW), times the rate (in this case forecast for any

section 20.8 would cover BPA's exposure to a failure by Alcoa to pay for 103 days of power deliveries, but it is unlikely that BPA would permit Alcoa to default on its payment obligations for that long.

i. Section 4.3

WPAG argues that section 4.3 as originally proposed amounted to a continuing commitment by BPA to perform under a contract found to be illegal by the Ninth Circuit. WPAG at 4. PPC echoes WPAG's views and states that including the provision only tends to foster the notion that BPA does not recognize a need to strictly comply with the Ninth Circuit's ruling when it comes to efforts to deliver a benefit to the DSIs. PPC at 8.

BPA agrees with the criticism of this provision, and so has amended it to provide that the Block Contract terminates upon issuance of the Court's mandate, absent a judicial extension of the period that BPA can provide service. See Block Contract section 4.3.

j. Covenants

Alcoa has made certain covenants, including agreeing not to challenge the validity of the Block Contract, any determinations by BPA regarding Equivalent Benefits, or any BPA determination under Exhibit B. See Block Contract section 25.1. In addition, Alcoa has agreed not to request any surplus power from BPA during the term of the Block Contract, and not to challenge any proposed or actual sale of surplus power by BPA, or to challenge any rate adopted by BPA for the sale of surplus power. See Block Contract section 25.2. Finally, Alcoa agreed that it will waive any claims it may have under Contract No. 06PB-11744, as amended, in the event BPA determines on remand in *PNGC I* and *PNGC II* that no payments are owing to or from either party under such contract, but that such waiver will be of no force or effect in the event that the Ninth Circuit issues its mandate in a case in which it has granted a petition for review and has issued an order that requires that payment be made. See Block Contract section 23.2

Some comments argued that the required covenants are inadequate. WPAG states the covenant in section 25.1 only covers BPA's Equivalent Benefit determination, and is silent with regard to any Forecast Net Cost determination made under Exhibit B, and that if BPA wishes to avoid unnecessary future litigation over the Block Contract, it should require Alcoa to covenant not to challenge any Forecast Net Cost and Cost Cap determinations. WPAG at 9. BPA has changed the language, as suggested by WPAG.

WPAG further argues that BPA should essentially use its bargaining power to extract further specific concessions, including agreement by Alcoa that it will pay to BPA any amounts BPA determines are payable by Alcoa to BPA as part of the remands in *PNGC I* or *PNGC II*. Others argued to similar effect. Snohomish 3-4; PPC, 5-6, 9; Canby 10; SUB 17.

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period not covered by current rates), times the number of hours in the maximum term of the contract (in this case 61,320 hours).

BPA does not believe that such heavy-handed tactics are necessary and declines to extract such a concession. No such concession has been required of BPA's preference customers in spite of the fact that Alcoa asserts that it is the one entitled to payment through the Lookback process. It would not be consistent with BPA's practices to require preference customers basically give up any legal argument that they may have to avoid collection in the event that Alcoa prevailed in its argument. BPA prefers, instead, to allow the process to run its course and leave all parties on an equal footing with respect to their respective legal positions.

In a similar vein, WPAG encourages BPA to use its perceived bargaining leverage to further weaken Alcoa's legal positions by forcing Alcoa to give up legal claims in exchange for BPA entering into a power agreement. WPAG at 8 (would make sound business sense for BPA to require Alcoa to waive its claims under the Prior Block Contract in order to obtain access to the benefits it will enjoy under the proposed Block Contract).

BPA disagrees that, as WPAG suggests, it makes good business sense, in the long run, to force a business partner to waive every conceivable right and make every possible concession simply because the sale to Alcoa is discretionary. BPA does not believe that *PNGC I*, *PNGC II*, or the Northwest Power Act require, or that it is otherwise consistent with principles of good faith and fair dealing, to place the preference interest groups at a legal advantage vis-à-vis the DSIs, simply because DSI service is now discretionary, and to require DSIs to waive any and all legal claims they may have before BPA will even consider providing service.

k. Damage Waiver Provision

The damages waiver provision in section 21.11 states:

> In the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final order that declares or renders this Agreement, or any part thereof, void or otherwise unenforceable, neither Party shall be entitled to any damages or restitution of any nature, in law or equity, from the other Party, and each Party hereby expressly waives any right to seek such damages or restitution. For the avoidance of doubt, the Parties agree this provision shall survive the termination of this Agreement, including any termination effected through any order described herein.[13]

In both rounds of comments, a number of parties commented that the damages waiver provision in section 21.11 is illegal, inasmuch as BPA is obligated by law to recover any benefits conferred on Alcoa under the Block Contract in the event the Block Contract is found unlawful. See *e.g.*, September 9, 2009, comments of PPC at 9-10 (provision

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[13] The waiver clause in section 21.7 (severability provision) commented on by Snohomish provides that neither party shall be liable to the other for any damages associated with any term being severed from the Agreement.

unlawful, inappropriate, and "extremely ill-advised" in light of *PNGC I* and *PNGC II*; ICNU at 3 (as a government agency BPA obligated to recover funds illegally paid); WPAG at 5 (provision illegal, and BPA has provided no business rationale for including it); PNGC at 4 (waiver provision "startling" in light of *PNGC I* and *PNGC II*, and cannot be justified based on reciprocal nature of the waiver since Alcoa's prior claims shown to be meritless); WMG&T at 2 (waiver provision unconscionable); Snohomish at 3-4 (waivers inappropriate and should be replaced with express refund language).[14]

Specifically, PNGC argued in its comments in an earlier process regarding service to Alcoa that the waiver provision is unlawful because it "attempts to excuse BPA and its employees from complying with obligations that they have under the Property Clause of the U.S. Constitution to recover payments erroneously or illegally made." PNGC in DCA09 at 4. In support of this position, PNGC cited *Wisc. Cent. R.R. Co., v. United States*, 164 U.S. 190 (1896); *United States v. Wurts*, 303 U.S. 414, 415 (1938); and *Barrett Ref. Corp. v. United States*, 242 F.3d 1055, 1063 (Fed. Cir. 2001). In addition, PPC and Snohomish cite *Fansteel Metallurgical Corp. v. U.S.*, 172 F.Supp. 268, 270 (Fed. Cl. 1959) for the proposition that BPA is obligated by law to seek a refund of funds erroneously or illegally paid. PPC at 9; Snohomish at 4.

In *Fansteel*, the United States was seeking a refund from a contractor for overpayments by the government under a contract. The Court of Federal Claims (known then as the Claims Court) first noted that no "amendment of the contract exists under which [Fansteel] could retain the overpayment" apparently recognizing that there could be cases in which the United States would have agreed by contract to limit or waive any right to seek recovery of overpayments under a contract. *Fansteel Metallurgical Corp.* at 270 (Ct.Cl. 1959). Nevertheless, the court then went on to hold that

> when a payment is erroneously or illegally made it is in direct violation of article IV, section 3, clause 2 of the Constitution. Under these circumstances it is not only lawful but the duty of the Government to sue for a refund.

Id. As authority for this conclusion, *Fansteel* cites generally *Royal Indemnity Co. v. United States*, 313 U.S. 289 (1941), but it is not clear that *Royal Indemnity* either held that the government is duty bound to seek restitution for payments erroneously or illegally made and that it may never waive such right by contract, or even if it did, that the holding can be applied to a case where the erroneous or illegal payments were made pursuant to a contract that was entered into by a government official exercising contracting authority conferred upon him by Congress. In *Royal Indemnity*, an Internal Revenue Service employee, who had accepted a surety bond filed with him by a taxpayer pending resolution of a disputed tax assessment, consented to termination of the bond before the taxpayer had paid the full amount of his adjudicated tax. Citing article IV, section 3, clause 2 of the Constitution, the court stated that "the power to release or

[14] Several parties reiterated these comments regarding the waiver provision in comments filed on November 9, 2009. See, WPAG at 7; PPC at 8; ICNU at 4; Snohomish at 4.

otherwise dispose of the rights and property of the United States is lodged in the Congress" and held in light of this that

> [s]ubordinate officers of the United States are without that power, save only as it has been conferred upon them by Act of Congress or is to be implied from other power so granted.

Id. at 294 (citations omitted). The court went on to hold that the Internal Revenue Service agent that had released the surety bond was a "subordinate officer charged with the ministerial duty of collecting taxes" and that only the Commissioner of the Internal Revenue Service "is authorized to compromise a tax deficiency for a sum less than the amount lawfully due." *Id*. However, the BPA Administrator is authorized by statute to enter into power sales contracts with each direct service industrial customer, including Alcoa, and to amend, modify, adjust, cancel, compromise, or settle any claim arising thereunder. See, Bonneville Project Act, 16 U.S.C. §§ 832, 832a(f); Northwest Power Act, 16 U.S.C. §§ 839, 839f(a). Where the commercial content of those contracts is not prescribed by Congress, the law affords the Administrator substantial discretion to determine reasonable commercial terms. 16 U.S.C. § 832a(f); 16 U.S.C. § 839f. The Bonneville Project Act, 16 U.S.C. § 832d(b), expresses Congress's recognition that BPA's commercial contracts for the sale of power "shall be binding in accordance with the terms thereof . . ."

BPA believes the damage waiver provisions, which are mutual waivers, represent a fair allocation between the parties of the risk that the Block Contract may be invalidated in whole or in part, thereby serving to protect BPA from any damages claims that Alcoa may otherwise choose to pursue against BPA in such event. Parties entering into commercial contracts with BPA have a legitimate expectation that the contracts are within BPA's authority and that they should be able to rely upon them. Because the waiver provisions of the Block Contract fall within the scope of the broad contracting authority conferred on BPA by Congress, they do not implicate the constitutional considerations that form the basis of the holdings in *Royal Indemnity* and *Fansteel*.

The other cases cited in comments to support the proposition that the damage waiver provisions in the Block Contract are *per se* illegal are likewise inapposite. *United States v Wurts*, 303 U.S. 414 (1938), cited by PNGC, does not address whether the United States is *obligated* to seek to recover funds erroneously or illegally paid, but rather holds only that it can "by appropriate action" recover funds which its agents have wrongfully, erroneously or illegally paid, and that no separate statutory authority to pursue such an action is required. Likewise, *Wisc. Cen. R.R. Co., v. United States*, 164 U.S. 190 (1986) is cited by several parties for the general principle stated in that case that "parties receiving moneys illegally paid by a public officer are liable *ex aequo et bono* to refund them." *Id.* at 211.[15] But this is nothing more than restating a basic rule of equity jurisprudence that a party that has been unjustly enriched, as a general rule and absent any equitable defenses, will be required *as a matter of equity* to refund the value of the benefits conferred upon him. The case does not hold, or even discuss, the proposition by

[15] *Ex aequo et bono*: According to what is just and good.

PPC and others that the government is obligated *as a matter of law* to seek restitution in every such case, and is therefore as a matter of law prohibited from contractually agreeing to waive any right to do so.

In sum, BPA believes the waiver provisions are lawful and represent a reasonable allocation of the risks between the parties associated with an invalidation of the Block Contract, in whole or in part.

l. Reserves

Alcoa will provide power reserves to BPA under the Block Contract, as specified in the Minimum DSI Operating Reserve – Supplemental section of BPA's 2010 General Rate Schedule Provisions (referred to below as the "Supplemental Operating Reserve"), and section 10.1 and Exhibit F of the Block Contract. Alcoa will provide approximately 30 MW of power reserves, within a time frame, in an amount, and for a duration consistent with applicable reliability standards, and as specified by Exhibit F.

Several parties raised issues with respect to the power reserve provisions in the Block Contract. PPC, SUB, and PNGC questioned whether Alcoa would be able to provide the reserves contemplated by the Block Contract in the event BPA calls on them, and PNGC posited the reserves may be of little value given the relatively small size of the Alcoa load, while SUB noted that such reserves will be unavailable (and therefore worthless) in the event Alcoa curtails its load. PPC at 2; SUB at 7; PNGC at 2. For its part, Snohomish commented that the exhibit addressing the details of reserves in the Block Contract is unclear in several respects, including the return energy provisions, and that the contract appears to provide that Alcoa would receive compensation for providing reserves in addition to the reserves credit embedded in the IP rate. Snohomish at 2-3.

The amount and quality of the reserves Alcoa will provide under the Block Contract are consistent with statutory requirements and BPA's established rate schedules, and BPA believes will be made available by Alcoa if and when called on by BPA under the Block Contract. In fact, Port Townsend provided the same reserve product under its power contract for October 2009 that permitted BPA to interrupt deliveries of electric power to them in the event of a power system disturbance. As such, BPA and Port Townsend implemented a test procedure to ensure Port Townsend could provide the reserves as specified. Port Townsend successfully complied with multiple tests of their provision of reserves to BPA. As such, BPA expects to conduct a similar test procedure with Alcoa and BPA believes Alcoa – a relatively larger and more sophisticated participant in the electric power market – will also be compliant with the reserve provision of the Block Contract when called upon by BPA.[16]

In addition, in the WP-10 rate proceeding, BPA contemplated that the DSIs may provide a last-off-first-on reserve, but BPA did not de-rate the value of the reserve because the stand-ready value of the reserve provided by a power sale to a DSI gives BPA roughly

[16] Please refer to BPA's data responses in the WP-10 rate proceeding for further information regarding Alcoa's corporate expertise and experience with power reserves in other jurisdictions.

full value in that it can displace operational capacity that would have otherwise been utilized as Supplemental Operating Reserve:

> We agree that we must consider any lack of flexibility when we value the reserve service provided by the DSIs. The fact that the DSIs may provide a last-off-first-on reserve and the fact that this reserve can be deployed a maximum of once a day may result in a smaller value for these reserves as compared to the Initial Proposal value of Supplemental Operating Reserve. We have not fully analyzed all these limitations and considerations, but due to the IOUs' point that standing ready has value; the new information provided through BPA-AL-01, Exhibit 1; and the assumption that load-based reserves would be deployed last, the stand ready value of the reserve provided by a power sale to a DSI gives BPA roughly full value in that it can displace operational capacity that would have otherwise been utilized as Supplemental Operating Reserve. Therefore, we propose not to de-rate the value of reserve in this rate case.

WP-10-E-BPA-36, page 21. Even as a last-off-first-on reserve, BPA expected to call on the reserve provided by the DSIs as described below:

> BPA analyzed our contingency reserve obligation and contingency reserve deployment for FY 2008 to determine how frequently the capacity was fully used. To capture the capacity component, the contingency reserve obligation and deployment were analyzed within hour on a one minute time interval. On a minute by minute basis, the observed peak contingency reserve obligation was 752 MW and observed peak contingency reserve deployment was 599 MW during the study period. Analysis showed that the contingency reserves deployed were within 40 MW of the contingency reserve obligation nine times during the study period. The full amount of the contingency reserve obligation was deployed five times. The contingency reserve deployments that were within 40 MW of full requirements did not occur more than once a month and the duration of deployment ranged from seventeen (17) to seventy-five (75) minutes.

WP-10-E-BPA-36, page 33. BPA expects to call upon the reserves provided by Alcoa, if needed, at least as frequently as the reserve contemplated in the WP-10 rate proceeding.

As to the value of reserves from different sized loads, the compensation realized by Alcoa is through a rate credit of $0.80 per MWh. By including the compensation in the IP rate, the amount "paid" to a DSI is directly proportional to the size of its load. If it is a large load capable of providing more reserves, such as Alcoa, the DSI will be compensated with a larger amount of dollars. If the DSI is a smaller load, such as Port Townsend, it will provide fewer reserves, but will be compensated with a proportionally smaller amount of money.

SUB's comments with respect to the effect of a possible curtailment on the value of the reserves provided by Alcoa are misplaced. Compensation for power reserves is provided through the NPA section 7(c)(3) rate credit reflected in the IP rate, so during curtailments Alcoa is not making power purchases and will not receive a rate credit. If Alcoa elects to terminate the Block Contract, any power Alcoa elects not to take but pay for during the 12-month take-or-pay period will be assessed the IP rate plus $0.80 per MWh to account for the value of the reserves not provided when curtailed during the termination period, up to its take-or-pay obligation, for the curtailed power.[17] (*See* Block Contract section 22.1.1.2.)

As stated earlier, Alcoa will provide reserves to BPA under the Block Contract, as specified in the Minimum DSI Operating Reserve – Supplemental section of BPA's 2010 General Rate Schedule Provisions, and Exhibit F of the Block Contract.

m. Transmission

Snohomish (ALC090151 at 2) commented that it is not possible to estimate how the cost BPA might incur if BPA provides power to Alcoa at a Scheduling Point of Receipt that is different from Alcoa's Primary Point of Receipt might affect BPA's Equivalent Benefits analysis. These are costs that would be incurred as result of a request by BPA to change a point of receipt and to allow BPA to make power available to Alcoa at a point other than Alcoa's Primary Point of Receipt. This is a right that provides additional BPA flexibility to make power available to its customers. While operational decisions by BPA to maintain reliability and the efficiency of the Federal system are not a consideration of the Equivalent Benefits analysis, all customers will actually benefit from such improved reliability and efficiency.

n. BPA has the option of conducting additional public review

WPAG commented that section 4.4 of the Block Contract appears to commit BPA, without additional public process, to confer with Alcoa in the event that the Ninth Circuit issues an opinion that modifies or eliminates the Equivalent Benefits standard in order to determine how to proceed based on the Court's ruling. WPAG at 5. BPA did not mean to imply, in agreeing to confer with Alcoa regarding an order that modifies *PNGC I* and *PNGC II*, that it would not seek input from a broader set of interests if that were the case. Language has been added to section 4.4 of the Block Contract to make that clear. However, such a change in law would have immediate implications for the Block Contract. Thus, it makes sense, from an contract administration standpoint, to provide specifically for consultation between the two contracts signatories at that juncture.

[17] SUB commented that Alcoa is not providing reserves under curtailment situations and that the $0.80 per MWh reserve credit should be added back in when determining the take-or-pay amount. After considering this comment BPA decided to add the credit back into the calculation under those circumstances and changed the contract language accordingly.

V. THE EQUIVALENT BENEFITS TEST

As indicated above, a key element of BPA's response to *PNGC II* was to implement an Equivalent Benefits Test to determine whether BPA should offer a contract for the sale of power to Alcoa which is not contingent on future events. First, BPA determined that its need to acquire power to serve the Alcoa load during the Initial Period was limited because BPA anticipates serving the Alcoa load from inventory under most water conditions. Second, BPA determined that it could offer service for a period of approximately 17 months, during which term the forecasted benefits of the sale equal or exceed any forecast costs.

Some comments objected to serving the DSIs from inventory. Canby at 1, and 6-7. Others object to the use of the test. INCU at 2-4. Yet others object to the manner in which the test was conducted. For example, SUB contends that the gas forecast is out of date and that BPA's test "failed to address risk". SUB at 4-5. Moreover, Snohomish asserts that BPA's comparison should be to the forward market and not a forecast of future prices. Snohomish at 2. The following sections describe the elements of the Equivalent Benefits Test, detail the analysis conducted, and address the concerns expressed by the parties.

a. BPA is unlikely to incur costs from serving Alcoa during the Initial Period

BPA does not forecast the need to make purchases specifically to serve Alcoa during the Initial Period under the Block Contract under most water conditions, although, as explained below, BPA has forecast the need to make some purchases, including some normal "balancing" purchases, to meet its total load obligations over the FY 2010 through FY 2011 rate period, under critical (*i.e.*, very poor) water conditions.[18] Some comments questioned BPA's ability to provide power under the Block Contract without making additional market acquisitions. Specifically, Snohomish indicates that BPA's "…forecast of winter deficits raises the question whether the DSIs can be served from existing FBS inventory or whether balancing purchases and additional augmentation will be required from the market." (Snohomish at 2) In addition, Canby asserts that "BPA's 'Equivalent Benefits' test is faulty because BPA assumes the augmented federal power system is in surplus and has sufficient inventory (460 aMW) to supply Alcoa and CFAC in every month of the year under 1937 'critical water' conditions." Canby at 2. See also ICNU at 2; PNGC at 2; and Snohomish at 2-3.

Pursuant to BPA's most recent load and resources study contained in the 2009 Pacific Northwest Loads and Resources Study ("2009 White Book"), which forecasts loads and resources for both the Federal system and the region as a whole for the 10-year period OY

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[18] Balancing purchases are market purchases that BPA makes either before or within a particular month in order to balance its forecast load and resource position within that month. Whether BPA makes any balancing purchases, and in what amounts, is dependent, among other things, on updated water flow forecasts which inform the amount of hydroelectric generation that can be expected in the month, and on within-month weather conditions impacting BPA customer load levels.

2010-2019,[19] BPA is forecast to have a surplus of approximately 1,731 aMW and 1,526 aMW on an average annual basis under the middle 80 percent of the historical water conditions for the OY 2010 and OY 2011 respectively. The Initial Period of the Block Contract includes just over 9-months in FY 2010 and just under 8-months in FY 2011. See 2009 White Book, Table 8 at 40, and Exhibits 11-12 at 104-107. Alcoa's load under the Block Contract represents approximately 20 percent of that forecast surplus. Moreover, the 2009 White Book reflects a surplus of 102 MW and deficit of 170 MW on an average annual based under 1937-Critical Water Conditions in OY 2010 and OY 2011, and does so assuming no augmentation and no service to the aluminum smelter DSIs.[20]

In the recently completed WP-10 Wholesale Power and Transmission Rate Adjustment Proceeding (WP-10) BPA forecast surplus available for secondary sales of 1,694 aMW for FY 2010 and 1,751 aMW for FY 2011 (which together encompass the Initial Period of the Block Contract for which the Equivalent Benefits Test is employed). See Table 4.8.1: Secondary Sales, WP-10-FS-BPA-05A, at 88. The WP-10 rate proceeding also forecasts that BPA will be in load resource balance under 1937-Critical Water Conditions, as is explained in more detail below. Canby's assertion that the Equivalent Benefits test is faulty because, even though the "augmented federal system is in surplus" and "has sufficient inventory… under *1937* 'critical water' conditions", BPA is still short of power five months of the year in critical water conditions, is incorrect.

BPA has not claimed that the Equivalent Benefits Test is based on 1937-Critical Water Conditions. To the contrary, BPA has based the Equivalent Benefits Test, which is used solely to satisfy BPA's conservative interpretation of *PNGC II*, on its forecasts of average water in the 2009 White Book and the WP-10 Loads & Resources Study. Nonetheless, BPA has set a portion of its rates for FY 2010 and FY2011 based on 1937-Critical Water Conditions as evidenced by Tables 2.3.1 and 2.3.2, WP-10-FS-BPA-01A at 10-13. However, another portion of BPA's rates, notably the Secondary Sales and Purchases, for FY2010 and FY2011 were set based on average water, specifically using the 1,694 aMW for FY 2010 and 1,751 aMW for FY 2011 referenced above, as evidenced by Tables 4.6.2, 4.8.1 and 4.8.2, WP-10-FS-BPA-05A at 77, 88-89.

BPA's forecast under average water in WP-10 takes into account certain market purchases, shown here, that BPA forecasts it may make, or has made, in order to meet its load obligations under critical (or very poor) water conditions in FY 2010 and FY 2011 (see Tables 4.8.2, 4.8.3, 4.8.4, WP-10-FS-BPA-05A, at 89-91):

	FY2010	FY2011
Balancing Purchases	193 aMW	149 aMW
Winter Hedging Purchases	~80 aMW	~80 aMW
Augmentation Power Purchases	476 aMW	680 aMW

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[19] Operating Year (OY) in the White Book is the 12-month period August 1 through July 31. For example, OY 2010 is August 1, 2009, through July 31, 2010.

[20] 2009 White Book, page 40.

Even after adjusting out these purchases, BPA expects on an annual basis to be surplus under average water conditions, and as such does not anticipate the need to alter its purchasing strategy for the sales made to Alcoa. This does not precluded the fact that BPA may have to occasionally make short term purchases during certain times of the year, should below average water conditions occur and, in such instances, Alcoa's load could add to the amount BPA needs to purchase. *See also*, Loads and Resources Data Used in the Equivalent Benefits Test, Part V, section (e) of this Record of Decision below.

BPA attempted to summarize its expectation with a handout entitled *Table A-30: Federal Surplus/Deficit – By Water Year* during a meeting with Public Power interests on November 3rd.[21] Some commenters, like Canby at 5-6, may have concluded from the title alone that this so-called "Table A-30" was part of the WP-10 Loads & Resource Study. It is not. BPA neglected to properly title its handout. Nonetheless, the information contained in the handout is an accurate composite of materials included in the WP-10 rate proceeding and can be constructed easily by applying the energy analysis of the federal system load resource balance contained in the WP-10 Loads & Resource Study, Tables 2.3.1 and 2.3.2 (WP-10-BPA-01A at 10-13) to the federal hydro generation from the Risk Analysis and Mitigation Study Documentation, Tables 3 and 4 (WP-10-BPA-04B at 23-26).[22] At the bottom of the last page pertaining to each fiscal year in the handout entitled *Table A-30: Federal Surplus/Deficit – By Water Year*, BPA subtracted 402 aMW, representing the average annual megawatt amount of augmentation purchases that equally offsets the line entitled "DSI PSC 2002" under Non-Utility Obligations section of the table, from the surplus under the ranked average middle 80-percent water condition to demonstrate that BPA expected to be surplus even after removing augmentation for DSIs. This too illustrates that even after adjusting out the average annual megawatt amount of augmentation associated with DSI service, BPA expects to be surplus under average water conditions.

In any case, the WP-10 Loads & Resources Study includes 403 aMW for service to the DSIs, including at least 285 aMW of service to Alcoa (see Table 4.6.2, WP-10-FS-BPA-05A, at 77), and so BPA has already factored such sales into the above referenced table of possible FY 2010 and FY 2011 purchases.[23] In addition, total DSI load over the term

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[21] The handout can be found under the link entitled "Federal Surplus/Deficit – By Water Year (11/4/2009)" on BPA's website: http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/#SDSI.

[22] Exhibits similar to the composite result of information from the WP-10 rate proceeding used in the handout are also included in the 2009 White Book at 104-107. Those exhibits are presented in the same manner as the handout *Table A-30: Federal Surplus/Deficit – By Water Year*. While the assumptions used in the 2009 White Book are somewhat different than the WP-10 Loads & Resources Study as explained above, and in more detail therein, the presentation format is materially the same and BPA's conclusion also remains the same in that it expects to be surplus under average water conditions, and as such does not anticipate the need to alter its purchasing strategy for the sales made to Alcoa.

[23] It should be noted that Table 4.6.2: Summary of Revenues at Proposed Rates (WP-10-FS-BPA-05A at 77) does reflect 403 aMW of DSI service, while Tables 2.3.1 and 2.3.2: Loads and Resources: Federal System (WP-10-FS-BPA-01A at 10-13) reflect 402 aMW of DSI service.

of the Block Contract may well be less than this 403 aMW amount because another DSI, Columbia Falls Aluminum Company (CFAC) is currently shutdown, making market purchases in addition to those referenced above less likely.[24]

As introduced above, Snohomish suggests that BPA's rationale for the Winter Hedging Purchases included in the table above "…raises the question whether the DSIs can be served from existing FBS inventory or whether balancing purchases and additional augmentation will be required from the market." Snohomish at 2. Snohomish is correct that BPA's rationale for these Winter Hedging Purchases was "increasing amounts of forecast HLH energy deficits during winter months under many water conditions." (WP-10-E-BPA-34 at 2) BPA continues to believe that the Winter Hedging Purchases are a prudent hedge. As a result, BPA is able to cost-effectively meet the load obligations of our customers, including Alcoa, under more adverse water conditions during HLH in the winter months. That said, BPA does not preclude actually making balancing purchases or augmentation purchases to serve customers' load obligations, including Alcoa, that were projected to be necessary under 1937-Critical Water Conditions used in WP-10. BPA simply expects that the actual need for such purchases to serve all of its customers, including Alcoa, is limited due to the surplus inventory we expect to have under most water conditions. See Tables 4.6.2, 4.8.1 and 4.8.2, WP-10-FS-BPA-05A at 77, 88-89 and Tables 3 and 4, WP-10-BPA-04B at 23-26.

NRU commented regarding Slice/Non-Slice cost shifts. ALC090151 at 1. To the extent BPA's most recent forecast used in the Equivalent Benefits Test is correct and the net cost of DSI service is well below the $38 million average annual that is already in rates (including the rates for both non-Slice and Slice purchasers), the benefits from such reduced costs would accrue solely to non-Slice purchasers. The Slice rate includes the $38 million average annual cost and there is no provision to alter that number through the annual Slice True-Up Adjustment Charge. Thus, no purchased power cost savings will flow to Slice customers.[25]

In addition, Snohomish commented that "…BPA assumed 30-minute persistence forecasting for wind. This persistence level uses the least amount of balancing reserves from the FBS to follow wind." It is true that both the 2009 White Book and the WP-10 Loads & Resource Study – and the materials cited from them herein – use regulated

[24] *Columbia Falls Aluminum Ceases Operations*, Flathead Beacon, October 31, 2009.

[25] NRU requests a determination that the Alcoa contract would not result in a cost shift between non-Slice and Slice purchasers. BPA cannot give NRU any assurance that there will be no cost shifts between non-Slice and Slice purchasers. In the WP-10 rate proceeding, issues regarding the risks inherent in assuming service to DSIs in the ratesetting process were raised by a number of parties. In response, BPA proposed an automatic rate adjustment mechanism that would have adjusted rates, including rates for both non-Slice and Slice purchasers, to account for changes in purchase power costs and IP rate levels. This proposal was forcefully opposed by a large number of BPA's preference customers. As a result, BPA declined to adopt a rate adjustment mechanism to account for DSI service costs. See WP-10 ROD, WP-10-A-02 at 225-226. Because any purchase power costs for DSI service, if any are incurred, would be included in either augmentation expense or balancing purchase expense, BPA has no ability to pass these cost changes to Slice purchasers through the annual Slice True-Up Adjustment Charge. Therefore, any changes in BPA's costs and revenues resulting from service to DSIs would fall solely on non-Slice purchasers.

hydro generation projections that reflect operating reserve levels associated with 30-minute wind persistence scheduling accuracy forecasts.[26] However, Snohomish goes on to assert that "…the FY10-11 rate case adopted both the 30- and 45-minute persistence forecasts" and that "[i]f the region is not successful in using 30-minute persistence to forecast wind generation, additional balancing reserves from the FBS would be required, reducing the amount of energy available from inventory." Snohomish at 3. BPA does not expect this to be the case given operating protocols BPA has put in place to adjust wind fleet operations to enable BPA to keep reserves at a level based on a 30 minute persistence forecast. BPA set its rates in WP-10 based on 30-minute persistence and operates its system to the same level of reserves.[27] Furthermore, BPA continues to believe the region will be successful in using 30-minute persistence to forecast wind generation and that additional balancing reserves from the FBS are not likely to be required. Thus, BPA does not anticipate the need to make specific additional purchases to serve the Alcoa load under average water conditions. Nevertheless, if any additional purchases become necessary, the average market price during the Initial Period of the Block Contract, as explained below, is expected to be at a level where the benefits of serving Alcoa equal or exceed the cost of buying the power.

b. Benefits to BPA will equal or exceed costs for the Initial Period of the Block Contract.

For the reasons outlined in this section, BPA forecasts that the revenues it will accrue from the sale to Alcoa of 285 aMW or power, (which pursuant to a request by Alcoa under the Block Contract will increase to 320 aMW effective by March 2010), at the IP rate during the Initial Period, will exceed by approximately $10,000 the forecast revenues BPA could otherwise obtain from selling that power into the market for the Initial Period. See Tables 1-6 below. As a consequence, BPA believes service to Alcoa under the Block Contract is consistent *PNGC II*, that service to a DSI only can be provided if benefits equal or exceed costs.

BPA's projected monthly revenues are determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rates for each month. BPA has calculated revenues under the Block Contract based on an initial sale of 285 aMW, increasing to 320 aMW in March 2010 as outlined in Table 1, of firm power each hour to Alcoa under the IP-10 rate schedule beginning December 22, 2009, the commencement of Firm Power deliveries pursuant to the Block Contract, and ending on May 26, 2011.[28] The energy entitlements are the

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[26] See 2009 White Book, at 23 and WP-10-FS-BPA-05A, at 77.

[27] "Accordingly, BPA will set the rate based on 30-minute persistence and will operate its system to the same level of reserves. BPA will also post the amount of reserves it is carrying on a regular basis to provide transparency to those who are worried BPA will offer a low rate but carry a higher amount of reserves." WP-10-A-02 at P-5.

[28] Prior to receiving Alcoa's letter requesting an increase to 320 aMW reflected in the monthly Demand (kW) in Table 1 above, BPA completed a substantially similar analysis of equivalent benefits based on a flat sale of 285 aMW commencing December 22, 2009 and ending on May 31, 2011. That analysis, included as Attachment F to this Record of Decision, forecasted that the revenues accruing to BPA from

projected amounts of megawatt-hours to be sold by diurnal period each month. The demand entitlement is the megawatt amount consumed during the hour of BPA's system peak. Since the Block Contract sells the same number of megawatts in every hour of the month, the demand entitlement is the monthly megawatt amount specified in Table 1. BPA's projected monthly revenues are then accumulated and the result is illustrated in Tables 1 and 2:

TABLE 1 - Usage and Rates

Month	Alcoa Ferndale Usage			IP-10 Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Dec-09	285,000	118,560	93,480	$2.30	$35.24	$31.13
Jan-10	300,000	120,000	103,200	$1.96	$38.46	$32.24
Feb-10	315,000	120,960	90,720	$1.99	$37.72	$31.73
Mar-10	320,000	138,240	99,520	$1.85	$35.94	$30.08
Apr-10	320,000	133,120	97,280	$1.74	$32.23	$26.95
May-10	320,000	128,000	110,080	$1.44	$31.69	$22.29
Jun-10	320,000	133,120	97,280	$1.32	$31.18	$23.29
Jul-10	320,000	133,120	104,960	$1.61	$33.33	$28.66
Aug-10	320,000	133,120	104,960	$1.89	$37.31	$31.40
Sep-10	320,000	128,000	102,400	$1.96	$36.49	$32.26
Oct-10	320,000	133,120	104,960	$2.05	$31.92	$27.01
Nov-10	320,000	128,000	102,720	$2.19	$33.33	$29.58
Dec-10	320,000	133,120	104,960	$2.30	$35.24	$31.13
Jan-11	320,000	128,000	110,080	$1.96	$38.46	$32.24
Feb-11	320,000	122,880	92,160	$1.99	$37.72	$31.73
Mar-11	320,000	138,240	99,520	$1.85	$35.94	$30.08
Apr-11	320,000	133,120	97,280	$1.74	$32.23	$26.95
May-11	320,000	128,000	110,080	$1.44	$31.69	$22.29
Jun-11	320,000	133,120	97,280	$1.32	$31.18	$23.29

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the sale of 285 aMW to Alcoa at the IP rate would exceed by approximately $151,000 the forecast revenues BPA could otherwise obtain from selling that power into the market.

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Dec-09	$655,500	$4,178,054	$2,910,032	$7,743,587	$7,743,587
Jan-10	$588,000	$4,615,200	$3,327,168	$8,530,368	$16,273,955
Feb-10	$626,850	$4,562,611	$2,878,546	$8,068,007	$24,341,962
Mar-10	$592,000	$4,968,346	$2,993,562	$8,553,907	$32,895,869
Apr-10	$556,800	$4,290,458	$2,621,696	$7,468,954	$40,364,822
May-10	$460,800	$4,056,320	$2,453,683	$6,970,803	$47,335,626
Jun-10	$422,400	$4,150,682	$2,265,651	$6,838,733	$54,174,358
Jul-10	$515,200	$4,436,890	$3,008,154	$7,960,243	$62,134,602
Aug-10	$604,800	$4,966,707	$3,295,744	$8,867,251	$71,001,853
Sep-10	$627,200	$4,670,720	$3,303,424	$8,601,344	$79,603,197
Oct-10	$656,000	$4,249,190	$2,834,970	$7,740,160	$87,343,357
Nov-10	$700,800	$4,266,240	$3,038,458	$8,005,498	$95,348,854
Dec-10	$736,000	$4,691,149	$3,267,405	$8,694,554	$104,043,408
Jan-11	$627,200	$4,922,880	$3,548,979	$9,099,059	$113,142,467
Feb-11	$636,800	$4,635,034	$2,924,237	$8,196,070	$121,338,538
Mar-11	$592,000	$4,968,346	$2,993,562	$8,553,907	$129,892,445
Apr-11	$556,800	$4,290,458	$2,621,696	$7,468,954	$137,361,398
May-11	$460,800	$4,056,320	$2,453,683	$6,970,803	$144,332,202
Jun-11	$422,400	$4,150,682	$2,265,651	$6,838,733	$151,170,934

c. Comparison of net revenues under the Block Contract to forecast revenues that might be obtained by selling an equivalent amount of power on the market.

BPA routinely shapes its inventory to meet the need of its portfolio of contracts and sells its surplus inventory by purchasing and selling in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[29] BPA established its forecast of Mid-C electricity prices in the WP-10 rate proceeding to value these purchases and sales.[30] For the period covered by the Block Contract BPA has updated its natural gas forecast from that used in BPA's WP-10 rate proceeding to forecast electricity prices to reflect a more contemporary understanding of natural gas fundamentals and to be consistent with the natural gas forecast used in *Summary of BPA's Analysis of the Block Contract for Port Townsend* and BPA's draft Resource Program released September 30th.[31]

[29] Refer to section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding for a more complete description of the operating risk factors BPA faces in the course of doing business – in particular "the variation in hydro generation due to the variation in the volume of water supply from one year to the next…" which significantly impacts market prices, our need for shaping purchases and our ability to make surplus sales. (see WP-10-FS-BPA-04 beginning on page 21)

[30] BPA employs its electricity price forecast for multiple purposes in the WP-10 rate proceeding as outlined in the *Market Price Forecast Study*. The study also details how BPA established its forecast of Mid-C electricity prices in the WP-10 rate proceeding. (See WP-10-FS-BPA-03, beginning on page 1.)

[31] BPA's natural gas forecast used in the WP-10 rate proceeding is outlined in section 3.3 of the Market Price Forecast Study. (See WP-10-FS-BPA-03, beginning on page 11.) BPA's more contemporary

In the absence of the Block Contract initially selling 285 aMW of firm power to Alcoa's Intalco Plant every hour, and subsequently increasing that amount to 320 aMW, BPA would have one less firm power requirement sale in its aggregated portfolio load shape to meet; as such BPA would have at least 285 aMW of surplus energy to sell in the market. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market using the same forecasting methodology applied in the WP-10 rate proceeding to incorporate our updated forecast of natural gas prices in the development of our electricity price forecast used in this analysis of the Block Contract for Alcoa.[32]

TABLE 3 - BPA's Forecasted Revenues Obtained from the Market

Month	Forecasted Market		Forecasted Revenues Obtained from the Market			
	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative ($)
Dec-09	$30.61	$27.41	$3,629,276	$2,562,520	$6,191,795	$6,191,795
Jan-10	$34.13	$29.51	$4,095,483	$3,045,278	$7,140,761	$13,332,556
Feb-10	$34.46	$29.77	$4,168,308	$2,700,699	$6,869,007	$20,201,563
Mar-10	$33.92	$29.16	$4,689,678	$2,901,972	$7,591,650	$27,793,213
Apr-10	$32.95	$28.05	$4,386,230	$2,729,010	$7,115,239	$34,908,452
May-10	$33.93	$24.45	$4,343,287	$2,691,520	$7,034,807	$41,943,259
Jun-10	$34.33	$26.33	$4,569,908	$2,561,356	$7,131,264	$49,074,523
Jul-10	$37.33	$32.18	$4,969,150	$3,377,181	$8,346,331	$57,420,854
Aug-10	$42.48	$35.63	$5,654,607	$3,739,247	$9,393,854	$66,814,708
Sep-10	$42.86	$38.00	$5,485,936	$3,890,844	$9,376,780	$76,191,488
Oct-10	$43.31	$36.85	$5,765,479	$3,867,640	$9,633,119	$85,824,607
Nov-10	$45.36	$40.59	$5,806,297	$4,169,181	$9,975,478	$95,800,085
Dec-10	$48.81	$43.42	$6,497,553	$4,557,662	$11,055,215	$106,855,300
Jan-11	$50.70	$42.13	$6,489,767	$4,637,348	$11,127,115	$117,982,415
Feb-11	$50.78	$42.80	$6,240,232	$3,944,303	$10,184,535	$128,166,950
Mar-11	$49.33	$40.83	$6,819,456	$4,063,290	$10,882,746	$139,049,696
Apr-11	$46.35	$38.79	$6,169,651	$3,773,488	$9,943,140	$148,992,836
May-11	$47.15	$32.65	$6,035,240	$3,594,350	$9,629,590	$158,622,426
Jun-11	$46.50	$33.58	$6,190,070	$3,267,141	$9,457,211	$168,079,637

Net Benefit (IP – Market)

understanding of natural gas market fundamentals caused a lowering of its natural gas price forecast in 2010 and an increase in 2011. The primary reasons for BPA's recent reductions became apparent in the progression of time since the natural gas price forecast for the WP-10 rate proceeding was constructed; these are: a) continued strength of natural gas production despite steep reductions in rig counts, b) continued slow recovery of natural gas demand – particularly on the industrial side, c) record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2009 hurricane season is nearly over. (See also Short-term Energy Outlooks from the EIA for September and October that have reduced their forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMbtu using EIA's conversion of 1 Mcf = 1.031 MMbtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, page 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, p. 3.)

[32] DSI load is assumed to include the total market load used to forecast the revenues obtained from the market at this stage. Please refer to the section on Demand Shift for how a shift in demand can affect BPA's surplus sales revenues.

BPA determined its net benefit of serving Alcoa's Intalco Plant at the IP rate for each month by subtracting the opportunity cost forecast to be obtained in the market detailed in Table 3 from the projected IP revenues described in Table 2. BPA's net benefit before adjustments is illustrated in Table 4:

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative ($)
Dec-09	$1,551,791	$1,551,791
Jan-10	$1,389,607	$2,941,399
Feb-10	$1,199,000	$4,140,399
Mar-10	$962,257	$5,102,656
Apr-10	$353,715	$5,456,370
May-10	($64,003)	$5,392,367
Jun-10	($292,532)	$5,099,835
Jul-10	($386,088)	$4,713,747
Aug-10	($526,603)	$4,187,145
Sep-10	($775,436)	$3,411,709
Oct-10	($1,892,959)	$1,518,750
Nov-10	($1,969,981)	($451,230)
Dec-10	($2,360,661)	($2,811,892)
Jan-11	($2,028,056)	($4,839,947)
Feb-11	($1,988,465)	($6,828,412)
Mar-11	($2,328,839)	($9,157,251)
Apr-11	($2,474,186)	($11,631,437)
May-11	($2,658,787)	($14,290,224)
Jun-11	($2,618,478)	($16,908,702)

d. Calculation of the net financial value of tangible benefits of selling power to Alcoa as opposed to selling an equivalent amount of power on the market.

BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power compared to a sale to Alcoa under the Block Contract at the IP rate. BPA conducted an economic analysis to determine the value of those benefits and included them in its analysis of the net value of the Block Contract to BPA. There were other, less tangible benefits accruing to BPA but assigning a financial value to those would have been more subjective, and based on the analysis below, doing so was unnecessary.

Value of Reserves

The Block Contract requires that Alcoa make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value to BPA of the reserves Alcoa is required to make available to BPA under the Block Contract. Sales at the IP rate reflect the value of a right for BPA to obtain contingency reserves.[33] Specifically, the energy rate tables in the IP-10 rate schedule include an $0.80 per MWh credit for the value of these reserves. Therefore, BPA's net benefit above compares a surplus power sale to a sale of power at the IP rate with reserves. We have adjusted for this by adding back a value of reserves that provides an equal and opposite offset to the $0.80 per MWh credit for the value of reserves in the IP-10 rate schedule.[34] As illustrated by Table 5a, this is done for every megawatt hour not sold to Alcoa:

TABLE 5a - BPA's Net Benefit Adjustments
Value of Reserves

Month	Month ($)	Cumulative ($)
Dec-09	$169,632	$169,632
Jan-10	$178,560	$348,192
Feb-10	$169,344	$517,536
Mar-10	$190,208	$707,744
Apr-10	$184,320	$892,064
May-10	$190,464	$1,082,528
Jun-10	$184,320	$1,266,848
Jul-10	$190,464	$1,457,312
Aug-10	$190,464	$1,647,776
Sep-10	$184,320	$1,832,096
Oct-10	$190,464	$2,022,560
Nov-10	$184,576	$2,207,136
Dec-10	$190,464	$2,397,600
Jan-11	$190,464	$2,588,064
Feb-11	$172,032	$2,760,096
Mar-11	$190,208	$2,950,304
Apr-11	$184,320	$3,134,624
May-11	$190,464	$3,325,088
Jun-11	$184,320	$3,509,408

Avoided Transmission and Ancillary Services Expenses

When BPA makes a DSI sale, the DSI customers – including Alcoa – cover the cost of transmission and ancillary services through their own transmission contracts. Market prices, on the other hand, assume power is delivered by the seller to Mid-Columbia trading hub (Mid-C). Power Services (PS) is the organization within BPA that is responsible for the management and sale of Federal power. PS must pay the transmission and ancillary services costs to move surplus power to the Mid-C delivery point in order to realize the full market value for its surplus sales. PS maintains an inventory of

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[33] Sales at the IP rate require the provision of the DSI Minimum Operating Reserve – Supplemental. The Block Contract is an IP sale and, accordingly, it requires that Alcoa make such a contingency reserve available to BPA, as defined in section 2.19 and implemented by section 10.1 and Exhibit F to the Block Contract.

[34] In other words, BPA has increased the IP rate by the value of reserves credit for purposes of this analysis so that the comparison to a surplus sale into the market is on an "apples to apples" basis.

transmission products and services to deliver the surplus power it intends to sell. However, this inventory is not sufficient to deliver all of the surplus power PS would sell under all load and resource conditions, especially under high stream flows. As a result, there is a subset of load and resource conditions under which PS would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales, if PS did not sign contracts to serve the DSI loads -– including the Block Contract with Alcoa. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding.[35] Since PS overall marketing strategy is to serve all its loads out of inventory and meet any power deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

PS valued these avoided transmission and ancillary services costs using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS' inventory of transmission products and services. In these computations, both fixed, take-or-pay costs and variable incremental transmission and ancillary service costs were computed under 3,500 load and resource conditions for each month. Incremental transmission and ancillary services costs were computed by comparing the amount of surplus energy available to the monthly excess amount of firm transmission products in the PS inventory. Tariff costs established by BPA's Transmission Services organization were applied to the amount of surplus energy in excess of the PS transmission products inventory. Total monthly transmission and ancillary services costs were computed assuming no service to the DSI and DSI service of 372 aMW.[36] The average total monthly expense values of the 3,500 games were computed with and without service to the DSI and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 372 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Alcoa has been allotted 76.6% of this PS benefit in each month as illustrated in Table 5b below. This percent allotment is the result of the proportion of the megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 372 aMW forecasted for all DSI customers.

[35] Refer to section 4 of the *Revenue Requirement Study*, WP-10-FS-BPA-02 and section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding.

[36]This number is comprised on 285 aMW for Alcoa, 70 aMW for Columbia Falls Aluminum Company, and 17 aMW for Port Townsend Paper Company.

TABLE 5b - BPA's Net Benefit Adjustments
Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative ($)
Dec-09	$149,883	$114,829	$114,829
Jan-10	$411,830	$332,121	$446,950
Feb-10	$323,594	$274,011	$720,961
Mar-10	$427,273	$367,546	$1,088,507
Apr-10	$546,922	$470,470	$1,558,978
May-10	$797,099	$685,676	$2,244,654
Jun-10	$706,870	$608,060	$2,852,714
Jul-10	$568,866	$489,347	$3,342,061
Aug-10	$127,860	$109,987	$3,452,049
Sep-10	$44,322	$38,126	$3,490,175
Oct-10	$39,191	$33,713	$3,523,888
Nov-10	$73,161	$62,935	$3,586,823
Dec-10	$150,605	$129,552	$3,716,375
Jan-11	$417,282	$358,952	$4,075,328
Feb-11	$318,185	$273,707	$4,349,035
Mar-11	$412,095	$354,490	$4,703,525
Apr-11	$492,378	$423,551	$5,127,077
May-11	$765,645	$658,619	$5,785,696
Jun-11	$669,032	$575,511	$6,361,207

Demand Shift

When BPA serves the DSI loads – including Alcoa – and they operate – as opposed to not operating if BPA does not sell to them – all of BPA's surplus sales realize increased revenues because the mean value of prices for electricity in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets. BPA has forecasted these increased revenues by reducing loads in the PNW by 372 aMW in each month for each of the 3,500 games AURORA simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of $0.29 per MWh and by $0.41 per MWh for fiscal years 2010 and 2011 respectively.[37] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from the WP-10 rate proceeding to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Alcoa. For the purposes of this analysis, Alcoa has been allotted 76.6% of this benefit to BPA in each month as illustrated in Table 5c below. This percent allotment is the result of the proportion of the megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 372 aMW forecasted for all DSI customers.

[37] AURORA is an electric energy market model that is owned and licensed by EPIS, Incorporated. The model assumes a competitive market pricing structure as the fundamental mechanism underlying how it estimates the wholesale electric energy market prices during the term of an analysis. In a competitive market, at any given time, electric energy market prices should be based on the marginal cost of production, which is the variable cost of the last generating unit needed to meet energy demand.

TABLE 5c - BPA's Net Benefit Adjustments

Month	Demand Shift Month ($)	Proportional Month ($)	Cumulative ($)
Dec-09	$39,719	$30,430	$30,430
Jan-10	$146,279	$117,967	$148,397
Feb-10	$181,585	$153,762	$302,159
Mar-10	$279,051	$240,044	$542,203
Apr-10	$428,356	$368,479	$910,682
May-10	$1,347,534	$1,159,169	$2,069,850
Jun-10	$900,404	$774,541	$2,844,392
Jul-10	$519,495	$446,878	$3,291,269
Aug-10	$32,901	$28,302	$3,319,571
Sep-10	($25,231)	($21,704)	$3,297,867
Oct-10	$1,755	$1,510	$3,299,377
Nov-10	($29,249)	($25,160)	$3,274,217
Dec-10	$38,606	$33,210	$3,307,427
Jan-11	$453,911	$390,461	$3,697,888
Feb-11	$295,680	$254,348	$3,952,236
Mar-11	$651,012	$560,010	$4,512,246
Apr-11	$619,527	$532,927	$5,045,173
May-11	$1,548,290	$1,331,862	$6,377,035
Jun-11	$1,222,884	$1,051,943	$7,428,978

Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA recovers from the 17-month IP sale to Alcoa (from December 22, 2009 through May 26, 2011) exceed by approximately $10,000 the forecasted revenues that BPA would otherwise obtain from the market. See Table 6 below. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's rate case. That process includes discovery, testimony, rebuttal testimony, and cross examination prior to a final determination by the Administrator. Further, the analysis is marked by thorough and thoughtful consideration of market fundamentals and other factors that insure the integrity of the results. BPA believes that it a reasonable assessment and that the concerns expressed in the comments have been fully considered and fairly evaluated.

TABLE 6 - BPA's Net Benefit after Adjustments

Month	Net Revenue or (Cost) (A) Month ($)	Value of Reserves (B) Month ($)	Avoided Tx Costs (C) Month ($)	Demand Shift (D) Month ($)	A + B + C + D Month ($)	Cumulative ($)
	BPA's Adjusted Net Revenue or (Cost)					
Dec-09	$1,551,791	$169,632	$114,829	$30,430	$602,156	$602,156
Jan-10	$1,389,607	$178,560	$332,121	$117,967	$2,018,255	$2,620,411
Feb-10	$1,199,000	$169,344	$274,011	$153,762	$1,796,116	$4,416,527
Mar-10	$962,257	$190,208	$367,546	$240,044	$1,760,056	$6,176,583
Apr-10	$353,715	$184,320	$470,470	$368,479	$1,376,983	$7,553,566
May-10	($64,003)	$190,464	$685,676	$1,159,169	$1,971,305	$9,524,872
Jun-10	($292,532)	$184,320	$608,060	$774,541	$1,274,390	$10,799,262
Jul-10	($386,088)	$190,464	$489,347	$446,878	$740,601	$11,539,863
Aug-10	($526,603)	$190,464	$109,987	$28,302	($197,849)	$11,342,014
Sep-10	($775,436)	$184,320	$38,126	($21,704)	($574,693)	$10,767,320
Oct-10	($1,892,959)	$190,464	$33,713	$1,510	($1,667,272)	$9,100,048
Nov-10	($1,969,981)	$184,576	$62,935	($25,160)	($1,747,630)	$7,352,418
Dec-10	($2,360,661)	$190,464	$129,552	$33,210	($2,007,435)	$5,344,983
Jan-11	($2,028,056)	$190,464	$358,952	$390,461	($1,088,178)	$4,256,805
Feb-11	($1,988,465)	$172,032	$273,707	$254,348	($1,288,377)	$2,968,428
Mar-11	($2,328,839)	$190,208	$354,490	$560,010	($1,224,130)	$1,744,297
Apr-11	($2,474,186)	$184,320	$423,551	$532,927	($1,333,388)	$410,909
May-11	($2,658,787)	$190,464	$658,619	$1,331,862	($400,770)	$10,139
Jun-11	($2,618,478)	$184,320	$575,511	$1,051,943	($806,703)	($796,565)

e. Commenter's Issues with the Equivalent Benefits Test

A number of comments questioned whether the market price forecast BPA is using to measure the cost (or benefit) of the Block Contract is too low, thereby underestimating potential costs, in the event BPA would need to make market purchases to support the sales to Alcoa, or the lost opportunity cost associated with selling to Alcoa in lieu of selling that power into what they believe will be a higher priced market (relative to the IP rate). See PPC at 1-2; Canby at 1-2; NRU at 1; PNGC at 2; SUB at 2-6; Snohomish at 2. Some comments suggested that BPA's surplus determination was flawed, and that in developing its market forecast BPA should have relied on forward price curves that guide commodities prices on a short term basis. See e.g., PPC at 4. Others questioned whether BPA's gas price forecast was too low. See e.g., ICNU at 2; Snohomish at 2; and SUB 2-6. A number of parties questioned BPA's loads and resources assumptions, and whether BPA would, in fact, need to make market purchases to support sales to Alcoa under the Block Contract. See e.g., Snohomish at 2-3; Canby at 2.

These issues are addressed below.

1. Loads and Resources Data Used in the Equivalent Benefits Test

Some comments questioned BPA's ability to provide power under the Block Contract without making additional market acquisitions and others suggested that the Equivalent Benefits Test is "faulty" because BPA is not surplus at critical water. See Snohomish at 2-3; Canby at 2. ICNU stated that BPA should demonstrate that it is surplus in each month it intends to sell power to the DSIs before moving forward with any new contract. ICNU at 2.

The following discussion reviews the approach BPA used to establish the loads and resources used in the Equivalent Benefits Test, and demonstrates that they are appropriate to the use of the Equivalent Benefits Test, which is solely to satisfy BPA's conservative interpretation of *PNGC II*.

The FY 2010-2016 net inventory (resources minus loads) values used for the demand shift and avoided transmission and ancillary services expenses analyses were based on using 3,500 simulated load and resource conditions for each month. Deterministic (opposed to probabilistic) data used in these analyses were based on loads and resources data produced at the time of the WP-10 Final Rate Proposal. Variable loads and resources data were derived via running a set of risk simulation models, collectively referred to as RiskSim. Variable net inventory values were computed by the RevSim Model. Both the RevSim and RiskSim models used in this analysis were used in the 2010 Wholesale Power Rate Final Proposal (see Risk Analysis and Mitigation Study and Documentation, WP-10-FS-BPA-04 and 04A).

Two sets of net inventory values reflecting no service to the DSI and DSI service totaling 372 aMW per FY were computed. Results from these two sets of net inventory numbers are identical except for the level of service to the DSI. Net inventory results from these computations reflect PS intent to serve the DSI load out of its energy inventory and meet any power deficits with short-term power purchases.[38] The demand shift analysis and the avoided transmission and ancillary services expenses analysis each encompass the two sets of inventory values.

The demand shift analysis evaluates the value of the price benefit achieved by PS's surplus energy sales when BPA serves the DSI load out of inventory. This price benefit accrues to PS's surplus energy sales because the DSI would not be expected to continue to operate in the absence of a long-term contract with BPA, resulting in lower PNW loads and consequently, lower prices for PS's surplus sales. As such, the demand shift analysis multiplies the prices resulting from the two different PNW loads by the inventory values reflecting DSI service totaling 372 aMW.

The transmission and ancillary services expense analysis evaluates the expense PS avoids when PS purchases fewer transmission and ancillary services. PS avoids these expenses when serving the DSI load out of inventory because the DSI provide their own transmission and ancillary services and our reduced surplus energy sales exceed our portfolio of firm transmission less often. As such, the transmission and ancillary services expenses analysis multiplies the tariff rates for transmission and ancillary services by both sets of inventory values and the expenses avoided are the differences between the two results.

Prior to adjustments that are discussed in this section, the deterministic FY 2010-11 loads and resources data input into the RevSim Model for this analysis are shown in Tables 1-2 (see Attachment B). These are the same data reported in the WP-10 Loads and Resources

[38] BPA owns the output of all energy produced by CGS, which produces approximately 1,150 aMW. CGS is owned and operated by Energy Northwest.

Study, which reflect loads and resources under the current Subscription contracts. See Loads and Resources Study Documentation, WP-10-FS-BPA-01A, pages 10-13. Also, prior to adjustments that are discussed in this section, the deterministic FY 2012-16 loads and resources data input into the RevSim Model for this analysis are shown in Tables 3-7 (see Attachment B). These FY 2012-2016 loads and resources data reflect the forecast under Regional Dialogue contracts and the Tiered Rates Methodology (TRM).

The FY 2010-11 loads and resources data reported in Tables 1-2 (Loads and Resources Study) were modified to reflect serving the planned CGS outage in FY 2011 from monthly inventory, the addition of the Winter Hedging contracts, removing all augmentation purchases, and replacing the DSI load of 402 aMW with two different levels of DSI service (0 and 372 aMW). The energy values associated with the Winter Hedging contracts were added to the data in Tables 1-2, since these energy values are not included in the data from the Loads and Resources Study for reasons discussed in Bliven et al., WP-10-E-BPA-34, pages 2-4. It was assumed in these analyses that all DSI load, to the extent there was any, would be served from inventory.

The loads and resources data reported in Tables 3-7 (see Attachment C) were modified in a similar manner such that, prior to adjusting for the Winter Hedging contracts and serving the planned CGS outages in FY 2013 and FY 2015 from monthly inventory, the PS inventory associated with only serving Tier 1 load under the TRM is in load and resource balance under critical water when there is no service to the DSI. It was assumed in this analysis that, on a forecast basis, there would be no firm energy surpluses or deficits associated with Tier 1 load. The basis for this assumption is that any firm surplus energy would be absorbed via the high water mark (HWM) allocations for Tier 1 power and all load growth (Tier 2 load) would be served by Tier 2 resources.

Given these deterministic FY 2012-16 loads and resources data, the RiskSim models used in the WP-10 rate filing were expanded to simulate risk data through FY 2016 for use in RevSim. The FY 2010-16 surplus and deficit energy values computed in RevSim for the 3,500 monthly games formed the basis for the net inventory values used in both the demand shift analysis and the avoided transmission and ancillary services expense analysis. The demand shift analysis used both the surplus and deficits energy values to account for the impact of surplus energy sales and balancing power purchases in the computations. The avoided transmission and ancillary services expense analysis only used the surplus energy values. This is because PS must pay the transmission and ancillary services expenses to move its surplus energy to the Mid-C delivery point to realize the full market value for its surplus energy sales. In contrast, when power purchases are made to meet energy deficits, the seller is responsible for paying the transmission and ancillary services needed to deliver the power to the BPA transmission system. Once the power is delivered to the BPA transmission system, the requirements or DSI customer has already purchased sufficient transmission and ancillary services to serve its load so there is no additional transmission and ancillary services acquisition expenses to either, BPA, the requirements customer, or the DSI.

2. Forward Price Curve

A number of comments questioned whether BPA's market price forecast is accurate, including in light of certain forward market prices around the time comments were submitted, which they believe indicate that market power prices during the term of the Block Contract will be significantly higher than BPA is forecasting. See, PPC at 1-2; Canby at 1-2; NRU at 1; PNGC at 2; SUB at 3-7; Snohomish at 1-3; ICNU at 3. Some suggested that, rather than develop a market forecast through rate case modeling tools and assessment of market fundamentals, BPA should instead rely more heavily on forward prices curves used in the real time short term markets. PPC asserts that forward prices for power were substantially above what BPA's model predicted they would be in the next few months, and concludes that BPA's reliance on its model is unreasonable without considering actual prices available in the current market. PPC at 6. See also ICNU at 3 (agrees with PPC BPA's calculation of the forecasted net revenues from a market sale of the power is too low).

Likewise, many of these same comments question whether BPA should be basing its revenue analysis of the Block Contract on a market price forecast at all, and suggest instead that BPA should be using, or at a minimum that its forecast is failing to adequately take into account, current forward market prices, which reflect higher prices than contained in BPA's forecast, and which they apparently believe are a better indicator of actual future prices. PPC at 2; Canby at 1; PNGC at 2; SUB at 4. Some of the public customers expressly reiterated the position they have taken elsewhere that the Ninth Circuit's opinion in *PNGC II* requires that BPA demonstrate that its revenues from an IP sale would be expected to be greater than a sale at market, or articulate a similar position. PPC at 1-2 (recent decisions require BPA to demonstrate service to DSI will result in financial benefit to BPA); PNGC at 2 (joining PPC's comments); SUB at 8 (Block Contract benefits only Alcoa and not region "as a whole"); Canby at 2 (BPA must "make money or break even"); NRU at 1 (Block Contract attempts to meet *PNGC II* by demonstrating positive net revenues compared to a market sale).

BPA will respond to the comments above, but reemphasizes that a sale of firm power pursuant to section 5(d) of the Northwest Power Act is not a sale of surplus power that can be sold at market prices. The IP rate is not a market rate, but instead is a cost based rate established pursuant to the directives of section 7(c) of the Act. Further, for the period over which BPA's current firm power rates apply, BPA has already credited those rates with projected secondary sales. *See* Table 4.8.1, WP-10-FS-BPA-05A at 88. Clearly, the market price forecast is an important component in BPA's forecast of expected net revenues under the Block Contract, serving to measure both the cost associated with purchases, if any, required to serve the Alcoa load, or the lost opportunity cost, if any, of selling the power earmarked for sale to Alcoa into the market instead. However, BPA does not agree with the view expressed in a number of comments that current forward market prices are a better indicator of average market prices over the 17-month term of the Block Contract than BPA's market price forecast given BPA does not normally sell or buy forward 17-month strips of power, but rather manages its inventory closer to the actual delivery month. In simplest terms, "forward market prices" are actual prices agreed to between a buyer and seller on any given day for power to be delivered at some time in the future, and therefore represent the price at which two parties are willing to transact *that day* for future delivery; but the market price on that future date of delivery may (and almost certainly will be) either higher or lower. For example, Snohomish commented it received a forward price quote of $59.25 on October 15, 2009, for delivery beginning October 1, 2010, of heavy load hour energy at the Mid-Columbia trading hub. See Snohomish comments in PTP090010 at 2 and Attachment A thereto. By contrast, a "forecast" of market prices seeks to determine what the actual market price will be on a given day (or hour) over a certain future period. Using the preceding example, a market price forecast would project the likely actual market price for delivery of heavy load hour energy at the Mid-Columbia trading hub on October 1, 2010, based on market fundamentals.

While forward market prices reflect the view – at least of those parties entering into forward market contracts – of a fair market price *that day* for power delivered on a future date, forward markets for electricity are increasingly susceptible to the episodic variability and volatility common in commodity markets. This phenomenon is borne out in later electricity forward market prices which dropped substantially from the mid-October forward market prices cited by Snohomish in its earlier comments. In the short passage of time, just three weeks from October 15th to November 6th, the flat average of the forward prices observed by BPA for the 14-month power sale to Port Townsend fell from $46.78 per MWh to $40.30 per MWh and reduced the cost asserted by Snohomish by more than half.[39] Most recently, prices have rebounded to some extent which is attributable to recent cold weather. This contributes to why BPA believes individual forward market price observations can be a volatile indicator and, as a result, a poor tool to employ for longer-term public policy decisions.

As a general matter, while BPA agrees that the forward market is an important benchmark of near-term market prices, it only comes into play if one is willing to lock in a forward purchase or sale for the period quoted. BPA believes price forecasts, in general, more accurately gauge prices that BPA will actually experience over longer periods because BPA tends to manage its inventory on a shorter term basis. Therefore, in the context of a longer-term IP sale that BPA expects to serve out of its inventory, and for purposes of valuing a transaction such as a longer-term IP sale, BPA believes it is more appropriate to rely less on the hour-to-hour, and day-to-day price fluctuations quoted in the broker market for forward delivery, and rely more on its forecast of market prices over the term of the subject contract. This is consistent with how BPA expects to serve this load and is also consistent with BPA's methodology for forecasting secondary revenues used to establish rates. (See generally WP-10-FS-BPA-03 and WP-10-FS-BPA-04.)

In addition to comparing to forward market prices as suggested by PPC and others, BPA has considered the following comparison of the actual historical spot prices for the Mid-C with posted IP rates for FY 2009 and FY 2010. Figure 1 illustrates, by month, whether

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[39] Please refer to Attachment H for additional detail on forward prices observed by BPA and BPA's re-creation of the analysis submitted by Snohomish in Attachment A to its October 19, 2009 public comment.

the average of the actual daily spot prices for electricity at Mid-C in each month of calendar year 2009 were above or below the IP rates adopted for FY 2009 and FY 2010.

Figure 1

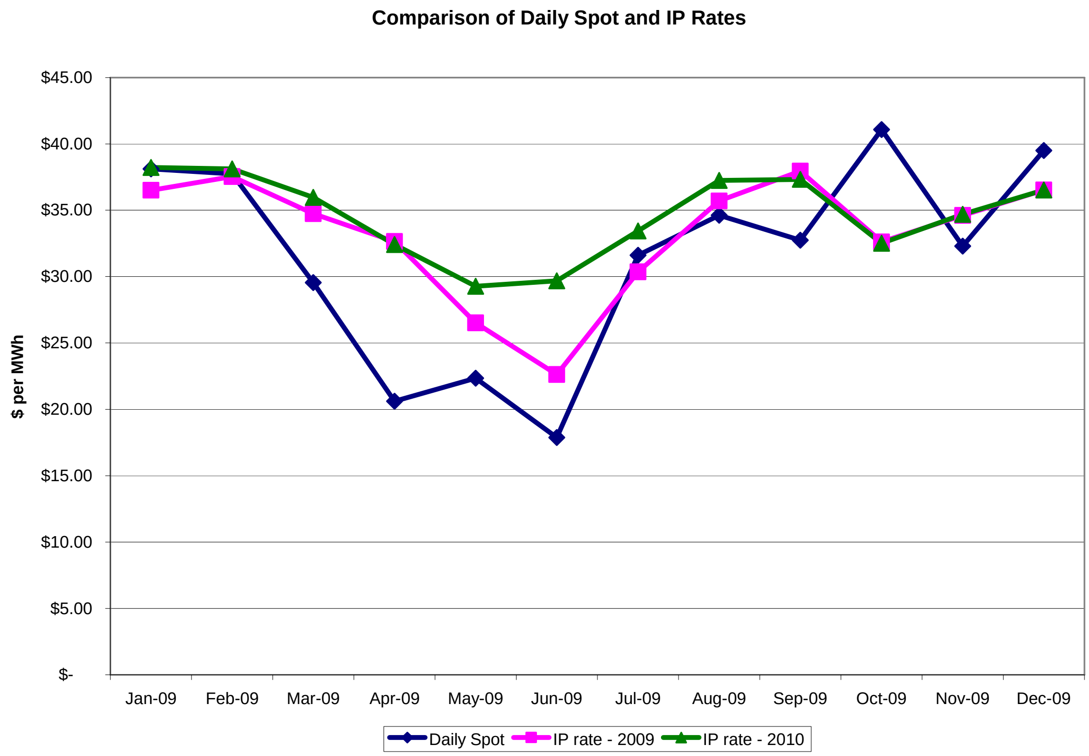

Figure 1 depicts that nine out of the twelve months of calendar year 2009, or seventy-five percent of the time, the monthly average of the daily spot prices was below the IP rate. This is important because BPA is forecasting the average of the daily spot prices at Mid-C, not forward market prices. As such, this demonstrates that it is consistent with recent history to expect that a forecast of the monthly average of the daily spot prices at Mid-C would be below the IP rate in some months. In Figure 2, BPA went on to sum the revenues that would have been received in calendar year 2009 from a 285 aMW sale to the market and a sale of the same amount at the IP rate.

Figure 2

Annual Comparison of Marketing Revenues and IP Revenues

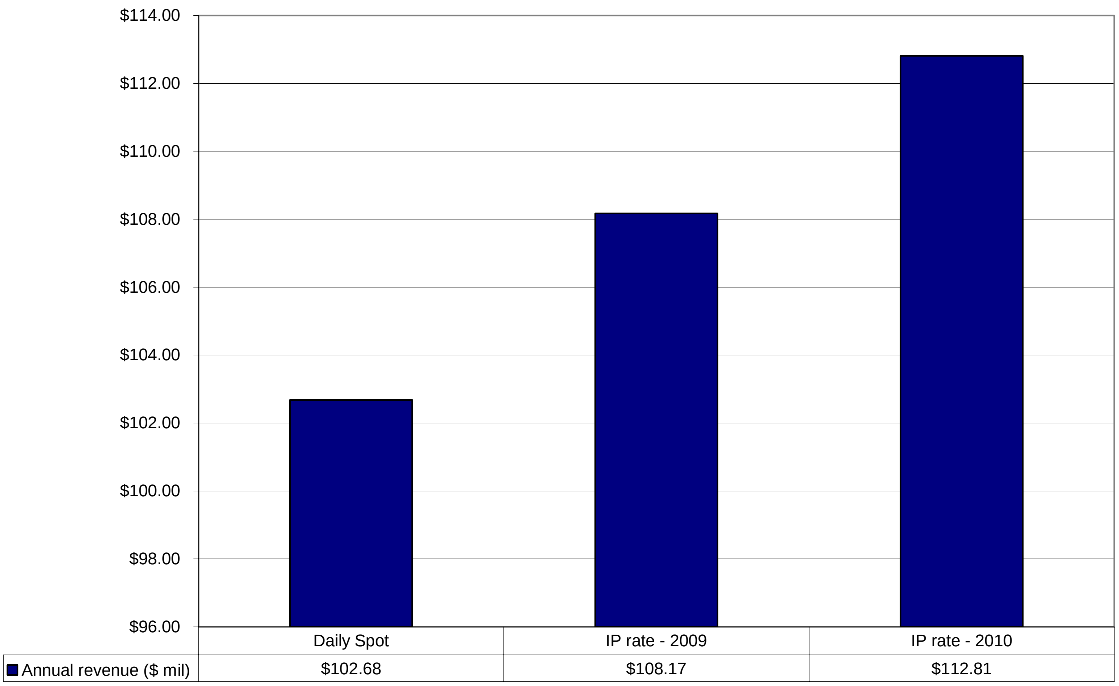

Figure 2 demonstrates that the revenues BPA would have received from the sale at the IP rate in calendar year 2009 would have exceeded by $10 million the revenues BPA would have received from a market sale of the same amount. This provides recent historical evidence to support BPA's expectation of positive net revenues in the Equivalent Benefits Test and illustrated in Table 4: BPA's Net Benefit Before Adjustment above. As such, BPA's market price forecast used in its evaluation of Equivalent Benefits *does not* "blindly adhere to the model's output," and *does not overlook* "important realities that BPA must consider if its decision is to be found in accordance with sound business principles." (PPC in ALC090150 at 6) Quite the contrary, BPA's evaluation reflects these important realities.

In BPA's view, the sale under the Block Contract meets its reading of the court's interpretation in *PNGC II* of "sound business principles" because BPA expects to accrue positive net revenues from the sale compared to its market forecast; in other words, BPA forecasts it will make more money on the transaction compared to selling the power into the short-term market. BPA does not believe either that this is a standard for discretionary sales to the DSIs required by statute, or that the court in *PNGC II* unequivocally held that this is the correct standard. However, if this is, in fact, the legally required standard, then it is met in this case.

However, some parties, including Snohomish and PPC, appear to argue that even this is not enough. These parties appear to take the position that BPA may not make a sale to a DSI at the IP rate even if such sale is forecast to result in positive net revenues compared to forecasted market revenues, if BPA could earn even greater revenues by selling the power into the current forward market. Snohomish at 1-2; PPC at 2.

First, as noted above, BPA does not typically sell its surplus into the forward markets this far in advance or for a term this long. Again, a forward sale means a sale consummated *that day* for delivery sometime in the future. By definition, and especially with respect to a hydro-based system, such sales contain some element of risk. This is because a forward surplus sale would be a firm commitment, and to the extent BPA forecasted surplus did not materialize, it would be required to purchase some or all of that power for delivery to the counterparty. The costs and risks of a BPA firm requirements sale – including the sale under the Block Contract at the IP sale – have been addressed in BPA's rate proceeding. In establishing its firm power rates BPA makes a load and resources forecast which covers its expected sales to regional customer loads – public, cooperative and federal agency customers, investor-owned utilities, and DSIs – and resource needs. In recent years BPA has moved away from making year-long forward sales of its surplus, instead making a majority of its surplus sales into the spot or short-term markets much closer to the time of delivery, when hydrological conditions, load shapes, and other factors impacting BPA's inventory are clearer.

Second, BPA does not believe there is any support, in either its enabling statutes or Ninth Circuit precedent, for the proposition that it may make an IP sale to a DSI customer only in the event there is no higher revenue alternative sale available. [40] These public customers' view appears to be based on the position that BPA is obligated by statute to maximize revenues through sales of surplus power in order to reduce preference customers' rates to the lowest possible levels. To the contrary, to the extent that BPA finds, consistent with Ninth Circuit case law, that serving DSI load benefits BPA's operations or otherwise promotes its other statutory mandates, then BPA may incur costs to serve DSI load, and allocate such costs to all its base rates, including its preference rates. See *Golden Northwest Aluminum, Inc., v BPA*, 501 F.3d 1037, 1043 (9th Cir. 2007).

It is also worth noting Alcoa has taken the position that BPA is obligated by the regional preference provisions in its enabling statutes to sell available surplus power to any DSI, at the IP rate, before such power can be sold out-of-region at market-based rates, and that *PNGC II* supports its position. See, *e.g.*, Alcoa comments dated August 3, 2009, regarding memorandum of understanding for long-term DSI service proposal, at 2; and Alcoa comments dated September 9, 2009, regarding draft seven-year power sales agreement, at 5 (Attachments D and E). While BPA disagrees with Alcoa's view of the scope of its regional preference right, and its reading of *PNGC II* with respect to that right, it is not unlikely that Alcoa – or perhaps another DSI - would seek to challenge an out-of-region long-term market priced surplus sale made in lieu of selling such power to it at the IP rate. The suggestion that BPA should simply sell into the current forward market the power it would otherwise sell to Alcoa under the Block Contract comes with its own set of litigation risks that would need to be evaluated in the context of putting a dollar value on such a transaction.

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[40] See also, *Aluminum Company of America v. BPA*, 903 F.2d 585 (9th Cir. 1990) (holding that BPA is not obligated to establish rates to maximize revenues).

Finally, ICNU and others commented that BPA's investor-owned utility customers (IOUs) recently filed market price forecasts as part of regulatory filings that show market prices much higher than those forecast by BPA. ICNU at 3; PPC at 2; SUB at 2-5; Snohomish at 1. The IOU forecasts were filed with the Oregon Public Utility Commission in June of 2009 and were probably prepared sometime before that date. A more recent forecast can reasonably be assumed to be more reliable for the purpose of projecting market prices for the 18 month initial period of this contract. Moreover, the filings were made as part of an avoided cost filing, whose purpose is to establish the minimum price that the utility must pay for "Qualifying Facilities" under PURPA. These filings are required to be submitted according to a methodology developed by the Commission for that purpose. From time to time, the methodology is reviewed and modified in a separate proceeding. However, the methodology itself is not reviewed as part of an avoided cost filing. Instead, the avoided cost filing is reviewed only to determine whether it conforms with the established methodology. In other words, there is no direct substantive review of the filing itself. In fact, ICNU and other parties to the relevant avoided cost proceedings sought to open the proceeding to a broader examination of the methodology itself, apparently based on their view that the methodology is flawed. However, the Commission ultimately left that examination to a separate proceeding. In the final analysis, due to the described circumstance, these IOU filings provide little basis for challenging BPA's forecast. See, Oregon Public Utility Commission, Docket No. 1442 and Docket No. 1443, which can be accessed through the Commission's website.

In sum, making a long-term forward surplus sale in lieu of selling 285 aMW to Alcoa, as advocated by some customers in comments, presents its own risks, is inconsistent with BPA's current surplus marketing program approach, and is not legally required, even if it may result in greater revenues compared to revenues under the Block Contract.

3. Gas Price Forecast

Several comments either challenged the gas forecast component of BPA's price forecast covering the period of the Block Contract, or asked BPA to provide additional detail regarding its gas price forecast. Comments submitted by SUB question the validity of the natural gas price forecast component of BPA's electricity market price forecast. SUB at 2-4. SUB believes that increases in gas market spot prices and gas futures prices at the time comments were submitted are evidence that BPA's current gas price forecast is too low, and that even using BPA's gas price forecast from the WP-10 rate case, "the net present value" of the Block Contract to BPA is a negative $1.8 million. ICNU felt that BPA's gas price forecast was understated based on the forecasts submitted in June of 2009 to the Oregon Public Utility Commission by investor owned utilities (discussed immediately above), which showed a market price forecast higher than BPA's.
BPA stands behind its own forecast.

As described below, BPA's forecast of natural gas prices is based on sound analytics and reflects a reasonable approach and methodology. The gas price forecast component of

BPA's electricity price forecast is important because natural gas price movements contribute to price movements in electric power markets in the Pacific Northwest, as a preponderance of the generating resources establishing marginal prices for electric power are fueled by natural gas. BPA's natural gas price forecast used in the WP-10 rate proceeding, the methodology for its development and its use as an input to BPA's electricity price forecasts, is outlined in section 3.3 of the Market Price Forecast Study (see WP-10-FS-BPA-03, beginning on p. 11). This natural gas price forecast was completed by BPA in May 2009, during BPA's fiscal third quarter.

To analyze the period covered by the Block Contract, BPA employed the most recent natural gas price forecast it had developed using the same methodology. This is an update to what BPA used in its WP-10 rate proceeding as an input to its forecast of electricity prices and is identical to the natural gas price forecast used in BPA's draft Resource Program released September 30, 2009. BPA's updated natural gas price forecast was completed at the end of July 2009, during BPA's fiscal fourth quarter. With the exception of the fiscal first quarter, BPA typically updates its natural gas and electricity price forecasts during each quarter to support financial reporting.

BPA's understanding of natural gas market fundamentals during the fiscal fourth quarter led BPA to lower its forecast of spot market natural gas prices at the Henry Hub in 2009-2010, and increase its forecast in 2011. BPA stated in the draft Resource Program:

> The effects of the economic recovery on short-term natural gas prices will be magnified by the cyclical nature of natural gas prices. An economic recession will first lower natural gas demand and therefore increase natural gas storage inventories. This will lower natural gas prices and lead to a decline in natural gas production. Typically, declines in natural gas production occur with declines in natural gas demand, but the production decline lags the decline in demand. The result is that when the economy and natural gas demand recovers, the recovery will occur during the downturn in natural gas production, and the natural gas price increase is magnified.

See draft *Resource Program*, Appendix B: Market Uncertainties, Bonneville Power Administration, September 30, 2009, at B-3, B-4).

BPA's fiscal fourth quarter natural gas price forecast also continues to reflect a more contemporary understanding of natural gas market fundamentals. The primary reasons for BPA's reductions in 2009-2010 remain apparent in the progression of time since the natural gas price forecast was constructed. These are: a) continued strength of natural gas production, despite steep reductions in rig counts, illustrates that BPA's statement in the draft Resource Program that "the production decline lags the decline in demand" remains apparent, b) continued slow recovery of natural gas demand – particularly on the industrial side – continues to reflect the lingering effects of "an economic recession that will first lower natural gas demand," and c) record amount of natural gas in storage continues to demonstrate the anticipated "increase in natural gas storage inventories" contemplated in the draft Resource Program.[41] Furthermore, with the majority of the hurricane season now over with no impacts on supply occurring, the reduction made in the fiscal fourth quarter natural gas price forecast appears to remain warranted.

BPA has also recently compared its latest forecasts of spot market natural gas prices at the Henry Hub to the forecasts produced by other forecasters in the industry. The comparison, shown in Figure 3 and 4 below, includes both a history of the Henry Hub spot prices – as opposed to the more frequently referenced NYMEX (now CME Group) forward market for Henry Hub natural gas prices – and other forecasters' views of the future. The forecasters, in alphabetical order, typically included in our comparisons are: Cambridge Energy Research Associates (CERA), the United States Department of Energy's Energy Information Administration (EIA), PIRA Energy Group, and Wood Mackenzie.[42] The historical observations reflect the monthly average of the daily spot market prices for natural gas at the Henry Hub quoted on the Intercontinental Exchange (ICE) for the months from July through October 2009.

[41] In addition, BPA has detailed, with contemporary information from the Energy Information Administration in Attachment H, ("Natural Gas Statistics"), the continued strength of natural gas production despite steep declines in rigs, the continued slow recovery of natural gas demand, and the record amount of natural gas in storage. See also Short-Term Energy Outlooks from the EIA for September and October showing EIA's lower forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMBtu using EIA's conversion of 1 Mcf = 1.031 MMBtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, at 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, at 3.

[42] With the exception of the EIA, each of these forecasters considers their information to be proprietary. The vintage of each forecast is late September to early October 2009. EIA forecast is from their *Short-Term Energy and Winter Fuels Outlook* released October 6, 2009.

Figure 3: Henry Hub Natural Gas Spot Price Forecasts (vintage September 2009)

Figure 3

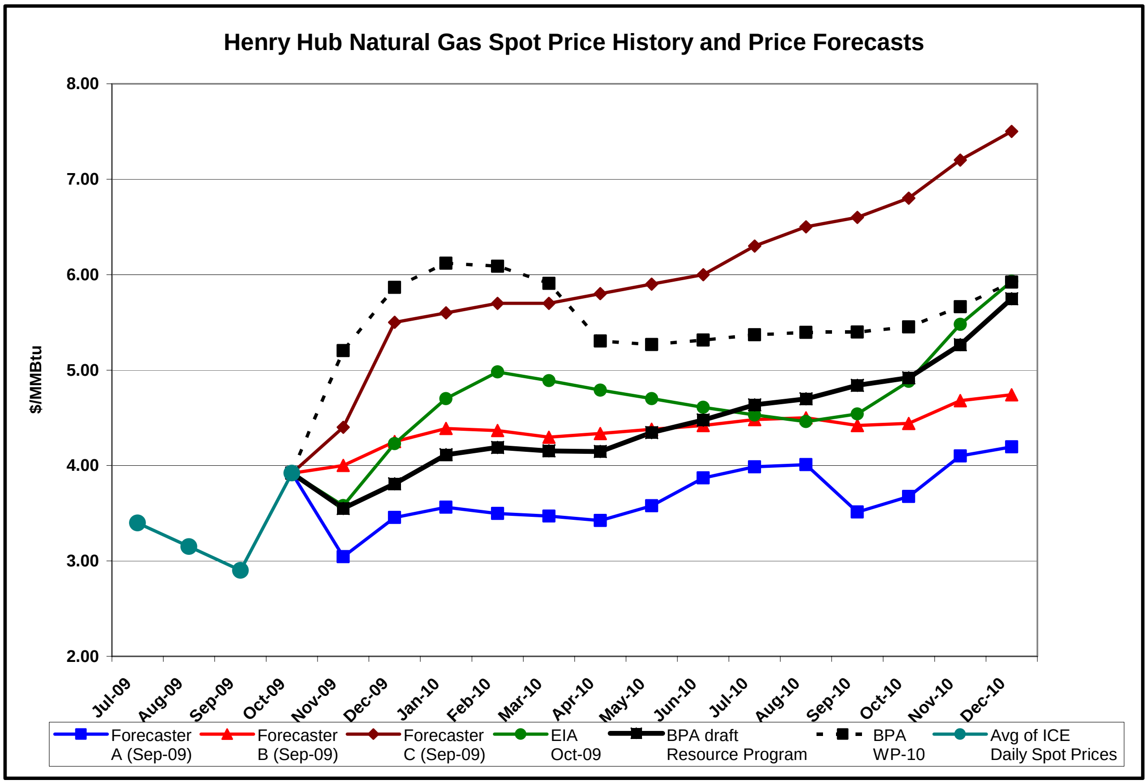
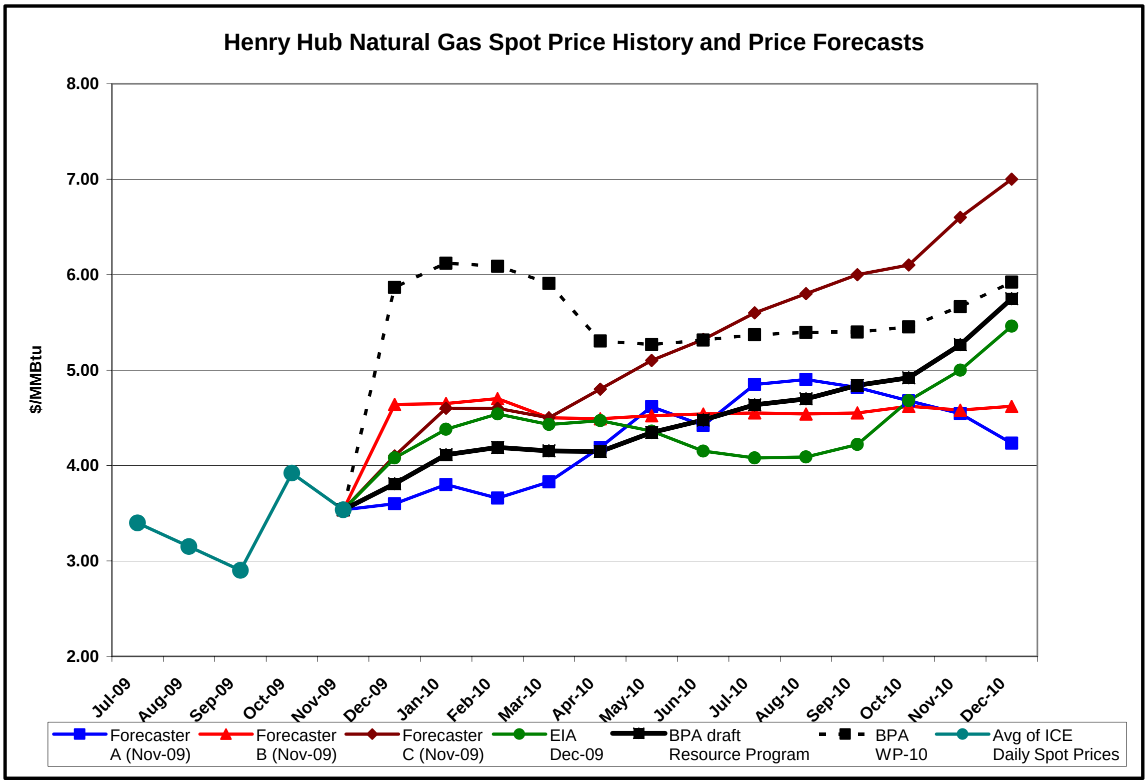


Figure 4: Henry Hub Natural Gas Spot Price Forecasts (vintage November 2009)

Figure 4

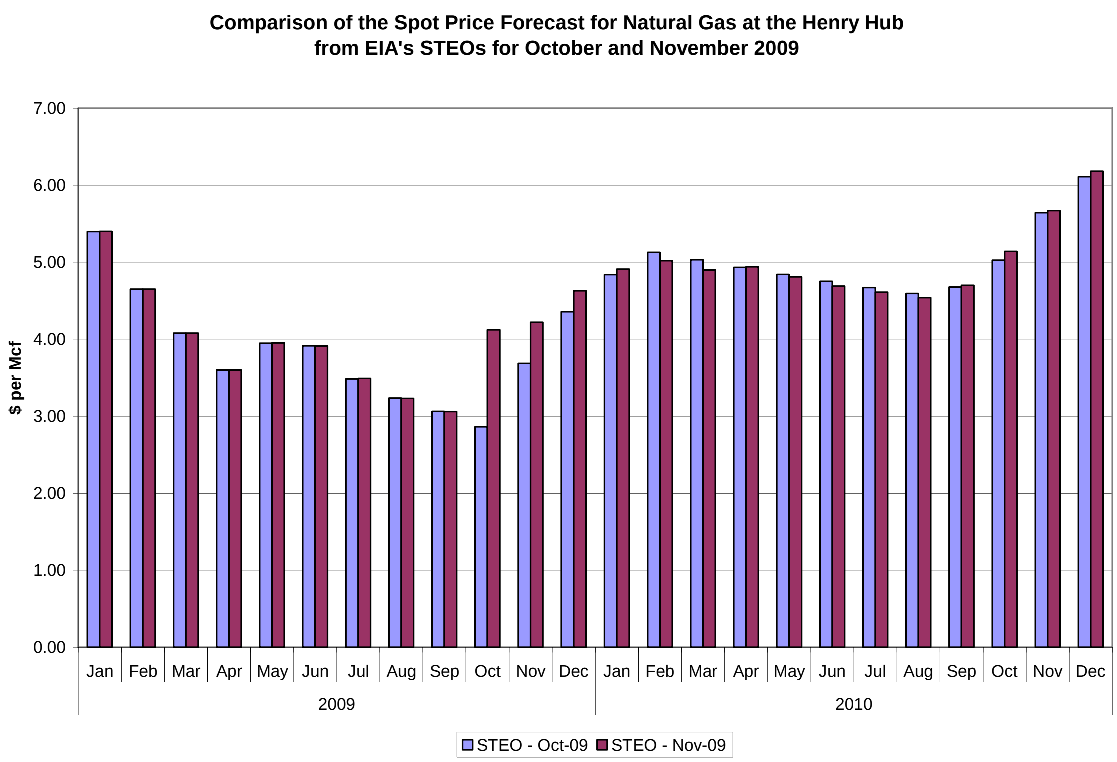


Figures 3 and 4 demonstrate that recent spot market prices for natural gas at the Henry Hub have been in the range of $3 to $4 per MMBtu from July to November 2009. These illustrations also demonstrate that the forecasts of three other industry experts were $4.25 per MMbtu and are now $4.10 per MMBtu or less for December 2009 – the starting month of BPA's equivalent benefits analysis – and both renditions of their forecasts remain lower than $5 per MMBtu through at least October 2010. BPA's updated forecast of spot price for natural gas at the Henry Hub is consistent with this view reflected by these three industry experts. Only one of the four forecasters expected spot prices for natural gas at the Henry Hub to rise above $5 per MMBtu during the winter of 2009-2010 in their September 2009 forecast and in their latest forecast from November 2009 they too expect spot prices for natural gas at the Henry Hub to remain below $5 per MMBtu during the winter of 2009-2010. As a result, BPA believes its updated gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts are expecting.

It is also important to note that BPA may conduct additional evaluation(s) of equivalent benefits in the future. For such future determinations, BPA intends to utilize inputs to the decision process that are as contemporaneous as can reasonably be applied. Such inputs may include updates to BPA's natural gas price forecast, hydroelectric generation forecast, or load forecast. BPA does not believe it would be reasonable to continue using WP-10 rate proceeding inputs when the agency has since updated those inputs.

Finally, SUB asserted in its comments that BPA "used a dated market forecast that does not reflect today's analysis" (SUB at 5) and selectively chose the forecast in BPA's September 2009 resource program as compared to its WP-07 forecast (SUB in PTP090001 at 4) in order to support "an unsound and incomplete forecast for Alcoa Paper…" (SUB in PTP090001 at 2). First, as elaborated above and included in Figure 4, BPA incorporated the EIA forecast from its October 2009 Short-Term Energy Outlook (STEO), which was released on October 6th, to conclude that its updated gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts are expecting – including EIA in its October 2009 forecast. This was the EIA's most current forecast of natural gas available at the time the analysis was produced and remained so when BPA's analysis was posted 7 days later on October 13th. Furthermore, BPA has reviewed the EIA's November 2009 STEO released on November 10, 2009, and EIA largely sustained the forecast of natural gas prices in their October 2009 STEO employed in Figure 4. As illustrated in Figure 5, EIA's most significant change to their forecast was made to the month of October 2009, increasing it from $2.86 per Mcf to $4.12 per Mcf, and their second most significant change was to November 2009, increasing it from $3.69 per Mcf to $4.22 per Mcf.

Figure 5: Comparison of Natural Gas Forecasts from EIA's STEOs



The entirety of October 2009 and 14 days in November 2009 are not within the term of the Block Contract and thus are not germane to BPA's analysis. Furthermore, the historical observations that BPA has incorporated reflect the monthly average of the daily spot market prices for natural gas at the Henry Hub quoted on the Intercontinental

Exchange (ICE) for the months from July *through October 2009*. BPA has not incorporated EIA's forecasted value for October 2009 as inferred by SUB.

Regarding the remaining months beginning with December 2009 and extending through December 2010, the EIA went on to say:

> Although [spot] prices [for natural gas at the Henry Hub] have more than doubled since reaching a low of $1.83 per Mcf on September 4, EIA expects any further price run-up to be limited through the remainder of the year. High storage levels and resilient domestic production are expected to keep prices around $5 per Mcf in the coming months, even as space-heating demand increases and economic conditions improve. Beyond the winter, limited demand growth constrains price increases through the forecast. The projected Henry Hub spot price averages $4.03 per Mcf in 2009 and $5.01 per Mcf in 2010.

Short-Term Energy Outlook – November 2009, at 6.

The effect of EIA's changes over the term of the Block Contract beginning November 15, 2009, and extending through December 31, 2010, increased their average forecast for the period from $4.92 per Mcf to $4.95 per Mcf, or a change of less than one percent (1%). As a result, BPA believes this sustains its earlier conclusion that BPA's updated natural gas price forecast is reasonable compared to a recent history of Henry Hub spot prices and compared to what other industry experts, including EIA, are expecting.

In summary, BPA has utilized the most recent forecast of Henry Hub natural gas spot prices that BPA has performed. BPA's updated natural gas price forecast also reflects a more contemporary understanding of natural gas market fundamentals than the WP-10 natural gas price forecast. Furthermore, BPA's updated natural gas price forecast is reasonable when compared with the recent history of spot market prices for natural gas at the Henry Hub and the natural gas price forecasts of other industry experts. Moreover, BPA has reviewed EIA's most current STEO and addressed the risk of prices deviating from expectations. Therefore, BPA believes the updates made to its forecast of Henry Hub natural gas spot prices and its use as an input to the Aurora model utilized in this analysis are reasonable.

4. Risks are Addressed in BPA's Equivalent Benefits Test

SUB and Canby each commented that BPA has inadequately addressed certain risks inherent in the sale to Alcoa, in particular the risk that market prices will trend significantly higher than BPA's forecast, including in the event a threatened drier than average water year materializes, leading to costs that have not been accounted for by BPA. SUB at 6-7; Canby at 2. Specifically, SUB asserts that BPA has "failed to address risk" and describes scenarios, mainly related to market prices and the availability of surplus on BPA's system, under which BPA may incur costs to serve Alcoa. SUB at 6-7). Similarly, PNGC argues that if market prices turn out to be higher than BPA is forecasting, which PNGC believes will be the case, then BPA is underestimating the cost to serve Alcoa under the Block Contract. PNGC at 2.

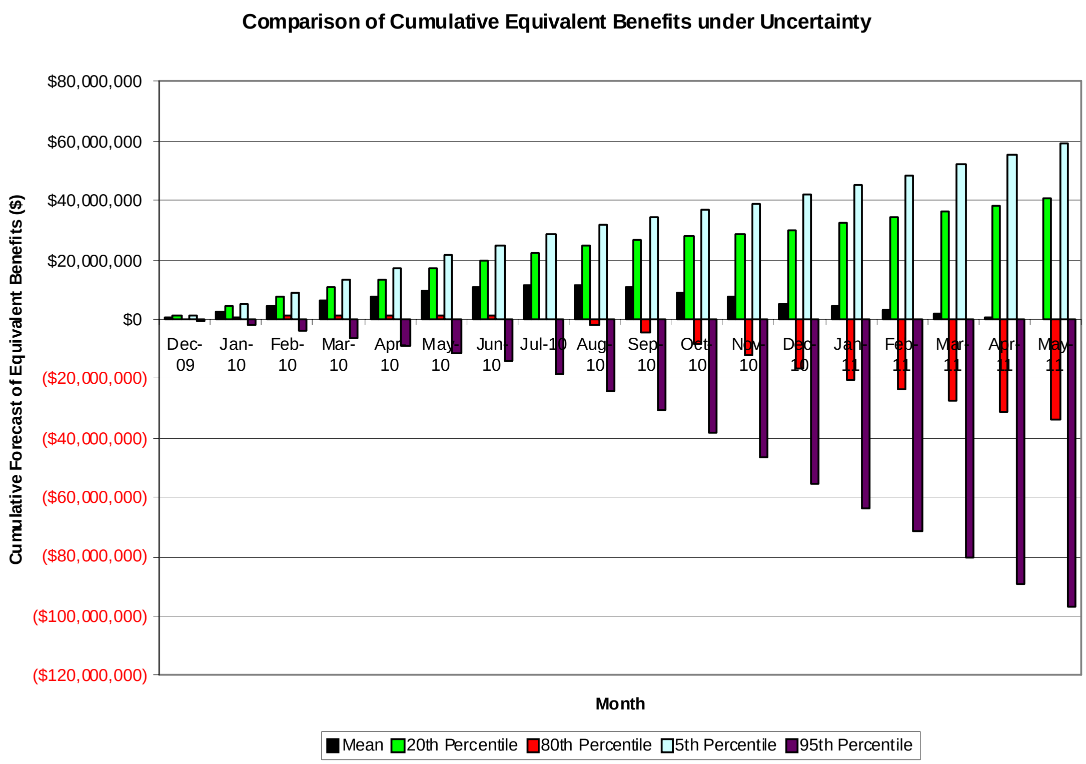
PPC's also argues that BPA is at risk that power prices could change from BPA's forecasts, and that if BPA's forecast is incorrect the costs of the transaction could easily turn out to outweigh any calculated benefits. PPC at 2.

In BPA's view, there are two primary elements of risk in this transaction. First, is the risk of market prices for electricity deviating from the prices forecast by BPA during the Initial Period. The second primary element of risk is the possibility of Alcoa curtailing. This is less of an issue during the Initial Period of the Block Contract because BPA anticipates serving Alcoa from the surplus energy inventory expected under most water conditions, as discussed above (see Loads and Resources section).

(i) Market Price Risk

BPA examined the Block Contract both in isolation and more broadly in consideration of BPA's other risk factors. In examining the Initial Period of the Block Contract and the effects on the Equivalent Benefits Test in isolation, BPA applied the full probability distribution of market prices associated with its market price forecast to arrive at the net benefits for specific percentiles in that distribution.

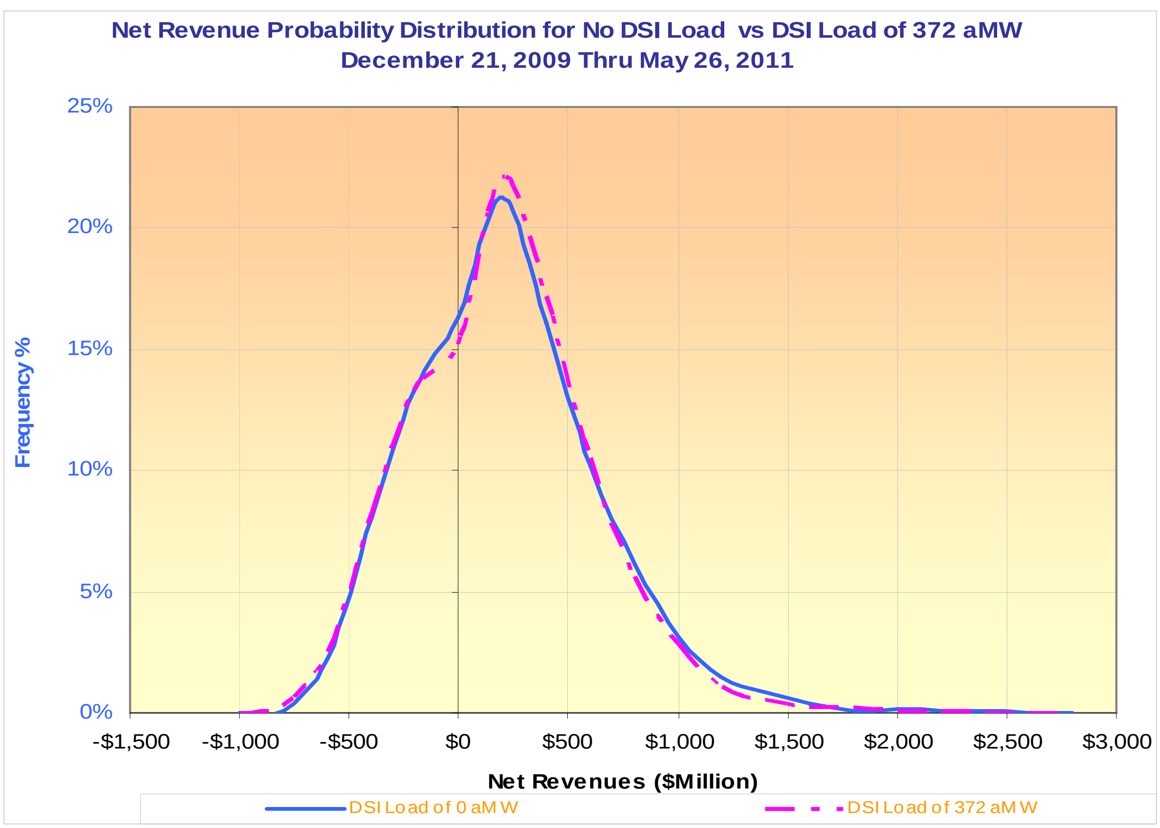
Figure 4: Comparison of Cumulative Equivalent Benefits under Uncertainty



If market prices for electricity are less than expected, BPA is better off financially serving Alcoa than selling this power on the wholesale electricity market. This is reflected in Figure 4 above for the 5th and 20th percentiles. Conversely, if market prices for electricity are higher than expected, the economics of the Equivalent Benefits deteriorate resulting in BPA being relatively worse off on this transaction alone. This is reflected in Figure 4 above for the 80th and 95th percentiles. These results in isolation, however, do not reflect the impact of this transaction on BPA's overall probability distribution of net revenues; which among other things, takes into account conditions in which a loss from the DSI sale under higher prices than forecast is associated with higher surplus energy revenues.

Regarding the financial risk that market prices deviate from the average of BPA's price forecast more broadly, and they will, BPA analyzed the probability distribution of its net revenue risk consistent with the methodology used in the WP-10 rate proceeding. *See* WP-10-FS-BPA-04 at 34 and WP-10-FS-BPA-04B at 82. The advantage of this broader approach is that considers the net revenue impacts to BPA in conjunction with all the other Operating and Non-Operating Risk Factors addressed in the WP-10 rate proceeding. *See generally* WP-10-FS-BPA-04. Our conclusion, as demonstrated in Graph 1 below, is that the probability distributions of BPA's net revenues, one of its broadest measures of financial impact, are not materially different whether it serves 372 aMW of DSI load or does not serve any DSI load during the Initial Period.

Graph 1



If there is a Second Period, it would be up to BPA to prudently manage any power purchases and address the financial risks it perceives for all of its load obligations, including Alcoa's Intalco Plant, in its future rate proceedings. All risk mitigation measures undertaken will be consistent with its then current Financial Risk Policy and the allocation of the cost and risks will be undertaken in future 7(i) proceeding(s).

(ii) Curtailment Risk

Regarding the risk of curtailment, the net revenue risk analyses above indicate that BPA financial risk exposure is not materially different depending on whether or not the DSI operate in the Initial Period. Furthermore, BPA does not expect Alcoa will curtail the Intalco Plant once at least 320 aMW of service is made available to it at the IP rate, which is provided in the Block Contract, because Alcoa requested an increase in firm power from 285 aMW to 320 aMW and Alcoa has consistently argued that a seven year contract is sufficient to "permit the Intalco [Plant] to survive through this difficult recession" and "will permit the Intalco smelter to survive." *See* Alcoa's December 15th letter requesting 320 aMW of firm power attached to this Record of Decision, Alcoa in DSL090057 at 5, and Alcoa in DCA090233 at 1. Conversely, if Alcoa did shut the Intalco plant down after signing the Block Contract, BPA does not expect, on a forecast basis, that this will have either a positive or negative impact on the Equivalent Benefits that BPA has determined above. This is because, as discussed in detail in the following subsection, the correlation between aluminum prices set on the international market and Pacific Northwest electricity prices set regionally was computed to be very weak (.0826), based on historical data from January of 1997 through October of 2009, and very inconsistent over different time-contiguous subsets over this period of time.

For the foregoing reasons, BPA believes it has adequately addressed the risks associated with the Block Contract. BPA has prudently accounted for actual costs and risks associated with DSI service in setting its rates and has determined that it can reasonably expect to achieve Equivalent Benefits from this transaction.

PPC also argues that the Block Contract is predicated on the assumption that BPA will incur a loss. PPC at 3. BPA does not believe that PPC's statement is accurate. BPA has determined that, for first seventeen months (the Initial Period) of its proposed term, the contract will provide benefits that equal or exceed the cost of providing service. That is not operating at a loss. Any additional service for the Second Period is contingent on application of whatever test the court ultimately requires. However, it is clear that the contingent period of the contract (i.e., the so-called Second Period), or any Transition Period, will only trigger upon BPA's finding that such service comports with both whatever analysis the court requires, as well satisfaction of the Cost Caps.

PPC also argues that BPA would not, in the ordinary course of business, enter into this transaction. PPC at 4. The basis for this conclusion by PPC is unclear. Dealing with the issue of providing service to DSI load has been part of the ordinary course of BPA's business for more than half a century. It does not follow that, simply because such service is now discretionary, it should be deemed, *ipso facto*, outside the ordinary course of BPA's business or mission. There is no indication, that in making DSI service discretionary, Congress was directing the Administrator to simply cast the DSIs aside and be done with them. To the contrary, by preserving a special rate for service (the section 7(c) rate), and requiring the continuing provision of reserves, Congress appears to have contemplated that BPA might well continue to serve DSI load in the ordinary course of business.

Moreover, PPC is comparing apples to oranges. PPC equates the business considerations regarding a DSI sale with those relevant to a market sale of surplus power. But that is not the case. As discussed earlier, DSI sales are not surplus sales. They are sales of industrial firm power. BPA does not apply the same principles to such a sale that it would normally apply to its surplus sales. One of the primary purposes of the Northwest Power Act is to assure the Pacific Northwest of an adequate, efficient, economical and reliable power supply. DSI customers have been, and are, an important part of the Northwest's economy, and as such are included in the purpose of the Northwest Power Act just noted. Similarly, Congress enacted the Regional Preference Act, 16.U.S.C. 837 *et seq*. "to guarantee electric consumers in the Pacific Northwest first call on" Federal hydropower, and in section 9(c) of the Northwest Power Act extended that protection to all BPA power, 16 U.S.C. 839f(c). Both an IP sale to a DSI and a surplus sale into the wholesale market are transactions that occur in the ordinary course of BPA's business, but each has its own unique characteristics and so the considerations relevant to each are not the same.

Nonetheless, PPC asserts that *PNGC II* requires BPA to compare DSI service to other options for disposing of the power, and that BPA should be evaluating any DSI sale to the other options available for disposing of that power, which in this case is a surplus sale into the wholesale market. PPC at 4.

BPA does not agree with PPC's interpretation of *PNGC II*, nor does it operate based on the "business procedures" that PPC would seek to impose. BPA's consideration of making a sale of industrial firm power at the IP rate is, for the Initial Period, whether the benefits of such a sale will equal of exceed the cost. In reaching that conclusion, BPA has considered potential lost opportunity costs based on the alternative of marketing the power as surplus into the real time markets, even though it is not clear that such an analysis is absolutely required. See discussion at section V. BPA has taken a cautious approach to its determination, based on its reading of the *PNGC II* opinion, even though BPA believes that less stringent approaches are at least arguable, even if not specifically articulated by the opinion. Moreover, PPC fails to recognize the inherent risks of under-recovery that could result from selling such power in the typically unpredictable real time markets, as opposed to locking in a revenue stream that BPA forecasts will result in positive net benefits. In short, *PNGC II* does not require the "comparative" analysis prescribed by PPC, but even if it did, BPA would still elect to provide service to Alcoa.

In addition, PPC's comment fails to recognize, in the first instance, that BPA is not a profit-making enterprise, but rather a government agency charged with balancing the interests of all regional consumers and maintaining the financial integrity of the agency.

BPA's primary responsibility is to meet its financial obligations and repay the Federal investment in the system over a reasonable period of time. In this instance, while an incomplete subset of BPA's analysis shows a potential lost opportunity cost of $17,000,000, it must be recognized that realization of such an amount through market sales is not guaranteed, but is subject to typical market risks. By contrast, the IP rate transaction with Alcoa guarantees a revenue stream that assures no significant adverse financial impacts will occur and the rates of BPA's customers will not be jeopardized. Additionally, BPA has identified and developed a value for tangible benefits derived by BPA through the transaction, which more than offset the lost opportunity costs.

For its part, WPAG characterizes the Block Contract as a subsidy by BPA to Alcoa. WPAG in DCA09 at 3. A subsidy would occur if BPA were selling the power at less than the IP rate, but that is not the case here. Given the specific rate protections afforded preference and DSI customers in the Northwest Power Act, there is no more basis to say DSI rates are subsidized than to say PF rates are subsidized. WPAG seems to suggest that BPA must attempt to maximize its "profits" for the financial benefit of preference customers by selling power on the market rather than selling to Alcoa at the IP rate. BPA has conducted extensive analysis regarding the merits of both scenarios, and has determined that there is less risk associated with a sale to Alcoa as opposed to accepting the inherent risks associated with the vagaries of the open commodities market. WPAG has provided no analysis that would cause BPA to believe it is unreasonable to provide service to Alcoa.

Further, in characterizing the transaction as a "subsidy," WPAG suggests that preference customers would have an entitlement to the proceeds of any secondary sales of surplus on the open market. However, surplus sales and their associated secondary revenues only occur once BPA's net requirement obligations are met. Section 5(f) of the Northwest Power Act is explicit that requirements sales come before surplus sales. 16 U.S.C. § 839c(f). As thoroughly discussed in a response by the Department of Energy's General Counsel to a Congressional inquiry, preference customers cannot legitimately claim an unreserved statutory entitlement to all surplus sales revenues.[43] Neither is the Administrator required to take the risk of making market sales, in lieu of generating revenues through the IP rate, a rate which generates significantly higher revenues per megawatt than the PF-preference rate. In short, the Administrator views service at the IP rate for the Initial Period of the contract as being consistent with recent Ninth Circuit opinion and his statutory mandates, such as to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply.

[43] See letter of David H. Hill, former DOE General Counsel, dated June 23, 2006, to Senator Maria Cantwell, entitled "Legal Authority for Administratively Pursuing the President's Budget Proposal That BPA Pre-pay Bonds When BPA's Annual Net Secondary Power Sales Revenues Exceed $500 Million.".

5. Examination of the Correlation between LME Aluminum Prices and Dow Jones Mid-Columbia Spot Prices

PPC commented that BPA's low forecasts for both aluminum and power prices may indicate there is "a correlation between a DSI's decision to curtail and a low market in which BPA would have to resell such power." PPC at 2.

Provided below is an analysis of the cross-correlation between two sets of contiguous historical price data over various durations in time. One of the sets of data is the three-month aluminum price at the London Metal Exchange and the other set of data is the price of electricity sold on the Dow Jones for the Mid-Columbia hub. To perform this analysis, BPA used historical price data from January of 1997 through October of 2009 and subdivided the data into one and a half, two, five, and seven year periods. The cross-correlation between the two sets of price data over the entire period is 0.0826, which is very weak and not materially different than zero. However, as reported in Tables 2-4 below, the cross correlations were found to vary dramatically depending on the time-contiguous subset of the period that is chosen.

By computing the cross correlations between LME aluminum prices and Dow Jones Mid-C electricity prices over different combinations of contiguous years and lengths of time, an evaluation can be made regarding how consistent or inconsistent are the correlations between these two sets of prices. By analyzing the historical record of price data, it can be observed that the correlation between these two sets of prices very much depends on which years are selected. This can be observed by comparing the very dramatic differences in the correlation values reported in Table 2 over eighteen month periods, which is the approximate length of the Initial Period of the Block Contract, and over two year periods.

Table 2: Two Year and Eighteen Month Correlations Between LME Aluminum Price and Dow Jones Mid-C Electricity Prices

Years	Two Year Correlation	Eighteen Month Correlation
1997 to 1998	-0.676	-0.004
1998 to 1999	0.190	-0.512
1999 to 2000	0.289	0.739
2000 to 2001	0.315	-0.135
2001 to 2002	0.889	0.890
2002 to 2003	0.450	0.182
2003 to 2004	0.355	0.018
2004 to 2005	0.728	0.267
2005 to 2006	-0.113	0.777
2006 to 2007	-0.236	-0.200
2007 to 2008	0.064	-0.574

2008 to 2009 [44]	0.675	0.194

Results reported in Table 3 for the five-year correlations and Table 4 for the seven-year correlations indicate that the correlations for these longer time periods are less variable than over two years periods, however, they are still very variable. Also, comparisons between the results in Tables 3 and 4 indicate that the impact of longer periods of time does not always reduce the observed spread in correlation values.

Table 3: Five Year Correlations Between LME Aluminum Price and Dow Jones Mid-C Electricity Prices

Years	Correlation
1997 to 2001	0.206
1998 to 2002	0.466
1999 to 2003	0.456
2000 to 2004	0.184
2001 to 2005	0.157
2002 to 2006	0.557
2003 to 2007	0.352
2004 to 2008	0.229
2005 to 2009 [45]	0.395

Table 4: Seven Year Correlations Between LME Aluminum Price and Dow Jones Mid-C Electricity Prices

Years	Correlation
1997 to 2003	0.252
1998 to 2004	0.255
1999 to 2005	0.160
2000 to 2006	-0.011
2001 to 2007	0.023
2002 to 2008	0.591
2003 to 2009 [46]	0.470

We can see from these figures that there is not a consistent cross-correlation between these time series. Additionally, the time periods examined are clearly not independent observations. Furthermore the number of observations for inference is small for both the two and five-year period lengths.

[44] Two year figure through October of 2009.

[45] Figure through October of 2009.
[46] Figure through October of 2009.

The relationship between the LME aluminum price and the Dow Jones Mid-C electricity price has not shown a consistent or stable enough relationship historically to allow for the basic inference drawn by PPC.

6. Avoided Transmission and Ancillary Services Expenses

SUB questioned BPA's inclusion of avoided transmission and ancillary services expenses as a benefit to BPA in the Equivalent Benefits Test. SUB at 9. BPA's explanation of the nature of this benefit is described above in section V(d). SUB questions BPA's analysis of the transmission and ancillary services expenses avoided by selling power to the DSIs out of its inventory as opposed to selling the same amount of power as surplus on the wholesale electricity market. *Id*. That is not what BPA forecasts to occur with service to Alcoa in the Initial Period.

Though not relevant to the analysis, SUB's question reflects a misunderstanding of the transaction that they described. BPA does not provide service to Alcoa on BPA's transmission inventory. BPA provides power to Alcoa from the Federal System. When BPA makes a market purchase, it may use that power to serve any of its obligations on the system. If BPA Power Service elects to use the market purchase to serve its obligation to Alcoa, BPA Power Service has the contractual right to supply power to Alcoa at non-federal point of integration where it receives the market purchase. Alcoa can use the firm Point to Point transmission it holds to move power from the FCRPS by redirecting that long term firm transmission to the non-federal point of integration. Alcoa's long term firm Point to Point transmission agreement is a type of firm transmission that can be redirected under the Transmission Service Business Practices. When BPA uses its contractual right to supply power to Alcoa at non-federal points of integration, BPA does face the risk that Alcoa may incur some congestion costs due to curtailment of the redirected transmission. BPA has not yet faced a situation where it needed to pay congestion costs due to curtailed non-firm transmission and does not expect to face this condition more than a few hours per year. BPA expects these congestion costs to be de minimus.

7. Demand Shift

WPAG asserts that the "Demand shift" calculation is nothing more than an ad hoc adjustment to make contracts appear more economic. WPAG at 4. For its part, PPC states there can in fact be no demand shift through BPA's selling of power to Alcoa since Alcoa has already secured power in the market which it will have to unload into the market in order to take BPA's power. PPC at 3. PPC finds it hard to believe that Alcoa's contractual right to do things it already has the right to do would make the difference between whether Alcoa operates or not. Id. at 5. PPC also contends that it is troubling and inconsistent for BPA to count a demand shift to be a benefit while at the same time not recognizing the costs imposed on it and its customers from transmission problems that are caused by high loads at the Alcoa Intalco facility. Id. SUB and ICNU echo these comments. SUB at 10; ICNU at 4.

First, BPA has clarified its assumption about plant operation. Upon execution of a contract with BPA, Alcoa's Intalco Plant will operate. After the contract is executed, Alcoa's Intalco Plant operation will be made based primarily on the prices for its output which are independent of power prices.

As indicated earlier, WPAG highlighted an acknowledged fact that if Alcoa, or other DSIs, are served by a third-party electric power supplier, their load will exist and the market price benefit will be received by BPA independent of whether BPA sold power to Alcoa or other DSIs. Other parties argued to similar effect. In BPA's view, Alcoa and other DSIs will not continue to operate unless they can secure a power sale at the IP rate from BPA. Subject to this view, the value derived from the demand shift benefit is dependent on BPA's decision to serve the DSI load.

PPC and ICNU argue that there can be no demand shift through BPA's selling of power to Alcoa. These parties take the position that since Alcoa has secured power from a third party for the initial period the proposed contract covers, Alcoa will need to sell its third party power into the market in order to take BPA's power. The parties argue that precisely the same amount of power will be available in the market whether BPA sells the power to Alcoa or not. BPA disagrees.

BPA's analysis is a demand side analysis. The resale of power into the market is not the driver of the price reduction. The loss of firm load is the driver of the price reduction. All else equal, a DSI plant shutdown will reduce the market demand for electricity. For every month of the analysis, the amount of demand will be less than it would otherwise be. Therefore, a reduced demand for energy will reduce the market-clearing price for energy, because a lower variable cost unit will supply the unit of electricity that creates supply and demand equilibrium.

The supply for the market load comes from a fixed set of resources. These resources are the electric power plants that are modeled in AURORA. The model uses the load forecast and the specification of plant cost components, physical plant characteristics and operating constraints for each of the supply-side generating resources to build an economic dispatch for each of the market zones in the model. Resources are dispatched according to variable cost, subject to operating constraints, until energy demand is met in each zone of the model.

Selling the third party power into the market will not change the fact that the market demand for electricity in the PNW is less than it would have been if the DSI plant was operating. Selling the third party power into the market will only establish an energy supplier for the pre-established energy demand. The third party power is one of many transactions that will establish the resources that will meet load in the PNW or an adjacent market.

ICNU also argues that if BPA assumes Alcoa will operate with a power sale at the IP rate, then Alcoa will operate with the power that is has secured from a third party for the initial period. ICNU at 4. ICNU argues that if BPA accurately forecasts market prices, Alcoa should be financially indifferent to an operation decision based on its current third party power contract or a power purchase from BPA plus the loss from selling its third party power at the market price in BPA's Mid-C price forecast. BPA disagrees with ICNU's conclusions. BPA has previously expressed its view that Alcoa and other DSIs will not continue to operate unless they can secure a power sale at the IP rate from BPA. Furthermore, ICNU erroneously applies BPA's Mid-C market price forecast as Alcoa's basis for making operating decisions. ICNU's assertion that Alcoa would be financially indifferent is true only if Alcoa manages its power supply portfolio on a short-term basis that is similar to the method that BPA manages its inventory, which it does not, given its fundamentally different interests. Alcoa's current power purchase from a third-party, and its desire for a long-term contract, are strong indicators that Alcoa would not manage its power supply in a manner that is similar to BPA's inventory management.

8. Puget Sound Area Northern Intertie ("PSANI")

PPC argued BPA should not count the "demand shift" due to transmission problems that it believes are attributable to Alcoa, and that it is both "troubling and inconsistent" for BPA to count a "demand shift" to be a benefit, while at the same time not recognizing the costs imposed on it and its customers from transmission problems that are caused by high loads at the Alcoa Intalco facility. PPC at 5. Snohomish argues that a physical delivery of power from the Federal system to Alcoa, rather than a secondary sale of surplus from the Federal System to the Mid-Columbia market hub, increases congestion through the Puget Sound Area and the likelihood of additional PSANI curtailments. Snohomish at 3.

The PSANI area consists of the interconnected electric systems, including BPA's network transmission facilities, in the Puget Sound area and BPA's Northern Intertie facilities. BPA monitors the system operating limits (SOL) of the Northern Intertie (NI) facilities in the south to north direction to determine if the NI SOL levels will be sufficient for the transaction commitments that affect those facilities for the next hour. The transactions affecting the NI SOL include south to north scheduled deliveries to all Puget Sound Area customers and scheduled deliveries over the NI. The measures that are monitored are identified as the PSANI mitigation or congestion measures. A PSANI congestion problem is a south to north problem that arises when multiple factors interact at the same time to affect the NI SOL in this direction. These factors include how planned or unplanned facility outages; temperature; the forecasted generation patterns in Puget Sound Area, the forecasted load in the Puget Sound Area, and all of the scheduled deliveries in the south to north direction to serve the load in the area and deliveries to Canada, taking into account any north to south deliveries (i.e., counterflows) from Canada. The load level at Aloca's Intalco Alcoa plant, by itself, is not the source of the problem.

All deliveries of power in a south to north direction contribute to the congestion problems in the area, including south to north deliveries to serve Alcoa's load. If Alcoa or any other load in the area acquires power from the north, in most cases those counterflows help to alleviate any PSANI congestion problems. However, if Alcoa does not operate the plant, that by itself is not likely to be sufficient mitigation to the area congestion.

BPA would continue to be obligated to manage the south to north deliveries to any load in the area including Snohomish, Seattle, BPA's transfer customers, Puget or deliveries to Canada. If the Alcoa load disappears, there are others in the transmission queue that are seeking rights to the transmission capacity that presently serves the Alcoa load. Further, Alcoa holds those transmission rights and may permanently transfer them to any eligible willing buyer. If any transmission capability reverts to BPA and is available, BPA must release it to the market under its open access transmission service policies. Since multiple factors contribute to the problem, and the congestion is specific to all of the conditions that apply at the time, BPA cannot definitively say that if Alcoa did not operate the plant, the congestion problem would disappear.

The PSANI congestion issues are not limited to whether the Alcoa plant is operating. As described above, many factors contribute to the congestion. While no new transmission rights are required to deliver the power made available under the Block Contract to Alcoa's load, BPA expects that ALCOA will increase slightly its south to north scheduled deliveries under its existing transmission rights above the scheduled delivery amounts observed in Calendar Year 2009. This is true regardless of whether the power is sourced from the FBS inventory either directly or as a secondary sale of surplus power from the FBS through the Mid-Columbia market hub. However, the conditions that contribute to the PSANI congestion are not static and must be subjected to detailed technical studies and analyses to state with more certainty what the pertinent contributing factors are at the time.

Management of the PSANI mitigation measures is labor intensive, and requires the involvement of multiple staff from several of BPA's transmission organizations. As described above, however, Alcoa's continued operation and the associated transmission arrangements and scheduled deliveries to support those operations are just some of the inputs to be considered. Thus, the costs associated with management of the PSANI mitigation measures will be incurred whether ALCOA continues to operate or not.

BPA has worked closely with Puget Sound Energy, Snohomish PUD and Seattle City Light ("Puget Sound Area customers") on issues contributing congestion in the PSANI area, including coordinating planned maintenance outages to minimize impacts, and undertaking efforts to encourage the Puget Sound Area customers to increase generation in the area during periods of congestion. BPA also invested in transmission reinforcements in the area and system automation, and has conducted training for operations and technical staff of the Puget Sound Area customers to ensure all entities fully understand implementation and operation of the PSANI curtailment procedures.

BPA is continuing to work with the Puget Sound Area customers to increase the accuracy of the inputs used by the curtailment tool and to come up with plans of service for the interconnected systems that will help to meet the future service needs. BPA is also participating with the parties in the Puget Sound Area Study Team which is specifically focused on service to this area. Since BPA manages PSANI congestion problems through curtailment protocols, there is no direct financial cost to BPA and hence it does not affect BPA's Equivalent Benefits Test Analysis.

In summary, BPA has addressed concerns raised in this section e by commenters and has decided that the Equivalent Benefits Test is based on solid analytics and is a reasonable, though conservative, approach to determining if the Alcoa Block Contract is consistent with sound business principles.

f. Intangible benefits that accrue or may accrue to BPA

BPA believes its forecast of positive net revenues is probably conservative, inasmuch as the sale to Alcoa encompasses certain additional intangible and qualitative benefits to BPA's operations. These benefits include, for example: a) Alcoa's waiver of any claim to money or any other remedy with respect to the Original Contract BPA;[47] b) Alcoa's agreements not to request surplus firm power from BPA or challenge BPA's sales of surplus firm power to other customers;[48] and c) potential for BPA's sales to the DSIs at the IP rate to mitigate the risk that BPA's surplus sales may be impacted by periods of negative pricing (i.e., suppliers would be paying counterparties to take their power) that are the result of rational economic behavior by suppliers of generation but not sufficiently addressed by models currently available to forecast prices of electric power.[49] They also include value that may be ascribed to the historical relationship BPA has had with Alcoa and the value that Alcoa may yet bring in the future as BPA and the power industry continue to evolve in the face of changing regulatory regimes, technological advancements, and fluctuating consumer behaviors.

However, adjustments for these benefits to BPA are not included or relied upon here because they are more qualitative than quantitative at this time and therefore do not presently affect BPA's decision to offer the Block Contract. Adjustments for these or other benefits may affect the tenor and/or megawatt amount of future sales. Nonetheless, in light of comments, BPA believes it is important to provide some discussion here of these prospective benefits.

Waiver of Claims

Alcoa's waiver of any claim to money or any other remedy with respect to the Original Contract could be important with respect to disposition of the Court's remand to BPA in *PNGC I* and *PNGC II* with respect to the application of the damage waiver and severability provisions of that contract.. Alcoa has asserted (though has not formally filed)a $190 million claim against BPA in connection with the Original Contract, based on its reading of *PNGC I*. Pursuant to the waiver provided by Alcoa in the Block Contract, in the event BPA issues a final decision on remand that no money is owed by either party to the other, and that decision, if challenged in a petition for review, is

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[47]Section 23.2.

[48] Section 25.2.

[49] *Frequent negative power prices in the West region of ERCOT result from wasteful renewable power subsidies*, Knowledge Problem, November 20, 2008, http://knowledgeproblem.com/2008/11/20/frequent_negati/

sustained by the Ninth Circuit, then Alco agrees not to pursue its claim. See Block Contract section 23.2. While it appears to BPA that Alcoa's claim that it was provided a legally insufficient amount of benefits under the Original Contract, as amended, probably has little merit, especially in light of the Court's opinion in *PNGC II*, Alcoa's waiver, if applied, would spare BPA the time and expense associated with litigating Alcoa's claim.

Alcoa Agrees not to Challenge Surplus Sales

Alcoa also agreed in section 25.2 of the Block Contract, subject to certain conditions, that it will not request any surplus firm power from BPA, will not challenge any proposed or actual BPA sales of surplus firm power, and will not challenge any BPA rates adopted by BPA for the sales of surplus power. Alcoa has taken the position in a number of different forums, including in briefs filed with the Ninth Circuit, that pursuant to the Pacific Northwest Consumer Power Preference Act (16 U.S.C. §§ 837, *et seq*.) (Preference Act) it is entitled to have its loads served with BPA surplus power, at BPA's lowest cost rate, prior to BPA selling such surplus power outside the Pacific Northwest. Alcoa has indicated that it believes this position was endorsed by the Court in *PNGC I*. BPA disagrees with Alcoa's interpretation of BPA's obligations under the Preference Act, and believes Ninth Circuit case law supports BPA's long-held position that the Preference Act provides only that the customers defined therein are given a priority with respect to the availability of BPA's surplus power, and not preferential pricing. See e.g., *Kaiser Aluminum & Chemical Corp. v. BPA*, 261 F.3d 843 (9th Cir. 2001). Nevertheless, as with the waiver of claims with respect to the Original Contract, Alcoa's waiver, if applied, would spare BPA the time and expense associated with litigating any Alcoa petitions for review with respect to BPA's surplus sales program. The waiver has the additional benefit of eliminating any possible hesitation a potential counterparty may have to executing a surplus power transaction with BPA based on the threat that the contract may be the subject of litigation in the Ninth Circuit.

Negative Pricing

Presently, the power industry is experiencing dramatic changes, especially with respect to facilitating the development and integration of wind resources. BPA has successfully integrated upward of 2000 MW of wind capacity on the Federal power system. However, successfully utilizing wind resources presents major challenges. In addition to the reliability problems inherent in the unpredictable nature of wind, there is a significant potential for certain market aberrations when the resource, such as wind resources, is heavily subsidized. In some areas, as shown below, the power market is dealing with "negative pricing" issues attributable largely to the integration of wind resources. Negative pricing, a phenomenon associated with certain renewable resources that receive tax of other monetary incentives associated with their output, occurs when, in certain market situations, the value of those incentives exceed the cost to a resource owner of paying counterparties to take its power.

For the past decade or so, wind projects have been eligible to receive production tax credits (PTCs) that have increased annually to their current level of $21.00/MW/Hr (2008 value). A wind project is eligible to receive PTCs for ten years from the date of commercial operation based on the amount of energy produced by the project. Until this year, most wind projects were financed with PTCs in mind, although recently federal legislation gave wind project developers the choice between taking PTCs or some other incentive. In many cases, PTCs were sold to tax investors at a discount to provide partial financing for a project. Thus, unlike conventional projects, wind projects receive two sources of revenue: (1) payments for power produced by the project, usually from a buying utility at prices negotiated pursuant to a Power Purchase Agreement (PPA), and (2) tax benefits in the form of PTCs.

At times, particularly in spring when the weather is mild, utilities with significant wind resources on their systems may experience periods of low load when the wind is blowing, thereby creating a risk of "over generation"—meaning more power is likely to be produced than is likely to be consumed, an unstable condition. When this happens, utilities shut down thermal resources (referred to as "displacement") in order to bring generation into balance with load. Some thermal resources cannot be displaced because they are needed to provide operating reserves, to maintain reliability, to serve anticipated load, or for other reasons.

In organized wholesale power markets, generators are invited to submit DEC bids, which are bids to reduce output from particular projects. When system output must be reduced, the system operator accepts these bids in inverse order of cost so as to shut down the most expensive operating resources first. Barring an exercise of market power or some other unusual event, generators usually set their DEC bids at the marginal cost of producing power from each project. In the case of a fossil fuel plant, these DEC bids reflect the variable cost of production, mostly fuel costs.

When a positive DEC bid is accepted, project output from the chosen project is reduced, the generator pays its DEC bid amount (but saves its fuel and other variable costs), and power is supplied from the system to meet the generator's delivery obligations. Through this mechanism, the generator is made whole, load is served, and the system stays in balance by reducing project output.

Thus, in a competitive market, a power supplier will typically offer power into the market at approximately the net marginal cost of supply. These offers are usually at positive prices; occasionally, however, in the short-term there may be some rationale for negative prices. For example, a power plant might choose to bid below the short-term marginal price in order to stay in the market and avoid shut down and start up costs. In the West Texas wholesale power market (the Electricity Reliability Council of Texas or ERCOT), negative pricing was first seen in 2006, and events of negative prices increased from 2007 through 2009 both in terms of duration and magnitude. In the first half of 2008, prices were below zero nearly 20 percent of the time (2006 had less than 5% of the time). During March 2008, when negative prices were most frequent, prices were below zero about 33 percent of the time. After mostly taking the summer off, negative power prices were back to near 10 percent in October 2008.

The Northwest Power Pool (NWPP) has followed what looks like a similar pattern as 2006 ERCOT. This year NWPP experienced its first daily negative prices on Light Load Hours (LLHs) with 5% of the days in 2008 having negative LLH prices.

This year was also the first year where the Dow Jones Mid-C Daily Firm index showed negative values. From May 27 through July 6, 2008, the Off Peak index showed negative values on 18 days. The average index value for those 18 days was -$1.45/MWh with a minimum value of -$7.50/MWh and a high value of -$0.04/MWh. The 18 days of negative index values include 3 days where the non-standard Sunday Off Peak index was negative but the standard Sunday All-Day index was actually positive. If you eliminate those 3 days, the average index value for the 15 days (now covering the period May 27 through June 26, 2008) was -$0.84/MWh with a minimum value of -$1.56/MWh and a high value of -$0.04/MWh. The two days with the largest negative values happen to fall on Sundays where the standard Sunday All-Day index was positive.

When BPA needs to displace generation, it offers to supply power to project owners at very low prices reflecting their project's variable cost of generation. When BPA's offer is accepted, project output is reduced, the generator receives power from BPA at low cost, uses it to meet its load obligations, and the system stays in balance.

In the case of a wind generator receiving PTCs, receiving replacement power at low prices does not make the generator whole because if the project does not produce power, no PTCs are earned. Thus, a wind generator receiving PTCs must be paid the value of its lost PTCs and receive replacement power to be made whole if it is asked to reduce output when the wind is blowing.

Thus, a wind generator receiving a PTC would logically submit a negative DEC bid, meaning it expects to be paid an amount at least equal to the value of the PTCs to reduce output by "spilling wind." Negative bids larger than the PTCs may occur, presumably reflecting the loss of renewable energy credits needed in some states to comply with renewable portfolio standards.

Complicating the problem on the BPA system is the fact that, under the current Endangered Species Act (ESA) biological opinion (Biop), the FCRPS must provide minimum water flows in the Columbia River during certain periods of the year to assist migrating salmon. Ideally, these minimum required flows would be used to generate power to minimize spill but, coincident with these minimum flow requirements, are minimum spill requirements (either as a fixed spill volume or as a percentage of project flow) along with narrowing forebay operating ranges in several projects. These conditions severely limit the operating flexibility of the Federal System when these limitations are in effect.

Under high spring flow conditions, water flows may increase to the point where spilled water increases the risk that migrating salmon will develop the bends from nitrogen super-saturation as high flows cause water to plunge deep into water pools below federal projects, increasing pressure, and causing more nitrogen to dissolve into released water.

This risk is managed in the Biop by setting dissolved gas limits to limit the exposure of fish to high levels of dissolved gas. Dissolved gas limits are adjusted regularly by the U.S. Army Corps of Engineers based on actual river conditions. The dissolved gas limit is taken very seriously. Deviations from dissolved gas limits are not allowed under the Biop except under a power system emergency. This limits the amount of spill permitted on the system.

Nitrogen super-saturation risk can be reduced by generating power to take the momentum out of released water so as to reduce the levels of dissolved gas in released water. When dissolved gas limits are reached, the Federal system must produce power from Federal projects, instead of spilling water, to keep dissolved gas levels within Biop limits.

When the risk of excess spill rises, BPA offers replacement power at low prices to displace operation of West Coast thermal projects. When West Coast thermal generation has largely been displaced, and excess generation is anticipated, additional steps must be taken to avoid over-generation, such as paying customers to take excess generation. This risk of low load and too much energy has become more significant with the integration of more than 2,000 MW of intermittent wind projects into the FCRPS.

When over-generation occurs in the FCRPS under these conditions, one of two actions must be taken by BPA to maintain system balance. Either the output at federal projects must be reduced by spilling more water or reducing output at wind projects by curtailing wind. Spilling water raises ESA compliance issues, particularly under conditions where there is little system flexibility to accommodate additional system spill without violating the Biop or associated injunctions

This problem can be mitigated to some extent when BPA has access to relatively flat, continuously operating loads. This load profile obviously is consistent with DSI operations, which use large blocks of continuous power at all hours and on all days. Thus, once again, the nature of the power industry and the need to cope with change, in this instance technological change, suggests that the Administrator should not abandon the DSI load. The better course is to continue to use that load as a means of providing value in terms of maintaining an adequate efficient economical and reliable power system.

Historical Perspective

Historically, DSI load has provided value to BPA in connection with ensuring an adequate, efficient, economical, and reliable power supply, by providing the Administrator with flexibility to help deal with the complexities and uncertainties of marketing large quantities of Federal power. There is no compelling reason to believe that will not be the case in the future.

As noted earlier, *PNGC I* affirmed that BPA has the authority, but not the obligation, to sell power to the DSIs and clarified the proper rate directives to follow in making an initial offer. BPA believes that the proposed service plan is a proper exercise of the Administrator’s discretion. The decision to serve the DSI load is consistent with the

Administrator's statutory responsibilities because DSI load will be important, as has been the case historically, in dealing with unpredictable supply and demand issues that must be reckoned with in order "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply; . . ." 16 U.S.C. § 839(2).

The DSI load has provided enormous value to BPA in the past and, as demonstrated below, it is reasonable to believe that it will do so again. DSI loads have historically benefitted BPA by taking power in relatively flat blocks that require little or no shaping; they have taken power from BPA at light load hours, when power has historically been difficult to market; and they have provided the Administrator with additional power reserves. Therefore, in comparison to load that varies by the minute and which cannot be relied upon for reserves, DSI load service provides important benefits. Further, retaining service to DSI load has also provided BPA revenue certainty during periods when its other customers' loads were decreasing. While the aggregate DSI load has decreased substantially over the past decade due to adverse global aluminum market forces, Alcoa has shown remarkable resilience in the face of huge challenges to remain competitive. There is ample reason to believe that they will continue to do so, if provided the opportunity to predict and manage their power costs, which account for about one-third of their overall costs.

In comments filed in earlier proceedings, some preference customer groups have argued, essentially, that DSIs provided benefits to BPA in the past during times when BPA needed a "sink" for power in order to guarantee a consistent revenue stream that promoted BPA's ability to make its Treasury payments in full and on time. Now, these customers claim that BPA will never face a situation where it will need to rely on the DSIs to provide such a benefit, largely because most of BPA's firm power is locked up in twenty year contracts with the Administrator's preference customers.

This perspective ignores the central purpose of the Northwest Power Act to solve allocation problems. Prior to passage of the Act, BPA acted as the statutorily designated marketing agent for all but a small amount of electric power generated by Federal hydro-electric plants in the Pacific Northwest constructed by the United States Corps of Engineers and by the Bureau of Reclamation. *See* Federal Columbia River Transmission System Act, 16 U.S.C. § 838f.[50] BPA had no specific obligation to serve in the traditional utility sense, beyond simply marketing the Federal power available to it consistent with statute. Against the backdrop of a potential regional battle over BPA's available supply in the 1970's, Congress in 1980 passed the Northwest Power Act to address regional power needs:

[50] Congress originally authorized the BPA Administrator to market low-cost hydroelectric power generated by the Bonneville project. Bonneville Power Act, 16 U.S.C. §§ 832-832m. Subsequent marketing of power was authorized by Executive Order and by the Flood Control Act of 1944. The Transmission System Act later expanded the Administrator's marketing authority to include nearly all the electric power generated by the Federal Columbia Power River System, which consists of a series of federal dams along the Columbia River in Oregon and Washington. 16 U.S.C. § 838f.

> The basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers. . . . This is a bill to solve a power allocation problem; . . . Along with section 5, this section [7] sets forth the basic power allocation system and 'rate package' of the bill, which is common to all versions of the bill and represents a regional consensus on the division of future power supplies and power costs.

Congressman Swift remarks on S. 885, 96th Cong., 94 Stat. 2697 (1980); Cong. Rec. H9851 (daily ed. Sept. 29, 1980); *see also* Cong. Rec. S14690-91 (daily ed. Nov. 19, 1980)(remarks of Senator Jackson). To complement BPA's new service authorities, section 6(a)(2) of the Northwest Power Act obligates BPA to acquire resources on a long-term basis, in addition to making short-term purchases (up to five years), to meet its firm contract obligations under section 5. 16 U.S.C. § 839d(a)(2). The Northwest Power Act also clearly provides that the Administrator may acquire resources to replace reductions in the Federal Base System resources. 16 U.S.C. § 839a(10). All that is to say, if BPA doesn't have enough power to meet load, it has the authority to, and must, acquire the power. Clearly, preference customers err when they argue that BPA should only serve the DSIs if it needs a sink for its existing power.

The preference customers' perspective is apparently based on the view that things will always be as they are now when, in fact, the Pacific Northwest has been, since passage of the Northwest Power Act, essentially subject to repeated dramatic and unanticipated change. On this level, no one knows with certainty what loads and resources might look like in the years ahead. For this reason, BPA has recognized that it "must position itself to be successful in the short-term and the long-term, so it must think in terms of short-term and long-term consequences." 1996 Wholesale Power Rates Final Record of Decision at 81. Moreover, the Administrator must always be mindful that "section 7(a) of the Northwest Power Act requires BPA to recover its costs 'under all economic conditions'." *Id.* at 169.

In meeting these objectives, DSI load has always been part of the mix and, until recently, the general assumption seemed to be that at various times, the DSI load was "at risk" and worth preserving, even if that took extraordinary measures. As noted in the 1996 ROD: "In 1986, DSI loads and revenues were at risk because of low aluminum prices. Today they are at risk because of competition." *Id.* at 169 Thus, efforts in the 80's to provide a variable rate based on the market price of aluminum enabled the DSIs to operate in both good market conditions and bad. This benefitted BPA financially, to be sure, because BPA would have otherwise been forced to unload DSI power into an underdeveloped market which would have assured receiving less revenue than BPA would receive from DSI revenues under the IP rate.

Preservation of the DSI load in the 1980's, however, provided a perhaps even greater benefit in the 1990's, when BPA was facing the problem of its cost-based rates being above prevailing market prices. The market for power was routinely offering prices that were competitive with BPA's PF preference rate, and some of BPA's preference customers threatened to find whatever means they could to get out of their existing BPA power sales contracts. As a consequence, facing a rapidly changing and increasingly competitive market for wholesale electric power, Congress in 1995 enacted P. L. 104-46, addressing Bonneville's power marketing authority. Energy and Water Development Appropriations Act of 1996, Pub. L. No. 104-46. The legislation modified regional preference to allow BPA to effectively market surplus Federal power abandoned by regional customers. See, Excess Federal Power provisions, 16 U.S.C. 832m(b). Without the legislation, provisions of BPA's authorizing legislation severely limited BPA's marketing flexibility with respect to such power, putting the agency at a competitive disadvantage and restricting the potential revenues from sales of such power. Sales or exchanges of surplus power which is surplus for reasons other than the reasons set out in the new legislation continued to be subject to existing marketing restrictions.

BPA's preference customers sought to reduce the amount of Federal power under BPA's then long-term power, 20-year power sales contracts. "[P]rojections of public utility purchases from BPA have been reduced to account for utilities that are seeking actively other suppliers. Supplemental Loads and Resources Study, WP-96-E-BPA-57, at 13; Supplemental Loads and Resources Study Documentation, Vol. 1, WP-96-E-BPA-57A, at 229. Without the certainty of the expected revenues from sales to DSIs, BPA's financial health would have further deteriorated. Some preference customers asserted that the situation was even more dire than BPA supposed and some of these same customers had already mounted legal challenges to obtain greater access to the competitive market:

> Customers represented by the Western Public Agencies Group (WPAG) argue that BPA has misjudged its position in the wholesale market, and has grossly underestimated the desire of its preference customers to diversify their power supply. Beck, et al., WP-96-E-WA-13, at 6, 10-11. They note that, at the time their testimony was submitted in November 1995, preference customers had made submissions to BPA pursuant to their power sales contracts to reduce their load on BPA by over 780 aMW, and that they expected to see this number increase. Id. Since that time, some of these customers have sued BPA in an attempt to access alternative power suppliers.

1996 Wholesale Power rates Final record of Decision at 18.

Thus, the Administrator was facing the loss of both public load and DSI load. The preference customer side of the problem was dealt with by a combination of contract amendments that were offered in order to obtain load commitments from some preference customers so that others, who were more adamant regarding access to the market, could be provided with the ability to diversify their load.

Preserving the DSI load was equally problematic. The loss of DSI load was a virtual certainty because, in a competitive market, the nature of the DSI loads made them particularly susceptible to competitive encroachment. As noted in the 1996 ROD:

> The DSIs can demand better prices from BPA's competitors because they offer valuable loads: they have high load factors and their loads are fairly constant throughout the day and over the course of the year. Thus, their loads are cheaper to serve than loads that vary more, and they are the objects of more intense competition than BPA's other loads. Moorman, Evans, E-BPA-65, at 5.

Part of BPA's strategy to resolve the loss of DSI load was a successful effort to retain as much of the DSI load as possible in spite of the fact that BPA's cost-based rates were higher than rates for power that could be purchased on the open market. Retention of this load supported BPA's ability to meet its financial obligations in full and on time, including its Treasury repayment obligation. As BPA observed at the time:

> As in 1986, so today BPA must be concerned with its resource planning, financial strength, and rate stability. As in 1986, so today BPA faces the prospect of power surplus and unrecovered fixed costs if it loses substantial load. That the DSIs may be unwilling, rather than unable, to pay higher rates is immaterial; if they purchase power elsewhere because BPA's rate is above the market, the consequences the Variable Industrial Rate ROD was intended to forestall will come to pass. Like BPA, BPA's customers operate in a competitive market, and must set rates competitively to retain load. The industrial customers of BPA's public body and cooperative customers are pressuring their utilities to set competitive rates or to provide them with direct access to the market so they can reduce their power costs. Hill, et al., WP-96-E-BPA-51, at 4.

Faced with the sudden changes in the market and the resulting high likelihood that the DSIs would exercise their contractual right to remove their load from BPA on nine months notice, BPA acted to protect its overall revenues and ability to recover its costs by negotiating block sale contracts, committing the DSIs to place a substantial amount of load on BPA for five years. *See* Administrator's Record of Decision, 1996 Power and Transmission Rate Proposal, § 2.2 at 18; see also, id. § 8.

Due to the many unanticipated changes that the electricity market has seen over the last two decades, BPA believes it would be short-sighted and unwise to conclude that retention of DSI load could never provide significant value to BPA in the future in much the same way as it has in the past. As the above illustrates, notwithstanding WPAG's comment on the new long-term power sales contracts between BPA and its preference customers, service to diversified customer loads, i.e., public body, cooperative, federal agency, direct service industries, and investor-owned utilities, provides a flexible and sound business approach to meet the uncertainties of the future. Given the current economic crisis and market conditions, it is certainly within the realm of possibility that BPA could find itself in a position similar to the 1990s, where BPA's cost based rates exceed prices available on the market. Recently, market prices have declined significantly while BPA has just proposed a rate increase. In fact, daily prices in the applicable markets have at times been significantly lower than some of BPA's cost-based rates. No one knows what the end result of these volatile market forces will be if the economy continues to decline, nor does anyone know with certainty what conditions in the power market will be like when the economy begins to improve.

Even at this time, the gap between market prices and BPA rates has narrowed considerably primarily due to depressed prices for natural gas. Natural gas is a primary driver of prices in the west coast markets because the marginal cost resource for the region is the combined cycle combustion turbine, which operates on natural gas. To the extent that fuel costs, in the form of natural gas, are depressed, that means that operators of combined cycle combustion turbines can offer lower prices in the market, which creates competition and drives market prices down. A recent Wall Street Journal article stated:

> Natural-gas futures fell to a fresh seven-year low as a glut of the fuel and tepid demand outweighed diminishing concerns about storms in the Atlantic. Natural gas for September delivery on the New York Mercantile Exchange fell 6.7 cents, or 2.1%, to settle at $3.096 a million British thermal units. That represents the lowest settlement since Aug. 14, 2002, and marks the ninth consecutive trading day of declines in gas futures.

"Natural Gas Falls to Seven Year Low", *Wall Street Journal*, August 19, 2009. The same article noted that natural gas supplies are expected to be less subject to unanticipated price spikes caused during hurricane season in the Gulf of Mexico area. The continued declines, even in the midst of hurricane season, underscore how booming onshore domestic gas production has led to an overabundance of the fuel, resulting in a market that relies less on Gulf output. In recent years, when the Gulf represented a fifth of the U.S. gas production and markets were strained, any threat of storms could send prices soaring. But gas output from the Gulf now accounts for about 11% of domestic supply as producers have increasingly moved on shore to tap gas-rich formations known as shales, putting less supply in the path of storms and boosting overall output from these new fields. Id. These types of developments in the energy industry are simply a fact of life and, because they cannot always be anticipated, planning for the future cannot be done on the basis of a rose-colored haze that simply presumes the status quo will be maintained, even over a relatively short time horizon.

Some preference customers have suggested that BPA need not worry about the future now because BPA's preference customers have executed long term contracts that contain take-or-pay obligations that protect BPA's revenues. That fact does provide potential mitigation of some of the issues faced by BPA in the 1990s. However, a significant portion of BPA contracts or load following contracts respond to overall economic conditions. In addition, BPA's surplus energy above critical water that is primarily being relied upon to serve Alcoa's load is not sold through take or pay contracts, is priced at market, and the revenue is subject to overall economic conditions.

In spite of the existence of these contracts, there is no guarantee that, overall, demand could not become depressed in the future and power supplies plentiful. Planning for the future must recognize that market prices are subject to supply/demand market fundamentals that are cyclical in nature but are also subject to volatility caused by unanticipated events and changes. Poor economic conditions, for example, can cause a decrease in business activity that can lead, in turn, to relocation of business enterprises and consequent population drift, all of which can result in localized suppression of demand for power and, assuming normal supply parameters, lower market prices for power. Current economic conditions are, in fact, having some effect with respect to suppressing demand for power. Similarly, in a market situation where BPA's rates were higher than market prices, having the DSI load available could well help the Administrator in retaining sufficient load to assure Treasury repayment as he weighs the cost and benefits of allowing customers to diversify their supply portfolios, as was done in the mid-90s, in the interest of achieving the lowest rates possible for consumers and diversifying the region's power sources in the interest of maintaining an adequate, efficient, economical and reliable power supply.

Thus, the issue raised by the preference customers (i.e., that the take-or-pay requirement in the long term Regional Dialogue contracts obviates any business need to continue service to DSI load) is overly simplistic and based on a static view of the future that, if history is any guide, is not supportable. Resolution of the complex issues that can arise in the management of the Federal FCRPS, planning for the future integrity of regional power supply, and mitigating the risk created by potential events that are unpredictable cannot reasonably be accomplished by taking the view that take-or-pay protection in requirements contracts will be all that is necessary to plan for the future. Instead, market fundamentals suggest that it is a reasonable business proposition for BPA to increase the certainty of its revenues through serving this load.

It is not as though BPA would, at a later time, have the ability bring that load back on line. The DSIs customers currently have no viable long-term alternative for their power needs and a decision not to sell power to DSIs would almost surely have the immediate consequence of the plants shutting down with a very high likelihood that they may never resume production.

Conclusion of Intangible Benefits

While adjustments for these intangible benefits to BPA are not included or relied upon here because they are more qualitative than quantitative at this time and therefore do not presently affect BPA's decision to offer the Block Contract, BPA believes it is important to acknowledge these prospective benefits. BPA continues to believe its forecast of positive net revenues is probably conservative, inasmuch as the sale to Alcoa encompasses certain additional intangible and qualitative benefits to BPA's operations.[51]

[51] Finally, it is worth noting that BPA and Alcoa included a provision in the Block Contract with respect to the possibility that Alcoa may provide to BPA certain additional reserve products or restriction rights that may only be supplied by the large, flat, but potentially flexible load at an aluminum smelter.
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VI. PNGC II

The following analysis largely restates BPA's analysis of *PNGC II*, as set forth in the record of decision dated November 13, 2009, for the 14-month sale by BPA to Port Townsend Paper Company of 20.5 aMW.

On August 28, 2009, the Ninth Circuit issued its opinion in *Pacific Northwest Generating Cooperative v. BPA*, 580 F.3d 828 (9th Cir. 2009) ("*PNGC II*"). BPA reads *PNGC II* as requiring that if the Administrator exercises his discretion to serve a DSI customer, the decision to serve must be consistent with "sound business principles," meaning in this context that the benefits to BPA of serving the DSI load must equal or exceed BPA's cost of serving the load during the period of service or, if they do not, there must be a demonstrated and realistic prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service. BPA refers to the *PNGC II* requirement herein as the "Equivalent Benefits Test".

As noted, the DSIs disagree with BPA's reading of *PNGC II*. Indeed, the DSIs' position comports with BPA's view of its statutory mandate to assure the Pacific Northwest, including the DSIs, an adequate, efficient, economical and reliable power supply. However, inasmuch as BPA believes the most sustainable reading of *PNGC II* is that service to the DSIs must be conservatively measured against an equivalent benefits test, BPA has constrained its consideration of Alcoa service options to those that will satisfy that test. Absent the equivalent benefits test, BPA would have considered other, longer-term service options. The Transition Period and Second Period only come into play if the Court determines that the equivalent benefits test should not apply.

Taking the opposite position, the PPC/ICNU comments state that BPA's approach "appears to recognize that the Ninth Circuit's recent decisions have established that BPA is authorized to serve the DSIs only if the agency demonstrates that doing so is calculated to financially benefit the agency." PPC at 1. PNGC agrees with and adopts the PPC comments.

Before addressing the more fundamental issue of the meaning of *PNGC II*, and whether the Equivalent Benefit Test is correct, we will address the subsidiary comments raised. Alcoa offered several points it believed BPA needed to consider in making its decision regarding the Block Contract, including the fact "BPA will deliver the same amount of power to Alcoa in every month rather than 'shaping' its power resources to meet varying electric loads as it does for most of its other customers." Alcoa at 6. Alcoa also points to other benefits that it believes provide value to BPA under the contract, including the waiver of any right to request surplus power (4), provision of reserves (6), and preservation of potential future benefits (7). Moreover, Alcoa states they "would prefer a longer-term contract because it could justify long-term capital expenditures at the Intalco plant and provide economic stability to the many people who depend on the plant's operation for their economic well being.

With regard to the concerns expressed by Alcoa, BPA understands, and is sympathetic with, the fact that long-term planning by Alcoa is impaired by the short-term nature of the proposed contract. If Alcoa is going to make capital investments, it needs reasonable certainty as to their future recovery. BPA's proposal does not allow that reasonable certainty, unless Alcoa can recapture its investments in the short period of the contract, and BPA has no basis to deny Alcoa's assertion that the time period of the contract is too short in that regard. However, BPA's analysis, as discussed in this ROD, looks into the future to see where the breakpoint is for purposes of satisfying the equivalent benefits test, which BPA forecasts is a 17-month contract.

With regard to the test itself, BPA did not mean to state or imply that benefits must exceed costs. Rather, as BPA reads *PNGC II*, it is sufficient if benefits equal or exceed costs. As to the demonstration of benefits, BPA agrees with Alcoa and does not believe that an "accounting analysis" is necessary to quantify the costs and benefits. However, certain costs and certain benefits can be reasonably quantified, and in that case it is reasonable to do so. BPA has presented that quantification in this record of decision. In the case of certain other benefits whose values are a matter of judgment, such as for example a litigation waiver or a waiver of a right to argue certain positions, we are not foreclosing such valuations, and did not foreclose them.

a. BPA's Interpretation of *PNGC II*

PNGC II unequivocally requires that a decision to serve a DSI customer be consistent with sound business principles: "Given that BPA is not obligated to sell to the DSIs and that its actions are generally reviewable under the 'sound business principles' standard, it follows that a decision by BPA to enter into a contract with a DSI, like other nonobligatory contractual decisions made by the agency, *see APAC*, 126 F.3d at 1171, must also conform to the 'sound business principles' standard." *PNGC II*, 530 F.3d at 835. In terms of what is demanded by that standard, the following and other statements in the Court's decision leave an overall and lasting impression that benefits must approximate or exceed costs:

> In short, neither the record in this case nor the record in PNGC contains any financial or other business analysis or evidence to support the agency's assertion that future benefits to the agency are (a) likely or (b) sufficiently large to make the decision to give $32 million away a sound business decision.

Id. at 844. While that passage uses the word "or" between (a) and (b), we do not believe the Court would divorce the two. In other words, if the benefits were likely but not equal to the costs, or huge but unlikely, the tenor of the Court's decision causes BPA to believe such benefits would be insufficient to satisfy a "sound business decision" test.

The Court elsewhere analogizes DSI sales to the incurrence by a utility of a non-necessary expense. *Id*. at 839, citing *McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006). In the context of providing power at the lowest cost consistent with sound business principles, if the DSI sale comes at a net cost, with the consequence that other customers' rates are increased, *PNGC II* appears to indicate that sound business principles would be violated. *Id*.

That conclusion is bolstered by the Court's discussion of parties' arguments that under the sound business principles, it would never make sense to sell power at the IP rate when market rates exceed that rate. The Court disagreed, but did so in a fashion that indirectly reinforced the Equivalent Benefits Test, as BPA has described it above (benefits to BPA of serving the load must equal or exceed BPA's costs of serving the load during the period of service or, if they do not, there must be a demonstrated and realistic prospect that the short-term net cost of providing DSI service will be offset by positive net benefits of future DSI service). The Court stated:

> We can envision several situations in which BPA might reasonably conclude that a below-market rate sale to the DSIs is a sound business decision. First, as the court alluded to in *PNGC*, BPA's governing statutes likely require it to offer power within the Pacific Northwest at established rates before the agency may sell power outside the region. If so, BPA might reasonably enter into a contract with the DSIs at the IP rate so as to "free up power to sell outside the Pacific Northwest."
>
> Second, BPA has asserted that the physical sale of power to the DSIs has indirect benefits that might offset a below market rate sale. For example, BPA noted in its letter explaining its justifications for the amended contract with CFAC that "DSI loads have historically benefitted BPA by taking power in relatively flat blocks that require little or no shaping; they have taken power from BPA at light load hours, when power has historically been difficult to market; and they have provided the Administrator with additional power reserves." These and other non-financial benefits to BPA could very well justify a less-than-market rate sale, but they have no direct application when, as here, BPA is not in fact physically selling power to the DSIs.
>
> Third, a soundly run business might reasonably offer a large customer a short-term discount with the expectation that the customer's future business at higher prices will more than make up for the short-term loss of revenue. Similarly, a reasonable business might offer a short-term discount to a customer in order to diversify its customer base or to offload unused capacity.

PNGC II, 530 F.3d at 835-836 (footnotes and citations omitted).

With regard to the first scenario, freeing up power to be sold outside the Northwest, two observations are in order. First, *Kaiser Aluminum & Chemical Corp. v. BPA*, 261 F.3d 843 (9th Cir. 2001), establishes that where BPA has a rate for surplus power sales that provides for the sales at a market rate, regional preference is satisfied if the power is made available first in the region at the same rate it could be sold for out of region. That means that if a DSI is willing to pay the higher rate, it would be entitled to the power. However, in that case, there would be equivalent benefits because DSI revenues and lost opportunity cost would be equal. Second, when the Court speaks of "reasonably" entering a DSI contract to free up power for sale outside the region, there is no indication that the Court would find the contract reasonable if the DSI contract resulted in a lost opportunity cost to BPA relative to out-of-region sales revenues.

In the second scenario, where the Court speaks of certain benefits such as sales in flat blocks possibly justifying a less-than-market rate sale, BPA reads the Court's opinion as indicating that the DSI revenues plus the other benefits must equal or exceed the lost opportunity costs of a less-than-market rate sale. In other words, the Court, while not requiring an accounting analysis, would at least require the Administrator to opine that the DSI revenues and listed benefits equal or exceed the costs, and to state why.

Finally, in the third scenario, the Court is explicit that a short-term discount could be justified if "higher prices will more than make up for the short-term loss of revenue." That all but says benefits must match costs so that there is no net cost over time. As to diversifying BPA's customer base, the Court rejected BPA's widespread use arguments in *PNGC I* so it is difficult to envision the Court allowing BPA to ascribe any real value to this. And, certainly, implicit in the Court's reference of a sale to "offload unused capacity" is the sense that the sale is the best, if not the only, economic use of the otherwise unused capacity. However, BPA is not in that situation.

b. Imposition of an Equivalent Benefits Standard Is Inconsistent With BPA's Enabling Statutes

As indicated, BPA has structured the Block Contract to comport with its reading of what the Court has required in *PNGC II*, a reading that Alcoa argues is wrong or overly conservative. BPA is not persuaded that the opinion can reasonably be interpreted in the fashion advanced by Alcoa. However, BPA does believe *PNGC II* errs by constraining the Administrator's discretion to serve DSI customers to a degree that is not in concert with BPA's enabling legislation. The Northwest Power Act expressly provides that one of BPA's key missions is "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply, . . ." 16 U.S.C. § 839(2). This purpose encompasses all BPA customers, including direct service industry customers, investor owned utilities, federal agency, and public body and cooperative customers (preference customers). It is true that Section 5(d)(1)(B) of the Northwest Power Act authorizes, but does not require, the Administrator of BPA to sell power to DSI customers once their "initial" contracts under the Act terminate. 16 U.S.C. § 839c(d)(1)(B); *PNGC I*, 550 F.3d at 866. It is equally clear that by referring to an "initial" contract Congress envisioned the potential for continuing DSI sales beyond expiration that contract. Section 5(d)(1)(B) requires only that "[s]uch sales shall provide a portion of the Administrator's reserves for firm power loads in the region." 16 U.S.C. § 839c(d)(1)(B). Section 5(d) does not otherwise mention, let alone require, that such sales shall provide other benefits to BPA or the region or be subject to a strict cost-benefits analysis that would seemingly preclude service in all but a few narrow sets of circumstances.

The rate charged to DSI customers further indicates that Congress intended that sales to DSI customers beyond the "initial" NPA contract would be the rule, rather than the exception. When the Administrator exercises his discretion to sell power to DSIs under section 5(d)(1)(B), the rate for such sales must be established pursuant to section 7 of the Act. 16 U.S.C. § 839c(a)("All power sales under this Act . . . shall be at rates established pursuant to section 7."); *see also PNGC I*, 550 F.3d at 869. For the period prior to July 1, 1985, but only for that period, section 7(c) of the Act required the IP rate to recover the cost of resources the Administrator determined were required to serve the DSI load. 16 U.S.C. § 839e(c)(1)(A); *see also* H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980). In other words, prior to July 1, 1985, the rate was based on cost of service. After July 1, 1985, however, section 7(c) requires that the IP rate shall be based upon the Administrator's rates to his public body and cooperative customers (preference customers) and the typical margins they include in their rates to their retail industrial customers, adjusted for certain specified factors, including the value of the reserves the sales provide the Administrator. 16 U.S.C. §§ 839e(c)(2), 839e(c)(3); *see also* H.R. Rep. No. 96-976, at 36. Consequently, when the Administrator now exercises his discretion to sell power to DSIs under section 5(d)(1)(B), the sale must be at the section 7(c) IP rate that is linked to BPA's cost of serving preference customers, not a rate tied to market, specific resource purchases, DSI cost of service, or benefits other than reserves. In other words, for sales beyond 1985, Congress specified that DSIs be served at a rate that is roughly in parity with rates paid by industrial load served by preference customers. It is not clear why the Court appears to believe that Congress would design a rate to achieve such parity and also intend that it be used only in limited and narrow circumstances, as required by *PNGC II*.

Notwithstanding the Administrator's authorization to serve and this clear statutory expression that the rate for DSI service is linked to the rate for service to BPA's preference customers, the *PNGC II* opinion effectively mandates that the Administrator can only serve the DSIs if he can do so at no net costs, *i.e.*, in a way that results in no differential between the cost of serving the DSIs and the revenues resulting from service at the statutory section 7(c) IP rate. *PNGC II*, 580 F.3d at 835. In other words, if serving the DSIs and application of the statutory IP rate means that some costs of serving the DSIs would not be recovered through the section 7(c) IP rate, *PNGC II* forbids the Administrator from serving the DSIs unless he can show that those costs of service are offset by equal or greater benefits resulting from the service. In so doing, BPA is concerned that *PNGC II* trumps the statutory rate directive in a manner that, for the reasons next explained, has no basis in law, and improperly undermines the Administrator's authority under the Northwest Power Act "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply, . . ." 16 U.S.C. § 839(2).

PNGC II relies upon a misreading and misapplication of "sound business principles" to arrive at its conclusion. The Court posits that (a) BPA's discretionary actions "are generally reviewable under the 'sound business principles' standard," *PNGC II* 580 F.3d at 834; (b) sound business principles means DSI service should come at no net cost to

BPA: and (c) the Administrator cannot serve the DSIs if benefits do not equal or exceed net costs of service. *Id*.

However, in developing this logic, the Court appears to confuse statutory rate setting directives, which reference "sound business principles" with BPA's decisions regarding service to DSI customers, which are not circumscribed by such references. The Court states:

> In sum, we hold that BPA's voluntary decision to contract with the DSIs, like its other non-obligatory contractual choices, must conform to the congressionally imposed requirement that the agency act in a manner "consistent with sound business principles." *See* 16 U.S.C. §§ 838g; 839e(a)(1); 825s. The mere fact that BPA has chosen to contract with a DSI at the statutorily authorized IP rate does not insulate the decision to contract from review under the "sound business principles" standard. (Footnote Omitted.)

PNGC II, 580 f.3d at 835. The first two references are to ratesetting, not a decision to serve or the incurrence of costs. Rate decisions and power service decisions are entirely separate in the Act, *compare* 16 U.S.C. § 839c (sale of power) *with* 16 U.S.C. § 839e (rates), and for purposes of what final actions are subject to judicial review, *compare* 16 U.S.C. § 839f(e)(1)(B)("sales, exchanges, and purchases of electric power under section 5") *with* 16 U.S.C. § 839f(e)(1)(G)("final rate determinations under section 7"). Section 7(a)(1) of the Northwest Power Act provides that when the Administrator sets rates for power and transmission "[s]uch rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, . . ." 16 U.S.C. § 839e(a)(1). This directive applies to all BPA rates, not just rates for DSI service.

Moreover, this statutory provision is not, as *PNGC II* determined, a directive that should be transported from the rate directive setting of the Act to which it explicitly applies and then applied to require that decisions *to sell* power be subject to identical standards. Ratemaking and power sales are two distinct activities, each of which has its own distinct requirements. The directive is limited to the establishment of rates to recover costs, *costs which have already been and will be incurred*, and to recover them consistent with sound business principles. Thus, the directive is explicit and limited, requiring that rates be set in a manner that underscores the importance of BPA recovering its cost in a manner consistent with assuring that BPA's treasury repayment obligations in full and on time. This reading is borne out by subsequent language in the same sentence of section 7(a) that refers to rates recovering "the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law." 16 U.S.C. § 839e(a). As the Court observed in *Golden Northwest Aluminum, Inc. v. BPA*, 501 F.3d 1037, 1052-53 (9th Cir. 2007), this ratesetting requirement "presupposes that BPA knows its costs or, at the very least, that it estimates them 'in accordance with sound business principles.'" Section 7(a) takes recovery of costs, regardless of how or when they were incurred, as a fundamental precept of rate making. The provision has absolutely nothing to do with, and is inapplicable to, decisions regarding sales to statutorily identified customer classes, or for that matter, sales of surplus power.

Even if section 7(a) could somehow be seen as applying to a decision to serve, the more specific language of section 7(c) would govern. Congress addressed section 7(a) in the context of the more specific rate directives, including section 7(c), as follows:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. *Subject to the general requirements (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates . . . [preference customer, exchange, DSI, other rates listed]*

H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980)(emphasis added). The import of this is that specific rate directives, including section 7(c), are not overridden by section 7(a) unless and, then, only to the extent necessary to assure total cost recovery. No question existed in *PNGC II* that DSI service would somehow jeopardize total cost recovery by BPA. Indeed, BPA's cash reserves dwarfed the cost incurred by BPA to provide DSI service. As to the rates themselves, BPA established the rates to recover the costs of the monetary benefits to the DSIs.

So, too, section 9 of the Transmission System Act of 1974, 16 U.S.C. § 838g, also cited by the Court, deals with ratesetting, but only ratesetting. It includes language that BPA's charges for the sale of power and transmission shall be established based on a number of factors, including "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." *Id*. Here, again, this is a directive dealing with the setting of charges, not with decisions by the Administrator whether to sell power. In any case, even if this language has any application to DSI ratesetting, it must be reconciled and harmonized with the very specific language of section 7(c) concerning what costs the DSI rate is to recover, not used as a basis to override it. As indicated, BPA is very concerned that *PNGC II* effectively trumps the section 7(c) directive by applying these general "sound business principles" ratesetting references to the Administrator's service decisions.

In *Cal. Energy Comm'n v. BPA*, 909 F.2d 1298, 1307-08 (9th Cir. 1990), the Court rejected claims that a BPA intertie access policy must be rejected because it failed to maximize BPA returns. Reviewing the language in 16 U.S.C. § 838g that rates be set "with a view to encouraging ... the lowest possible rates to consumers . . ." the Court observed with some prescience:

> nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the "lowest possible rates" standard advanced by DSI[] were accepted, the discretion that Congress vested in the Administrator would be eliminated.

Id. The Court in *Cal. Energy Comm'n,* clearly recognized in the preceding passage that a revenue maximization test would inappropriately rob the Administrator of the discretion afforded him by Congress. *PNGC II* appears to swing full tilt in the other direction, inconsistently imposing a rigid cost/benefit test that all but eliminates the Administrator's discretion.

In sum, the statutory requirements that BPA "establish" or "periodically review and revise" or "fix and establish" its rates "at the lowest possible rates to consumers consistent with sound business principles" cannot be read as concerning anything more than just that, the establishment of rates and the recovery of costs that have been and will be incurred. 16 U.S.C. § 838g; 16 U.S.C. § 839e(a)(1). The rates can be no lower in total than would be consistent with sound business principles so as to assure total cost recovery. In addition, rates are to be established to "recover, in accordance with sound business principles, the costs" borne by BPA. 16 U.S.C. § 839e(a)(1). Recovering the costs is, however, a matter separate from the incurrence of the costs, including through decisions to serve.

PNGC II also relies in passing on language of section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s, which provides that in marketing the output of Corp of Engineers' reservoir projects, the Secretary shall "transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . ." Here, again, this reference to lowest possible rates to consumers consistent with sound business principles cannot serve to override the specific directive of Northwest Power Act section 7(c) or the authorization to serve in section 5(d).[52] Even as a marketing matter, this language supports service to the DSIs rather than negates it. If *PNGC II* is to be read as saying that there can be no DSI service if it comes at a net cost, then the Flood Control Act language should apply in equal fashion to all service decisions since the consumers referred to in section 5 of the Flood Control Act of 1944 encompass preference customers, federal agencies, and aluminum companies. That would mean that if the power could be sold at market, such that one set of consumers' rates could receive a greater revenue credit and so have lower rates, that is what BPA should do. But that makes absolutely no sense since there is no basis in the language to elevate one class of regional customers over

[52]Giving effect to the whole of section 5 the term "consumers" means the entities to which BPA markets Federal power. Those "consumers" or entities are identified within the language of the section itself. In pertinent part, section 5 provides, "in order to make the power and energy generated at said projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal Government, public bodies, cooperatives, and privately owned companies." The last of these consumers, "privately owned companies" is a reference to privately owned aluminum plants In testimony before the subcommittee of the Senate Committee on Commerce drafting Section 5 language, Arthur Goldschmidt, Director of the Division of Power, Department of Interior, testified that: "At Bonneville . . . we seek that kind of a customer, such as aluminum or magnesium, or carbide, where they take juice in huge quantities and take it around the clock. . . . That base-load operation is the kind of operation that we prefer to have, and the private company operating that type of operation prefers to be upon our power line because it wants to have a direct service with the actual generation of the power. . . . For that reason all of the aluminum in the Northwest is directly on our lines, both the Government-owned aluminum and the privately owned aluminum plants, . . ." Bonneville Power Administration, legislative History of Section 5 Flood Control Act of 1944.

another in terms of lowest possible rates. Also, the *Cal. Energy Comm'n* case rejected that very approach. The power marketing administrations do not operate on a profit-making basis, but must balance a number of considerations.[53]

Finally, *PNGC II* references in passing section 9(b) of the Northwest Power Act. That section requires that the "Secretary of Energy, the Council, and the Administrator shall take such steps as are necessary to assure the timely implementation of this Act in a sound and business-like manner." 16 U.S.C. § 839f(b). As the legislative history makes clear, the purpose of this provision was to recognize the respective responsibilities of the Department and the Administrator, so that "Bonneville cannot be delayed in its activities while these [DOE] officials review contracts, budgets, labor agreements, and other matters" and the legislation be "carried out effectively and in a timely manner." Cong. Rec. H 10685 (November 17, 1980)(Remarks of Rep. Dingell). A requirement to take such steps as are necessary to assure the timely implementation of the Act in a sound and business-like manner goes to, as it says, timely implementation, and cannot be read to say that every decision, discretionary or otherwise, of the Administrator must be consistent with "sound business principles," as that term has been defined by the *PNGC II* court. Yet, that is precisely what *PNGC II* appears to require by setting sound business principles up as the yardstick by which to test the Administrator's decision to serve the DSIs. If section 9(b) did have the broad application evidenced by *PNGC II*, Congress need not have referenced sound business principles, as it did, in connection with the establishment of rates.

BPA has broad authority to act in a businesslike manner, but that authority rests on the Administrator's expansive contracting authority under section 2(f) of the Bonneville Project Act, 16 U.S.C. § 832a(f). That section provides:

> Subject only to the provisions of this Act, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.

The Congressional intent behind this language was "to enable the Administrator to employ business principles and methods in the operation of a business enterprise . . ."

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[53] Five circuits have considered whether the widespread use clause of section 5 of the Flood Control Act provides law to apply to an administrator's decisions in power marketing. Each has concluded that it does not. *See Salt Lake City v. Western Area Power Administration,* 926 F.2d 974, 979 (10th Cir. 1991); *City of Santa Clara v. Andrus,* 572 F.2d 660, 668 (9th Cir. 1978), *cert. denied,* 439 U.S. 859 (1978); *Brazos Elec. Power Coop. v. Southwestern Power Admin.,* 819 F.2d 537, 543-44 (5th Cir. 1987); *Electricities of North Carolina v. Southeastern Power Admin.,* 774 F.2d 1262, 1266 (4th Cir.1985); *Greenwood Util. Comm'n v. Hodel,* 764 F.2d 1459, 1464-65 (11th Cir.1985).

H.R. Rep. No. 777, 79th Cong., 1st Sess., 3 (June 21, 1945). The Northwest Power Act extended section 2(f)'s expansive authority to enter into contracts under that Act.[54]

With the passage of the Northwest Power Act, the Administrator's responsibilities were significantly expanded. The broad grant of contracting authority to enable the Administrator to employ business principles and methods was incorporated into BPA's statutes as a means to enhance BPA's ability to implement its statutory authorities, not to restrain them.

Earlier cases illustrate the important distinction of bringing sound business principles into play when Congress has not clearly addressed a matter and it is necessary to fill the gaps, versus the situation where Congress has specifically authorized the Administrator to take an action, such as serve DSI customers. In cases such as *Bell v. BPA*, 340 F.3d 945 (9th Cir. 2003) (buying out contractual obligations), *Aluminum Co. of America v. BPA*, 903 F.2d 585 (9th Cir. 1989) (wheeling non-Federal Power), and *Dep't of Water & Power of the City of Los Angeles v. BPA*, 759 F.2d 684, 693 (9th Cir.1985) (intertie access), the statute did not address the matter at hand and there was, in the words of *Association of Public Agency Customers v. BPA*, 126 F.3d 1158, 1170 (9th Cir. 1997) (sale of transmission to DSIs), a gap to fill with "how best to further BPA's business interests consistent with its public mission." Indeed, the Northwest Power Act does not address the monetization of contracts, so there again, as in *PNGC I*, it is appropriate to determine what is prudent and businesslike. In other cases, the issues dealt with rates, and a legitimate question arose as to compliance with the sound business principle rate language. *See, e.g., Public Power Council, Inc. v. BPA*, 442 F.3d 1204, 1206 (9th Cir. 2006)(rate adjustment). Here, however, where the question in the first instance is whether the Administrator may choose to serve the DSIs—a contractual decision that then leads to the separate question of monetization at issue in *PNGC II*—Congress authorized but did not require the Administrator to provide service to DSI customers. 16 U.S.C. § 839c(d)(1)(B). There is simply no reason to look to section 2(f) or 9(a) when reviewing the Administrator's decision to serve DSIs, for the simple reason that DSI sales are authorized and offered under section 5(d)(1)(A), not section 2(f), 9(a) or any other provision of BPA's enabling legislation.

BPA's concern that the *PNGC* panel fundamentally misreads the statutory references to "sound business principles" as having expansive sweep is confirmed by the following passage:

> Even more relevantly, the Sixth Circuit, in interpreting *a statutory directive very similar to the statutory requirements at issue here*, concluded that there was sufficient law to apply. *See* <u>*McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006)</u>. In *McCarthy*, the Sixth Circuit held that an electric cooperative's decision to incur "non-necessary expenses," if proven true, would "clear[ly]" violate

[54] "Subject to the provisions of this Act, the Administrator is authorized to contract in accordance with section 2(f) of the Bonneville Project Act of 1937 (16 U.S.C. 832a(f)). Other provisions of law applicable to such contracts on the effective date of this Act shall continue to be applicable." 16 U.S.C. § 839f(a).

> the cooperative's statutory duty under Tennessee law to provide its "members with electricity 'at the lowest cost consistent with sound business principles.' " *Id.* at 410 (citing Tenn. Code Ann. § 65-25-203).

PNGC II, 835 F.3d at 838 (emphasis added). BPA does not operate under a statutory duty to provide its customers with electricity at the lowest cost consistent with sound business principles, such that every facet of its business is reviewable under that standard. It operates under responsibilities to *set rates* as low as possible consistent with sound business principles, to *timely implement* the Northwest Power Act in a sound and business-like fashion, to *exercise its section 2(f) and 9(a) authorities* in a business-like manner, and to market some power in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles. See also, section 2(4) of the Act, ("to provide that the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources to meet the region's electric power requirements, including the amortization on a current basis of the Federal investment in the Federal Columbia River Power System"). None of the foregoing, however, can be read to mean that BPA may not take a discretionary action, such as serving DSI load, if that would increase other customers' costs. This is not how the standard has ever been applied and is not how it was ever intended to be applied. In short, the Court appears to have turned the standard on its head so that it now shackles BPA and is a basis for constraining agency flexibility rather than expanding it, as was Congress's original intent.

However, regardless of these concerns and arguments, BPA must ensure its Block Contract with Alcoa is consistent with *PNGC II*.

VII. REGIONAL JOB IMPACTS AND COST CAPS

a. Cost Caps

If service were to be provided to Alcoa for a Second Period, which requires the court to modify the Equivalent Benefits test, at a forecasted cost matching the maximum allowable under the Cost Caps, and if it were to be served at a weighted average annual IP rate linked to BPA's Tier 1 PF rate forecasted to be $38.22 per MWh, a cost of only $60 million per year, or $300 million for the entire Second Period, would be borne by the preference customers. (*See* Table 2 of Exhibit B in the Block Contract) Using the traditional yardstick that $60 million in cost per year translates into a one mill per kWh impact in the PF rate, the PF rate would increase by approximately one mill per kWh. That is a modest and tolerable rate increase, and one that BPA believes is reasonable given the tangible and intangible benefits of continued DSI service, as discussed in this ROD. We project that even with such an increase, the Tier 1 PF rate will be no more than 4% greater (and lower under an expected case) than they otherwise would be as a result of service to the DSIs (all other things being equal), a level that continues to assure preference customers very substantial system benefits. The PF rate would still be substantially below expected market rates.

Responding to extensive comments discussed and rationale detailed in Part IV, section (e) of this Record of Decision, Cost Caps will apply only to BPA's evaluation of whether it will provide service under the Block Contract during the Transition and Second Periods. That said, it is important to note that in response to comments on the Term Sheet (*See e.g.* PPC at 1, August 3, 2009), $300 million Cost Cap in the Second Period (see Exhibit B of the Block Contract) was reduced relative to the $350 million Cost Cap for the similar period in Term Sheet posted July 17, 2009. Reducing the proposed reduction in the Contract Demand from 390 aMW in the Original Contract to 320 aMW discussed immediately below also contributed to this decision.

b. Reduction in Quantity

As discussed above, the 320 aMW contract demand is a reduction relative to the 390 aMW available to it in the Subscription Contract and even higher amounts available under previous contracts. On the other hand, it is more than the 240 aMW offer in the December Draft Contract. *See also* Parts III and IV of this Record of Decision. That said, what is important is that the 320 aMW level supports Alcoa efforts to operate the Intalco Plant under a diversity of aluminum price environment (*see* Alcoa at 1, June 22, 2009), but also reduced the risks to BPA and its other customers when done in combination with the $50 million reduction in the Cost Cap for the Second Period discussed above.

c. Term Reduced from 17 to 7-years

In the lead-up to the December Draft Contract, Snohomish encouraged BPA to reduce the term length to mitigate risks. See Snohomish in MOU080610 at 2. We took this under consideration in releasing our Term Sheet and shortened the term from 17-years under consideration in the December Draft Contract to 7 years in the Term Sheet. This allows the costs and risks BPA and its customers may be exposed to in the future as it relates to DSI service to be considered more contemporaneously with future contract offers for DSI service, if any. BPA decision to have a seven year term for the Block Contract is also discussed in section IV(d) of the ROD.

d. Socio-Economic Implications

In determining whether to offer DSI power service, the Administrator also considered the regional economy and the potential for net positive employment. He did so because, as the Court has concluded, the agency has discretion whether to offer contracts to the DSIs. Operating within the confines of the law, as interpreted by the Court, the Administrator believes this discretion should be used in the context of whether it promotes public benefits, including such issues as job impacts.

A large number of comments were supportive in this regard. U.S. Senators Murray and Cantwell, along with Representatives Larsen and Inslee, representing the State of Washington, offered the following comments:

> We also appreciate BPA's efforts to continue negotiating long term contracts with the direct service industries (DSIs). While we realize the legal complexities around this issue, we believe this modified draft contract will give Alcoa, Inc. an opportunity to continue operations and keep over 500 family-wage jobs in Whatcom County.
>
> According to recent studies, aluminum companies make a positive contribution to Washington state's economy, in particular by providing family-wage jobs. The Intalco smelter opened its doors in 1966 and is currently one of the top employers in Whatcom County, with over 500 workers. With high unemployment levels across the region, and while our country continues to face tough economic times every job is valuable.
>
> We have worked for decades across state borders and political parties to protect the value of our low cost federal power system for everyone in the region and to distribute those benefits as widely as possible within the confines of the law.

Washington Governor Christine Gregoire offered similar sentiments:

> I know you understand the importance of this issue to the state. There are over 500 family-wage jobs at stake, jobs that are essential to our ability to make it through and recover from this recession. The Intalco facility is critical to the health of the local communities and to the economic health of this depressed area of the state.
>
> In our view, the proposed power contract readily meets your statutory requirement to ensure sound business principles. The contract secures the benefits of ongoing employment, provides certainty of future power demand, and offers clear benefits to the transmission system. The proposed power reserves provide the flexibility needed to integrate intermittent renewable energy sources such as wind—a high priority for our state. The two phases provide sufficient flexibility to resolve and meet the requirements of the court.

See also, comments of Washington State Senator Kevin Ranker ("I remain baffled by the fact that this original BPA customer continues to be singled out and treated inequitably compared to other customers of this federally owned power system"); Whatcom County Executive Pete Kremen ("Intalco's presence contributes far more than economic stability; it is an important thread of the social fabric of this community"); and dozens of supportive comments from Intalco employees, citizens of Whatcom County; and local businesses.

Despite these expressions of legitimate concern over the economic well-being of the region, public preference groups have attempted to use the Administrators' responsiveness as a means of impugning BPA's motivations and undermining its legal analysis. PPC, for example, posits that the Administrator's long-standing commitment to preserving regional jobs is evidence the contract is not based on sound business principles. PPC goes on to make an even more startling accusation: "[BPA's] October 30th letter, as well as the contract itself, indicates that one of the main reasons for which BPA is proposing to enter the deal is to continue to try to advance its policy goal of prioritizing smelter jobs over other jobs in the region." WPAG strikes a similar note, arguing that BPA is using the same justification that has already been discredited by the Court: "BPA is again arguing that it has the authority to offer the proposed Agreement because it strikes a reasonable balance between the rate impacts to its other customers and keeping the Alcoa smelter in operation in order to save family wage jobs in the region." (1) citing Burns October 30 Letter, p. 1**.** ICNU joins this chorus as well, announcing, apparently that the Court has ordered the Administrator to desist from any consideration of the health of the regional economy: "Once again, BPA is relying upon a rationale inconsistent with the 9th Circuit's decision to justify the new Alcoa contract [i.e., strike a balance between minimizing impacts to BPA rates and providing the direct service industries (DSIs) a chance to continue operating in the Pacific Northwest]." (2)

Such statements suggest that the Administrator does not understand that his policies in this connection do not, in and of themselves, provide legal justification for the proposed contracts. As this ROD itself attests, the Administrator is keenly aware that the Court has determined that saving regional jobs is not an adequate legal justification for offering service to a DSI customer. He is cognizant of the fact that the Court has found that such a determination must be predicated on sound business principles, as articulated by the Court. However, the Administrator does not understand the Court to have issued a gag order that would foreclose the Administrator from even speaking about his concerns about employment in the Pacific Northwest. Nor does the Administrator believe that the Court has imposed a standard so strict, and so out of touch with reality, that the Administrator cannot, in a Record of Decision, public announcements, or in court pleadings, that speak to the socio-economic issues that are influenced by the decisions he makes.

We understand that the Court has ruled that BPA cannot use net job impacts as the legal justification for offering Alcoa a contract. BPA is not using that logic in this ROD. BPA does not agree with the Court that public benefits, such as employment impacts, should not be considered, but for purposes of this decision, has conformed its practices and analysis to the Court's conclusion.

In this ROD, BPA has made the case for continued DSI service within the confines of the Court's opinions. The Administrator fully intends, to exercise discretion where it is available to seek to implement good public policy. Further, he will continue to develop policies that he believes are the right policies from a public interest standpoint, rather than considering only a limited set of interests. If the Administrator did not believe that the proposed contract was sustainable under the Court's newly-announced standard, he would not offer it under any circumstances. If he believed, however, that the contract did not promote sound policy goals, he would certainly be less inclined to offer it, even if the legal sustainability of the proposal was essentially a "slam dunk."

Expressing the Administrator's policy concerns and goals is not a license for PPC and others to argue that the entire legal predicate for providing DSI service is fatally flawed at the outset. Responding to legitimate concerns expressed in public comments which are not completely aligned with public power does not undercut the legal and economic analysis developed by BPA in response to the Court's opinion, even if such concerns do not, in and of themselves, provide the legal basis for the Administrator's decision.

More specifically, the Administrator does not, as PPC suggests, have a "policy goal of prioritizing smelter jobs over other jobs in the region." (3) BPA's position has been clear in this regard for many years now. The Administrator believes that the agency should do what it can, within the bounds of the law, to provide service to smelters in a manner that promotes, but does not guarantee, their continuing survival and only if the result is a likely public benefit such as a net positive employment impact. To be clear, that is not BPA's legal justification, but rather the policy setting for providing a legally sustainable contract. That is why, in light of the *PNGC* opinions, BPA determined in this instance to offer firm power service only for a seventeen month period during which it can be shown that the benefits of providing such service equal or exceed the costs. BPA does not believe the Equivalent Benefits Test should be the only means of providing service to Alcoa, but unless and until there is more clarity concerning legal requirements, BPA stands by its equivalent benefits analysis.

As to the economics of the transaction, BPA's analysis shows that continuing service to Alcoa via the Block Contract, within the Cost Cap levels specified in Exhibit B, will result in net positive gains in employment. The following discussion summarizes BPA's use of the 2006 *Regional Employment and Economic Study* to contemplate the 7-year Block Contract power sale contract that makes available physical service at the IP rate for up to 2-potlines at the Intalco facility and why we believe that it remains an indicator that moving forward with this contract should yield a small, positive economic benefit to the region.

The study evaluated four alternatives representing different delivery mechanisms and levels of benefits for the two aluminum smelters:

> Alternative 1 – No benefits; meaning that BPA would not offer power sales to the DSIs
>
> Alternative 2 – Financial benefits based on up to 560 average megawatts (aMW) capped at $59 million of net annual benefits.
>
> Alternative 3b – Up to 560 aMW at BPA's industrial preference (IP) rate
>
> Alternative 4 – Up to 560 aMW at BPA's priority firm (PF) rate.

Alternative 1 has no adverse impact on BPA's other customers. Alternative 2 capped the rate impact on BPA's other customers at $59 million – the equivalent of a $1.00 per MWh change in the PF power rate. Under this alternative, the regional economic study indicated a long-term net gain in employment between 95 and 1,232 jobs, considering a loss of up to 1,110 jobs in non-DSI related sectors, and a gain of up to 2,342 jobs at the smelters and in related sectors.[55] Alternatives 3b and 4 were both evaluated using a BPA power rate of $31.50 per MWh.[56] Both of these alternatives represented power sales of up to 560 aMW. As illustrated in Table 18-A included here for reference, a range of uncapped, market-priced purchases to support these power sales was then used to calculate BPA's cost for providing this power to the DSIs:[57]

TABLE 18-A - Market Prices and BPA Exposure

Market Price ($ / MWh)	40	45	50	55	60	70
BPA Exposure ($ millions)	40	64	88	111	135	182

The study then concluded that the short-term "positive economic impact of DSI service is significantly reduced as market prices go up" for Alternatives 3b and 4, and illustrated how this exposure adversely affected non-DSI employment in Table 19.[58] Importantly, the authors then contemplated the long-term employment impact of Alternative 2 in Table 21. The indirect non-DSI employment impacts were constant as the price of electricity changed because of the capped nature of the exposure from DSI benefits under Alternative 2 on BPA's other customers.

It is important to understand that the value of the study to BPA was, and is, as an estimate of the potential regional employment impact if it were to offer new contracts to the DSIs. The economic assumptions were not intended to be absolutely predictive. However, the estimates continue to be instructive and help BPA make the decision to proceed or not proceed with a contract offer to the DSIs, including establishing the appropriate Cost Cap levels to support an outcome of expected potential net employment gains in the region.

This Block Contract does that by establishing cost caps for the purchase of power to supply the DSIs, including other provisions to limit BPA's financial exposure and requiring Alcoa to maintain jobs even during periods of curtailment. The contract also limits the amount of power BPA would supply to the DSI aluminum smelters to no more than 460 aMW (i.e., 320 aMW for Alcoa and 140 aMW for CFAC, even though CFAC has declined the current offer). These mechanisms – taken together – are designed to limit the exposure of BPA' s other customers to no more than $86 million per year in the last 5 years (i.e. $60 million for Alcoa plus $26 million for CFAC) – proportionately

[55] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 2.

[56] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 20.

[57] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 20. While the study indicated "not all of the 560 MW would be used", the BPA Exposure in Table 18-A is substantially equal to the difference of the Market Price less $31.50 per MWh, multiplied by 560 MW times 8,760 hours in a year (i.e. $41.7 million = (40-31.5) * 560 * 8760).

[58] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 21.

reflecting the $50 million reduction in Alcoa's cost cap to $300 million in the last 5 years of the contract.[59]

These Cost Cap limits on the exposure of BPA's other customers are in contrast to the $182 million exposure of Alternatives 3b and 4 at a $70 per MWh market price described in Table 18-A included above, and are more comparable to the capped nature of Alternative 2, but do so under a physical power sale. To further consider the potential regional economic impacts of such limits in a contract offer, BPA revised Table 21 (taken from the study and included below) by updating four inputs to be consistent with this contract and to reflect more contemporary economic analysis. First, the indirect non-DSI job loss was increased from 1,110 to 1,316 – proportional to the increase from the $59 million capped cost in Alternative 2 to Alcoa's $300 million cost limit for the Subsequent 5-year Period in this contract, respectively.[60] Second, the effective power rate in this contract is the IP rate which is now forecast to escalate from the $34.60 per MWh in fiscal year 2010 at 2.5% each year thereafter, as opposed to the market price of power purchases minus the $12 per MWh financial benefit contemplated in Alternative 2.[61] This updated IP rate forecast reflects the IP rate adopted in the WP-10 rate proceeding and results in a $2 per MWh reduction in the cost cap. Third, direct smelter employment was reduced to 528 jobs – or 2,640 job-years – to reflect minimum employment commitments during periods of 2-potline smelter curtailment operations possible in the Block contract for Alcoa.[62] Lastly, BPA employed the Primary Metals multiplier of 2.782 released by the State of Washington in May 2008 which is lower than 3.2 – the simple average of the high and low indirect employment multipliers (3.9 and 2.5, respectively) utilized in the regional economic study.[63] The combined effect of updating these assumptions to be consistent with this Block contract for Alcoa is illustrated by this revised Table 21:

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[59] Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 3 of Exhibit B.

[60] Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 2; Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 3 of Exhibit B.

[61] Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 3 of Exhibit B; and Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 2.

[62] Draft Power Sales Agreement with Alcoa, Bonneville Power Administration, August 19, 2009, page 1 of Exhibit G.

[63] "2002 Washington State Input-Output (I-O) Study", State of Washington, Office of Financial Management, May 2008, page 15; and Regional Employment and Economic Study, William B. Beyers, Lloyd O'Carroll, Paul Sorensen, August 14, 2006, page 13.

TABLE 21 - Long Term Employment and Income Impact Alternative 2 [REVISED]						
Price of Electricity $/MWh (IP rate)	40	45	50	55	60	70
Employment (job-years)						
Direct DSI	2,640	2,640	2,640			
Alcoa	2,640	2,640	2,640	**5 - YEAR**		
CFAC	-	-	-	**JOBS ASSESSMENT**		
Indirect DSI	4,704	4,704	4,704			
Indirect non-DSI	(5,640)	(5,640)	(5,640)			
Total	1,704	1,704	1,704	**NO CURTAILMENT**		

As this revised Table 21 continues to indicate, BPA believes there is a small, genuine economic benefit to our region in the form of a net employment gain of up to 1,704 job-years – or 312 jobs – as a result of this contract. This is an increase relative to the net employment gain of up to 764 job-years – or 152 jobs – reflected in the jobs assessment released with the term sheet and is the result of the lower cost cap.

In addition, the Block contract reduces the cumulative length of curtailment in the last 5-years of the contract term from 24-months to 18-months and added Alcoa's commitment to provide at least 120 jobs over the duration of each curtailment. When combined with the lower cost cap, BPA's revision to Table 21 below indicates that net jobs would at least remain neutral to slightly positive under the assumption that Alcoa were to curtail its maximum amount for 18-months during the last 5-years of the proposed contract:

TABLE 21 - Long Term Employment and Income Impact Alternative 2 [REVISED]						
Price of Electricity $/MWh (IP rate)	40	45	50	55	60	70
Employment (job-years)						
Direct DSI	2,028	2,028	2,028			
Alcoa	2,028	2,028	2,028	**5 - YEAR**		
CFAC	-	-	-	**JOBS ASSESSMENT**		
Indirect DSI	3,613	3,613	3,613	**1.5 - YEAR CURTAILMENT**		
Indirect non-DSI	(5,640)	(5,640)	(5,640)	**120 jobs during curtailment**		
Total	1	1	1			

There is also potential for the net gain in regional employment to approach 1,500 jobs – or 7,000 job-years – if BPA and Columbia Falls Aluminum Company come to agreement on principles for a long-term power sales contract, Alcoa returns to its October 2008 employment level of 660 workers at Intalco and BPA is able to purchase power at a $52 per MWh forward price, which is $6 per MWh below the reduced per unit cost caps in this draft contract, thereby reducing the costs borne by its other customers by $25 million per year and mitigating the Indirect non-DSI employment impact. The combined effect of these events is illustrated in BPA's revision to Table 21 below:

TABLE 21 - Long Term Employment and Income Impact Alternative 2 [REVISED]						
Price of Electricity $/MWh (IP rate)	40	45	50	55	60	70
Employment (job-years)						
Direct DSI	4,455	4,455	3,300			
Alcoa	3,300	3,300	3,300			
CFAC	1,155	1,155	-			
Indirect DSI	7,938	7,938	5,880			
Indirect non-DSI	(5,640)	(5,640)	(3,948)			
Total	6,753	6,753	5,232			

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Based on the analysis just discussed, BPA has decided to execute the Block Contract with Alcoa, with Cost Caps as defined in Exhibit B. In addition to meeting the legal requirements as set forth by the Court, the Block Contract is expect to result in benefits to the region in the form of a small but positive net employment gain.

In addition, even if service were to be provided to Alcoa for a Second Period at a cost matching the maximum allowable under the Cost Caps, and if it were to be served at an IP rate linked to BPA's Tier 1 PF rate, a cost of only $60 million would be borne by preference customers. Using the traditional yardstick that $60 million in cost per year translates into a one mill per kWh impact in the PF rate, the PF rate would increase by approximately one mill per kWh.65 That is a modest and tolerable rate increase, and one that is well worth the cost given the tangible and intangible benefits of continued DSI service, as discussed in this ROD. We project that even with such an increase, the Tier 1 PF rate will be no more than 4% greater than they otherwise would be as a result of service to the DSIs (all other things being equal), a level that continues to assure preference customers very substantial system benefits. The PF rate would still be substantially below expected market rates.

VIII. PROCEDURAL AND OTHER ISSUES

a. Adequacy of Contract Review

Several parties raise a concern over the adequacy of the time allowed them to review and participate in the drafting of the Block Contract. Many complained that BPA provided insufficient information to evaluate the proposed transaction, that such information was not provided in a timely manner, that BPA's analysis should be subject to a hearing under section 7(i) of the Northwest Power Act, or requested that BPA meet with them to answer their questions with respect to the Block Contract. PPC at 2 (requesting meeting with BPA); NRU at 2 (requesting meeting with BPA); PNGC at 2 (requesting meeting with BPA); Snohomish at 1 (economic analysis not timely posted, too little time); SUB at 1-2, 7 (each of the foregoing complaints). WPAG echoed these concerns, claiming the contract was drafted in a closed process in a manner that conflicts with BPA's standard business practice, which has deprived BPA of the timely input of all but Alcoa, and that given the technically complex contract one week to review and comment was unreasonable. WPAG at 3-4.

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[64] If the Block Contract results in financial losses to BPA, there would be no rate impact to BPA's customers until at least October 2011. Rates are set for FY 2010-2011 and the probability of the cost recovery adjustment clause triggering in FY 2011 is near zero.

[65] As mentioned previously, the rates established in the WP-10 rate proceeding include approximately $38 million per year to address the costs and risk of industrial firm power service to the DSIs in FY10 and FY11. (*See* WP-10-FS-BPA-05A) A $60 million annual cost would represent an increase of $22 million over what is already included in the rates BPA has adopted. Such an increase would represent an increase of approximately one-third of one mill per kWh to the average annual PF rate of $27.22 per MWh, or less than 1.5%-percent.

BPA disagrees that there has been inadequate public review and participation in the drafting of the Block Contract. In situations where preference customers are negotiating contracts, there are many situations where there is broad alignment on the issues. There are some situations where that is not the case, but still it is appropriate to hear a variety of views. In such situations, it can make sense to conduct meetings that include a wider variety of interests. Negotiating with DSIs is a different matter, where BPA is dealing with a commercial customer rather than utility customers and there is no alignment of interests that would counsel broader participation. Moreover, given the contentious positions adopted by most preference customers, it is unlikely that inclusion of preference customers in negotiations would lead to a more effective or more efficient negotiating process. In fact, BPA believes that the result would be quite the opposite. Therefore, BPA's approach of making draft contracts available for review and comment makes more sense. It should be noted that the public processes have included broader public meetings which allowed parties with very different points of view to freely voice their opinions to BPA executives. BPA's approach in this connection is sufficiently transparent and inclusive. BPA has considered comments on DSI service issues eight times over the course of the past two years.

As BPA and Alcoa have worked to develop a power service agreement there has been an ongoing public process to review the proposed agreements. As described in the Background section of this ROD, there has been a regular public process to review all draft contracts and to provide input on them. In PPC's November 9, 2009, comments it stated, "As you know, based on numerous comments and discussions we have had on this topic, PPC opposes any service the Direct Service (DSIs) that comes at the expense of the preference customers." PPC added a footnote which states that PPC and other parties have now submitted numerous comments to BPA on the topic of whether it should sign a long-term contract for service to the DSIs. PPC went on the incorporate by reference all of its previously submitted comments on the topic submitted over the past two years. Id. Similarly, WPAG states in its November 9, comments that this is the fourth time that the WPAG utilities have submitted comments to BPA on the proposed service. WPAG adds that the proposed Agreement is not new, but is essentially a repeat of the agreement upon which the WPAG utilities have previously commented. ICNU's November 9 comments also state that ICNU and BPA's preference customers have previously filed comments regarding the details of BPA's proposed agreements with Alcoa and CFAC. In response to comments that the Block Contract was negotiated behind closed doors and out of their view, it is BPA's practice to negotiate with private companies in a manner that respects and protects the business sensitive information those companies often divulge. This is unlike the public body, municipal, and cooperative utility customers that are consumer owned and operated in a manner open to the public. Once BPA and a DSI customer, like Alcoa, have reached terms the Administrator believes are reasonable they are brought into the open for review and comment by the public. As such, BPA acts in a sound and reasonable business-like manner.

Given the request by its public customers to meet with them to discuss the draft Block Contract, BPA's Deputy Administrator and other BPA staff met with several preference customers at the offices of the PPC on November 3, 2009. The prepared materials that BPA presented at this meeting are attached hereto. Attachment G. As further noted by PNGC in its comments of November 9, 2009, "BPA has met with its consumer-owned utility customers and discussed the assumptions and resulting forecasts in conjunction with actual market prices for the proposed agreements." With respect to the amount of time allowed for comments, BPA can only note that it provided adequate time given that these issues have been thoroughly discussed in the past. BPA is mindful that the development of the Block Contract has been ongoing for over a year, which has included several public meetings and opportunities for review and comment on proposed service alternatives. Given the relatively straight-forward nature of the Block Contract and BPA's economic analysis, BPA believes customers had sufficient time to carefully evaluate the contract and BPA's analysis, and that this fact is evidenced in the generally high quality of comments received.

SUB commented that BPA's analysis of the Block Contract is subject to a section 7(i) hearing under the Northwest Power Act, or that it must be subjected to the same level of scrutiny associated with a section 7(i) hearing. SUB at 7. This is incorrect. A decision to offer a contract for the sale of power under section 5 of the NWPA is not a proposal to set wholesale power rates under section 7 of the act. BPA's analysis of the economic effect of a proposed contract is clearly not subject to a section 7(i) rate hearing, since BPA is not establishing rates in the Block Contract, nor could it. SUB cryptically suggests BPA is "decoupling" its forecast of benefits under the Block Contract from "the WP-07 rate setting process which includes a number of components – including loads and risks." SUB at 7. SUB appears to be suggesting that any contract BPA proposes to execute during the term of a rate period requires BPA to re-open its rate proceeding to reconcile the rate impacts of the contract to BPA's rate case final decisions with respect to, among other things, "loads and risks." Id. In simplest terms, BPA sets its rates to recover its forecast costs over the term of the rate period. As noted, BPA allocated $37 million in forecast costs to its base rates to serve DSI load in the WP-10 rate proceeding, which covers the term of the Block Contract. That is not to say, as is suggested by SUB, that any proposed action by BPA within the WP-10 rate period that could result in BPA incurring costs not expressly contemplated in the rate case requires BPA to re-open that rate case; such costs, if incurred, would be paid for through cash reserves, planned net revenues for risk, or other risk mitigation tools such as the cost recovery adjustment clause.

In sum, a section 7(i) proceeding is required only to set BPA's rates for power and transmission service. The applicable charge for power sold under the contract is the IP 10 rate, which BPA established in the WP-10 Wholesale Power Rate Proceeding. BPA is not changing or modifying that rate as a part of the transaction. There is no other rate involved. Therefore, a 7(i) proceeding is not required.

b. Sequencing of *PNGC I* Remand

PPC argues "BPA cannot plausibly argue that any exigent circumstances compel this cart-before-the-horse approach, since BPA's own analysis shows that Alcoa should be basically indifferent to whether BPA offers the 19-month sale or not." (6) PPC goes on to say "Once BPA concludes that process [the lookback] it will be required to seek repayment from Alcoa. It would be odd indeed for BPA to agree to forego a contractual provision guaranteeing such a payment by Alcoa." SUB commented in an earlier process that BPA must resolve any lookback amounts owing by the DSIs, including Alcoa, associated with the Court's remand in *PNGC I*. *See* SUB comments dated September 9, 2009, regarding "Draft Seven-Year Agreements: Alcoa & Columbia Falls Aluminum Company", at 6. BPA believes that final decisions by BPA in connection with that remand are unrelated to BPA's decision to enter into the Block Contract, and that nothing in the Block Contract precludes BPA from seeking restitution from Alcoa in connection with the remand if, in fact, that is the outcome on remand, or in later raising rates to Alcoa to effect such restitution. Final resolution, including judicial review, of the issues on remand in *PNGC I* are likely to be contentious and time consuming, and BPA sees no good reason to delay entering into a new Block Contract with Alcoa until that process is completed.

c. BPA's exposure to market purchases in excess of the IP rate

NRU suggests that there should be a check-in half way through the term of this contract to determine whether the contract is still in the money. If it is not, then an adjustment should be made to the IP rate so that the IP rate as applied to the Alcoa and CFAC loads will generate more revenues than BPA would have obtained through market sales of power. *See* NRU in ALC090151 at 1.

NRU's proposal would fundamentally deprive Alcoa of the benefit of its bargain, and is commercially unreasonable. Not only is NRU's proposal unfair, it is also unnecessary. Alcoa has agreed to purchase power from BPA at the IP rate, which is set to recover BPA's cost. On average the IP rate for a substantial portion of the Initial Period of the Block Contract is above BPA's existing forecast of market prices. Certainly, Alcoa has its own reasons for entering into this transaction, and presumably believes purchasing from BPA, even at a small premium to market, is in its own best interests. If market prices fall lower than forecast by BPA, Alcoa is locked into paying the IP rate which would be that much higher as compared to market. If market prices rise above the IP rate, it is commercially unreasonable that Alcoa would also face the possibility of an adjustment to the IP rate to, as NRU proposes, "generate more revenues than BPA would have obtained through market sales of power." Therefore, BPA does not find this to be a reasonable or business-like proposition, or one that is required by the Court.

d. Loss of Money to Benefit the DSIs

In its November 9, 2009 comments PPC states that the contract is founded on the notion that BPA will incur losses in order to benefit the DSIs, at the expense of BPA's preference customers. PPC at 3. PPC asserts that the only rational reason Alcoa would want to purchase power at the IP rate is if it perceives that BPA's IP rate will be below the market in which it can unload its power, the same market into which BPA could sell the power if it were not selling to Alcoa. *Id.*

BPA is not privy to Alcoa's internal business reasons for why it decided to enter into the Block Contract. Whether or not Alcoa will remarket any other power supply is within its discretion and does not preclude BPA from marketing industrial firm power to Alcoa at the IP rate. Such a decision by Alcoa to remarket its own power does not affect the IP rate that will apply to sales of industrial firm power. Assuming, as PPC asserts, that Alcoa decides to unload its power into the market, then it is Alcoa that is taking on the risk of the market and its volatile prices, as it seeks to cover its power costs. BPA, on the other hand, will achieve revenue certainty through its IP rate.

BPA understands that Alcoa has reasons for desiring a long term contract with BPA that go beyond the vagaries of the real time market. A long term contract with BPA provides some degree of price stability that cannot be achieved purchasing in the real time markets. For example, Alcoa can use long term stability in connection with hedging transactions in the aluminum market. A longer term power supply also provides a planning horizon sufficient to allow Alcoa to determine the viability of making capital improvements in the plant itself. *See* Alcoa in DSL090057 at 2.

e. Relationship to BPA's Financial Plan

Springfield Utility Board raised two issues regarding the relationship of the Block Contract and BPA's Financial Plan. First, SUB argues that the proposed contract violates the Good Year/Bad Year (GY/BY) section of the Financial Plan published in January 2008. Second, Springfield Utility Board argues that the Financial Plan implies that the "cost of providing service to DSI's can create volatility . . . and that DSI's can have a significant effect on BPA's costs and risks." SUB in ALC090155 at 8.

Specifically, SUB argues that the proposed contract is a specific Good Year/Bad Year plan of action that should be addressed in a rate case 7(i) process. SUB argues that the proposed contract violates the GY/BY standards outlined in the Financial Plan in that the proposed metric differs from those discussed in the plan, that the proposed metric is complex, unfamiliar and not well understood in the utility and business communities, and that it is biased and obscures tradeoffs between customer groups. SUB at 8.

SUB misinterprets the stated intent of the GY/BY chapter of the Financial Plan, which is to "identify potential alternatives courses of action, propose a framework for comparing them, and discuss the trade-offs between various options." BPA Financial Plan, January 2008, at 23. The Plan also notes that "the purpose of this Good Year and Bad Year planning effort is to generate, document, and begin evaluating issues and possible actions BPA might consider taking over the long term." *Id.* at 26. Finally, the Plan states that "the purpose of the Financial Plan is not [emphasis added] to produce a detailed Good Year/Bad Year plan with specific metrics, thresholds, and detailed courses of action." *Id.* at 30. In other words, the GY/BY chapter is no more than a conceptual discussion of the subject rather than a specific plan. This makes it difficult to violate the terms of a plan as alleged by SUB if a plan does not exist.

SUB also mistakenly interprets the DSI contract as a GY/BY plan. BPA's Financial Plan views such a plan as a tool that allows BPA to take advantage of the opportunities afforded by better than expected financial results or, conversely, to adapt to the changes created by worse than expected results. *Id.* at 23. For example, the different metrics for assessing whether a year is good or bad focus on the target for a specific year. The possible actions available depending on the financial circumstances are actions taken in the year being assessed, in the case of a bad year, or in the following year, in the case of a good year. *Id.* at 26-29. The Block Contract does not propose a similar construct.

Finally, assuming that the Block Contract is a GY/BY plan, SUB mistakenly assumes that the Financial Plan requires the contract to be addressed in a rate case 7(i) process. SUB at 8. While the Financial Plan does state that a detailed GY/BY plan would be addressed in a rate case, BPA reserved the right "to pursue any of these actions if circumstances warrant it, based on continued internal analysis and discussion with BPA's stakeholders." BPA Financial Plan, January 2008, at 30. If this contract is truly a GY/BY plan, BPA may implement it without using a 7(i) process because BPA has conducted the internal analysis and has given stakeholders opportunity for discussion and involvement.

In addition, in a discussion of the evolving nature of BPA's risk profile, the Financial Risk Metrics section of the Financial Plan states that sales to aluminum smelters as so small today that they have little effect on BPA's sales revenues. Plan at 9. SUB also argues that the Financial Plan infers that "the cost of providing service can create volatility." SUB at 8. This interpretation reads a great deal into a very plain statement about aluminum smelters. The Financial Plan is completely silent on how the variability of costs related to DSI service can affect BPA. The only statement about DSI's in the Plan is the one referenced at the beginning of this paragraph and it only notes that sales variability has declined dramatically since the publication of BPA's 10-year Financial Plan in 1993. For the forgoing reasons, the Block Contract does not violate the Financial Plan.

f. BPA has not allocated Equivalent Benefits to any customers

SUB questions whether allocating all benefits to DSIs is consistent with the aim of the DDC to allocate good financial outcomes to customers. SUB at 12. BPA does not entirely understand SUB's statement BPA has allocated all of the benefits to the DSIs and its conclusion that there should be some kind of DDC impact. As noted in BPA's WP-10 rates ROD, "[t]he aggregate impacts of risks on reserves are used to calculate TPP and therefore PNRR during rate cases; after the conclusion of a rate case, further aggregate changes to reserves can result in the triggering of a CRAC or DDC." WP-10-A-02 / TR-10-A-02, Chapter 7 (Risk Analysis and Mitigation) at 45. BPA has assigned a monetary value to benefits received by making the sale to Alcoa. BPA has not allocated those benefits to any customers at this time because they will not actually accrue until the contract is performed. BPA does not believe that type of prospective financial outcome that should contribute to triggering the DDC. However, this type is a ratemaking issue and it would be more appropriate for discussion during a section 7(i) rate proceeding.

IX. ENVIRONMENTAL EFFECTS

a. NEPA Evaluation

BPA has reviewed the proposed block power sales contract with Alcoa for potential environmental effects that could result from its implementation, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, et seq. Based on this review, BPA has determined that the Block Contract falls within a class of actions excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA. More specifically, this contract fall within Categorical Exclusion B4.1, found at 10 CFR 1021, Subpart D, Appendix B, which provides for the categorical exclusion from NEPA of actions involving "[e]stablishment and implementation of contracts, marketing plans, policies, allocation plans, or acquisition of excess electric power that does not involve: (1) the integration of a new generation resource, (2) physical changes in the transmission system beyond the previously developed facility area, unless the changes are themselves categorically excluded, or (3) changes in the normal operating limits of generation resources." The Environmental Clearance Memorandum that documents this categorical exclusion for the contract has been posted at BPA's website at: http://www.efw.bpa.gov/environmental_services/categoricalexclusions.aspx.

b. Comments on Environmental Effects

During the public comment period for the proposed Block Contract, BPA received comments from two entities – Canby Utility Board and Springfield Utility Board – that raised issues concerning the NEPA process for the Block Contract. The following identifies these issues and provides responses.

EIS is not Necessary

SUB argues that BPA should prepare a new Environmental Impact Statement (EIS) before entering into the Block Contract. SUB at 17.

Under NEPA, EISs are required for proposed major federal actions – i.e., those proposed actions with the potential for a significant environmental impact. Accordingly, if a proposed action would not have the potential for a significant environmental impact, no EIS is required. Furthermore, an EIS is not required where the federal action maintains the environmental status quo.

As explained above, BPA has reviewed the Block Contract under NEPA and determined that the federal action of continuing to supply power, whether in monetized form or any actual power transfer, would not have the potential for a significant environmental effect. BPA expects to supply power to Alcoa's Intalco Plant from existing generation sources, and these sources would be expected to continue to operate within their normal operating limits. This power would be supplied to the Intalco Plant over existing transmission lines that connect the existing Intalco Plant to BPA's electrical transmission system, and no physical changes to this system would occur. In addition, the Block Contract would not cause a change in the Intalco Plant's existing operations in such a way that environmental impacts would significantly differ from the currently existing situation. Therefore, BPA has appropriately prepared a Categorical Exclusion for the proposal to continue power sales to Alcoa, and an EIS is not necessary.

No Change in Environment Impacts

Canby argues that BPA should analyze environmental impacts that may occur from purchases of power needed to fulfill the Block Contract. Canby at 11.

As indicated above, BPA expects to provide power to Alcoa from existing generation sources that would continue to operate within their normal operating limits. As such, there would be no change in any environmental impacts associated with implementation of the Block Contract with Alcoa. If BPA is not able to obtain power to fulfill its obligations under the Block Contract from only existing generation sources operating within their normal operating limits (either through market purchases or from a specific resource), BPA would review the proposed power acquisition under NEPA and conduct additional NEPA evaluation, as appropriate, for the proposed acquisition, once more information is known about the nature, type, and source of the acquisition. BPA also will prepare additional NEPA documentation as necessary prior to making such an acquisition.

Business Plan EIS Is Not Relevant to this Decision

Canby also asserts that the Block Contract appears to be inconsistent with the Market-Driven Alternative that was analyzed in BPA's Business Plan Final EIS (DOE/EIS-0183, June 1995) and adopted by BPA in the Business Plan Record of Decision (ROD, August 1995). Canby at 11.

Because BPA is not basing its decision to enter into the Block Contract on the Business Plan EIS and ROD, these documents are not relevant to this decision. As discussed above, BPA has prepared a Categorical Exclusion for this decision, which is appropriate given the nature of BPA's action under the Block Contract.

X. CONCLUSION

For the foregoing reasons, BPA has signed the Block Contract on the date of this record of decision.

Issued at Portland, Oregon, this 21st day of December, 2009.

____/s/ Stephen J. Wright ________________
Stephen J. Wright
Administrator and Chief Executive Officer