20.5 aMW POWER SALE TO PORT TOWNSEND PAPER COMPANY FOR THE PERIOD NOVEMBER 15, 2009 THROUGH DECEMBER 31, 2010

ADMINISTRATOR'S RECORD OF DECISION

November 13, 2009

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BONNEVILLE POWER ADMINISTRATION
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BACKGROUND

In September 2006, the Bonneville Power Administration ("BPA") entered into a surplus firm power sales agreement (the "BPA/Clallam Contract") with Public Utility District No. 1 of Clallam County, Washington ("Clallam"), whereby BPA agreed to sell to Clallam 17 aMW for the period October 1, 2006, through September 30, 2011. The power to be sold by BPA to Clallam under the BPA/Clallam Contract was for the purpose of, and was expressly conditioned upon, resale by Clallam to Port Townsend Paper Company ("Port Townsend") under a contract by and between Clallam and Port Townsend (the "Clallam/Port Townsend Contract"). The rate paid by Port Townsend under the Clallam/Port Townsend Contract equaled the rate paid by Clallam under the BPA/Clallam Contract, plus a mark-up to cover certain of Clallam's costs associated with providing such service. Petitions for review of the BPA/Clallam Contract were subsequently filed in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit" or "Court").

In December 2008, the Ninth Circuit issued its opinion in *Pacific Northwest Generating Cooperative v. Bonneville Power Administration*, 550 F.3d 846 (2008) ("*PNGC I*"), in which the Court, among other things, held that the rate in the BPA/Clallam Contract was below both the market rate and the Industrial Firm (IP) Power rate and was therefore invalid. *Id*. at 879.

Port Townsend filed a petition for panel rehearing in February 2009, and BPA filed a motion seeking clarification of certain aspects of the opinion in March 2009. In the meantime, so as not to be delayed when the mandate did issue, BPA posted for public comment on June 22, 2009, a draft contract by and between BPA and Port Townsend for the period October 1, 2009, through September 30, 2011, (the "Two-Year Contract") which would have served as a replacement contract for the two years remaining in the BPA/Clallam/Port Townsend transaction. Comments on this draft contract were due July 10, 2009.

On August 5, 2009, the Court amended its original opinion in certain respects in response to BPA's petition but denied Port Townsend's requests for panel rehearing. Port Townsend then filed a motion to stay issuance of the mandate in the case for 90 days. On

August 14, 2009, the Court issued an order staying issuance of the mandate in *PNGC I* for 30 days "to provide Port Townsend and the Bonneville Power Administration time to attempt to arrange for the provision of power to Port Townsend." BPA had prepared an interim contract it believed complied with *PNGC I*, and the parties entered into that contract for the period September 1, 2009, through September 30, 2009 (the "September Interim Contract"). That contract is described in *Bonneville Power Administration Record of Decision For 30-Day Sale of 17 MW to Port Townsend Paper Company Commencing September 1, 2009*, issued on August 27, 2009.

After close of the comment period on the Two-Year Contract, BPA determined that it was unlikely to make a final determination regarding that contract before October 1, 2009. BPA decided more time was needed to fully consider the issues surrounding DSI service in general; BPA believed that any multi-year contract with a DSI customer should be informed by the Court's disposition of petitions for review challenging an amendment to BPA's power sales contract with Alcoa entered into in response to *PNGC I*. That amendment provided financial benefits to Alcoa for a nine month period commencing on January 1, 2009, and ending on September 30, 2009. BPA believed the Court's disposition of those petitions could provide additional clarity with respect to the legal requirements for providing service to the DSIs, including Port Townsend.

On August 28, 2009, the Ninth Circuit issued its opinion in the case challenging the Alcoa amendment in *Pacific Northwest Generating Cooperative v. BPA*, Slip Op. 09-70228 (August 28, 2009) ("*PNGC II*"). *PNGC II* raised additional issues to be resolved regarding service to DSI customers, and BPA concluded it could not reach a final decision whether to offer the Two-Year Contract referenced above prior to October 1, 2009. Specifically, 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 Port Townsend, is consistent with "sound business principles" as BPA believes that standard was described in *PNGC II*.

However, in order to avoid disruption of power service at the Port Townsend facility, and because it could do so consistent with the most conservative reading of *PNGC II*, BPA offered a second interim contract, this one for the period October 1, 2009, through October 31, 2009 (the "October Interim Contract"). BPA forecast that it would earn positive net revenues under the October Interim Contract, and concluded based on that finding that the contract complied with even the most conservative reading of the Court's direction regarding "sound business principles" in *PNGC II*. That contract is described in *Bonneville Power Administration 31-Day Sale of 20 MW to Port Townsend Paper Company Commencing October 1, 2009 – Administrator's Record of Decision*, issued on September 30, 2009.

Prior to expiration of the October Interim Contract, BPA offered a third interim contract, this one for the period November 1, 2009, through November 7, 2009, and then a fourth interim contract for the period November 8, 2009 through November 14, 2009 (together the "November Interim Contracts"), in order to provide BPA with additional time to complete its evaluation of the comments filed by parties with respect to modifications

made to the Two-Year Contract (referred to hereafter as the "Block Contract" as described immediately below), and to draft this record of decision detailing its final decisions with respect to that contract.

BLOCK POWER SALES AGREEMENT

On October 8, 2009, BPA posted for public comment a draft power sales contract with Port Townsend for the period November 1, 2009, through December 31, 2010, (the "Block Contract") whereby BPA proposed to sell to Port Townsend up to 20.5 aMW of power over the term priced pursuant to the IP-10 rate schedule.[1] Comments were due October 19, 2009. This record of decision addresses the comments received, and provides the rationale supporting BPA's decision to enter into the Block Contract, which modifies the Two-Year Contract to comport with *PNGC II*.

1. Description of the Block Contract

Subject to certain possible downward adjustments discussed below, BPA will sell to Port Townsend, and Port Townsend will purchase from BPA, up to 20.5 aMW (up to 21 MW on any hour) of firm power at the point of receipt, over the 14-month term of the Block Contract. Block Contract, Exhibit A.[2] The rationale for making available up to 20.5 aMW is described separately below in section 2. As noted, the rate paid by Port Townsend will be as specified in the IP-10 rate schedule. Block Contract, section 3.1.

Port Townsend's obligation is take-or-pay, but, as noted by Snohomish PUD in its comments (Snohomish at 2), Port Townsend's take-or-pay obligation equals 13 aMW each month, not 20.5 aMW. Block Contract, section 4.1. The take-or-pay amount is less than the 20.5 aMW maximum contract demand due to occasional disruptions experienced in the production process in paper and pulp operations. Snohomish PUD noted in its comments that the contract language "suggests Port Townsend is only required to compensate BPA should [Port Townsend] purchase dip below 13 aMW" and "any fluctuation between 13 aMW and 20.5 aMW is therefore permissible." Snohomish at 2. Snohomish goes on to state its concern that "this conflicts with the general notion of an advance purchase of a specific block of energy." Snohomish at 2. In other words, Snohomish is suggesting that if BPA is offering a block of up to 20.5 aMW to Port Townsend, that BPA will likely purchase resources to serve that firm obligation, and that Port Townsend's take-or-pay obligation should equal the full 20.5 aMW. However, as discussed at length in section 4 below, BPA expects to serve this load from inventory and does not anticipate the need to make specific additional purchases to serve the Port Townsend load. In particular, BPA does not anticipate the need to make *advance* purchases to serve the Port Townsend load. Additionally as further discussed,

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[1] BPA, Clallam, and Port Townsend have agreed this transaction replaces deliveries of surplus firm power to Port Townsend under the BPA/Clallam and Clallam/Port Townsend Contracts through September 2011, and those contracts will be terminated upon commencement of deliveries under the Block Contract.

[2] Section 4.3 of the Block Contract provides for Port Townsend to take up to 21 MWs from BPA on any hour, since power may only be scheduled in whole megawatts.

curtailments allowed under the Block Contract are not forecast to have an advantageous or disadvantageous effect on the equivalent benefit analysis. Therefore, BPA does not anticipate being harmed by, nor does it anticipate any effect on its equivalent benefits analysis given, the 13 aMW take-or-pay amount.

While this take-or-pay obligation is waived to the extent Port Townsend curtails its load pursuant to section 5, Port Townsend remains obligated to pay BPA any amount by which the market value of such curtailed power is below the applicable IP rate. In response to a comment by the Springfield Utility Board (SUB at 7-8) concerning the time lag between when such damages may be incurred by BPA and the time they are paid by Port Townsend, BPA has changed the contract to provide that Port Townsend pay BPA any amounts owing under section 6 of the Block Contract as part of the power bill issued for the month such amounts are incurred, rather than at the end of the fiscal year.[3] In any case, Port Townsend historically has operated its facility with limited curtailments, and while it is unlikely that it will curtail its load over the term of the Block Contract, if it does it is unlikely such curtailment would be for a long duration.

Port Townsend is obligated to prepay each month for 13 aMW. To the extent that Port Townsend takes more power than 13 aMW during the month, then it will pay for such incremental amounts in the following month. Block Contract, Exhibit C. However, to mitigate the payment risk exposure associated with power deliveries in a month in excess of 13 aMW, prior to commencement of deliveries under the contract Port Townsend will pay BPA approximately $213,000 as security. This amount represents the difference between 13 aMW (which Port Townsend is prepaying each month) and 20.5 aMW (the most power Port Townsend can take in any month), multiplied by the highest IP rate over the term of the contract. Block Contract, Exhibit C, section 6. In addition, BPA has the right to demand additional assurance from Port Townsend in the event reasonable grounds for insecurity arise with respect to Port Townsend's performance. Block Contract, section 16.8. If Port Townsend fails to make any payment within 3 business days of its due date, BPA may suspend its own performance, and if Port Townsend fails to make any payment within 7 days of the due date, BPA may terminate the contract. BPA believes the foregoing provisions taken together provide it with ample protection against any default by Port Townsend.

Port Townsend will provide power reserves to BPA under the Block Contract, as specified in BPA's 2010 General Rate Schedule Provisions and Exhibit H of the contract.

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[3] The curtailment provisions are taken from earlier, multi-year DSI contracts. The original purpose behind payment by the DSI of any curtailment damage amounts at the end of the fiscal year, as opposed to monthly, was to allow BPA to calculate a net amount over the entire year, because in the event BPA obtained revenues from remarketed curtailed power in excess of IP revenues, such amounts were to be used as a credit to be applied against damages resulting when BPA revenues from remarketed curtailed power were less than IP revenues, with this calculation being performed at the end of the contract term or fiscal year. As now drafted, in the event Port Townsend pays BPA damages under section 6 in one or more months, but over the term BPA calculates Port Townsend would not owe any amounts because on a net basis BPA remarketed any curtailed power above the IP rate, then any such monthly payments made to BPA by Port Townsend will be refunded. This eliminates the credit risk identified by SUB in its comments.

Block Contract, section 5.2. Issues raised in comments with respect to the reserves to be provided by Port Townsend are addressed in section 6 below.

2. Summary of Comments

BPA received written comments from 12 parties, including from individual public utility customers Springfield Utility Board (SUB), Clatskanie PUD, Canby Utility Board, and Snohomish PUD; umbrella groups representing public utility customers (Public Power Council (PPC)[4], Pacific Northwest Generating Cooperative (PNGC), and Northwest Requirements Utilities (NRU)), and each of the DSIs (Alcoa, Columbia Falls Aluminum Company (CFAC), and Port Townsend).

Public customer comments focused on 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 Port Townsend, or the lost opportunity cost associated with selling to Port Townsend in lieu of selling that power into what they believe will be a higher priced market (relative to the IP rate). PPC at 1-2; Canby at 1-2; NRU at 1; PNGC at 2; SUB at 2-6; Snohomish at 2. 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 Port Townsend 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).

Several comments, in particular 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.

Public customers also questioned whether BPA will be able to serve Port Townsend from inventory, or if it will be required to make market purchases to serve some or all of the

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[4] The Industrial Customers of Northwest Utilities (ICNU), an umbrella group representing the industrial customers of BPA's public preference utility customers, filed comments jointly with PPC.

load. PPC at 2; Canby at 1; PNGC at 2. PPC, SUB, and PNGC also questioned whether Port Townsend 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 Port Townsend load, while SUB noted that such reserves will be unavailable (and therefore worthless) in the event Port Townsend 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 Port Townsend would receive compensation for providing reserves in addition to the reserves credit embedded in the IP rate. Snohomish at 2-3.

SUB and Canby each commented that BPA has inadequately addressed certain risks inherent in a 14-month sale to Port Townsend, 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 4-5; Canby at 2. Similarly, PNGC suggested that the contract be amended to cap BPA's exposure to market purchases equal to the IP rate, and to allow BPA to remarket power under the Block Contract in the event market prices exceed the IP rate by some "reasonable margin," which PNGC noted could be as little as ten percent above the IP rate. PNGC at 2.

Port Townsend expressed concern that the relatively short-term of the Block Contract "impairs the long-term planning so important to an industrial customer such as Port Townsend." Port Townsend at 1. Citing BPA's letter that accompanied publication of the draft Block Contract for public comment, Port Townsend commented that it appeared BPA was taking the position that *PNGC II* prohibits a power sale to a DSI "unless the price is above the market price of power for the time period the power is offered," and that it believed such a reading is at odds with the plain language of that opinion. *Id.* at 2. Alcoa made a similar comment, citing extensively from *PNGC II* to support its position that BPA "need not conduct an accounting analysis that demonstrates that the economic benefits of the contract are equal to, or exceed the cost of providing service" to a DSI. Alcoa at 1-2. CFAC echoed this position, and also commented that BPA needed to take into account transmission costs it would avoid by making the sale to Port Townsend in lieu of selling the power into the market. CFAC at 1.

Port Townsend offered several points it believed BPA needed to consider in making its decision regarding the Block Contract, including the fact Port Townsend's load is "a predictable and stable 24/7 load"; that the Block Contract addresses BPA's credit risk; that Port Townsend has been a BPA direct-service customer for over 60 years, and but for its legal status as a DSI, that it would be entitled to be served by its local utility with BPA power for 40 percent less cost; and that BPA will be locking-in a higher rate "on in-region power sales for all service to Port Townsend, and not just for the power sold during higher-cost periods that Port Townsend otherwise has the right to call upon." Port Townsend at 2.

Parties' comments are addressed herein.

3. Contract Demand of 20.5 aMW

As noted above, BPA will make available to Port Townsend up to 20.5 aMW over the term of the Block Contract, and up to 21 MW on any hour.[5] SUB commented that BPA "has not clearly articulated" why it is proposing "to give Port Townsend more power benefits." SUB at 6.

20.5 MW equals Port Townsend's historic contract demand, as provided by the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §§ 839, 839c(d)(1)(B) ("Northwest Power Act"), as implemented and established in Port Townsend's 1981 power sales contract. Section 5(d)(1)(B) of the Northwest Power Act 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 Port Townsend, this amount was 16.6 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 March 1996 Port Townsend applied to BPA for such an increase associated with its so-called old corrugated cardboard ("OCC") facility load (see Attachment A). BPA approved the request in January 1997, thereby increasing Port Townsend's contract demand (*i.e.*, the maximum amount of IP power BPA may legally provide to Port Townsend) from 16.6 MW to 20.5 MW (see Attachment B).

In the record of decision for the October Interim Contract, BPA inadvertently stated that it had concluded in a 2005 record of decision that its 1997 determination that the OCC expansion load qualified as a technological allowance was incorrect, but qualified instead as a plant expansion under its so-called Atochem policy, and was therefore eligible for PF service from Clallam. In fact, BPA did not conclude in the 2005 record of decision that its 1997 determination was incorrect, and the two things – a technological allowance under the 1981 contract and a plant expansion per the Atochem policy – while not equivalent, are not mutually exclusive. In other words, BPA's 1997 determination regarding the technological allowance remains a valid agency final decision, and Port Townsend's historic contract demand is currently 20.5 MW.

However, BPA's conclusion in the 2005 record of decision that the approximately 3 aMW of production load at the OCC facility could be served by Clallam at the PF rate also remains a valid final decision. As noted above, to the extent this 3 aMW of load is shifted to Clallam, then Port Townsend's contract demand under the Block Contract will be reduced by the same amount.[6] Nevertheless, inasmuch as BPA is forecasting, as

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[5] The Block Contract permits Port Townsend to avail itself of 21 MW in any hour because power may be scheduled only in whole megawatts. For purposes of this discussion BPA's uses the 20.5 MW number.

[6] As noted in the record of decision for the October Interim Contract, Clallam and Port Townsend have undertaken negotiations regarding the terms and conditions under which Clallam would serve OCC load.

discussed in section 5 below, that the average IP rate for the term of the Block Contract exceeds the average market price over the same period, BPA will benefit from increased revenues to the extent Port Townsend avails itself of the opportunity to take as much of its full contract demand of 20.5 MW, rounded up to 21 MW on any hour, or its full average contract demand over the term of the Block Contract of 20.5 aMW, as its operations warrant. For its part, Port Townsend will benefit from the firm availability of up to 20.5 MW, rounded up to 21 on any hour, of IP priced power to meet most of its load requirements, with only amounts above 20.5 aMW priced above IP.[7]

4. BPA Does Not Anticipate Making Additional Market Power Purchases to Serve Port Townsend

Several parties in comments questioned whether BPA believes it will be able to serve Port Townsend over the term of the Block Contract without acquiring additional power. See PPC at 2; Canby at 1; PNGC at 2. PNGC argues that if market prices turn out to be higher than BPA's is forecasting, which PNGC believes will be the case, then BPA is underestimating the cost to serve Port Townsend under the Block Contract. *Id*. BPA does not forecast the need to make purchases specifically to serve Port Townsend under the Block Contract, 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.[8]

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 2010-2019,[9] BPA is forecast to have a surplus of approximately 1,731 aMW on an average annual basis under the middle 80 percent of the historical water conditions for the term of the Block Contract. See 2009 White Book, Table 8 at 40, and Exhibits 11-12 at 104-107. Port Townsend's load under the Block Contract represents less than 2 percent of that forecast surplus. In the recently completed WP-10 Wholesale Power and

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[7] Section 4.3 of the Block Contract provides for Port Townsend to take up to 21 MWs from BPA on any hour, since power may only be scheduled in whole megawatts. To the extent that Port Townsend scheduled more than 20.5 aMW during any month off the BPA system, it would pay BPA for such power pursuant to the Unauthorized Increase Charge contained in BPA's 2010 General Rate Schedule Provisions. The Unauthorized Increase Charge is a penalty rate that reflects market conditions and is three to ten times the IP-10 rate.

[8] 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.

[9] 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.

Transmission Rate Adjustment Proceeding (WP-10) BPA forecast surplus available for secondary sales of 1,694 aMW for FY 2010 (which encompasses most of the term of the Block Contract) and 1,751 aMW for FY 2011 (see Table 4.8.1: Secondary Sales, WP-10-FS-BPA-05A, at 88).

BPA's surplus forecast takes into account certain market purchases, shown here, that BPA forecasts it may make 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

Even after adjusting out these purchases, BPA 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 Port Townsend. In any case, the WP-10 Loads & Resources Study includes 403 aMW for service to the DSIs, including 17 aMW of service to Port Townsend (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. In addition, total DSI load over the term of the Block Contract may well be substantially less than this 403 aMW amount, making market purchases in addition to those referenced above even less likely.

Thus, BPA does not anticipate the need to make specific additional purchases to serve the Port Townsend load. Nevertheless, if any additional purchases become necessary, the average market price during the term of the Block Contract, as explained below, is expected to be below the IP rate paid to BPA by Port Townsend. In addition, and as described in more detail below in response to comments that BPA has not adequately accounted for the risks surrounding the Block Contract, BPA has already included approximately $37 million in DSI service costs in its base rates for each year in the period covered by the Block Contract. Therefore, even if it turns out that BPA does incur some unexpected power purchase costs to serve Port Townsend, it is highly unlikely such costs would exceed the costs BPA already included in its WP-10 rates for DSI service, or even that portion of the $37 million that could be attributed to Port Townsend.[10]

[10] The 20.5 aMW service to Port Townsend contemplated in the Block Contract represents approximately five percent of the 403 aMW of DSI service contemplated in WP-10. BPA has already included approximately $37 million in DSI service costs in its base rates for each year in the period covered by the Block Contract. Therefore, the five percent share of the $37 million that is attributable to Port Townsend is approximately $1.8 million. Given an average annual IP rate of $34.60 per MWh, market prices would have to exceed $44.90 per MWh for the cost to BPA of the service to Port Townsend to exceed the $1.8 million per year that BPA has included in its base rates for the fiscal years 2010 and 2011. Such an average price for a flat load over all of FY2010 is expected to occur in less than 10% of the 3,500 games considered in the uncertainty analysis that is part of BPA's most recent market price forecast. (See generally WP-10-FS-BPA-05, WP-10-FS-BPA-05A and WP-10-FS-BPA-04)

5. BPA Forecasts It Will Accrue Positive Net Revenues Under the Block Contract

For the reasons outlined in this section 5, BPA forecasts that the revenues it will accrue from the sale of up to 20 aMW to Port Townsend at the IP rate will exceed by approximately $75,000 forecast revenues BPA could otherwise obtain from selling that power into the market. See Tables 1-5 below. As a consequence, BPA believes service to Port Townsend under the Block Contract is consistent with even the most conservative interpretation of "sound business principles" as described in *PNGC II*, to wit, that service to a DSI only can be provided if benefits equal or exceed costs.

In addition, BPA believes its forecast of positive net revenues is probably conservative, inasmuch as a firm sale to Port Townsend could redound in certain additional tangible and intangible benefits to BPA's operations. Tangible and quantifiable benefits include, for example: a) avoided transmission costs for a portion of surplus sales;[11] and b) a projected increase in the market price of electricity for BPA's other surplus sales as a result of DSI load operating.[12] Other intangible and qualitative benefits include, for example: a) the 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 so-called "negative pricing" that are the result of rationale economic behavior by suppliers of generation but not

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[11] When BPA makes a requirements sale, its customers – including Port Townsend – cover the cost of transmission through their own transmission contract. Market prices assume power is delivered by the seller to Mid-C. BPA Power Services must pay those transmission costs to move the power to the Mid-C delivery point in order to realize the full market value for its surplus sales. BPA PS maintains an inventory of transmission to move the surplus power it intends to sell. However, this inventory is not sufficient to move all of the surplus power BPA would sell under all water conditions. As a result, there is a subset of water conditions under which BPA would incur an incremental transmission cost to sell the incremental surplus energy if it did not sign contracts to serve the DSI loads – including the Block Contract with Port Townsend. These incremental transmission costs are avoided when BPA makes an IP sale(s) to the DSIs.

BPA would determine the value of these avoided transmission costs using the same methodology it used in the WP-10 rate proceeding to establish the costs and risks associated with its transmission inventory. Specifically, we would identify the subset of water conditions. Then we would apply the tariff costs established by BPA TS to the incremental transmission need under each water condition. The mean value of the 3,500 games for which this was done represents the forecasted cost of the incremental transmission avoided when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Port Townsend.

The avoided transmission costs are dependent on the combined amount of all DSI sales. For example, BPA's bulk marketing function may have sufficient pre-purchased transmission inventory to cover only an incremental 20.5 aMW sale in a given scenario, but not have sufficient transmission inventory to cover a 20.5 aMW sale to Port Townsend plus a 285 aMW sale to Alcoa.

[12] When BPA serves the DSI loads – including Port Townsend – and they operate – as opposed to not operating if BPA does not sell to them – BPA's surplus sales realize increased revenues because the mean value of prices for electricity for 3,500 games in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets.

sufficiently addressed by models currently available to forecast prices of electric power;[13] and b) Port Townsend's provision of additional reserve products or restriction rights to BPA.[14]

However, adjustments for these other benefits to BPA are not included or relied upon here because this 20.5 aMW sale, in and of itself, is not of sufficient magnitude to significantly impact the financial benefit to BPA. However, the accrual of other potential benefits associated with the Block Contract could be significant if the accumulation of additional sales to the DSIs in total were taken into account, resulting in a favorable impact to BPA's forecast of positive net revenues resulting from the Block Contract.

BPA's Projected Revenues Under the Block Contract

BPA's projected monthly revenues under the Block Contract 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 the sale of 20 MW of firm power (not 20.5 MW because power is scheduled in whole megawatts) each hour to Port Townsend under the IP-10 rate schedule beginning November 15, 2009, the commencement of Firm Power deliveries pursuant to the Block Contract, as opposed to November 1, 2009 used in BPA's analysis posted on October 13, 2009. In addition, the energy entitlements are the 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.

BPA's analysis also assumes that Port Townsend operates subsequent to its execution of the Block Contract, at which time BPA believes its decision to operate will be made based primarily on the prices for its production output which are independent of power prices. Therefore, curtailments allowed under the Block Contract are not forecast to have an advantageous or disadvantageous effect on this analysis. Nonetheless, the analysis is proportional, so whether Port Townsend's usage under the Block Contract is 13 aMW, 20.5 aMW, or some amount in between, the term of BPA's net positive revenue conclusion would remain the same.

BPA's projected monthly revenues are then accumulated and the result is illustrated in Tables 1 and 2:

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[13] Negative pricing, a phenomenon associated with certain renewable energy resources that receive tax or 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. See, *e.g. 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/

[14] See Block Contract, section 5.3, Additional or Alternative Arrangements for Power Reserves.

TABLE 1 - Usage and Rates

Month	Port Townsend Usage			IP-10 Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Nov-09	20,000	3,840	3,840	$2.19	$33.33	$29.58
Dec-09	20,000	8,320	6,560	$2.30	$35.24	$31.13
Jan-10	20,000	8,000	6,880	$1.96	$38.46	$32.24
Feb-10	20,000	7,680	5,760	$1.99	$37.72	$31.73
Mar-10	20,000	8,640	6,220	$1.85	$35.94	$30.08
Apr-10	20,000	8,320	6,080	$1.74	$32.23	$26.95
May-10	20,000	8,000	6,880	$1.44	$31.69	$22.29
Jun-10	20,000	8,320	6,080	$1.32	$31.18	$23.29
Jul-10	20,000	8,320	6,560	$1.61	$33.33	$28.66
Aug-10	20,000	8,320	6,560	$1.89	$37.31	$31.40
Sep-10	20,000	8,000	6,400	$1.96	$36.49	$32.26
Oct-10	20,000	8,320	6,560	$2.05	$31.92	$27.01
Nov-10	20,000	8,000	6,420	$2.19	$33.33	$29.58
Dec-10	20,000	8,320	6,560	$2.30	$35.24	$31.13
Jan-11	20,000	8,000	6,880	$1.96	$38.46	$32.24

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative ($)
Nov-09	$43,800	$127,987	$113,587	$285,374	$285,374
Dec-09	$46,000	$293,197	$204,213	$543,410	$828,784
Jan-10	$39,200	$307,680	$221,811	$568,691	$1,397,475
Feb-10	$39,800	$289,690	$182,765	$512,254	$1,909,730
Mar-10	$37,000	$310,522	$187,098	$534,619	$2,444,349
Apr-10	$34,800	$268,154	$163,856	$466,810	$2,911,158
May-10	$28,800	$253,520	$153,355	$435,675	$3,346,834
Jun-10	$26,400	$259,418	$141,603	$427,421	$3,774,254
Jul-10	$32,200	$277,306	$188,010	$497,515	$4,271,770
Aug-10	$37,800	$310,419	$205,984	$554,203	$4,825,973
Sep-10	$39,200	$291,920	$206,464	$537,584	$5,363,557
Oct-10	$41,000	$265,574	$177,186	$483,760	$5,847,317
Nov-10	$43,800	$266,640	$189,904	$500,344	$6,347,660
Dec-10	$46,000	$293,197	$204,213	$543,410	$6,891,070
Jan-11	$39,200	$307,680	$221,811	$568,691	$7,459,761

BPA compared these IP revenues to forecasted revenues that would be obtained in the event this power was sold into the market over the term of the Block Contract, using the market price forecast from the WP-10 rate proceeding, but with an updated natural gas forecast component. BPA routinely shapes its inventory to meet its contracted loads and manages its surplus inventory by purchasing and selling in the Pacific Northwest power

market as described in BPA's WP-10 rate proceeding.[15] BPA established its forecast of Mid-Columbia trading hub electricity prices in the WP-10 rate proceeding to value these purchases and sales.[16]

As noted, 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 reflect a more contemporary understanding of natural gas fundamentals, and to be consistent with the natural gas forecast used in BPA's draft Resource Program released September 30, 2009. BPA's updated natural gas forecast is discussed in more detail below. In the absence of the Block Contract, BPA would have one less firm power sale obligation included in its aggregated portfolio load shape to (potentially) purchase for and would expect to have more 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 electricity market price forecasting methodology applied in the WP-10 rate proceeding, and incorporating BPA's recently updated forecast of natural gas prices.

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 ($) (HLH + LLH)	Cumulative ($)
Nov-09	$28.75	$26.38	$110,386	$101,285	$211,671	$211,671
Dec-09	$30.61	$27.41	$254,686	$179,826	$434,512	$646,183
Jan-10	$34.13	$29.51	$273,032	$203,019	$476,051	$1,122,233
Feb-10	$34.46	$29.77	$264,654	$171,473	$436,127	$1,558,361
Mar-10	$33.92	$29.16	$293,105	$181,373	$474,478	$2,032,839
Apr-10	$32.95	$28.05	$274,139	$170,563	$444,702	$2,477,541
May-10	$33.93	$24.45	$271,455	$168,220	$439,675	$2,917,217
Jun-10	$34.33	$26.33	$285,619	$160,085	$445,704	$3,362,921
Jul-10	$37.33	$32.18	$310,572	$211,074	$521,646	$3,884,566
Aug-10	$42.48	$35.63	$353,413	$233,703	$587,116	$4,471,682
Sep-10	$42.86	$38.00	$342,871	$243,178	$586,049	$5,057,731
Oct-10	$43.31	$36.85	$360,342	$241,727	$602,070	$5,659,801
Nov-10	$45.36	$40.59	$362,894	$260,574	$623,467	$6,283,268
Dec-10	$48.81	$43.42	$406,097	$284,854	$690,951	$6,974,219
Jan-11	$50.70	$42.13	$405,610	$289,834	$695,445	$7,669,664

BPA determined its net benefit of serving Port Townsend 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 to reflect the value of reserves) is provided in Table 4:

[15] 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, BPA's need for shaping purchases and its ability to make surplus sales. See WP-10-FS-BPA-04, at 21.

[16] BPA employed 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-Columbia electricity prices in the WP-10 rate proceeding. See generally WP-10-FS-BPA-03.

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Cumulative ($)
Nov-09	$73,704	$73,704
Dec-09	$108,898	$182,601
Jan-10	$92,640	$275,242
Feb-10	$76,127	$351,369
Mar-10	$60,141	$411,510
Apr-10	$22,107	$433,617
May-10	($4,000)	$429,617
Jun-10	($18,283)	$411,334
Jul-10	($24,130)	$387,203
Aug-10	($32,913)	$354,290
Sep-10	($48,465)	$305,826
Oct-10	($118,310)	$187,516
Nov-10	($123,124)	$64,392
Dec-10	($147,541)	($83,149)
Jan-11	($126,753)	($209,903)

Finally, BPA took into account the value to BPA of the reserves Port Townsend is required to make available to BPA under the Block Contract.[17] Sales at the IP rate reflect the value of a right for BPA to obtain operating reserves. 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 firm surplus sale to a sale at the IP rate with reserves. BPA 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. As illustrated by Table 5, this is done for every megawatt-hour of the power not sold to Port Townsend:

[17] Issues raised in comments with respect to reserves are discussed in more detail below

TABLE 5 - BPA's Net Benefit after Adjustments

Month	Value of Reserves		BPA's Adjusted Net Revenue	
	Month ($)	Cumulative ($)	Month ($)	Cumulative ($)
Nov-09	$6,144	$6,144	$79,848	$79,848
Dec-09	$11,904	$18,048	$120,802	$200,649
Jan-10	$11,904	$29,952	$104,544	$305,194
Feb-10	$10,752	$40,704	$86,879	$392,073
Mar-10	$11,888	$52,592	$72,029	$464,102
Apr-10	$11,520	$64,112	$33,627	$497,729
May-10	$11,904	$76,016	$7,904	$505,633
Jun-10	$11,520	$87,536	($6,763)	$498,870
Jul-10	$11,904	$99,440	($12,226)	$486,643
Aug-10	$11,904	$111,344	($21,009)	$465,634
Sep-10	$11,520	$122,864	($36,945)	$428,690
Oct-10	$11,904	$134,768	($106,406)	$322,284
Nov-10	$11,536	$146,304	($111,588)	$210,696
Dec-10	$11,904	$158,208	($135,637)	$75,059
Jan-11	$11,904	$170,112	($114,849)	($39,791)

As a result, this analysis demonstrates how the projected revenues BPA recovers from the 14-month IP sale (through December 2010) to Port Townsend exceed by $75,059 the forecast revenues that BPA would otherwise obtain from the market.

Forward Markets Compared to Market Forecasts

As noted above, a number of parties 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; NRU at 1; PNGC at 2; SUB at 2-4; Snohomish at 2.

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 Port Townsend load, or the lost opportunity cost, if any, of selling the power earmarked for sale to Port Townsend 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 14-month term of the Block Contract than BPA's market price forecast given BPA does not normally sell or buy forward 14-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. Snohomish, Attachment A. 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 current electricity forward market prices which have dropped substantially from the mid-October forward market prices cited by Snohomish in its 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 term of the Block Contract fell from $46.78 per MWh to $40.30 per MWh and reduced the cost asserted by Snohomish by more than half.[18] 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.)

Gas Forecast Component of BPA's Price Forecast

Several parties 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. PPC at 2; SUB at 2-5; Snohomish at 1. SUB provided documentation in its comments showing that both spot and futures prices for natural gas had increased around the time its comments were submitted, and concluded that BPA's "analysis used a dated market forecast that does not reflect today's reality." SUB at 4.

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

[18] Please refer to Attachment G 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 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.[19] 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 1 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.[20] 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.

[19] 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.

[20] 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 1: Henry Hub Natural Gas Spot Price Forecasts

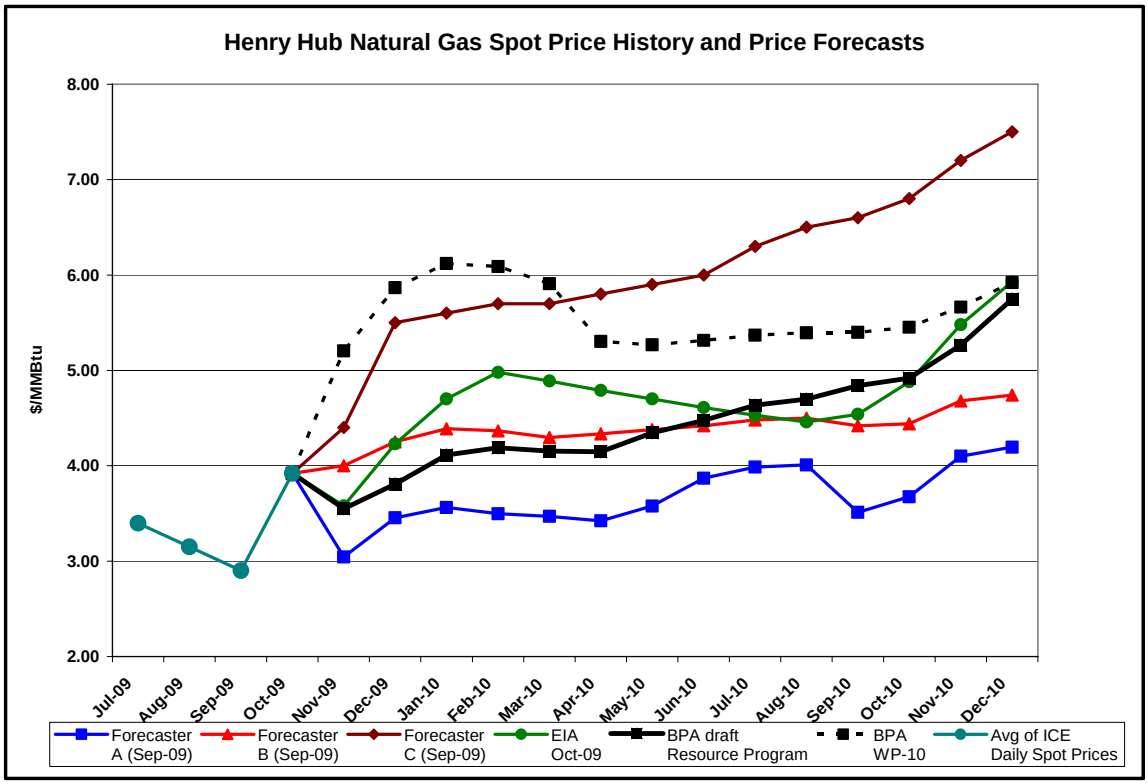


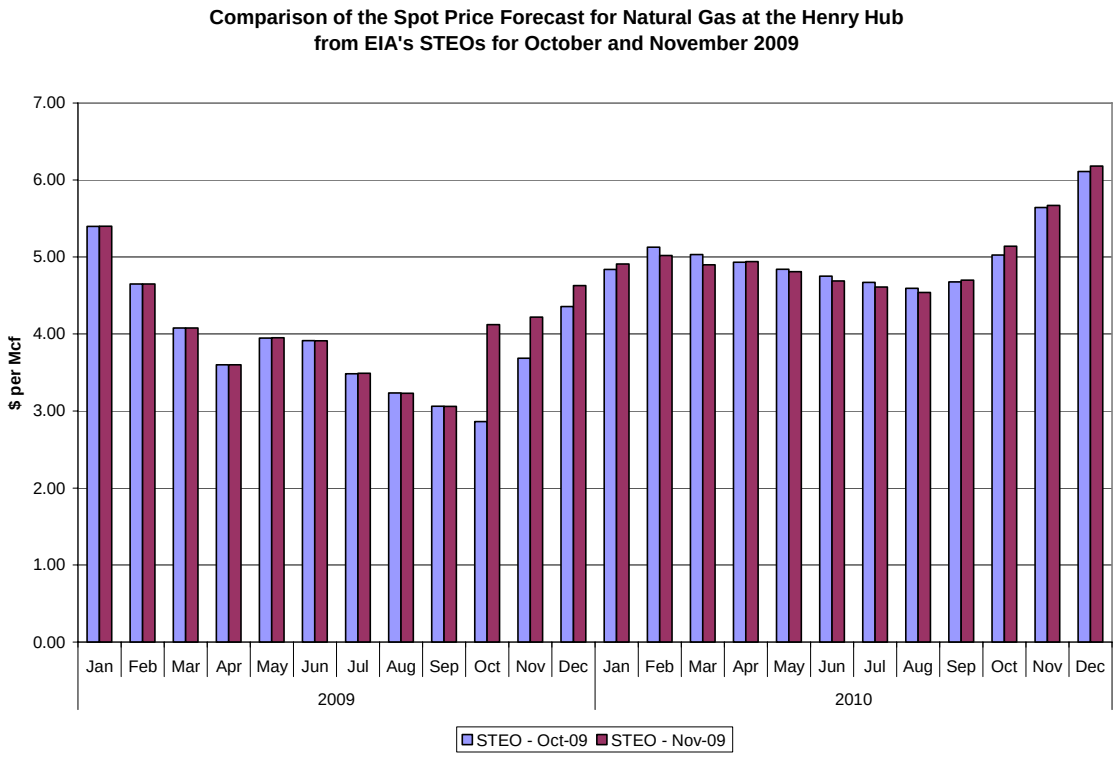
Figure 1 demonstrates that recent spot market prices for natural gas at the Henry Hub have been in the range of $3 to $4 per MMBtu from July to October 2009. This illustration also demonstrates that the forecasts of three other industry experts are $4 per MMBtu or less in November 2009 – the starting month of BPA's equivalent benefits analysis – and 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 expects spot prices for natural gas at the Henry Hub to rise above $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 4) and selectively chose the forecast in BPA's September 2009 resource program as compared to its WP-07 forecast (SUB at 4) in order to support "an unsound and incomplete forecast for Port Townsend Paper…" (SUB at 2).

First, as elaborated above and included in Figure 1, BPA incorporated the Energy Information Administration (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 1. As illustrated in Figure 2, 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 2 – 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 $4.95per 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.

Forward Market Sale

In BPA's view, the sale under the Block Contract meets the most conservative, yet still plausible, 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, 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 such a forward surplus sale would not have been addressed in BPA rates, whereas 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 in *PNGC I* or *PNGC II*, 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. 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. There is nothing in BPA's statutes, or Ninth Circuit case law, including *PNGC II*, supporting this position.[21] 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). Further, BPA is authorized to sell as surplus power that power which is surplus after having met its contractual obligations under sections 5(b), (c), and (d) of the northwest Power Act. 16 U.S.C. § 839c(f). Thus, a sale under section 5(d) is not a sale of surplus power.

Finally, it is 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;

[21] 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).

and Alcoa comments dated September 9, 2009, regarding draft 7-year power sales agreement, at 5 (Attachments C and D). 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 Port Townsend 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.

In sum, making a long-term forward surplus sale in lieu of selling 20.5 aMW to Port Townsend, 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.

6. Power Reserves

Port Townsend 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 (referred to below as the "Supplemental Operating Reserve"), and Exhibit H of the contract. Port Townsend will provide approximately 2 MW of reserves, within a time frame, in an amount, and for a duration consistent with applicable reliability standards, and as specified by Exhibit H.

Several parties raised issues with respect to the reserve provisions in the Block Contract. PPC, SUB, and PNGC also questioned whether Port Townsend 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 Port Townsend load, while SUB noted that such reserves will be unavailable (and therefore worthless) in the event Port Townsend 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 Port Townsend 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 Port Townsend 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 Port Townsend if and when called on by BPA under the Block Contract. In fact, Port Townsend provided the same reserve product under the October Interim Contract that permitted BPA to interrupt deliveries of electric power to Port Townsend 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 believes Port Townsend will be compliant with the reserve provision of the Block Contract when called upon by BPA.

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 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 Port Townsend, if needed, at least as frequently as the reserve contemplated in the WP-10 rate proceeding.

As to the value of reserves from a small load, the compensation realized by Port Townsend 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, 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 compensated with a proportionally smaller amount of dollars.

SUB's comments with respect to the effect of a possible curtailment on the value of the reserves provided by Port Townsend are misplaced, because if Port Townsend curtails its load, providing no reserves, BPA will not be compensating Port Townsend for such reserves not provided. Compensation is provided through a 7(c)(3) rate credit, so if Port Townsend curtails, it will not be paying the IP rate and therefore will not receive a rate credit. And in any case, as noted above, Port Townsend remains obligated to keep BPA whole in an amount equal to the IP rate plus $0.80 to account for the value of the reserves not provided when curtailed, up to its take-or-pay obligation, for any curtailed power.[22]

As stated earlier, Port Townsend 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 H of the Block Contract.

Snohomish commented that language in section 6 of Exhibit H of the Block Contract suggested BPA was considering an adder to the IP-10 rate to provide additional compensation – in addition to the credit already embedded in the rate - for any reserves it may call upon. Snohomish at 2. BPA is not proposing to adjust the IP-10 rate as a part of compensation for Minimum DSI Operating Reserve – Supplemental. The language in section 6 of Exhibit H is meant to specify how Port Townsend is compensated for providing Minimum DSI Operating Reserve – Supplemental under the Block Contact. BPA revised the referenced language to make clear that the adjustment for Port Townsend providing this reserve has already been made to the IP-10 rate determinants as part of the WP-10 rate making process.

Snohomish also commented that the Return Energy provisions in section 7 of Exhibit H of the Block Contract did not make sense because "it is unclear how Port Townsend would make use of the returned energy." *Id*. at 3. After considering the party's comment, and discussion with Port Townsend, BPA has reconsidered returning energy curtailed when BPA requested Minimum DSI Operating Reserve – Supplemental from Port Townsend. BPA has decided instead to "cash out" the energy that was to be made available to Port Townsend by BPA. BPA will credit Port Townsend an amount equal to the product of the amount of Return Energy (MWh) and the appropriate IP Monthly Energy Rate on its following Monthly Wholesale Power Bill.

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[22] SUB commented that Port Townsend is not providing reserves under curtailment situations and that the $0.80/MWh reserve credit should be added back in when determining liquidated damages. After considering this comment BPA decided to add the credit back into the calculation under those circumstances and changed the contract language accordingly.

7. Other Issues

Several parties complained that BPA did not provide sufficient time for them to review the Block Contract, that BPA had 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).

In an attempt to address the questions and concerns of it public preference customers, BPA's Deputy Administrator and certain BPA staff met with these customers on November 3, 2009. The prepared materials that BPA presented at this meeting are attached hereto. Attachment E. With respect to the amount of time allowed for comments, BPA can only note that it provided as much time as possible under the circumstances, which includes reserving enough time to evaluate comments as part of its decision-making process. 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.[23]

SUB filed a comment that appears to argue 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. 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

[23] While BPA is committed to providing reasonable opportunities for meaningful public comment on proposed DSI contracts, there is no legal requirement, under either the Administrative Procedures Act or any of BPA's enabling statutes, that BPA provide notice and comment when executing a contract with a DSI customer. See e.g. *Alcaraz v. Block*, 746 F.2d 593 (9th Cir. 1984) (APA does not apply to matters relating to contracts); *Rainbow Valley Citus Corp. v Federal Crop Insurance Corp*., 506 F.2d 467 (9th Cir. 1974).

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.

SUB also asserts that the Block Contract will "create job losses throughout the region." SUB at 1. SUB provides no evidence to support this extraordinary conclusion, but it seems unlikely that BPA's decision to sell up to 20 aMW to a small paper mill for 14-months (from a system that generates over 9,000 aMW annually), at a rate forecast to be above the market over the term of the contract, will lead to any job losses whatsoever. Even in the event that SUB is right, and BPA's forecast of market prices is too low, or BPA's forecast that it will not be required to make additional purchases to serve Port Townsend is wrong, and that BPA will incur some cost in excess of the costs already allocated to BPA's WP-10 base rates for DSI service - an extremely low probability event - the impact on the preference rate of such a result would be miniscule, if there would be any impact at all.[24]

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 Port Townsend (SUB at 4-5). In fact, each of SUB's concerns have been examined by BPA as part of its economic analysis of the Block Contract, as described in this record of decision. BPA has simply come to different conclusions based on its view of the market. In addition, the Block Contract itself, as described above, contains a number of risk mitigation provisions. The residual risk that BPA may incur costs to serve Port Townsend resulting in an increase to the rates paid by SUB is very small, and if it were to materialize, would likely result in no, or a negligible, increase in SUB's rates.

PNGC suggested that the contract be amended to cap BPA's exposure to market purchases equal to the IP rate, and to allow BPA to remarket power under the Block Contract in the event market prices exceed the IP rate by some "reasonable margin," which PNGC noted could be as little as ten percent above the IP rate. PNGC at 2. PNGC's proposal would fundamentally deprive Port Townsend of the benefit of its bargain and is not commercially reasonable, and would be highly unfair to Port Townsend which according to BPA's forecast has agreed to purchase power from BPA for a price, on average over the term of the Block Contract, which will be above market. Certainly, Port Townsend 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, Port Townsend is locked into paying an even higher premium to market. Under PNGC's proposal, if prices rise, Port Townsend would also face the possibility of losing its BPA power supply. BPA does not find this to be a reasonable or business-like proposition, or one that is required

[24] 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.

by *PNGC II*. In any case, BPA believes its economic analysis of the Block Contract is conservative, so that PNGC's proposals are not only unfair, but unnecessary.

SUB commented in an earlier process that BPA must resolve any lookback amounts owing by the DSIs, including Port Townsend, associated with the Court's remand in *PNGC I*. See SUB comments dated September 9, 2009, re "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 Port Townsend in connection with the remand if, in fact, that is the outcome on remand, or in later raising rates to Port Townsend 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 Port Townsend until that process is completed.

8. PNGC II

On August 28, 2009, the Ninth Circuit issued its opinion in *Pacific Northwest Generating Cooperative v. BPA*, Slip Op. 09-70228 (August 28, 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 Port Townsend service options to those that will satisfy that test. Absent the equivalent benefits test, BPA would have considered other, longer-term service options.

As indicated earlier, Port Townsend expressed concern that the relatively short-term of the Block Contract "impairs the long-term planning so important to an industrial customer such as Port Townsend." Port Townsend at 1. Citing BPA's letter that accompanied publication of the draft Block Contract for public comment, Port Townsend commented that it appeared BPA was taking the position that *PNGC II* prohibits a power sale to a DSI "unless the price is above the market price of power for the time period the power is offered," and that they believed such a reading is at odds with the plain language of that opinion. *Id*. at 2. Alcoa made a similar comment, citing extensively from *PNGC II* to support its position that BPA "need not conduct an accounting analysis that demonstrates that the economic benefits of the contract are equal to, or exceed the cost of

providing service" to a DSI. Alcoa at 1-2. CFAC echoed this position, and also commented that BPA needed to take into account transmission costs it would avoid by making the sale to Port Townsend in lieu of selling the power into the market. CFAC at 1.

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. With regard to the concerns expressed by Port Townsend, BPA understands, and is sympathetic with, the fact that long-term planning by Port Townsend is impaired by the short-term nature of the proposed contract. If Port Townsend 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 Port Townsend can recapture their investments in the short period of the contract, and BPA has no basis to deny Port Townsend'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 14-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.

BPA's Reading 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*, Slip Op. at 11972. In terms of what is demanded by that standard, the following (*PNGC II*, Slip Op. at 1989-90) 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.

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 minimal, or huge but unlikely, the tenor of the Court's decision causes BPA to believe that would be insufficient to satisfy the equivalent benefits test.

The Court elsewhere analogizes DSI sales to the incurrence by a utility of a non-necessary expense. *PNGC II*, Slip Op. at 11980, 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. *PNGC II*, Slip Op. at 11980.

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, Slip Op. at 11972-973 (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.

BPA Believes Equivalent Benefits Test 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 Port Townsend and Alcoa argue is wrong or overly conservative. BPA is not persuaded that the opinion can reasonably be interpreted in the fashion advanced by Alcoa and Port Townsend. 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, 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.[25] 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 indicate that Congress intended that sales to DSI customers beyond the "initial" NWPA 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*.

[25] Not to belabor the point but Webster's II New Riverside Dictionary defines "initial" as "of, being, or happening at the beginning." Random House College Dictionary similarly defines "initial" as "of or pertaining to the beginning; first." Roget's Thesaurus proffers the following synonyms for "initial": "first, starting, beginning, opening, commencing, primary, introductory, incipient, initiatory, inaugural, maiden; original, germinal, primal." Recommended antonyms are "last, ultimate, ending, final, closing, concluding, terminal."

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*, Slip Op. at 11989-90. 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* Slip Op. at 11972; (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. *PNGC II*, Slip Op. at 11972, 11974.

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, Slip Op. at 11975; *see also id*. at 11980. 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). Even as a marketing matter, this language supports service to the DSIs—widespread use of power—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 all consumers are referred to in section 5 of the Flood Control Act of 1944. That would mean that if the power could be sold at market, such that other 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 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.[26]

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.

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[26] 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).

The Congressional intent behind this language was "to enable the Administrator to employ business principles and methods in the operation of a business enterprise . . ." H.R. Rep. No. 777, 79th Cong., 1st Sess., 3 (June 21, 1945). The Northwest Power Act extended section 2(f)'s expansive authority to enter into contracts under that Act.[27]

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* *McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006). In

[27] "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).

> *McCarthy*, the Sixth Circuit held that an electric cooperative's decision to incur "non-necessary expenses," if proven true, would "clear[ly]" violate 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, Slip Op. at 11980 (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. 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 Port Townsend is consistent with *PNGC II*.

9. Environmental Effects

This agreement represents a continuation of service to Port Townsend at a rate consistent with the court's decisions in *PNGC I* and *PNGC II*, and the sale will not lead to any changes in environmental effects. Further, this type of agreement is consistent with BPA's Short-Term Marketing and Operating Arrangements ROD of January 22, 1996, a copy of which is attached hereto as Attachment F.

CONCLUSION

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

Issued at Portland, Oregon, this 13th day of November, 2009.

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

ATTACHMENT A

March 19, 1996

Chuck Forman
Account Executive
Bonneville Power Administration
1835 Black Lake Blvd. S.W.
Olympia, WA 98512-5623

Dear Chuck:

The BPA Power Sales Contract, Section 5(d) - Technological Allowances, provides a method to request an increase in Contract Demand for technological reasons. Port Townsend Paper Corporation has consistently invested in its facilities to meet both the needs of our customers and the more stringent environmental regulations placed on our industry. The capital improvements have been substantial without expanding the overall production. We have been switching from a chemical pulping process to a recycled fiber process.

Section 5(d) of the Power Sales Contract provides that Port Townsend Paper may request a Technological Allowance increase in Contract Demand to cover the increased power requirements associated with the improvement and modification of equipment due to changes in technology.. Addition of environmental protection equipment is also covered by the Technological Allowance provision.

Attached is a list of the major equipment additions and modifications at the Port Townsend facility. Port Townsend Paper Corporation requests a Technological Allowance increase in Contract Demand in the amount of 3.818 MW to cover the environmental protection load and the improvements implemented at the plant as shown on the attached list. This would make our Contract Demand 20.42 MW and would allow us to purchase this additional electricity from BPA rather than having to buy it from another supplier.

Per our discussion, it is understood that BPA will evaluate this request even though the specified submittal date of February 1 has passed and will respond within 60 days as provided in the Power Sales Contract. Port Townsend Paper appreciates your review and consideration of this request and is willing to meet to discuss any aspect of this request at your convenience.

Sincerely,

Bruce McComas

Bruce McComas
Manager: Power, Recovery,
Utilities, Pulping & Recycle
Port Townsend Paper Corp.
P.O. Box 3170
Port Townsend, WA 98368

Port Townsend Paper Corp
Technological Improvements
Equipment list

Equipment Type / Project Name		date installed year	Hp	Increase Demand Requirements MW	
Environmental Control					
Turbotac Scrubber					
2 air compressors		**1987**	600	0.312	
scrubber & quench pumps			20	0.010	
Additional pressure drop			250	0.130	
Precipitators for Recovery Boiler		**1992**	175	0.091	
Total for Environmental control				**0.544**	**MW**
OCC Recyling Plant	**Quantity**	**1996**			
Electric motors, Hp					
5	4		20	0.010	
6	1		6	0.003	
7.5	3		22.5	0.012	
10	8		80	0.042	
15	8		120	0.062	
25	4		100	0.052	
30	3		90	0.047	
40	3		120	0.062	
50	7		350	0.182	
60	1		60	0.031	
75	6		450	0.234	
100	6		600	0.312	
125	11		1375	0.715	
200	3		600	0.312	
300	1		300	0.156	
500	1		500	0.260	
1500	1		1500	0.781	
Total for OCC Recyle Plant				**3.275**	**MW**
Total Increased Demand				**3.818**	**MW**

ATTACHMENT B

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

January 29, 1997

Contract Demand
Tech. Increase = 20.5 MW

In reply refer to: PSW/700

Mr. Bruce McComas
Power, Recovery and Utilities Manager
Port Townsend Corporation
P.O. Box 3170
Port Townsend, WA 98368-3170

Dear Bruce:

The Bonneville Power Administration (BPA) has reviewed your letter dated March 19, 1996, requesting a technological allowance to increase contract demand by 3.82 megawatts (MW). Section 5(d) of Port Townsend Paper Corporation's Power Sales Contract, Contract No. DC-MS79-81BP90347 (PSC) with BPA allows for, subject to provisions therein, increases in contract demand for technological reasons other than plant expansion.

Based on your letter and my subsequent on-site review of equipment additions, BPA has determined that the addition of equipment associated with the substitution of recycled fiber for chemically derived fiber and the addition of environmental protection equipment is in accordance with the PSC provisions for a technological allowance. Port Townsend Paper is hereby granted a technological allowance of 3.9 MW.

The technological allowance is effective at 2400 hours on September 30, 1996. Enclosed for your signature are two signed originals of Exhibit C, Revision No. 1, reflecting the increase in contract demand from 16.6 MW to 20.5 MW. Please return one signed original to me at the above address.

Feel free to call me at 503-230-5831 if you have questions.

Sincerely,

Charles W. Forman Jr.
Account Executive

Enclosure

ATTACHMENT C

August 3, 2009

Allen Burns D-7
Acting Deputy Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Re: DSI Long-term Service

Dear Allen:

Thank you for the opportunity to comment on long-term service to BPA's last remaining direct service industrial customers (DSIs) and the draft proposed term sheet as described in your letter directed to regional customers, stakeholders and interested parties, dated July 17, 2009. Alcoa Inc. ("Alcoa") appreciated the opportunity to discuss DSI contract issues with other BPA customer groups at BPA's June 8, 2009 public meeting and appreciates BPA's efforts to put in place a long-term contract to address the Ninth Circuit's decision in *PNGC v. BPA*. While issues will likely arise during the formulation of final contract which will require resolution, we think the term sheet represents a fair effort by BPA to balance the interests of the DSIs with the interests of BPA's other customers within the discretion granted BPA by the Court in *PNGC*.

At the outset we think it is important to note that the *PNGC* decision grants BPA the authority to serve the DSIs, the Court also recognized that Section 7(c) of the Northwest Power Act determines how the rates to the DSIs are to be developed. That section provides

> "The rate or rates applicable to direct service industrial customers shall be established—
>
> for the period beginning July 1, 1985, at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region."

A comparison between BPA's proposed service under the July 17, 2009 term sheet with the terms of service that form the basis for BPA service to consumer owned utilities' industrial customers is worth evaluating when considering whether Alcoa's terms of service and rates are equitable in relation to the retail rates charged by consumer owned utilities to their industrial consumers in the region. The comparison reveals that industrial consumers of publicly owned utilities will receive more favorable terms, at

more favorable rates than the two remaining aluminum DSIs would receive under BPA's proposed term sheet:

	DSIs	Consumer Owned Utilities' Base Service for Their Industrial Customers
Conditions	Service linked to market Power Prices	None
Quantity	2/3 of historic load	100% of historic loads
Price	IP RATE = $34.6/MWH at 100% LF	PF Rate = 27.4/MWH at 100% LF
Term	7 years.	20 years.
Quality	Partially interruptible to preserve firm loads including consumer owned utility industrial loads	Firm

Alcoa makes this comparison to give some perspective to the campaign that consumer owned utilities and their industrial customers are waging against the compromise contract that BPA has proposed. We recognize that many of BPA's preference customers will urge BPA to end all power supply service to Alcoa. Many will argue that providing electric power service to the DSIs will unfairly raise rates to other customers and thereby increase the loss of jobs elsewhere in the region. Alcoa loads are located within the service territories of consumer-owned utilities and have been served by BPA resources longer than many industries that will continue to have all of their electricity needs served with low-cost tier-1 BPA power through those utilities in the future. Of course DSI loads have been in a substantial decline for the last decade. During the same period, preference loads have grown. Thus, increases in BPA power purchases are required to meet growing preference customer loads, not diminishing DSI loads.

Moreover, more than one-third of Alcoa's production costs are made up of power costs. There is no evidence on the record that any other major industry in the Northwest is as electricity dependent as the aluminum industry. As proposed, the maximum impact on BPA costs for purchasing the 320 MW needed to operate 2 of the 3 potlines at Intalco would be capped at $70 million per year. This represents an impact of about $1.20/MWh on rates to all of BPA customers, and the likely impact will probably be less since BPA will probably be able to make purchases at less than the capped amount.

Assuming the worst case for impact on other customers, that is, market rates at the cap of $65/MWh; let us look at the impact of the proposal on Intalco and on other industries served by consumer-owned utilities. Without the proposed service, Intalco power rates would increase from the IP rate of $34.6/MWh to $65/MWh (88%) resulting in Intalco closure and the loss of more than 2000 direct and indirect jobs as discussed later in this letter. Rates to consumer-owned utilities would be reduced by $1.20/MWh (4%) with questionable impact on employment levels. Thus, BPA may save the Intalco jobs by

offering to serve the DSI loads with adequate power at the IP rate. But there is no assurance that it could save other Northwest industries by offering artificially subsidized PF rates. Indeed PNGC's employment data introduced in the BPA WP-10 rate case reveals that many Northwest industries have closed their plants notwithstanding having electric power rates from BPA's preference customers that are substantially below Intalco's electric power rates. Therefore, we urge that BPA do what it can, within its discretion, to retain Alcoa as a 70-year power customer and retain more than 2028 direct and ndirect jobs,[1] rather than succumbing to an argument that some unknown number of jobs might be saved if BPA knowingly causes Intalco to close by failing to provide it with power at the statutorily set rate that Intalco needs to operate.

1. *Providing Industrial firm power (IP) in an amount sufficient to operate two potlines at Alcoa's Ferndale is critical to the smelters' survival.*

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As Intalco demonstrated at the June 8 public meeting, it has historically operated three potlines at its Ferndale smelter. The smelter and its related facilities were designed to achieve optimum operations with three potlines in use. Partial operation of potlines (for example, 50% of capacity or one and one-half potlines) robs the smelter of electrical efficiency and less than three potlines significantly increases unit costs due to the loss of economies of scale. Because aluminum is a worldwide commodity, Alcoa cannot recapture these lost efficiencies through increasing product prices. While Alcoa negotiated with BPA in good faith to make a one and one-half potline operation work under the January 23 draft contract, in the end, Alcoa realized that it simply couldn't plan to operate the Intalco smelter with less than two-potlines and have the smelter survive the inevitable downturns in cyclical aluminum markets. While Alcoa could achieve much greater efficiency with its historic three-potline operation, it recognizes that BPA's proposal represents a compromise, designed to accommodate the needs and desires of both its preference customers and its DSIs.

To put BPA's proposed compromise into context, it is worth recalling that the Block Sale Agreements, that are effective from 2007 through 2011, contemplate that the aluminum DSIs will receive 560 aMW of service. BPA retained the ability to convert the contract to a physical sale of power which would result in 560 aMW of sales to Intalco and Columbia Falls Aluminum Company ("CFAC") based on the reallocation of Unused Benefit Amounts due to the reassignment of Goldendale Aluminum's unused 100 aMW allocation. Intalco's share of the 560 MW total is 390 MW. Thus, BPA's proposal for 320 MW to Intalco provides less power than the conversion of the existing contract to a power sale would automatically accomplish. In the absence of a contrary agreement, Alcoa believes that BPA would be obligated to provide 560 aMW of power to Intalco and CFAC under the severability clause, contained in the Block Sale Agreement, for the remaining two-year term of the Agreement. Thus, the agreement for Alcoa to forego 70

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[1] Dick Conway and Associates, "The Economic Impact of the Intalco Works Aluminum Plant, June 2008, page 4 (finding a multiplier effect of 2.9 additional jobs for each aluminum job in Washington).

aMW of power constitutes a part of the DSIs' consideration for BPA's agreement to extend the term of the DSI power sale agreements. Alcoa appreciates BPA's willingness to propose providing Intalco a sustainable amount of power for its operations even if that amount of power is less than: a) the amount of power that BPA has historically provided to serve Intalco's 3-potline operation and b) less than the amount of power committed under the 2007-2011 Block Sale Agreement.

2. *BPA has a sufficient amount of surplus power that might be used to provide service to the DSIs to mitigate the cost of buying power for all of BPA's needs.*

The Regional Preference Act (P.L. 88-552) and the Excess Federal Power statute 16 U.S.C. §832m) and Sections 5(f) and 9(c) of the Northwest Power Act require the Administrator to provide power in excess of his firm power contract obligations to customers in the region at any rate established for the disposition of such capacity and energy. The Ninth Circuit recently held in *PNGC* that BPA must offer such power to the DSIs at the IP rate. While Alcoa recognizes that BPA has a different view of its obligations, at a time when the Northwest has surplus power, it makes little sense to export power outside the Pacific Northwest when the power could be used to meet the loads of a class of customers statutorily recognized by the Northwest Power Act.

In its preliminary work preparing for the Sixth Power Plan the Northwest Power Planning Council recognizes that the Northwest is presently surplus. They also recognize that this surplus may continue with the acquisition of renewable resources and cost-effective conservation. This is particularly the case during the current severe economic recession that has disproportionately impacted the Pacific Northwest and reduced BPA's firm loads. BPA has modified its Tiered Rate Methodology to deal with this phenomenon. During these conditions and the currently favorable market prices for power on the West coast, BPA can use its surplus power and acquire power to serve the loads of all of its customers including Intalco and CFAC with much lower net costs than was previously the case. As a result, whether, under these conditions, BPA is obligated to sell power to the aluminum DSIs, or has the discretion to do so, it would be a missed opportunity (and an abuse of its discretion) if BPA failed to use its available resources and favorable market purchases to serve the Intalco and CFAC loads.

3. *Section 3 of the Draft Term Sheet is Critical to Alcoa and Could Provide Large Benefits To the Northwest Region*

BPA's Draft Term Sheet provides for BPA to meet up to two potlines of the DSIs power requirements for the remaining two-years of the existing Block Sale Agreement with a physical power sale, provided that power can be purchased at less than $48 per MWH. BPA will provide power to the DSIs for an additional 5-year term provided that BPA can serve the DSIs at a power cost of less than $64/MWH. Section 3 of the Term Sheet provides for BPA to make an early determination of the feasibility of extending aluminum DSI power service under a new contract for an indefinite period following the

expiration of the intermediate 5-year term. Alcoa appreciates BPA's willingness to consider such a follow-on term as such an extension, if it comes early enough to assure a

10-year power supply may allow Alcoa to make capital investments at the Intalco smelter that would have significant benefits not only to Intalco, its employees and the community that it serves, but also to the Northwest economy as a whole. Moreover, if BPA acts quickly, it may lock-in power prices that will permit it to serve the aluminum DSIs at the lowest feasible net cost to BPA.

A contract duration of 10 years or more would allow Alcoa to make capital investments with a sufficient period of time to amortize the cost of the capital investments. On the other hand, Alcoa recognizes that if a 10-year contract requires BPA to seek to secure the full 10 years of power to serve Intalco, then the corresponding requirement for a long-term power acquisition process under Section 6(c) of the Northwest Power Act could defer action by BPA at a critical decision point for Alcoa concerning closure of the Intalco smelter.

If BPA can promptly commit to a two-year contract with an additional 5-year term and commit to consider a possible follow-on contract under acceptable terms, aggregating 10 years, this might permit capital expenditures by Alcoa that would permit longer-term operation of the smelter. This could be accomplished by permitting Alcoa to modernize the Intalco facilities to achieve greater energy and production cost efficiencies. A 10-year contract could also enable Alcoa to make and amortize investments in greenhouse gas reduction technologies that would enable the Northwest region to better meet greenhouse gas emission reduction goals. The closure of the smelter would not count toward the achievement of the goals (presumably because policy makers realize that an equivalent amount of aluminum would be required to be produced elsewhere in the world with uncertain greenhouse gas implications).

Large benefits would accrue to Alcoa's employees and the local community if a longer-term contract term is promptly achieved. Just as a longer-term contract allows Alcoa to plan for its future, it affords employees, businesses, local government, and community organizations the same opportunity. Based on the foregoing, Alcoa urges BPA to retain Section 2 of the Term Sheet and to accelerate its consideration of a follow-on contract as to offer such a contract as early as possible after October 1, 2012, in order to optimize the chances of Alcoa making needed capital investments for its own benefit and for the benefit of the region.

4. *Intalco can provide critical regional power reserves.*

As recognized by the "Rate" recital in the draft Term Sheet, Intalco can provide significant power reserves to the Northwest region as contemplated in BPA's WP-10 power proceeding. In addition to the capacity reserves contemplated in the proposal, with the addition of necessary electronic controls, the Intalco smelter load can be varied to accommodate within-hour fluctuations from new wind generations projects in the

Northwest. These potential reserves, contemplated by the Northwest Power Act, are possible if the Intalco plant continues to operate, and are yet another way in which continued electric power service to Intalco could benefit the Northwest region.

5. *The curtailment rights under Section 9 of the draft Term Sheet are a critical term of the Agreement.*

Section 9 of the draft Term Sheet permits Alcoa to curtail deliveries twice during the term of the contract. Such a provision is consistent with historic DSI contract rights and is crucial to any take or pay contract for a cyclical industry in a commodity business.

The provision results in a balanced contract where BPA may impose take-or-pay obligations, where Alcoa's curtailment rights are limited to 2 curtailments, not exceeding 24 months in total duration and where BPA has no obligation to compensate Alcoa for the excess value of power during any such curtailment. In addition, Alcoa may not seek third-party power supplies during a curtailment, thus mitigating any risk to BPA that Alcoa might curtail in order to get lower power prices. The result is a contract that disciplines Alcoa to curtail only based on low aluminum prices that make it uneconomic to operate. Further mitigating risk to BPA is the fact that the term of the contract is of relatively short duration, making it likely that BPA would recover at least as much as the IP rate for sales of power that BPA might have due to a DSI curtailment. Alcoa urges BPA to reject any revisions to this provision of the contract and upsetting the carefully balanced rights and responsibilities embodied in this section.

6. *Section 11 of the draft Term Sheet provides BPA with additional protections and provides sufficient incentive for Alcoa not to terminate the contract.*

Section 11 of the draft Term Sheet contemplates that Alcoa must give 12-months notice of termination of the contract. This provision will allow BPA time to remarket the power if Alcoa terminates the contract and during the 12-month notice period. Alcoa is obligated to pay for power at the IP rate whether or not it takes power during the notice period. This disciplines Alcoa not to terminate the contract unnecessarily, protects BPA by giving it the opportunity to remarket or find other uses for the power. Section 8 of the draft Term Sheet, provides further protection against a frivolous or unjustified termination of the contract as following a notice of termination, Alcoa is prevented from requesting power service as a DSI from BPA. Again, the critical balance achieved in this provision between BPA's and Alcoa's interests should not be upset through revisions that might tip the balance of rights and obligations unfairly, and it a way that would make the risks of the contract too great to permit Alcoa's management to sign the contract.

7. *Section 4 of the draft Term Sheet is a critical term.*

At present, Congress has before it cap and trade legislation that will define the rights and obligations of generators, utilities and industries. The version of the legislation passed by the U.S. House of Representatives will impose very large costs on emitters of greenhouse

gases. The U.S. Senate is presently considering the House version of the bill and knowledgeable observes believe that the Senate is likely to make substantial changes to the House version of the bill. Section 4 of the draft Term Sheet places the risks of future carbon taxes, greenhouse gas mitigation costs or other similar environmental or

regulatory costs on the parties who will be supplying BPA power acquired to serve Alcoa by requiring the generators to include any such costs in their contracts. The provision also imposes some risk (but a measurable risk) on Alcoa by providing that the cost of power, including such greenhouse gas mitigation expenses, must fall under the price caps in Sections 1 and 2 of the draft Term Sheet.

8. *Section 5 of the draft Term Sheet imposes unpredictable risks on Alcoa that, in the aggregate could defeat the contract.*

Section 5 of the draft Term Sheet contemplates two bases for BPA to impose on Alcoa the costs of renewable energy portfolio standards obligations or costs imposed on BPA directly for carbon taxes or charges, greenhouse gas mitigation costs or other environmental or regulatory charges: 1) recovery through rates or 2) through some other unspecified mechanism. While the provision also entitles Alcoa to terminate the contract if such costs are imposed, that right would, of course, come at the cost of closure of the Intalco smelter. Alcoa urges BPA to develop language in the contract that would eliminate or at least minimize the possibility of allowing BPA to recover presently undefined and unspecified greenhouse gas costs from Alcoa through a mechanism other than rates. BPA has ample ratemaking authority through Section 7(g) of the Northwest Power Act to fairly allocate unanticipated costs—but within the disciplined context of a contested rate case where Alcoa and other parties can evaluate the nature and cause of various costs and advocate the spreading of those costs based on equitable principles.

Conclusion

The preference customers have asserted in various forums that BPA violates the discretion accorded BPA by the Ninth Circuit in the *PNGC* decision if it provides power to the aluminum DSIs at less than market price. Alcoa strongly urges BPA to reject this illogic. The consumer owned utility rates are more than 26 percent lower than the rates that would presently apply to the power sold under a contract to Alcoa. The Ninth Circuit authorizes BPA to serve the DSIs at the IP rate (not to impose market prices on the DSIs) and the three regional preference statutes were clearly enacted to give preference to Northwest regional loads. To fail to serve Intalco and CFAC at the IP rate during the current severe economic recession and in the face of BPA's surplus would not only fail to meet Congressional intent in enacting the three regional preference statutes, but would constitute an abuse of BPA's discretion. We urge BPA to move forward with a contract that adheres to the proposal embodied in its July 17 Draft Term Sheet in order equitably to serve one of BPA's longest-term customers (Alcoa) and to preserve the jobs that are so important to the Northwest's economic recovery from this deep and protracted recession.

Alcoa, and the Ferndale, Washington community that has over 2000 jobs associated with the Intalco facility are grateful to BPA for seeking a middle ground that will give Intalco an opportunity to continue to operate under difficult market conditions. The provisions of the draft Term Sheet will allow Intalco to continue to provide the employment and other economic and community benefits and electric power reserves that are achieved with physical power service from BPA. It will also help the United States to preserve industrial manufacturing capability that is important to not only employment, but also to the balance-of-trade and security interests of the country.

Sincerely,

Mike Rousseau

Mike F. Rousseau
Plant Manger, Alcoa Intalco Works

cc: Governor Gregoire,
NW Congressional Delegation

ATTACHMENT D

September 9, 2009

Allen Burns – A-7
Acting Deputy Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Re: 7-year Power Sale Agreement

Dear Allen:

Alcoa appreciates the opportunity to comment on BPA's proposed physical power sale to Alcoa's Intalco smelter. For the last several years, Alcoa has been advocating for a physical power sale to Intalco, more along the lines represented by Alcoa's historic 70-year relationship with BPA. Despite BPA's two good-faith efforts to offer Alcoa monetized power contracts, the Ninth Circuit Court of Appeals has rejected the approach. We appreciate BPA's willingness to return to a form of power contract expressly contemplated by the Northwest Power Act. 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 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.

Relative Rate Equity

BPA's rates to its preference customers remain amongst the lowest electric power rates in the nation. This is true despite the fact that the cost of incremental BPA power resources is much higher than BPA's average resource cost, and BPA preference customer loads have been growing. In just the period between 1999/2000 and 2008/2009, preference customer loads are expected to increase from 8,060 aMW[1] to 8,949 aMW.[2] DSI loads have declined from a high of 3,153 aMW in FY 1991 to 474 aMW in FY 2009.[3] In other words, the incremental loads responsible for driving up prices for all customers, whether preference or DSI, are the growing preference customer loads, not the decreasing DSI loads. Alcoa recognizes that BPA's preference customers would prefer to view aluminum smelter loads as incremental loads that should pay rates reflecting BPA's marginal costs

[1] *See* Bonneville Power Administration, 1998 Pacific Northwest Loads and Resources Study, Table 3 (Also available at: http://www.bpa.gov/power/pgp/whitebook/1998/.

[2] *See* Bonneville Power Administration, 2007 Pacific Northwest Loads and Resource Study, Table 9. Also available at: http://www.bpa.gov/power/pgp/whitebook/2007/.

of power. But since DSI loads are declining, and preference customer loads are increasing, and since Alcoa would receive under the 7-year Agreement, at most two-thirds of its power requirements that have historically been served by BPA, one can understand why Alcoa rejects the notion that its loads are contributing to BPA's increasing costs for meeting its growing loads. Moreover, BPA calculated, in its WP-10 power rates, currently before the Federal Energy Regulatory Commission, the rates that the Northwest Power Act establishes as the correct power rates for Alcoa's loads.

Under BPA's proposal, Alcoa will pay $34.60 per MWh for its power purchased from BPA. BPA's preference customers, on the other hand, will pay average rates (at the same load factor) that are $27.40 per MWH. Thus under BPA's proposal, Alcoa will already be paying 26% more for power than BPA's preference customers. While Alcoa recognizes that BPA's preference customers would prefer to be able to either purchase or gain all of the economic value from all of the power that BPA can produce—and that doing so would keep their rates even lower, such a result would be completely contrary to the express objective of the Northwest Power Act to provide some reasonable distribution of benefits of the federal system over all three classes of BPA's historic customers: its preference customers, the direct service industries, and the investor owned utilities (and their residential and small farm customers). The following table depicts the benefits that the BPA preference customers, and their industrial customers, derive from Section 7(b)(2) of the Northwest Power Act, and BPA's service decisions relative to the impact on DSI rates and quality of service:

	DSIs	Consumer Owned Utilities' Base Service forTheir Industrial Customers
Conditions	Service linked to market Power Prices	None
Quantity	2/3 of historic load	100% of historic loads as well as load growth
Price	IP RATE = $34.6/MWH at 100% LF	PF Rate = 27.4/MWH at 100% LF
Term	7 years	20 years
Quality	Partially interruptible to preserve firm loads including consumer owned utility industrial loads	100% firm

Moreover, more than one-third of Alcoa's production costs are made up of power costs. There is no evidence that any other major industry in the Northwest is as electricity-dependent as the aluminum industry. As proposed, the maximum impact on BPA costs for purchasing the 320 aMW needed to operate 2 of the 3 potlines at Intalco would be capped at $60 million per year for the final 5 years of the Agreement. This represents a maximum potential impact of about $1.00/MWh on rates to all of BPA customers, and the likely actual impact will most likely be less since BPA will probably be able to make purchases at less than the capped amount.

The consequences of not providing Alcoa with the proposed service are dramatically different that the consequences of doing so, even assuming the worst-case impact on the rates of BPA's customers (i.e. market rates at the cap of $58.50/MWh). Without the proposed service, Intalco power rates would increase from the IP rate of $34.60/MWh to $58.50/MWh (69%) resulting in the closure of the Intalco smelter and the loss of more than 2,000 direct and indirect jobs. BPA may save the Intalco jobs by offering to serve the DSI loads with the proposed levels of service (320 aMW) at the IP rate.
But without the proposed service, rates to consumer-owned utilities would be reduced by $1.00/MWh (3%) with no discernable positive impact on employment levels, and there is no assurance that BPA could save other Northwest industries by offering artificially subsidized PF rates. Indeed PNGC's employment data raised in its comments (TDS 090201) dated August 3, 2009, demonstrates the regrettable impact that the economic downturn has had on the Northwest. It also reveals that many Northwest industries have closed their plants notwithstanding having electric power rates from BPA's preference customers that are substantially below Intalco's electric power rates. Closing the Intalco plant would not restore employment to other regional workers.

Therefore, we urge that BPA do what it can, within the bounds of its discretion, to retain Alcoa as a 70-year power customer and retain the more than 2,059 direct and indirect jobs that would result,[4] rather than succumbing to an argument that some hypothetical number of jobs might be saved if BPA knowingly causes Intalco to close by failing to provide it with power at the statutorily set rate that it needs to operate.

Alcoa continues to believe the decision to offer electric power service to Alcoa should be made on the basis of BPA's long-term historic relationship with Alcoa, and that BPA should exercise the discretion it has been accorded by Congress to preserve both the customer diversity and jobs that such service would provide. BPA has, instead, determined that it will look for some positive net economic benefit to the region from offering a contract for the Intalco plant. Alcoa believes that such a standard is discriminatory (no other customer is required to make any such demonstration) and therefore the standard is arbitrary and capricious. Nevertheless, BPA's own economic studies demonstrate that there is a positive economic benefit from offering the contemplated service to Alcoa.[5] Alcoa believes that the 2006 and 2008 Conway Studies, previously submitted by Alcoa to BPA in DSL090058 and DSL090059, are a far better way to assess economic impact of providing electric power service to Alcoa than the "Regional Employment and Economic Study" approach. The latter approach seeks to quantify impacts on other regional employers of BPA rate decisions that the study

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[4] Dick Conway and Associates, *The Economic Impact of the Intalco Works Aluminum Plant*, June 2008, page 4 (finding a multiplier effect of 2.9 additional jobs for each aluminum job in Washington).

[5] "Summary of BPA's Use of the Regional Economic Study to Contemplate the Service Concept."
http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/2009/2009-08-28_BPAsUse-of-RegionalEconomicStudy-for-Contemplation-of-ServiceConcept-Summary.pdf

automatically (and incorrectly) ascribes to DSI service, rather than discussed herein, the more conventional economic theory that would ascribe marginal power costs to customers who are imposing load growth on the BPA.

DSI's historic benefits to BPA

Alcoa has been a BPA customer ever since Administrator Paul Raver signed a contract with Alcoa on December 20, 1939.[6] In the ensuing 70 years, Alcoa has consistently bought power from BPA. In the aggregate, the DSIs historically constituted about one-third of BPA's load and paid BPA revenues for power that permitted BPA to amortize the Federal Columbia River Power System. The DSIs, until the last four years, have always been a substantial part of BPA's loads and revenues. For example, in 1942, the DSIs accounted for 92% of BPA's power commitments[7]. Based on more than $7.5 billion in Treasury amortization repayments since 1940, one can conservatively estimate that the DSIs have paid BPA amortization of approximately$2.5 billion or more (since DSI rates have historically exceeded preference customer rates, and during the 1980s, were substantially higher in order to pay for the residential exchange mandated by the Northwest Power Act).

To say that providing power to Intalco results in a "subsidy" (as some BPA customers have suggested) ignores the substantial equity in the BPA system that Alcoa and the other DSIs have contributed over the years. Alcoa was one of BPA's first customers, has consistently paid its bills, and like other valuable BPA customers, has an equitable claim to BPA power service. It is also clear that the DSI load reductions have permitted the region to meet growing public agency loads. The load reductions have also allowed regional utilities, including BPA, to make very lucrative sales outside the region. The preference customers now seem to assert a claim to virtually all of the benefit of BPA's surplus sales for themselves, a claim clearly at odds with the Regional Preference Act (16 U.S.C. § 837), the Northwest Power Act (16 U.S.C. §839f(c), and the Excess Federal Power provision (16 U.S.C. § 832m).

Benefits to BPA and Its Other Customers From the 7-year Agreement

a. Waiver of Rights to Surplus BPA Power

Following the Court's opinion in *Pacific Northwest Generating Cooperative v. BPA*, (9th Cir. Case No. 09-70228, August 28, 2009) (*PNGC II*), BPA approached Alcoa to discuss proposed modifications to the 7-year contract, from the version proposed in BPA's notice, to address elements of the Court's opinion. Provided that other terms of the contract remain as in the draft Agreement, Alcoa agreed to surrender any claim to additional power required to serve its loads. In *PNGC II*, the Court stated:

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[6] Bonneville Power Administration, *Columbia River Power For The People*, p. 123 (1981).
[7] *Id.*

> 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. *See PNGC*, 550 F.3d at 876 n.35. 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." *Id.*

Slip. Op. at 11973.

In response, Alcoa agreed to revise the proposed 7-year Agreement to provide as follows:

> Other than as set forth in sections 4, 5, 6, and 23 of this Agreement, during the period October 1, 2009 through September 30, 2016, Alcoa will make no additional request for power from BPA, surplus or otherwise; *provided, further*, that Alcoa agrees not to file a petition for review in the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) challenging (a) any proposed or actual sale of surplus power by BPA to any other BPA customer, whether inside or outside the Pacific Northwest region, or (b) any rate adopted by BPA, and approved on a final basis by the Federal Energy Regulatory Commission, for the sale of surplus power; *provided, however*, that the foregoing commitment by Alcoa will be of no force or effect in the event the Ninth Circuit issues its mandate in a case in which it has granted a petition for review challenging this Agreement and has issued an order or opinion that declares or renders this Agreement void or if BPA terminates this Agreement.

This provision clearly frees up the power associated with one-third of the Intalco load (160 a MW), as well as an additional 150 MW of load that BPA has historically provided for the operation of Alcoa's Wenatchee smelter. These are both loads that will not be served under the 7-year Agreement for sales outside the Pacific Northwest, but which would otherwise be subject to regional preference. With this provision, Alcoa will not make any claims for the portion of its load that is unserved at the IP Rate in way that could interrupt BPA's sales outside the region. Alcoa believes such a claim would otherwise be meritorious and successful. *See Pacific Northwest Generating Coop. v. BPA*, 550 F.3d 846, 873 (9th Cir. 2008), *amended on denial of reh'g*, No. 05-75638, --F.3d--, 2009 WL 2386294 (9th Cir. Aug. 5, 2009), [8] Therefore, the waiver of Intalco's

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[8] **"**We conclude that BPA's interpretation of its governing statutes as providing authority to sell surplus power to the DSIs under § 839c(f) at an FPS rate without first offering to sell that amount of power under either § 839c(d) or § 839c(f) at a rate set under § 839e(c) is not reasonable. The statutory text of the NWPA, the agency's own prior interpretation of the Act, and the NWPA's legislative history, are all to the contrary. We therefore hold

claim for its otherwise unmet power needs, that BPA must first offer within the Northwest region to Alcoa at the IP rate, has a significant economic value (measured by BPA's surplus power times the difference between market prices and the IP rate). It also has the value of not disrupting BPA's marketing of electric power sales outside the region at BPA's market-based rates, the benefits of which overwhelmingly accrue to BPA's preference customers.

b. Waiver of Lookback Claims

In further response to the Court's opinion in *PNGC II* Alcoa agreed (subject to other terms of the draft Agreement remaining in place) to waive its claim to the net difference it paid for power under the Block Sale Agreement and the IP rate in circumstances where BPA determines that (in its view) the damages waiver contained in the Block Sale Agreement is effective. Alcoa has quantified the basis for its claim and estimates that, by the end of the Block Sale Agreement, its damages reflected in that claim will be $195 million. Alcoa has included as Attachment A to this letter the Exhibit that it filed with the Ninth Circuit documenting its claim. The proposed revision to the contract provides:

> In the event BPA issues a final record of decision with respect to the issues remanded to BPA (the Remand ROD) by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) in *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, 550 F.3d 846 (9th Cir. 2008) (*PNGC I*), and *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, Nos. 09-70228, 09-70236, 09-70988 (9th Cir. Aug. 28, 2009) (*PNGC II*), in which BPA determines that no payments are owing by Alcoa to BPA or by BPA to Alcoa, then Alcoa agrees that it waives any legal, equitable, or other claim or right of any nature that it has, or may have in the future, for money or any other remedy, with respect to the Block Power Sales Agreement by and between Alcoa, BPA, and Public Utility District No. 1 of Whatcom County, Washington (Contract No. 06PB-11744) (the Block Contract), as amended; *provided, however*, that the foregoing waiver by Alcoa 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 challenging the Remand ROD and has issued an order or opinion that finds such payments are required under the Block Contract or if BPA terminates this Agreement.

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that BPA improperly refused to offer the aluminum DSIs energy at a rate set under § 839e(c) before selling them power at an FPS rate."

BPA sought, and was denied rehearing on this question. Therefore, the surrender of Intalco's claim for one-third of its otherwise unmet power needs that BPA must first offer within the Northwest region to Alcoa at the IP rate has a significant economic value, as well as the value of not disrupting BPA's market-based electric power sales outside the region.

This waiver of the right to seek $195 million in restitution of the difference between the IP rate and the net power costs that Intalco actually incurred under the Block Power Sales Agreement forms additional consideration to BPA for entering into the 7-year contract. The Ninth Circuit in *PNGC II* observed:

> Petitioners also maintain that BPA's decision to enter into the amended contract was not consistent with sound business principles because the agency did not first seek a refund of funds it improperly paid to Alcoa pursuant to the 2007 Contract. As BPA notes, however, there is a significant possibility that the DSIs do not owe BPA a refund. *See infra* Part IV.

PNGC II, Slip op. at 11986-87, footnote 11. Alcoa imparts value to BPA in waiving its claim for damages (assuming that BPA concludes that neither party owes the other in the lookback) because Alcoa could otherwise pursue its damages either as an appeal of BPA's determination on the lookback or as a claim in the U.S. Court of Federal Claims. At the very least, elimination of the claim (as conditioned) will prevent BPA from having to mount a defense of the claim, with the attendant costs and risk (to BPA's other customers) associated with such litigation.

<u>Power reserves</u>

In its last rate case, BPA developed a standard for the reserves that the Northwest Power Act requires BPA to seek from its DSI customers. Alcoa also provides regional transmission reserves through its transmission contract with BPA. The proposed 7-year Agreement also contemplates the negotiation by BPA and Alcoa of additional valuable reserves to help BPA integrate wind-power and other renewable energy sources into its system:

> The Parties recognize that with the addition of certain electronic controls at the Intalco Plant, the Intalco Load can be varied to help accommodate within-hour fluctuations on BPA's system associated with wind power generation. The Parties agree to undertake discussions within 60 days after the execution of this Agreement to identify and implement any agreed to actions and agreements necessary to achieve such wind integration benefits.

Proposed Power Sale Agreement at Exhibit F, Section 2.

For the foregoing reasons, Alcoa believes that its historic contributions to the Pacific Northwest power system and the benefits that it can continue to contribute to BPA, its other customers, and the regional economy in the future, justify offering Alcoa physical power for service to its Intalco plant. Alcoa urges BPA to move forward with an Agreement that adheres to the proposal embodied in Draft Agreement, with the additional regional benefits that BPA would derive from Alcoa's modifications to the Agreement since the August 19, 2009 draft. This would allow equitable service to one of BPA's

longest-term customers (Alcoa) and preserve over 2,000 jobs that are so important to the Northwest, particularly during this deep and protracted recession.

Alcoa, and the Ferndale, Washington, community, that has over 2,000 jobs associated with the Intalco facility, are grateful to BPA for seeking a middle ground that will give Intalco an opportunity to continue to operate under difficult market conditions. The benefits identified in this letter can only be achieved through physical power service from BPA. With an appropriate Agreement, Alcoa is willing to do its part to preserve industrial manufacturing capability that is so vital to regional employment, while also maintaining the balance-of-trade and security interests of the country.

Sincerely,

Mike Rousseau

Mike F. Rousseau
Plant Manger, Alcoa Intalco Works

cc: Governor Gregoire,
NW Congressional Delegation

Pacific Northwest Generating Cooperative v. BPA

Case No.: 09-70228, 09-70236

Opening Brief of Intervenor Alcoa, Inc.

Exhibit 1:

Affidavit of Jack A. Speer
In Support of Opening Brief of Intervenor Alcoa, Inc. (Apr. 20, 2009)

Case No.: 09-70228, 09-70236

UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

PACIFIC NORTHWEST GENERATING COOPERATIVE, *et al.*,
Petitioners,

ALCOA INC., Intervenor,

v.

BONNEVILLE POWER ADMINISTRATION; et al., Respondents

AFFIDAVIT OF JACK A. SPEER

IN SUPPORT OF

OPENING BRIEF OF INTERVENOR ALCOA INC.

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STATE OF WASHINGTON)
) ss
Chelan County)

I, Jack A. Speer, attest as follows:

1) My name is Jack A. Speer. I am the owner of Speer Energy Consulting LLC, and serve as consultant to Alcoa Inc. ("Alcoa") in rate and contract proceedings before the Bonneville Power Administration ("BPA"). I am competent to testify on the matters contained herein, which are based on my personal knowledge.

2) In June 2006, Alcoa entered into the Block Power Sales Agreement with BPA. The Block Power Sales Agreement is contained in the Administrative Record in this proceeding. *See* A.R. 0216-0264.

3) As part of its obligations under the Block Power Sales Agreement, Alcoa is required to provide BPA with "contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power" used to calculate the monetary benefit provisions with respect to Alcoa's Intalco plant in Ferndale, Washington. E.R. 7, A.R. 0227.

4) The specific power sale contracts that Alcoa entered into are confidential documents containing commercially sensitive information.

5) The data that Alcoa supplied to BPA was marked as confidential.

6) Under the terms of the Block Power Sales Agreement, "Information provided to BPA which is subject to a privilege or confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligations under the Freedom

of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement." Block Power Sales Agreement Section 14(c), E.R. 11-12; A.R. 0239-0240.

7) Since 2006, Alcoa has provided BPA with such "contracts, invoices, or other documents" in accordance with the Block Power Sales Agreement. These documents evince the prices Alcoa actually paid for power under the individual power sale agreements in reliance on the agreement.

8) In an effort to cure the defects in the Block Power Sales Agreement identified in this Court's December 2008 decision in *Pacific Northwest Generating Cooperative v. Bonneville Power Admin.*, 550 F.3d 846 (Dec. 18, 2009), BPA offered Alcoa a contract amendment (the "Amendment") in January 2009 (the "Amended Contract"). A copy of the Amendment is included in the Administrative Record before this Court. *See* E.R. 13-35; A.R. 0267-0287.

9) The Amendment, which is the subject of this proceeding, established the Monetary Benefit BPA will use to attempt to address the net difference between BPA's statutory industrial power ("IP") rate and the market rate at which BPA would have had to acquire power to serve Alcoa. The fifth recital of the Amendment recognizes the significantly higher rates Alcoa actually paid for power between December 2008 and September 2009 by stating, "In reliance on the payments to be made to it by BPA under the Agreement, Alcoa acquired power in the wholesale power market to serve its industrial load during the full term of the Agreement. The average cost of Alcoa's acquisitions exceed BPA's currently forecasted wholesale market

price for the Amendment Period". E.R. 15, A.R. 0267.

10) The Amendment recognizes that BPA had information before it on the rates Alcoa actually paid to purchase power from non-BPA sources in reliance on the underlying Contract. *See, e.g.*, E.R. 15, A.R. 0267. ("The average cost of Alcoa's acquisitions exceed BPA's currently forecasted wholesale market price for the Amendment Period." Such information, however, is not included in the Administrative Record before the Court in this proceeding, perhaps because of BPA's understanding of the confidentiality provisions of the Contract.

11) Attached to this affidavit, as Exhibit A, is a true and correct copy of rebuttal testimony I prepared on Alcoa's behalf in the WP-10 proceeding currently pending before BPA. That proceeding will determine, among other things, the IP rate applicable to Alcoa and other direct service industrial ("DSI") customers for Fiscal Year ("FY") 2010-2011. *See* 74 Fed. Reg. 6,609 (Feb. 10, 2009).

12) The rebuttal testimony accurately summarizes information submitted by Alcoa to BPA under the Block Power Sales Agreement, namely, the rates it actually paid to purchase power from non-BPA sources in reliance on that agreement, by aggregating the data and not identifying the specific power suppliers or the prices under the individual power sale agreements. Despite the fact that it had the specific information on the Alcoa power sale agreements and considered it as part of the decision at issue in this proceeding, BPA did not include the information as part of the Administrative Record here.

13) The rebuttal testimony includes two exhibits that relate to issues now before the Court – Rebuttal Exhibits 3 and 6. Alcoa initially submitted these exhibits on March 20, 2009, as part of my original direct testimony in

the WP-10 proceeding.

14) On April 12, 2009, the BPA-10 Hearing Officer in WP-10 granted Pacific Northwest Generating Cooperative's ("PNGC") and BPA's Motions to Strike portions of my original testimony. A copy of the Hearing Officer's Order is attached as Exhibit B to this affidavit.

15) On April 17, 2009, Alcoa submitted my rebuttal testimony, which included Rebuttal Exhibit 3 and Rebuttal Exhibit 6. Those exhibits were identical to exhibits attached to my original testimony, but which the Hearing Officer struck based on the motions to strike. The Hearing Officer's Order, however, suggested that Alcoa could submit the exhibits as rebuttal testimony in order to respond to the testimony of PNGC and other preference customers relating to the allegations that power provided to Alcoa constituted a subsidy. PNGC has attempted to prevent evidence of Alcoa's actual net power costs in BPA proceedings. Alcoa believes that such evidence is responsive to PNGC's continuing allegations that the net price Alcoa pays for power is in violation of BPA's statutes and a "subsidy."

16) Rebuttal Exhibit 3 summarizes the rates Alcoa actually paid for power for the Intalco plant from non-BPA sources between December 2008 and September 2009 – the term of the Amendment at issue here.

17) The figures and calculations in Rebuttal Exhibit 3 are based on, and accurately reflect, the information Alcoa submitted to BPA as part of its obligations under the Block Power Sales Agreement, namely "contracts, invoices, and other documents." The figures and calculations accurately reflect the price Alcoa has paid to provide the Intalco plant with power between December 2008 and September 2009. The figures also include estimates of revenues from future sales of surplus power since the Intalco plant expects to use less power than purchased during this period. As

summarized in Rebuttal Exhibit 3, Alcoa's average price for power from non-BPA sources between December 2008 and September 2009 (after remarketing unused power) is expected to be $ $62.13 per megawatt hour ("MWh").

18) During that same time period, the Monetary Benefit under the Amendment will average $15.24 per MWh.

19) The net price expected to be paid by Alcoa during the term of the Contract Amendment (rates paid, less remarketing revenue and less Monetary Benefit) is $46.89 per MWh.

20) The actual price expected to be paid by Alcoa ($46.89) exceeds the published average industrial power ("IP") rate ($33.76) by $13.13 per MWh. As a result, Alcoa is expected to pay $27,768,590 in excess of the IP rate for power during the term of the Amendment.

21) Rebuttal Exhibit 6 aggregates Alcoa's anticipated overpayments for power in excess of the IP rate during the entire term of the Block Power Sales Agreement (October 2006 through September 2011). The figures and calculations in Rebuttal Exhibit 6 are based on, and accurately reflect, the information Alcoa submitted to BPA as part of its obligations under the Block Power Sales Agreement, namely "contracts, invoices, and other documents."

22) Rebuttal Exhibit 6 specifically aggregates the following categories of overpayments: (a) Alcoa's overpayments between October 2006 and November 2008 ($20,719,823); (b) Alcoa's expected overpayments between December 2008 and September 2009 ($27,768,590); (c) Alcoa's expected overpayments between October 2009 and September 2011 ($98,175,231); and (d) overpayments due to BPA's incorrect calculation of the IP-07 rate ($48,648,685). In total, Alcoa is expected to pay $195,312,329 for power

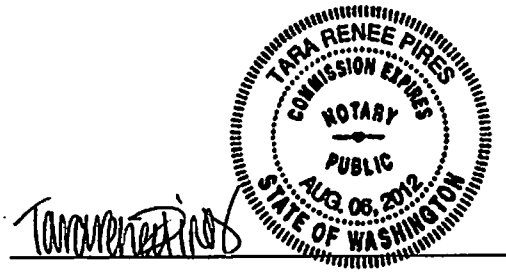
during the term of the Block Power Sales Agreement (October 2006 through September 2011) that it would have had BPA provided Alcoa with physical power at a correctly calculated IP rate.

23) On April 9, 2009 BPA held a "DSI Service Workshop" various issues relating to continuing DSI service under the terms of the opinion in *PNGC*. I submitted, and BPA accepted for the record, the exhibits which I had attempted to introduce as direct testimony in the WP-10 proceeding. Those exhibits are identical to the exhibits attached to this affidavit with the exception that Column P of Rebuttal Exhibit 3 (IP Rate $/MWh) contained an error in the last line of the exhibit that did not impact any of the calculations in the exhibit. That error has been corrected in my rebuttal testimony exhibit and in the exhibit attached to this affidavit. I have also resubmitted the corrected exhibit as part of the DSI Service Workshop record.

Executed this 20th day of April 2009.

Jack A. Speer
Speer Energy Consulting LLP
918 Briarwood Dr.
East Wenatchee, WA 98802

Subscribed and sworn to before me, this 20th day of April 2009.



NOTARY PUBLIC FOR THE STATE OF WASHINGTON

My commission expires: August 06, 2012.

Pacific Northwest Generating Cooperative v. BPA

Case No.: 09-70228, 09-70236

Affidavit of Jack A. Speer

Exhibit A:

Rebuttal Testimony of Jack A. Speer
(WP-10-E-AL-02, Apr. 17, 2009) and (WP-10-E-AL-02-E01, Apr. 20, 2009)

UNITED STATES OF AMERICA

US DEPARTMENT OF ENERGY

BEFORE THE

BONNEVILLE POWER ADMINISTRATION

2010 WHOLESALE POWER RATE ADJUSTMENT PROCEEDING	))	BPA Docket WP-10

REBUTTAL TESTIMONY OF JACK A. SPEER

ON BEHALF OF

ALCOA INC

FILED: APRIL 17, 2009

Q. **Please state you name and your affiliation.**

A. My name is Jack A. Speer. I am the owner of Speer Energy Consulting LLC, and represent Alcoa Inc. in this proceeding. My qualifications are contained in WP-10-Q-AL-E01.

Q. **Did you file direct testimony in this proceeding?**

A. Yes. I filed direct testimony marked as WP-10-E-AL-01.

Q. **What is the purpose of this rebuttal testimony?**

A. I am providing rebuttal testimony in response to the direct testimony of the JP7 group (PPC, ICNU, and Tacoma Power), PNGC, and the Western Public Agency Group (WPAG).

Typical Margins

Q. **Did parties file testimony in this case recommending that BPA increase its "typical margins" charged as part of the IP rate?**

A. Yes. Both PNGC and the JP-7 Group propose that BPA adjust upward the typical industrial margin required by Section 7(c) of the Northwest Power Act. WP-10-E-PN-01, p. 5, line 8 through p. 7, line 10 and WP-10-E-JP7-1, p. 6, line 9 through p. 7, line 13. The testimony is based entirely on supposition that such margins have changed because "many utility costs have risen during that time [since the last study 4 years ago]." WP-10-E-JP7-1 at 5, lines 15-17. PNGC testifies that: (1) retail sales are falling, so margins must be increasing; and (2) "one could conclude" that typical industrial margins have also changed because the Handy-Whitman Index of Public Utility Construction Costs has risen. WP-10-E-PN-01, p. 6, line 4 through p. 7- line 10.

Q. **Do these conclusions make sense?**

A. No. First, as the JP7 Group notes, in the past the PPC has conducted surveys of its members to provide data from which BPA could calculate a typical margin. It didn't do so this year, although presumably it could have done so in order to support its testimony. The typical industrial margin has been constant for many rate cases even when the PPC data was available. So the passage of time and inflation in utility rates should not lead to the inference that typical margins have increased. When data was available, typical margins didn't increase so, all the more, in the absence of any hard evidence on this point, no inference is justified that such typical margins have increased.

Second, a reduction in retail sales doesn't necessarily lead to an increase in margins. Typical, cost-based ratemaking implies that a customer pays the cost that a utility incurs in serving a customer or customer class. As retail sales decrease, so do the costs of serving that load. In addition, sound utility practice would be to reduce expenses as much as possible, before increasing ratepayer margins to all classes. That may also have happened. It is just as likely to infer that the costs of providing service to customers have decreased in proportion to retail sales as to infer that margins have increased. And even if there were evidence that margins to other customers were increasing (rather than just inferred) that does not constitute evidence that *industrial* margins are increasing. Many of the industrial contracts may have margins that are fixed under long-term contracts. Moreover, as I understand it in developing the typical margin BPA must consider "the comparative size and character of the loads served, the relative costs of electric capacity, energy, transmission and related delivery facilities provided and direct and indirect overhead costs" as related to delivery of power to industrial customers. In other words, PNGC, and the JP7 parties ask the

Administrator to ignore the characteristics he is required to consider and to presume there has been an increase in typical industrial margins based on the further assumption that increases in costs, in general, have increased typical industrial margins. Finally, the Handy Whitman Index of Public Utility Construction Costs, by its own name, suggests that it has almost nothing to do with utility margins—certainly no direct correlation could be drawn sufficient to support the statutory standards that BPA must consider as outlined above.

Q. **Could the parties recommending an increase in industrial margin have submitted data to support their testimony on this point?**

A. Yes. As indicated, the PPC has conducted these surveys in the past for BPA and thus could gather such data. Presumably, no party would have better access to customers who are paying these margins than the Industrial Customers of Northwest Utilities (ICNU), many of whose members are among the larger industrial customers of publicly owned utilities in the region. Yet ICNU's witness not only failed to produce any data indicating that typical industrial margins have increased as part of his testimony, ICNU refused to provide any data whosoever in response to Alcoa's data request asking for evidence of the asserted increases in typical margins. *See* Alcoa Data Request AL-JP7-3 and response (attached as Rebuttal Exhibit 1).

Q. **The Joint Parties recommend including the Washington State revenue tax in the typical industrial margin. WP10-E-JP7-1, p. 6, lines 1-8. Do you agree with this recommendation?**

A. No. The Washington State revenue tax is not a "typical margin included by such public body and cooperative customers in their retail industrial rates." Instead, it is a tax imposed by the State of Washington, unrelated to the margin the utilities charge

(and keep) for their own use. It therefore doesn't fit within definition of margin within the Northwest Power Act or as understood by BPA in the past.

DSI Load Assumptions

Q. **The JP7 parties testified as follows:**

> Our understanding is that BPA determined the number by calculating the difference between the IP rate and market power price and then calculating the MWHs that could be provided at a cost of $59 million, which represents the cost that the agency deems appropriate to incur for the DSIs
>
> *Q. Is this a proper method of forecasting DSI load?*
>
> A. No. BPA should forecast DSI loads using normal load forecasting methods aimed at accurately estimating actual amounts of expected load.
>
> *Q. Why is it improper to simply assume that the DSIs will operate at a sufficient level to impose the entire cost BPA appears willing to incur for the DSIs?*
>
> A. There are several reasons. The first is that the economy has deteriorated markedly over the past several months. Commodity prices have taken a hit. A recent Wall Street Journal table (3/12/09) shows that the spot market price for aluminum is down over 50% from a year ago. Press reports of statements from Alcoa and CFAC indicate that they could shut down or curtail production. BPA has not provided a reasonable basis for its assumptions about the likely magnitude of DSI load.
>
> *Q. Would it ever be appropriate for BPA to assume a limit on the amount of costs it assumes to occur to provide DSI service?*
>
> A. Yes. Our understanding is that BPA has no obligation to serve the DSIs, so if it chooses to, and is authorized to do so, it could make a reasonable determination to serve them only up to an amount that would correspond with a certain cost. However, the issue here is that BPA is unreasonably assuming that the DSIs will operate at a level that will correspond with the amount of service that BPA may provide. WP-10-E-JP7 1, p. 2, line 7 through p. 3, line 9.

Do you agree with the JP7 parties' testimony?

A. I disagree with the JP7 parties' conclusion about the likely level of DSI operations if DSIs receive the IP Variable Rate I propose. I agree that BPA starts with the assumption that the level of service should be derived based on an assessment of what BPA believes its customers can "afford" or "is appropriate to incur for the DSIs." The $59 million figure that the JP7 parties mention is the same dollar level for the Monetary Benefits proposal that the Court found to be invalid. BPA uses that figure to back into an amount of power it will provide, as opposed to a determination of the amount of power it determines it has available to serve the DSI load [see WP-10-E-BPA-10, page 11, lines 17-21 and page 12, lines 19-25]. BPA does this by taking the $59 million and dividing by the difference between the market rate and the IP rate to arrive at the number of average megawatts BPA will sell to the aluminum DSIs. The JP7 parties and Alcoa agree that this is improper. However, unlike the JP7 parties, I believe BPA's approach simultaneously: a) results in too little power for Alcoa's Intalco smelter to operate (as opposed to too much power as JP7 parties testify) and b) derives from an artificial dollar cap that was successfully challenged by both Alcoa and PNGC in the *PNGC* case. Alcoa believes that BPA has ample authority: (1) to provide physical power service to Alcoa; (2) to price this service at an IP rate that is developed consistent with the methodology that BPA used in developing its final IP rate in its WP-07 Supplemental rates; (3) to develop a variable rate that will recover BPA's allocated IP costs over the long-term of the contract that BPA is to develop; and (4) to provide reserve credits to the DSIs consistent with the methodology and valuation methods proposed in this testimony. Alcoa does not believe that BPA should begin its service assumptions with a dollar limit as suggested by the JP7 parties.

Q. Do you agree with the JP7 parties in how BPA should exercise its discretion to serve DSI loads?

A. No. Given the discretion to sell DSIs firm power, or not, BPA should serve these historic DSI loads. To fail to do so would result in the death of an industry with flat loads that has been historically served by BPA while BPA serves the JP7 group's growing loads at rates that do not reflect the cost of providing their growing service needs.

Appropriate Pricing Principles

Q. Do you agree with PNGC's argument that the DSIs "embedded cost of service" is $215 million and that a lower rate is a subsidy to the DSIs?

A. No. The rate directives in section 7 of the Northwest Power Act require an IP rate that is based on the PF rate with certain adjustments. It would not be appropriate to use a different methodology that contradicts the plain language of the law in order to allocate additional costs to the IP rate as suggested by PNGC. If the DSIs are charged market-based rates, rather than the properly constructed IP rates, then a clear subsidy would result in favor of PNGC and the other preference customers. BPA's rates to the DSIs are statutorily constrained in a way that simply does not permit marginal cost pricing. So the load growth of the preference customers has not been reflected in BPA's past rates, and won't be for this rate period. BPA, however, would voluntarily send the wrong price signals to the growing preference customer loads if it artificially increases the DSI rate in order to lower rates for preference customers at the cost of the demise of the entire DSI customer class.

Q. **Is there another reason for serving the historic DSI loads at accurately measured embedded cost?**

A. Yes. For nearly 70 years, the DSIs have paid rates that have paid off the debt for large portions of BPA's system. While they have not built up "equity" in the sense of gaining ownership of BPA's system, they certainly have contributed to the construction

of the Federal Columbia River Power System and the related transmission that give rise to BPA's ability to serve consumer owned utility customers at the low rates they enjoy today.

Existence of a Contract

Q. **WPAG testifies as follows:**

> *Q. "Does BPA have in place a contract with the smelter DSIs for a power sale during the rate period?*
>
> A. Not to our knowledge. The contracts offered to the smelter DSIs were not executed, so there is currently no contract with them for a power sale for the coming rate period." WP-10-E-WG-01, p. 20, lines 1-5.

Do you agree with WPAG's conclusion?

A. No. As I understand the Ninth Circuit opinion to which the WPAG witness refers, the form of the monetary benefit in the DSI Block Sale Agreements was invalidated, but the Court did not hold that the contracts were void, as if they never existed. Instead, the Court observed that BPA does have the authority to sell physical power to the DSIs and remanded the contract back to BPA to make a determination as to the impact of the contract's severability clause on the other ongoing provisions of the contract. The Block Sale Agreement has a provision for the sale of physical power to Alcoa (and CFAC) and it is possible that BPA will conclude that portion of the contract may be performed for its intended term—that is, through September 2011.

The Question of Subsidy

Q. **WPAG testifies as follows concerning service to the DSIs:**

> Unfortunately, there is no assurance that the cost to preference customers of subsidizing the power costs of these DSIs will be limited to the $59 million forecast in the Initial Proposal, or at or near zero based on more recent power market prices.
>
> The market price of power changes on a daily basis. While the current forward prices might suggest a near zero-cost to

> preference customers from a power sale to the DSIs (forecast IP revenues and market power costs being nearly equal), if market power prices go up during the rate period, the cost to preference customers of this subsidy could escalate. We have seen recent examples of this phenomenon. In the initial rate proposal for the 2000 BPA rate case, power sales commitments by BPA exceeded its supply, and it was generally assumed that market power could be procured at a price that would not cost materially more than the PF rate, resulting in no major cost impacts to preference customers from such power sales commitments. Unfortunately, the market price of power escalated substantially, resulting in major changes to the costs of these commitments. WP-10-E-WG-01, p. 20, lines 17-22 and p. 21, lines 3-13.

Do you agree with WPAG's assertions?

A. No. Alcoa does not agree that the payment by BPA for power to serve the DSIs is a subsidy. This question has been presented to the courts on several occasions, only the most recent being in the case WPAG refers to in its testimony. As I understand it, the Ninth Circuit has concluded that BPA has discretion to purchase power for the DSIs and that it may roll the cost of such purchases into its rates, including preference customer rates and that BPA should charge the IP rate for sales of power to the DSIs. The WPAG testimony labels this result as a "subsidy" and concludes:

> Finally, it is neither fair nor practical to ask preference customers to subsidize jobs outside their service territories while jobs are being lost within their service territories. Therefore, we recommend BPA assume zero cost to serve DSIs for purposes of setting rates in this rate period. WP-10-E-WG-01, p. 21, lines 18-22 through p. 22, lines 1-2.

Q. Would that be a prudent assumption on BPA's part?

A. No. BPA has announced that it will undertake a "lookback" proceeding in the near future to determine whether rates to the DSIs should be adjusted due to the Ninth Circuit's invalidation of the former Monetary Benefit. In that proceeding, Alcoa will demonstrate that the Monetary Benefit caused it to pay, and will, in the future cause it

to pay rates that exceed the IP rate that the Ninth Circuit held BPA must collect for DSI service.

Q. PNGC asserts in WP-10-E-PN-01 that BPA's prior IP ratemaking is flawed through the use of "nominal loads." WP-10-E-PN-01, p. 8, line 24 through p. 10, line 2. Does Alcoa agree?

A. We agree that the monetization of the DSI contracts led to odd IP ratemaking, but contrary to PNGC's allegations of subsidy resulting from the existing rates, we think that BPA's "lookback" proceeding should reach just the opposite conclusion about BPA's prior rates, particularly because they exceeded the adopted IP rates.

Q. Please describe the amount that Alcoa has paid or is likely to pay above the IP rate because of the monetized contract?

A. The expected overpayment can be segregated into 4 categories:

1. First, is the difference between the amounts actually paid for power from non-BPA sources minus the amount of BPA monetized benefits received compared to the IP-07 and IP-07R rates from October 1, 2006 through November 30, 2008 under the original DSI Block Sale Agreement. This is summarized in Rebuttal Exhibit 2 to this testimony.

2. Second, is the difference between what Alcoa is likely to pay for power pre-purchased from non-BPA sources minus the monetized benefits BPA paid to Alcoa under the Amended Block Sale Agreement and minus revenues received from the remarketing of surplus pre-purchased power compared to what Alcoa would have been paid under the IP-07R rate from December 1, 2008 through September 30, 2009. This is summarized in Rebuttal Exhibit 3 to this testimony.

3. Third is the difference between what Alcoa is likely to pay for power from BPA at an expected IP rate plus what Alcoa is likely to pay for pre-purchased power from non-BPA sources minus any BPA monetary benefits BPA pays Alcoa during such period

and minus revenues from remarketing pre-purchased power as compared to what Alcoa would have paid to BPA under the proposed IP-10 rate from October 1, 2009 through September 30, 2011. This is summarized in Rebuttal Exhibit 4 to this testimony.

4. Fourth is the difference between the improperly high IP-07 rate and what Alcoa would have paid had BPA under the revised the IP-07 rate during the WP-07R proceeding. When BPA conducted its supplemental 2007 rate case, it adjusted future PF rates to comply with the remanded Residential Exchange Program settlement agreements. This had the effect of reducing the IP rate as well. However, BPA did not adjust the incorrect IP-07 rate methodology retroactively to be consistent with the correct methodology used to determine the IP-07R rate. This resulted in artificially high IP-07 rate as compared to the IP-07R rate. This is summarized in Rebuttal Exhibit 5 to this testimony.

Q. Did Alcoa object to the IP-07 methodology?

A. No. Alcoa was not purchasing power under that rate, but under the monetized power contract at the time, and was not impacted by that rate. However, Alcoa did actively advocate for a correctly calculated IP rate in the WP-07 Supplemental proceeding in the (correct) belief that the Ninth Circuit might invalidate the Monetary Benefit in the Block Sale Agreement and mandate the application of a correctly calculated IP rate.

Q. What should the IP-07 rate have been?

A. It is very difficult to replicate the calculations in the development of the IP-07 rates under the methodology used in the IP-07R rate development. As an estimate I assume that the IP-07 rates would have been equal to the IP-07R rates because the DSI loads remained roughly the same in both rate periods under the Block Sale Agreement.

Q. Please summarize the total amount of the expected overpayment between October 1, 2006 and September 30, 2011.

A. Contrary to WPAG's assertion of a "subsidy" the total expected overpayment by Alcoa in excess of the appropriate IP rate is summarized in Rebuttal Exhibit 6.

Q. How do you propose that BPA remedy the expected overpayment summarized in Rebuttal Exhibit 6?

A. As described on page 16, lines 15 through page 17, line 6 of WP-10-E-AL-01, we propose a true-up mechanism to insure that aluminum variable rate DSI customers will not pay less than the standard IP rate for contracted power. We believe the overpayment amount should be a part of that true-up mechanism.

Q. **Do you propose that the entire $195 million shown in Rebuttal Exhibit 6 be included in the variable rate true-up calculation?**

A. No. We realize the amount of work required for BPA to retroactively revise its rates from October 1, 2006 through September 30, 2008. In the spirit of cooperation and long-term problem solving we propose to eliminate any adjustment in the fourth category identified in Rebuttal Exhibit 6 (Overpayments Due to Improper IP-07 Rate) in the true-up of a variable aluminum rate. This would reduce the total estimated true-up to the $147 million subtotal for the first three categories shown in Rebuttal Exhibit 6. If the variable rate is not adopted, Alcoa of course reserves the right to claim the total amount as damages in the appropriate forum.

Q. How will the true-up be calculated for the other aluminum company that may have a contract that allows purchases under the variable aluminum rate?

A. A true-up using the same methodology would be used beginning with power costs under BPA contracts on October 1, 2006. Of course, the numbers will be different for the other company because of different operating levels and different power costs.

Q. What would the effect be of adopting WPAG's recommendation as to assumptions about DSI service costs in this case?

A. BPA, in its "lookback proceeding," or the Court of Appeals or another court, could conclude during the two-year proposed term for these rates that BPA owes Alcoa the difference between its net power costs and the IP rate. The result of WPAG's "assume no cost or no service" recommendation could well result in a $195 million under-recovery of costs to BPA. The more reasonable way to resolve BPA's uncertainties would be for BPA to adopt the Variable Rate that Alcoa proposes in this rate case which would, as I testified, spread the impact of any restoration of overpayment by the DSIs over longer-term contracts that will negotiated in follow-on BPA proceedings.

Value of Reserves Adjustment

Q, **Did parties testify on value of reserve adjustments in this proceeding?**

A. Yes. But the testimony largely dealt with what should be contained in the contracts that will wrap around whatever value of reserve credits BPA adopts for this rate case. As I understand it, those issues are to be addressed in a parallel proceeding.

Q. Does this complete your testimony?

A. Yes

Response is past due after seven (7) days.

Request (click to view)	Exhibit	Responded	Requesting Party	Responding Party	Date Filed	Response (click to view)
AL-JP7-1	WP-10-E-JP7-01	Yes	ALCOA	Joint Party 7	3/26/2009 2:40 PM	Select Request to view Response
AL-JP7-2	WP-10-E-JP7-01	Yes	ALCOA	Joint Party 7	3/26/2009 2:42 PM	Select Request to view Response
AL-JP7-3	WP-10-E-JP7-01	Yes	ALCOA	Joint Party 7	3/26/2009 2:43 PM	Select Request to view Response

You are viewing page 1 of 1

Request Detail

Request ID: AL-JP7-3
Page Number: 6
Line Number: 1-21
Exhibit Filing: WP-10-E-JP7-01

Technical Contact Name: Michael Dotten
Technical Contact Phone: 503.882.4937
Technical Contact Email: mcdotten@msn.com
Legal Contact Name: Michael Dotten
Legal Contact Phone: 503.882.4937
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Request Text:

Please provide all electric power bills issued to each of the Industrial Customers of Northwest Utilities' ("ICNU") members for all periods between January 1, 2007, and March 24, 2009, for facilities located in the Pacific Northwest.

Response Detail

Date Response Filed: 4/2/2009 3:44:31 PM
Contact Name: Irion A. Sanger
Contact Phone: 503.241.7242
Contact Email: ias@dvclaw.com
Response Text:

ICNU objects to the data request because the data request is vague and ambiguous, the data request is not relevant to the issues identified in this proceeding, the data request seeks information not addressed in the testimony, the production of the data requested would be unduly burdensome, the data request is overly broad, the production of the requested data could reveal highly confidential competitive information, and ICNU intervened for ICNU and did not request party status for its members. Notwithstanding these objections, ICNU responds that it has no documents responsive to this request.

Files Submitted for this Response:

REBUTTAL EXHIBIT 2

Overpayment Above IP Rate in Effect from October 1, 2006 through November 30, 2008

Notes: 1. IP rates are calculated at 100 % Load Factor
2. Loads are actual Intalco energy up to BPA contract limits

Year	Month	aMW	Hours	MWh	Rate Paid	Dollars Paid	BPA Ben. $/MWh	BPA Benefit $ Paid	Actual Dollars Net $ Paid	Actual Rate $/MWh	IP Rate $/MWh	IP Dollars $ at IP Rate	Overpayment $/MWh	Overpayment $
2006	Oct	192.4	745	143,301	$65.69	$9,413,033	18.32	$ 2,625,403	$6,787,630	$47.37	44.98	$ 6,445,679	$2.39	$341,951
	Nov	197.0	720	141,809	$50.59	$7,173,542	17.96	$ 2,547,246	$4,626,296	$32.62	52.03	$ 7,378,322	-$19.41	-$2,752,026
	Dec	200.2	744	148,961	$64.23	$9,567,658	17.62	$ 2,625,403	$6,942,255	$46.60	54.40	$ 8,103,478	-$7.80	-$1,161,223
2007	Jan	201.2	744	149,719	$61.01	$9,134,128	17.56	$ 2,628,403	$6,505,725	$43.45	49.08	$ 7,348,209	-$5.63	-$842,484
	Feb	242.7	672	163,102	$61.27	$9,992,685	14.54	$ 2,371,332	$7,621,353	$46.73	50.41	$ 8,221,972	-$3.68	-$600,619
	Mar	320.0	744	238,080	$59.82	$14,241,946	11.01	$ 2,622,403	$11,619,543	$48.81	48.06	$ 11,442,125	$0.75	$177,418
	Apr	320.0	719	230,080	$59.82	$13,763,386	11.08	$ 2,548,889	$11,214,497	$48.74	39.68	$ 9,129,574	$9.06	$2,084,922
	May	320.0	744	238,080	$59.82	$14,241,946	11.01	$ 2,620,330	$11,621,616	$48.81	34.82	$ 8,289,946	$13.99	$3,331,670
	Jun	320.0	720	230,400	$59.82	$13,782,528	11.06	$ 2,548,585	$11,233,943	$48.76	33.01	$ 7,605,504	$15.75	$3,628,439
	Jul	320.0	744	238,080	$59.82	$14,241,946	11.01	$ 2,620,434	$11,621,512	$48.81	40.61	$ 9,668,429	$8.20	$1,953,083
	Aug	320.0	744	238,080	$59.82	$14,241,946	11.06	$ 2,633,372	$11,608,574	$48.76	45.84	$ 10,913,587	$2.92	$694,986
	Sep	320.0	720	230,400	$59.82	$13,782,528	11.01	$ 2,535,743	$11,246,785	$48.81	48.22	$ 11,109,888	$0.59	$136,897
	Oct	358.0	745	266,705	$61.66	$16,445,005	12.03	$ 3,207,583	$13,237,422	$49.63	45.11	$ 12,031,063	$4.52	$1,206,359
	Nov	361.0	720	259,942	$61.12	$15,887,753	12.09	$ 3,142,273	$12,745,480	$49.03	52.03	$ 13,524,782	-$3.00	-$779,302
	Dec	358.8	744	266,938	$60.30	$16,095,854	12.03	$ 3,210,226	$12,885,628	$48.27	54.40	$ 14,521,427	-$6.13	-$1,635,799
2008	Jan	367.2	744	273,179	$60.75	$16,594,829	11.87	$ 3,242,807	$13,352,022	$48.88	49.08	$ 13,407,625	-$0.20	-$55,603
	Feb	367.4	696	255,735	$62.14	$15,891,382	12.20	$ 3,120,147	$12,771,235	$49.94	50.34	$ 12,873,700	-$0.40	-$102,465
	Mar	368.6	744	274,247	$61.01	$16,731,830	11.48	$ 3,149,518	$13,582,312	$49.53	47.94	$ 13,147,401	$1.59	$434,911
	Apr	369.4	719	265,617	$59.17	$15,717,535	12.22	$ 3,246,157	$12,471,378	$46.95	39.80	$ 10,571,557	$7.15	$1,899,821
	May	375.5	744	279,393	$58.03	$16,213,567	11.64	$ 3,251,633	$12,961,934	$46.39	34.82	$ 9,728,464	$11.57	$3,233,470
	Jun	384.2	720	276,636	$56.40	$15,601,771	11.39	$ 3,150,146	$12,451,625	$45.01	32.82	$ 9,079,194	$12.19	$3,372,431
	Jul	381.3	744	283,701	$60.93	$17,285,620	11.46	$ 3,251,633	$14,033,987	$49.47	40.76	$ 11,563,653	$8.71	$2,470,334
	Aug	379.5	744	282,336	$61.30	$17,306,910	11.52	$ 3,253,363	$14,053,547	$49.78	45.70	$ 12,902,755	$4.08	$1,150,792
	Sep	380.8	720	274,165	$59.39	$16,282,344	11.49	$ 3,150,146	$13,132,198	$47.90	48.34	$ 13,253,136	-$0.44	-$120,938
	Oct	381.1	745	283,947	$55.32	$15,708,287	11.45	$ 3,251,633	$12,456,654	$43.87	39.01	$ 11,076,772	$4.86	$1,379,882
	Nov	336.7	720	242,415	$59.77	$14,489,536	13.42	$ 3,253,363	$11,236,173	$46.35	41.10	$ 9,963,257	$5.25	$1,272,917
Total/Avg				6,175,048	$59.95	$ 369,829,493	$12.67	$75,808,171	$ 294,021,322	$47.28	$44.71	$273,301,499	$2.57	$20,719,823

REBUTTAL EXHIBIT 3 (Corrected 4-20-09)

Expected Overpayment Above IP Rate in Effect from December 1, 2008 through September 30, 2009

Notes:
1. IP rates are calculated at 100 % Load Factor
2. Loads are estimated
3. Market rates are estimated
4. Market rate forecast is as of March 16, 2009

Year	Month	Intalco Load aMW	Hours	Intalco Load MWh	Prepurchased MWh	Prepurchased $/MWh	Market Sales MWh	Market Rate $/MWh	Rate Paid	Dollars Paid	BPA Ben. $/MWh	BPA Benefit $ Paid	Actual Dollars Net $ Paid	Actual Rate $/MWh	IP Rate $/MWh	IP Dollars $ at IP Rate	Overpayment $/MWh	Overpayment $
2008	Dec	304.7	744	226,667	234,360	59.82	7,692.96	55.77	59.96	$13,590,379	$ 14.20	$3,218,672	$10,371,707	$45.76	42.96	$ 9,737,616	2.80	$634,091
2009	Jan	300.4	744	223,483	234,360	59.82	10,877.28	38.11	60.88	$13,604,882	$ 15.35	$3,430,460	$10,174,422	$45.53	36.51	$ 8,159,354	9.02	$2,015,068
	Feb	296.0	672	198,912	211,680	59.82	12,768.00	34.13	61.47	$12,226,926	$ 15.35	$3,053,299	$9,173,627	$46.12	37.54	$ 7,467,156	8.58	$1,706,470
	Mar	288.0	743	213,984	234,045	59.82	20,061.00	27.29	62.87	$13,453,107	$ 15.35	$3,284,654	$10,168,453	$47.52	34.96	$ 7,480,881	12.56	$2,687,572
	Apr	288.0	719	207,072	226,485	59.82	19,413.00	22.14	63.35	$13,118,529	$ 15.35	$3,178,555	$9,939,974	$48.00	32.45	$ 6,719,486	15.55	$3,220,487
	May	288.0	744	214,272	234,360	59.82	20,088.00	19.55	63.60	$13,626,695	$ 15.35	$3,289,075	$10,337,620	$48.25	26.70	$ 5,721,062	21.55	$4,616,557
	Jun	288.0	720	207,360	226,800	59.82	19,440.00	25.73	63.02	$13,066,985	$ 15.35	$3,182,976	$9,884,009	$47.67	22.62	$ 4,690,483	25.05	$5,193,526
	Jul	288.0	744	214,272	234,360	59.82	20,088.00	35.55	62.10	$13,305,287	$ 15.35	$3,289,075	$10,016,212	$46.75	30.17	$ 6,464,586	16.58	$3,551,625
	Aug	288.0	744	214,272	234,360	59.82	20,088.00	38.01	61.86	$13,255,870	$ 15.35	$3,289,075	$9,966,795	$46.51	35.91	$ 7,694,508	10.60	$2,272,288
	Sep	288.0	720	207,360	226,800	59.82	19,440.00	34.94	62.15	$12,887,942	$ 15.35	$3,182,976	$9,704,966	$46.80	37.78	$ 7,834,061	9.02	$1,870,906
Sum/Avg		291.7	729.4	226,667	234,360.00	59.82	169,956.24	33.12	62.1	$132,136,602	15.24	$32,398,818	$99,737,784	$ 46.89	33.76	$71,969,194	13.13	$27,768,590

WP-10-E-AL-02-E01

REBUTTAL EXHIBIT 4

Expected Overpayment Above IP Rate in Effect from October 1, 2009 through September 30, 20011

Notes:
1. IP rates are calculated at 100 % Load Factor
2. Loads are estimated
3. Market rate forecast is as of March 16, 2009
4. Assumes a sale of all prepurchased energy at market and a purchase of IP rate power to meet load

Year	Month	Intalco Load aMW	Hours	Intalco Load MWh	Prepurchased MWh	Prepurchased $/MWh	Market Sales MWh	Market Rate $/MWh	Rate Paid	Dollars Paid	BPA Ben. $/MWh	BPA Benefit $ Paid	Actual Dollars Net $ Paid	Actual Rate $/MWh	IP Rate $/MWh	IP Dollars $ at IP Rate	Overpayment $/MWh	Overpayment $
2009	Oct	288.0	746	214,848	234,990	59.82	234,990	35.92	62.61	$ 13,451,768	$ -	$ -	$13,451,768	$62.61	36.47	$ 7,835,507	26.14	$5,616,261
	Nov	288.0	720	207,360	226,800	59.82	226,800	42.06	61.27	$ 12,703,910	$ -	$ -	$12,703,910	$61.27	41.84	$ 8,675,942	19.43	$4,027,968
	Dec	288.0	744	214,272	234,360	59.82	234,360	55.24	49.07	$ 10,514,193	$ -	$ -	$10,514,193	$49.07	44.06	$ 9,440,824	5.01	$1,073,369
2010	Jan	288.0	744	214,272	234,360	59.82	234,360	52.64	47.26	$ 10,127,164	$ -	$ -	$10,127,164	$47.26	39.41	$ 8,444,460	7.85	$1,682,705
	Feb	288.0	672	193,536	211,680	59.82	211,680	42.00	60.19	$ 11,649,053	$ -	$ -	$11,649,053	$60.19	40.70	$ 7,878,915	19.49	$3,772,138
	Mar	288.0	743	213,984	234,045	59.82	234,045	34.41	66.64	$ 14,260,362	$ -	$ -	$14,260,362	$66.64	38.85	$ 8,313,278	27.79	$5,947,083
	Apr	288.0	720	207,360	226,800	59.82	226,800	26.40	68.70	$ 14,246,280	$ -	$ -	$14,246,280	$68.70	32.15	$ 6,666,624	36.55	$7,579,656
	May	288.0	744	214,272	234,360	59.82	234,360	25.97	65.02	$ 13,932,702	$ -	$ -	$13,932,702	$65.02	28.00	$ 5,999,616	37.02	$7,933,086
	Jun	288.0	720	207,360	226,800	59.82	226,800	33.30	55.62	$ 11,532,586	$ -	$ -	$11,532,586	$55.62	26.61	$ 5,517,850	29.01	$6,014,736
	Jul	288.0	744	214,272	234,360	59.82	234,360	44.90	49.17	$ 10,535,486	$ -	$ -	$10,535,486	$49.17	32.85	$ 7,038,835	16.32	$3,496,651
	Aug	288.0	744	214,272	234,360	59.82	234,360	44.90	53.18	$ 11,394,717	$ -	$ -	$11,394,717	$53.18	38.86	$ 7,888,066	16.32	$3,496,651
	Sep	288.0	720	207,360	226,800	59.82	226,800	47.67	52.27	$ 10,838,513	$ -	$ -	$10,838,513	$52.27	38.88	$ 8,082,893	13.29	$2,755,620
	Oct	288.0	746	214,848	234,990	59.82	234,990	47.19	50.28	$ 10,803,430	$ -	$ -	$10,803,430	$50.28	36.47	$ 7,835,507	13.81	$2,967,924
	Nov	288.0	720	207,360	226,800	59.82	226,800	47.16	55.69	$ 11,547,230	$ -	$ -	$11,547,230	$55.69	41.84	$ 8,675,942	13.85	$2,871,288
	Dec	288.0	744	214,272	234,360	59.82	234,360	47.47	57.57	$ 12,335,170	$ -	$ -	$12,335,170	$57.57	44.06	$ 9,440,824	13.51	$2,894,346
2011	Jan	288.0	744	214,272	234,360	59.82	234,360	47.53	52.85	$ 11,324,744	$ -	$ -	$11,324,744	$52.85	39.41	$ 8,444,460	13.44	$2,880,284
	Feb	288.0	672	193,536	211,680	59.82	211,680	47.61	54.05	$ 10,481,528	$ -	$ -	$10,481,528	$54.05	40.70	$ 7,878,915	13.35	$2,584,613
	Mar	288.0	743	213,984	234,045	59.82	234,045	39.09	61.52	$ 13,165,031	$ -	$ -	$13,165,031	$61.52	38.85	$ 8,313,278	22.67	$4,851,753
	Apr	288.0	720	207,360	226,800	59.82	226,800	30.12	64.63	$ 13,402,584	$ -	$ -	$13,402,584	$64.63	32.15	$ 6,666,624	32.48	$6,735,960
	May	288.0	744	214,272	234,360	59.82	234,360	29.66	60.99	$ 13,067,914	$ -	$ -	$13,067,914	$60.99	28.00	$ 5,999,616	32.99	$7,068,298
	Jun	288.0	720	207,360	226,800	59.82	226,800	37.07	51.49	$ 10,677,550	$ -	$ -	$10,677,550	$51.49	26.61	$ 5,517,850	24.88	$5,159,700
	Jul	288.0	744	214,272	234,360	59.82	234,360	49.12	44.55	$ 9,546,487	$ -	$ -	$9,546,487	$44.55	32.85	$ 7,038,835	11.70	$2,507,652
	Aug	288.0	744	214,272	234,360	59.82	234,360	49.86	47.75	$ 10,232,292	$ -	$ -	$10,232,292	$47.75	36.88	$ 7,898,066	10.89	$2,334,226
	Sep	288.0	720	207,360	226,800	59.82	226,800	51.34	48.26	$ 10,006,157	$ -	$ -	$10,006,157	$48.26	38.98	$ 8,082,893	9.28	$1,923,264
sum/average		288.0	730	5,048,336	5,519,430	59.82	5,519,430	42.03	55.86	$ 281,756,851	0.0	0.0	$ 281,756,851	55.86	36.40	183,581,620	19.46	$ 98,175,231

REBUTTAL EXHIBIT 5

Overpayment Due to Improper IP-07 Rate from October 1, 2006 through September 30, 2008

Notes:
1. IP rates are calculated at 100 % Load Factor
2. Loads are actual Intalco energy up to BPA contract limits

Year	Month	aMW	Hours	MWh	IP-07 Rate In Effect	Dollars Paid At IP-07 Rate	IP-07R Rate	Dollars Paid At IP-07R Rate	Overpayme $/MWh	Overpayment $
2006	Oct	192.4	745	143,301	44.98	$6,445,679	36.47	$ 5,226,187	8.51	$1,219,492
	Nov	197.0	720	141,809	52.03	$7,378,322	41.84	$ 5,933,289	10.19	$1,445,034
	Dec	200.2	744	148,961	54.40	$8,103,478	44.06	$ 6,563,222	10.34	$1,540,257
2007	Jan	201.2	744	149,719	49.08	$7,348,209	39.41	$ 5,900,426	9.67	$1,447,783
	Feb	242.7	672	163,102	50.41	$8,221,972	40.70	$ 6,638,251	9.71	$1,583,720
	Mar	320.0	744	238,080	48.06	$11,442,125	38.85	$ 9,249,408	9.21	$2,192,717
	Apr	320.0	719	230,080	39.68	$9,129,574	32.15	$ 7,397,072	7.53	$1,732,502
	May	320.0	744	238,080	34.82	$8,289,946	28.00	$ 6,666,240	6.82	$1,623,706
	Jun	320.0	720	230,400	33.01	$7,605,504	26.61	$ 6,130,944	6.40	$1,474,560
	Jul	320.0	744	238,080	40.61	$9,668,429	32.85	$ 7,820,928	7.76	$1,847,501
	Aug	320.0	744	238,080	45.84	$10,913,587	36.86	$ 8,775,629	8.98	$2,137,958
	Sep	320.0	720	230,400	48.22	$11,109,888	38.98	$ 8,980,992	9.24	$2,128,896
	Oct	358.0	745	266,705	45.11	$12,031,063	36.47	$ 9,726,731	8.64	$2,304,331
	Nov	361.0	720	259,942	52.03	$13,524,782	41.84	$ 10,875,973	10.19	$2,648,809
	Dec	358.8	744	266,938	54.40	$14,521,427	44.06	$ 11,761,288	10.34	$2,760,139
2008	Jan	367.2	744	273,179	49.08	$13,407,625	39.41	$ 10,765,984	9.67	$2,641,641
	Feb	367.4	696	255,735	50.34	$12,873,700	40.70	$ 10,408,415	9.64	$2,465,285
	Mar	368.6	744	274,247	47.94	$13,147,401	38.85	$ 10,654,496	9.09	$2,492,905
	Apr	369.4	719	265,617	39.80	$10,571,557	32.15	$ 8,539,587	7.65	$2,031,970
	May	375.5	744	279,393	34.82	$9,728,464	28.00	$ 7,823,004	6.82	$1,905,460
	Jun	384.2	720	276,636	32.82	$9,079,194	26.61	$ 7,361,284	6.21	$1,717,910
	Jul	381.3	744	283,701	40.76	$11,563,653	32.85	$ 9,319,578	7.91	$2,244,075
	Aug	379.5	744	282,336	45.70	$12,902,755	36.86	$ 10,406,905	8.84	$2,495,850
	Sep	380.8	720	274,165	48.34	$13,253,136	38.98	$ 10,686,952	9.36	$2,566,184
Total/Avg				5,648,686	$ 45.10	$ 252,261,470	$ 36.40	$ 203,612,784	$ 8.70	$ 48,648,685

REBUTTAL EXHIBIT 6
SUMMARY OF OVERPAYMENTS

REBUTTAL EXHIBIT 2: OVERPAYMENTS ABOVE IP RATE IN EFFECT FROM OCTOBER 2006 THROUGH NOVEMBER 2	$	20,719,823	
REBUTTAL EXHIBIT 3: EXPECTED OVERPAYMENTS FROM DECEMBER 2008 THROUGH SEPTEMBER 2009	$	27,768,590	
REBUTTAL EXHIBIT 4: EXPECTED OVERPAYMENTS FROM OCTOBER 2009 THROUGH SEPTEMBER 2011	$	98,175,231	
SUBTOTAL OF OVERPAYMENTS IN REBUTTAL EXHIBITS 2, 3, and 4			$ 146,663,644
REBUTTAL EXHIBIT 5: OVERPAYMENTS DUE TO IMPROPPER IP-07 RATE	$	48,648,685	
TOTAL EXPECTED OVERPAYMENT BY OCTOBER 1, 2011			$ 195,312,329

ATTACHMENT E

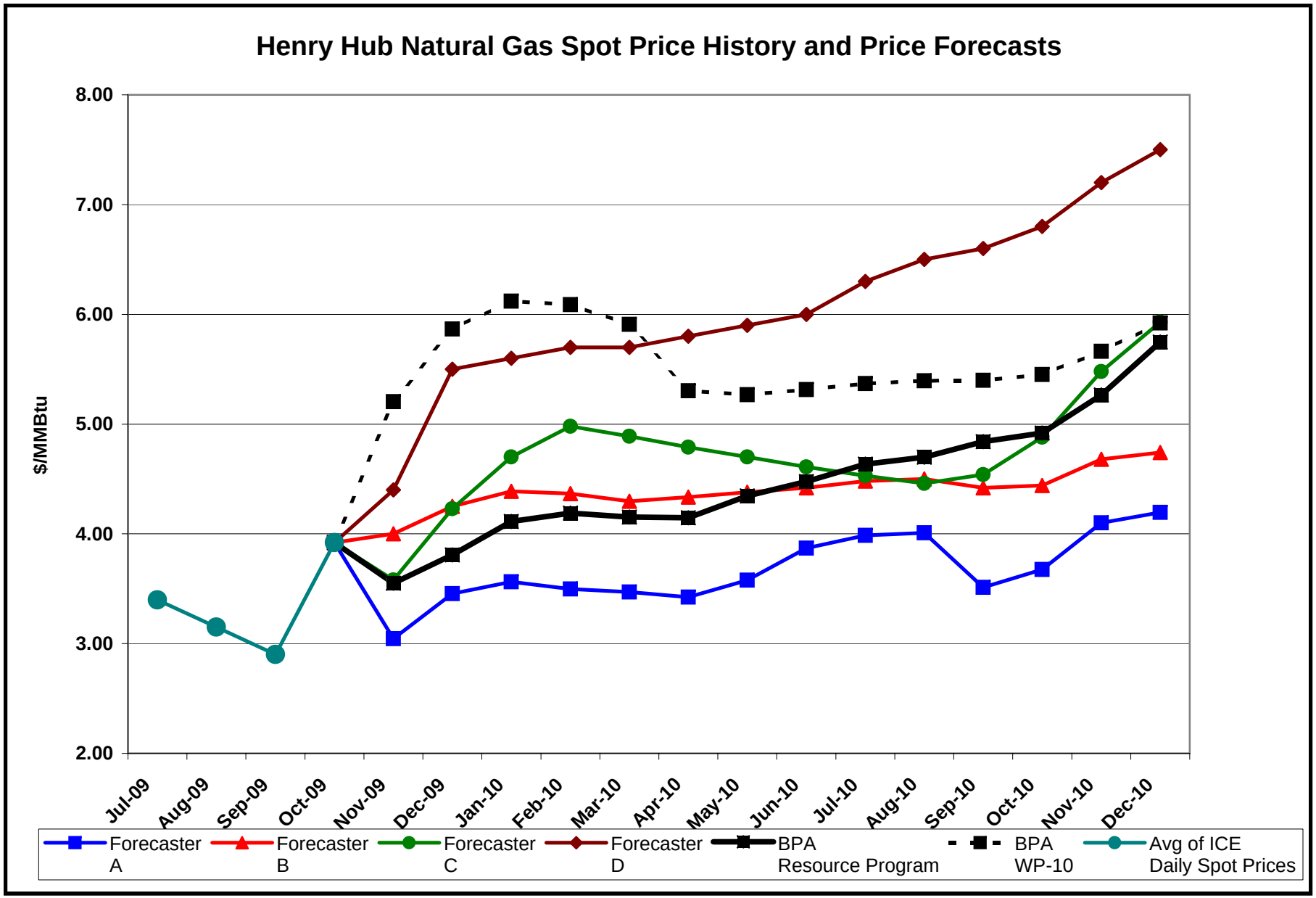

Henry Hub Natural Gas Spot Price History and Price Forecasts
$/MMBtu
8.00
7.00
6.00
5.00
4.00
3.00
2.00
Jul-09
Aug-09
Sep-09
Oct-09
Nov-09
Dec-09
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Forecaster A
Forecaster B
Forecaster C
Forecaster D
BPA Resource Program
BPA WP-10
Avg of ICE Daily Spot Prices

Table A-30: Federal Surplus/Deficit - By Water Year
PNW Loads and Resource Study
2009 - 2010 Fiscal Years **7/21/2009**
[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
1929 Federal Surplus/Deficit	234	-71	-669	-793	-889	175	87	632	1999	981	-319	10	117
1930 Federal Surplus/Deficit	479	13	-574	-700	-936	-163	805	312	663	799	-502	-163	6
1931 Federal Surplus/Deficit	306	177	-425	-803	-827	-418	-285	1042	522	1062	158	312	73
1932 Federal Surplus/Deficit	-111	-424	-686	-1347	-1409	468	3079	5595	3928	1732	7	424	948
1933 Federal Surplus/Deficit	465	-489	330	2907	1342	-89	2013	4321	3787	3258	1979	708	1714
1934 Federal Surplus/Deficit	941	1718	2974	3255	2913	3212	4003	4593	3752	1788	-492	169	2397
1935 Federal Surplus/Deficit	297	-766	-360	2291	2697	-333	1351	3773	2549	2694	778	-119	1228
1936 Federal Surplus/Deficit	332	-137	-734	-1647	-458	-96	2070	4606	4130	1344	130	-260	775
1937 Federal Surplus/Deficit	418	269	-643	-638	-1082	-592	-1112	1632	799	422	311	129	0
1938 Federal Surplus/Deficit	390	-255	194	2372	402	1801	3667	5348	3874	2225	-300	493	1691
1939 Federal Surplus/Deficit	522	-135	-845	-623	-899	622	2251	4798	1847	946	-599	-292	641
1940 Federal Surplus/Deficit	569	283	443	-803	-542	2240	3160	3260	2944	85	-718	98	922
1941 Federal Surplus/Deficit	367	177	-95	-1066	-741	1135	395	1401	890	897	103	720	354
1942 Federal Surplus/Deficit	-59	133	640	466	533	-223	1306	3206	4502	3286	1153	303	1271
1943 Federal Surplus/Deficit	465	-473	-191	1725	2002	2404	4101	5510	3892	3121	381	-627	1857
1944 Federal Surplus/Deficit	346	-43	-761	-731	-774	-67	205	412	55	213	-6	457	-55
1945 Federal Surplus/Deficit	-53	-418	-750	-1112	-1437	-434	-1364	3585	3241	732	-138	-147	152
1946 Federal Surplus/Deficit	103	238	408	1031	-123	2929	4064	5103	3858	3050	583	392	1813
1947 Federal Surplus/Deficit	271	191	2549	2867	2576	3300	3027	4979	4284	3237	322	238	2320
1948 Federal Surplus/Deficit	2163	1930	1164	3709	1011	1631	2997	5516	3544	3908	1896	605	2520
1949 Federal Surplus/Deficit	674	1	138	-677	894	3370	3775	5471	4077	530	-548	-542	1429
1950 Federal Surplus/Deficit	352	-250	-56	1864	2671	3896	3853	4982	3464	3527	1076	404	2145
1951 Federal Surplus/Deficit	1242	1345	2889	3451	3064	3899	4007	5198	3853	3781	1128	224	2840
1952 Federal Surplus/Deficit	1692	844	1258	3733	1329	641	4444	5488	4351	2583	502	-168	2228
1953 Federal Surplus/Deficit	388	-203	-682	-181	2516	949	893	4952	4261	3912	675	261	1469
1954 Federal Surplus/Deficit	661	278	802	1691	3315	1307	2759	5496	3395	3082	3524	2187	2368
1955 Federal Surplus/Deficit	679	872	718	-362	-640	180	761	3042	3998	3178	1857	37	1204
1956 Federal Surplus/Deficit	842	1446	2756	3791	3559	3893	3846	5023	3434	3864	968	344	2812
1957 Federal Surplus/Deficit	844	-192	617	646	243	2474	3327	5721	3827	1817	-126	153	1620
1958 Federal Surplus/Deficit	388	112	-251	484	2200	1630	3046	5789	4392	1728	59	27	1625
1959 Federal Surplus/Deficit	613	638	1956	3711	3535	1815	3362	5112	3555	2381	1032	2444	2502
1960 Federal Surplus/Deficit	2681	2749	2255	2720	1052	2002	3911	4241	4338	2506	143	320	2415
1961 Federal Surplus/Deficit	491	-96	-194	2007	1295	2577	2822	5430	3937	2188	552	-120	1744
1962 Federal Surplus/Deficit	105	133	308	1198	1136	327	3460	4883	4522	1203	130	-156	1433
1963 Federal Surplus/Deficit	1075	852	1765	1921	1837	-104	1513	3985	4509	2846	805	277	1770
1964 Federal Surplus/Deficit	152	10	204	220	962	-167	1000	4403	4228	3692	1539	945	1432
1965 Federal Surplus/Deficit	1201	703	2799	3875	3453	3845	3369	5534	4726	2374	1493	455	2817
1966 Federal Surplus/Deficit	782	-51	123	1557	230	-419	3199	3836	3293	2819	637	-82	1331
1967 Federal Surplus/Deficit	260	-239	308	3424	3750	1761	799	4005	3984	3946	1152	403	1953
1968 Federal Surplus/Deficit	590	-86	296	2317	2130	1818	464	2884	4004	3856	1458	1532	1770
1969 Federal Surplus/Deficit	1251	1572	1308	3771	3994	2157	3835	5347	4103	3559	167	68	2583
1970 Federal Surplus/Deficit	703	154	-420	-136	1824	1444	1447	3794	4712	2107	-162	-153	1267
1971 Federal Surplus/Deficit	357	57	56	3762	3785	3869	4096	5219	3758	3733	2128	577	2609
1972 Federal Surplus/Deficit	829	133	523	3759	3846	3418	3451	5236	3576	3173	2933	726	2629
1973 Federal Surplus/Deficit	675	72	875	480	-571	118	-231	2546	1379	895	-674	-262	451
1974 Federal Surplus/Deficit	294	-558	1930	3595	3310	3655	3901	5149	3586	3262	1943	371	2536
1975 Federal Surplus/Deficit	88	-93	-340	1184	1017	2433	1056	5397	3992	3839	739	724	1677
1976 Federal Surplus/Deficit	1384	1705	3312	3502	3689	3090	4163	5411	4305	3636	3934	3097	3435
1977 Federal Surplus/Deficit	699	52	-628	-724	-556	-11	-564	-192	-468	328	241	291	-125
1978 Federal Surplus/Deficit	-551	-588	894	932	557	1424	3282	4768	3473	2784	428	1610	1587
1979 Federal Surplus/Deficit	855	171	-504	-442	771	2213	1296	4586	1203	580	-685	-296	814
1980 Federal Surplus/Deficit	338	145	321	-1279	175	67	2203	5607	4378	1537	-231	260	1127
1981 Federal Surplus/Deficit	426	271	2420	3523	1894	1613	834	3497	4059	4072	2416	261	2115
1982 Federal Surplus/Deficit	542	444	382	2445	3950	3493	3727	5664	4065	3498	1897	1451	2618
1983 Federal Surplus/Deficit	1392	652	882	3259	1646	3806	3623	4891	4274	4055	1846	709	2594
1984 Federal Surplus/Deficit	685	2149	484	3673	1250	4151	4631	3991	4648	4024	732	618	2590
1985 Federal Surplus/Deficit	594	637	273	916	-844	1657	3705	4901	2035	318	-990	-54	1106
1986 Federal Surplus/Deficit	604	1197	-526	1895	2706	4058	3938	3366	3693	2179	285	-215	1920
1987 Federal Surplus/Deficit	149	509	-290	-723	-433	781	1657	2962	2979	945	-617	-399	628
1988 Federal Surplus/Deficit	160	-61	-1007	-1002	-989	-321	464	2154	53	1387	138	-8	88
1989 Federal Surplus/Deficit	-34	-403	-288	-1114	-202	1210	3903	4414	2546	678	-817	-147	813
1990 Federal Surplus/Deficit	282	207	1083	2667	1598	1259	3798	3940	4048	2065	810	-254	1790
1991 Federal Surplus/Deficit	-2	1476	1333	3482	3452	930	2622	5148	4035	3577	1784	-26	2309
1992 Federal Surplus/Deficit	193	-279	-939	-585	-980	1748	547	1840	890	645	-712	-509	164
1993 Federal Surplus/Deficit	199	-91	-553	-699	-802	199	644	4159	1653	1560	324	-538	515
1994 Federal Surplus/Deficit	172	329	-44	-771	-400	-141	1204	2247	1271	985	-633	-389	321
1995 Federal Surplus/Deficit	95	-367	-227	-29	1783	2964	1882	3906	3605	2603	189	183	1378
1996 Federal Surplus/Deficit	916	2716	3290	3431	2971	3374	3785	5563	4532	3903	1473	285	3019
1997 Federal Surplus/Deficit	570	52	1256	3528	3518	3589	3866	5209	3815	3672	1664	1553	2686
1998 Federal Surplus/Deficit	2718	1109	199	2093	1448	1793	1711	4278	4298	2656	391	149	1906
Ranked Averages													
Top Ten Percent	998	1157	2404	3619	3443	3587	3784	5311	4034	3486	1942	955	2891
Middle Eighty Percent	556	281	409	1289	1201	1599	2479	4409	3533	2397	538	257	1580
Bottom Ten Percent	377	48	-673	-770	-865	-199	-57	856	518	742	3	147	15
DSI Augmentation	402	402	402	402	402	402	402	402	402	402	402	402	402
Less DSI Augmentation	154	-121	7	887	799	1197	2077	4007	3131	1995	136	-145	1178

Table A-30: Federal Surplus/Deficit - By Water Year
PNW Loads and Resource Study
2010 - 2011 Fiscal Years **7/21/2009**
[59] 2010 Final Rate Case - 30 Minute Wind (Final)

Energy (aMW)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
1929 Federal Surplus/Deficit	399	91	-496	-623	-716	352	-305	38	1404	1044	9	174	117
1930 Federal Surplus/Deficit	644	175	-401	-530	-765	14	414	-282	68	862	-173	0	6
1931 Federal Surplus/Deficit	471	339	-252	-633	-654	-241	-679	449	-72	1126	487	476	74
1932 Federal Surplus/Deficit	54	-262	-513	-1178	-1237	643	2914	5550	4086	1795	336	588	1075
1933 Federal Surplus/Deficit	631	-328	504	3065	1516	87	1623	3735	3943	3500	2311	872	1791
1934 Federal Surplus/Deficit	1107	1866	3634	3895	3781	3367	4390	4009	3125	1853	-163	332	2591
1935 Federal Surplus/Deficit	462	-605	-186	2457	2840	-156	959	3186	1956	2761	1108	44	1226
1936 Federal Surplus/Deficit	497	25	-561	-1478	-285	80	1679	4019	3963	1407	460	-96	811
1937 Federal Surplus/Deficit	583	432	-470	-467	-909	-415	-1506	1039	203	484	641	293	0
1938 Federal Surplus/Deficit	555	-93	368	2538	574	1978	3568	5248	3283	2289	29	657	1757
1939 Federal Surplus/Deficit	687	27	-672	-452	-727	799	1861	4212	1254	1009	-271	-129	642
1940 Federal Surplus/Deficit	734	446	618	-633	-371	2418	2770	2673	2353	147	-389	262	923
1941 Federal Surplus/Deficit	532	340	78	-854	-620	1313	3	809	294	960	433	885	354
1942 Federal Surplus/Deficit	105	295	813	637	706	-46	914	2618	3911	3353	1484	467	1273
1943 Federal Surplus/Deficit	631	-312	-18	1889	2151	2581	4640	4918	3937	3185	710	-465	1984
1944 Federal Surplus/Deficit	510	119	-588	-560	-601	111	-187	-182	-542	274	323	622	-56
1945 Federal Surplus/Deficit	111	-256	-577	-942	-1267	-257	-1758	2996	2648	794	191	16	152
1946 Federal Surplus/Deficit	268	400	582	1202	49	3099	4030	5071	3266	3116	913	556	1890
1947 Federal Surplus/Deficit	435	353	2716	3032	2725	3463	2637	4385	4164	3304	651	401	2355
1948 Federal Surplus/Deficit	2310	2094	1339	4258	581	1809	2695	5481	3695	4144	2228	769	2635
1949 Federal Surplus/Deficit	839	162	312	-507	1067	3523	3773	5241	3846	592	-219	-379	1519
1950 Federal Surplus/Deficit	517	-88	117	2029	2820	4364	3487	4384	3623	3704	1406	567	2241
1951 Federal Surplus/Deficit	1407	1508	3049	4462	3941	4400	4452	5049	3262	3968	1458	388	3109
1952 Federal Surplus/Deficit	1850	1006	1432	3891	1493	818	4305	5454	4228	2648	832	-5	2334
1953 Federal Surplus/Deficit	553	-41	-509	-11	2665	1126	501	4363	4418	4092	1005	425	1540
1954 Federal Surplus/Deficit	826	440	976	1856	3457	1484	2368	4957	3557	3324	3858	2336	2447
1955 Federal Surplus/Deficit	844	1035	892	-191	-468	358	369	2454	4155	3420	2189	200	1282
1956 Federal Surplus/Deficit	1007	1609	2915	4751	3301	4047	3920	4988	3602	4050	1298	507	3002
1957 Federal Surplus/Deficit	1009	-31	791	818	416	2651	2937	5533	3997	1881	202	316	1718
1958 Federal Surplus/Deficit	552	274	-78	655	2349	1808	2656	5535	4449	1792	389	190	1706
1959 Federal Surplus/Deficit	778	800	2123	4475	3670	1263	2943	4413	3722	2446	1365	2593	2538
1960 Federal Surplus/Deficit	2824	2889	2422	2886	1226	2180	3893	3655	4231	2572	473	484	2482
1961 Federal Surplus/Deficit	657	65	-20	2173	1443	2756	2432	4837	3694	2253	882	43	1772
1962 Federal Surplus/Deficit	270	295	482	1370	1309	504	3587	4298	4411	1266	459	7	1516
1963 Federal Surplus/Deficit	1240	1014	1932	2088	1986	72	1123	3397	3947	2912	1135	441	1772
1964 Federal Surplus/Deficit	316	172	378	392	1136	10	607	3817	4382	3933	1871	1110	1510
1965 Federal Surplus/Deficit	1367	866	2966	4837	4407	3999	3574	5190	4457	2439	1824	618	3040
1966 Federal Surplus/Deficit	947	111	297	1729	403	-243	3103	3250	2702	2886	967	81	1357
1967 Federal Surplus/Deficit	425	-77	483	4200	3747	1144	359	3411	3610	4190	1483	568	1953
1968 Federal Surplus/Deficit	755	76	470	2483	2279	1997	73	2295	3913	3924	1789	1689	1810
1969 Federal Surplus/Deficit	1417	1735	1483	4596	3647	2055	4446	5245	3880	3627	497	232	2730
1970 Federal Surplus/Deficit	868	316	-247	33	1974	1622	1056	3207	4763	2170	167	10	1319
1971 Federal Surplus/Deficit	521	219	230	4334	4461	3914	3727	5182	3917	3972	2460	741	2797
1972 Federal Surplus/Deficit	995	294	697	4223	4038	4997	3482	5200	3733	3415	3266	890	2933
1973 Federal Surplus/Deficit	840	234	1049	650	-399	295	-623	1957	784	958	-346	-99	452
1974 Federal Surplus/Deficit	459	-397	2097	4401	3932	5015	4343	5109	3753	3504	2275	535	2918
1975 Federal Surplus/Deficit	253	70	-167	1348	1191	2611	665	4804	4151	4078	1068	888	1753
1976 Federal Surplus/Deficit	1550	1868	3966	4435	4099	2549	4234	5297	4147	3877	4284	3248	3628
1977 Federal Surplus/Deficit	864	214	-454	-553	-383	167	-957	-785	-1063	391	572	455	-124
1978 Federal Surplus/Deficit	-387	-427	1058	1103	729	1601	2877	4174	2881	2849	758	1759	1585
1979 Federal Surplus/Deficit	1021	333	-330	-271	945	2391	905	3999	608	642	-356	-132	815
1980 Federal Surplus/Deficit	504	308	495	-1088	324	243	1812	5399	3787	1600	98	424	1160
1981 Federal Surplus/Deficit	592	433	2588	4393	1035	1785	417	2892	4219	4316	2749	425	2170
1982 Federal Surplus/Deficit	708	606	555	2611	4502	4963	3182	5370	3670	3563	2228	1605	2786
1983 Federal Surplus/Deficit	1557	815	1056	3416	1794	5168	3217	4297	3681	4122	2178	873	2691
1984 Federal Surplus/Deficit	850	2296	657	4446	639	4501	4122	3403	4796	4091	1061	782	2646
1985 Federal Surplus/Deficit	759	799	447	1088	-673	1836	3298	4315	1441	380	-663	109	1105
1986 Federal Surplus/Deficit	769	1360	-352	2059	2842	4802	3842	2777	3100	2244	614	-52	1990
1987 Federal Surplus/Deficit	313	671	-116	-553	-260	959	1267	2374	2389	1008	-288	-236	629
1988 Federal Surplus/Deficit	325	102	-834	-831	-816	-144	72	1565	-543	1451	467	156	88
1989 Federal Surplus/Deficit	131	-242	-114	-944	-30	1387	3581	3828	1954	740	-489	17	819
1990 Federal Surplus/Deficit	447	369	1259	2833	1773	1437	3850	3354	4199	2129	1141	-90	1889
1991 Federal Surplus/Deficit	163	1640	1508	3963	3542	606	2225	4560	3445	3818	2116	138	2303
1992 Federal Surplus/Deficit	358	-118	-767	-414	-808	1927	156	1248	296	708	-383	-346	164
1993 Federal Surplus/Deficit	365	71	-379	-528	-630	374	251	3570	1056	1623	653	-375	515
1994 Federal Surplus/Deficit	337	492	130	-601	-227	36	813	1658	678	1049	-305	-225	322
1995 Federal Surplus/Deficit	260	-205	-53	142	1931	3119	1491	3318	3012	2668	519	347	1375
1996 Federal Surplus/Deficit	1081	2864	3933	4477	3832	4732	4138	5391	4682	4144	1804	448	3459
1997 Federal Surplus/Deficit	736	214	1430	4267	4270	4946	4101	5174	3974	3912	1995	1707	3054
1998 Federal Surplus/Deficit	2860	1272	372	2257	1613	1971	1321	3681	4453	2722	720	313	1965
Ranked Averages													
Top Ten Percent	1163	1318	2708	4493	3984	4239	3986	5184	3980	3686	2276	1115	3175
Middle Eighty Percent	719	442	591	1554	1344	1815	2209	3927	3280	2501	868	419	1640
Bottom Ten Percent	542	210	-499	-600	-692	-22	-450	263	-78	805	332	311	15
DSI Augmentation	402	402	402	402	402	402	402	402	402	402	402	402	402
Less DSI Augmentation	317	40	189	1152	942	1413	1807	3525	2878	2099	466	17	1238

ATTACHMENT F

ADMINISTRATOR'S RECORD OF DECISION

SHORT-TERM MARKETING AND OPERATING ARRANGEMENTS

INTRODUCTION

The Bonneville Power Administration (BPA) has decided to enter into short-term marketing and operational arrangements in order to participate continuously in the open electric power market. These arrangements would enable BPA to achieve the best reliability and expected economic outcome, as well as to best meet its environmental responsibilities, given diverse market conditions. This decision would support power cost control, enhance BPA competitiveness, and provide public benefits. The amount of hydropower available to BPA will be defined by the System Operation Review (SOR), a separate process underway to determine future hydro operations. The decision documented in this Record of Decision (ROD) is a direct application of BPA's earlier decision to use a Market-Driven approach for participation in the increasingly competitive electric power market.

The decision to enter into these short-term contractual arrangements is consistent with BPA's Business Plan, the Business Plan Environmental Impact Statement (BP EIS) (DOE/EIS-0183, June 1995) and the BP ROD (August 15, 1995). In response to a need for a sound policy to guide its business direction under changing market conditions, BPA explored six alternative plans of action in its BP EIS. The six alternatives were: Status Quo (no action), BPA Influence, Market-Driven, Maximize Financial Returns, Minimal BPA, and Short-Term Marketing. In the subsequent BP ROD, the BPA Administrator selected the Market-Driven Alternative. Although the Status Quo and the BPA Influence alternatives were environmentally preferred, the differences in total environmental impacts among alternatives were relatively small. Other business aspects, including loads and rates, showed greater variation among the alternatives. The Market-Driven Alternative strikes a balance between marketing and environmental concerns. It also helps BPA to ensure the financial strength necessary to maintain high level of support for public benefits such as energy conservation and fish and wildlife mitigation activities.

The BP EIS and ROD were also intended to guide BPA in a series of related decisions on specific issues and actions. Decisions on providing short-term marketing and operational arrangements are some of these subsequent actions, and the subject of this tiered ROD. Tiering subsequent RODs to the BP ROD helps delineate BPA decisions clearly and provides a logical framework for connecting broad programmatic decisions to more specific actions.

Before taking specific action on any of these issues, BPA affirmatively stated that it would review the BP EIS to ensure that a particular action was adequately covered within the scope of that EIS and, if appropriate, issue a tiered ROD. This ROD, which summarizes and incorporates information from the BP ROD, is a result of such a review. It describes specific information on the decision to provide short-term marketing and operational arrangements, and summarizes the environmental impacts associated with this decision, as described in the BP EIS.

NEW COMPETITIVENESS IN THE ELECTRIC INDUSTRY

The electric utility industry is becoming increasingly competitive and dynamic. Four factors are substantially affecting BPA's ability to compete: market change, increased non-power obligations, deterioration of BPA's cost/price advantage, and lost hydro output. The emergence of competition has led to significantly lower prices for wholesale electric power. At the same time, BPA's costs for providing major public benefits (including fish and wildlife enhancement and support of energy efficiency) have increased significantly. A series of dry years and changes in hydro system operations have also seriously affected BPA's ability to produce power and generate revenues.

The current West Coast surplus, decline in costs of competing generating resources, low cost of energy, and difficulty in siting and developing new generating facilities continue to lead electric utilities and other parties to emphasize shorter-term commitments to buy and sell. In addition, the recent market deregulation has fostered the emergence of marketers and broker parties. These parties by their nature concentrate on shorter-term commitments than do utilities that have extended obligations to serve load.

However, BPA must be able to balance its costs and revenues. The availability of power at competitive prices from other suppliers prevents BPA from meeting costs simply by raising rates for its customers. That BPA firm power rate level above which a rate increase would no longer increase BPA's revenue and cover BPA's costs would produce BPA's maximum sustainable revenue. Allowing BPA's rates to exceed this level would not be consistent with sound business principles. BPA's total revenue would be reduced, as would BPA's ability to fund public benefits.

SHORT-TERM MARKETING CUSTOMERS

BPA will negotiate short-term marketing and operating arrangements and related transmission services with parties able to participate in the open electric power market. Potential customers include utilities and Direct Service Industries within the region, and other power purchasers inside and outside the Pacific Northwest (PNW).

DESCRIPTION OF THE PROPOSED SHORT-TERM MARKETING AND OPERATIONAL ARRANGEMENTS AND RELATED TRANSMISSION ARRANGEMENTS

Short-Term Marketing

BPA will continuously participate in the bulk electric power market via its short-term marketing arrangements. Short-term marketing and operating arrangements cover a variety of scheduling periods--hours, weeks, days, months, or years. The vast majority of these market-based actions cover periods of less than 1 year, although some actions could have terms of up to 5 years.

BPA's short-term marketing actions will try to maximize the value of hydrosystem conditions that result from decisions made by other agencies. (As noted earlier, the amount of hydropower available to BPA will be defined by the SOR. Decisions made by the Corps of Engineers or Bureau of Reclamation to manage river operations for navigation, flood control, irrigation, recreation and fish and wildlife activities determine how much water is available for generation and when it is available.) Maximizing hydrosystem value can take a number of forms. For example, throughout the late spring and summer months, BPA sells very large amounts of surplus energy generated from flow provided for downstream salmon migration, as prescribed by the National Marine Fisheries Service 1995 Biological Opinion. During the fall, BPA often purchases large quantities of energy to recover depleted reservoirs, in preparation for winter loads. BPA also makes purchases to meet extreme weather conditions and unexpected resource or transmission outages.

The peak load demands of the PNW and California occur at different times. The PNW peaks occur in winter, while California's demand peaks in summer. During the summer, the PNW hydro-based systems tend to have excess capacity that can be used to help meet California's peak demands. Similarly, California's thermal-based system tends to have excess capacity in the winter, which can be used to help the PNW meet its peak demands. BPA has several seasonal and capacity/energy exchange contracts with California utilities.

In general, BPA will be in the market buying or selling to match energy supplies to load and/or to execute operational strategies. To the extent permitted by statute and consistent with sound business principles, BPA will also expand its short-term marketing activity beyond the disposal of surplus generation or the meeting of short-term load. BPA will look continuously for marketing opportunities in power-related trading and financial transactions. BPA's objective will be to improve net revenues, reduce costs, and reduce the risk of periodic revenue shortfalls due to changes in supply or market conditions.

Water Management

The Power Supply Manager may arrange for water storage, rentals or other physical water management operations for fish-related or other non-power purposes; for energy storage as a service to other utilities; and for implementation actions related to the Pacific Northwest Coordination Agreement, the Columbia River Treaty annual operating plan or detailed operating plan, and non-Treaty coordination operations such as the Non-Treaty Storage Agreement.

ENVIRONMENTAL ANALYSIS

Consistent with the BP ROD, the Administrator reviewed the BP EIS to determine whether (1) entering into short-term (5 years or less) marketing and operational arrangements in order to participate continuously in the open electric power market and (2) making generation operation decisions that accommodate that participation were adequately covered within the scope of the BP EIS. The BP EIS was intended to support a number of decisions, including short-term contractual arrangements lasting 5 years or less. The chosen Market-Driven Alternative includes the offering of flexible short-term arrangements with customers. In addition, one of the other alternatives analyzed in the EIS, Short-Term Marketing, limited BPA's marketing activities to short-term marketing of power and transmission products and services.

The BP EIS showed that environmental impacts are determined by the responses to BPA's marketing actions, rather than by the actions themselves. These market responses include resource development, resource operation, transmission development and operation, and consumer behavior.

Environmental Impacts

Short-term marketing and operating arrangements are an integral part of the marketing efforts of a Market-Driven BPA. As such, the potential impacts on resource development, resource operations, transmission system development and operations, and consumer behavior were considered in determining the potential environmental impacts of adopting a Market-Driven approach to participation in the competitive electric utility market.

Regionally, fewer new resources (most likely combustion turbines) would be developed because less load would be shifted away from BPA. However, the operation of existing generation would be greater, as other participants compete within the utility market. The higher emissions levels of these mostly older, less-efficient thermal resources would result in higher levels of air emissions and water use. Transmission system development would be unchanged; transmission system operation would likely be more efficient. BPA rates would be competitive with market rates.

Marketing Impacts

The expected broad marketing impacts of BPA's adopted approach will be (1) to preserve or increase BPA's market share in the PNW and West Coast open markets as much as possible, given the deregulated and competitive nature of the market, (2) to maximize BPA's power operations efficiency, in context with non-power objectives, and (3) mutually to benefit BPA's power economics and power system operations through coordinated short-term trading and risk management arrangements. Many of BPA's customers and other parties participating in the open market are expected to respond to BPA's short-term marketing and operating arrangement efforts. Flexible contracts responding to the pricing and unbundling forces emerging with the opening of the wholesale power market will meet customer needs for competitively priced products and services, improve customer relations, assist BPA in reducing costs, and enhance BPA's ability to use a Market-Driven approach to participate continuously in the open electric market. Systematic efforts to meet customer needs, offer feasible service options, and lower rates will help BPA to continue to serve the bulk of its historic loads. Load will be lost mainly as customers seek ways to diversify their sources of power, and not through dissatisfaction with BPA. To the extent that BPA is successful in applying a Market-Driven approach to its business activities, BPA will be more likely to maintain revenues and be better able to fund public benefits.

Public Benefits

Consistent with the Market-Driven approach, the decision to undertake short-term contractual arrangements lasting 5 years or less strikes a balance between marketing and environmental concerns. BPA will actively participate in the competitive market for power, and will use its success in the market to ensure the financial strength necessary to produce the public benefits that BPA affords to the region.

Mitigation

In deciding to enter into these short-term contractual arrangements under the Market-Driven approach, BPA understands that the conditions that permit the agency to function successfully may change over time. Therefore, the Market-Driven Alternative contains preparatory mitigation measures (response strategies) to respond to change and allow the agency to balance cost and revenues. Such mitigation will enhance BPA's ability to adapt to changing market conditions.

These response strategies--which include means to decrease spending, increase revenues, and transfer costs--could be implemented if BPA's costs and revenues did not balance. BPA has already decided (in the BP ROD) to apply as many mitigation response strategies as necessary whenever BPA's costs and revenues do not balance. These mitigation strategies, or equivalents, will be implemented to enable BPA to best meet its public service and environmental obligations, while remaining competitive in the wholesale electric power market.

PUBLIC AVAILABILITY

Copies of the Business Plan EIS and the Business Plan ROD, as well as additional copies of this ROD, are available to all interested and affected persons and agencies from BPA's Public Involvement Office, P.O. Box 12999, Portland, Oregon 97212. Copies of these documents may also be obtained by using BPA's nationwide toll-free request line, 1-800-622-4520.

CONCLUSION

I have decided that BPA will enter into short-term marketing and operational arrangements (consistent with the SOR) in order to participate continuously in the open electric power market.

This decision is consistent with BPA's Market-Driven approach for participation in the increasingly competitive power market, since it will enable BPA to increase the value of its short-term power products, increase net revenues, and control costs. BPA seeks to be responsive to its customers' needs, while ensuring the financial strength necessary to produce public benefits such as fish and wild life mitigation and energy conservation.

Issued in Portland, Oregon, on January 22, 1996.

/s/ Randall W. Hardy
Administrator and Chief
Executive Officer

bcc:
Adm. Chron. File – A

Official File - KEC (EQ-14 – Business Plan EIS – 1996)

KPierce:ljc:1/19/96

Original Electronic File:
W\ECN\ECN96\EQ-14\BPEIS\STMARROD.doc)

This Electronic File:
W\KEC\EISs – EQ-14\Business Plan\All Finalized BP RODs\
Short-Term Marketing ROD 1-22-96.doc

ATTACHMENT G

BPA's Re-creation of Snohomish Analysis

Snohomish Public Utility District asserted in its October 19th comment that:

> "Calendar year 2010 physical energy prices for the Mid-Columbia Market Hub are higher than BPA's revised market forecast [see Attachment A]. Snohomish estimates a forward sale at market would generate $2.47 million more than from the same sale at the IP rate. We therefore conclude a forward sale at market provides greater financial benefit to BPA." (See Snohomish at 2)

BPA has re-created Snohomish's analysis based on market prices from November 6th to illustrate that individual forward market price observations can be a volatile indicator to employ in longer-term public policy decisions. Specifically, BPA developed the following described below and presented on the subsequent pages:

1) Figure 1 was re-created just as Snohomish presented in its October 19th comment with prices from October 15, 2009
2) Figure 2 was re-created illustrating all of the inputs, including BPA's Nov-09 and Dec-09 prices from TFS, BPA's estimation of TFS light load hour (LLH) pricing since LLH prices are not published by TFS, and the Flat Average forward price for the period
3) Figure 3 was re-created continuing to illustrate all of the inputs from Figure 2, using BPA's market price inputs from TFS for November 6, 2009, BPA's estimation of TFS LLH market pricing for November 6, 2009, and the Flat Average forward price for the period

Figure 1 – Snohomish's Attachment A

Attachment A: Mid-C Electricity Prices and Revenue Comparison
Version 1: as submitted by SnoPUD in Oct 19th comment

Mid-Columbia Energy Prices	HLH	LLH		**BPA Revised Market Forecast**	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Q1 - 2010	$49.50	$43.50	BPA does not agree	**Jan-10**	$34.13	$29.51
				Feb-10	$34.46	$29.77
				Mar-10	$33.92	$29.16
Q2 - 2010	$39.00	$27.00	BPA does not agree	**Apr-10**	$32.95	$28.05
				May-10	$33.93	$24.45
				Jun-10	$34.33	$26.33
Q3 - 2010	$58.25	$42.25	BPA does not agree	**Jul-10**	$37.33	$32.18
				Aug-10	$42.48	$35.63
				Sep-10	$42.86	$38.00
Q4 - 2010	$59.25	$50.75	BPA does not agree	**Oct-10**	$43.31	$36.85
				Nov-10	$45.36	$40.59
				Dec-10	$48.81	$43.42

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010	
Estimated BPA revenues based on the IP rate	$7,104,839
Estimated BPA revenues based on BPA's revised market forecast	$6,997,593
Difference between revenue at the IP rate and BPA's revised market forecast	$107,246
Estimated BPA revenues based on sale at Mid-Columbia Power Prices	$9,588,434
Difference between revenues at the IP rate and Mid-C Power Sale at Market Prices	($2,483,595)

Figure 2 – BPA's re-creation of Snohomish's Attachment A

Attachment A: Mid-C Electricity Prices and Revenue Comparison
Version 2: as adjusted by BPA using Oct 15th market prices

Mid-Columbia Energy Prices	HLH	LLH	Source
Nov	$45.50	**$39.42**	not provided
Dec	$55.50	**$47.98**	not provided
Q1 - 2010	$49.50	**$43.87**	changed; derived LLH
Q2 - 2010	$39.00	**$25.93**	changed; derived LLH
Q3 - 2010	$58.25	**$41.80**	changed; derived LLH
Q4 - 2010	$59.25	**$50.07**	changed; derived LLH
Flat Average		**$46.78**	

BPA Revised Market Forecast	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Nov-09	$28.75	$26.38
Dec-09	$30.61	$27.41
Jan-10	$34.13	$29.51
Feb-10	$34.46	$29.77
Mar-10	$33.92	$29.16
Apr-10	$32.95	$28.05
May-10	$33.93	$24.45
Jun-10	$34.33	$26.33
Jul-10	$37.33	$32.18
Aug-10	$42.48	$35.63
Sep-10	$42.86	$38.00
Oct-10	$43.31	$36.85
Nov-10	$45.36	$40.59
Dec-10	$48.81	$43.42

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010

Estimated BPA revenues based on the IP rate	$7,104,839
Estimated BPA revenues based on BPA's revised market forecast	**$6,997,512**
Difference between revenue at the IP rate and BPA's revised market forecast	$107,327
Estimated BPA revenues based on sale at Mid-Columbia Power Prices	$9,567,039
Difference between revenues at the IP rate and Mid-C Power Sale at Market Prices	($2,462,200)

BPA's addition to clarify results provided by Snohomish
BPA's adjustment to values provided by Snohomish

Figure 3 – BPA's re-creation of Snohomish's Attachment A using Nov 6th price data

Attachment A: Mid-C Electricity Prices and Revenue Comparison
Version 3: as adjusted by BPA using Nov 6th market prices

Mid-Columbia Energy Prices	HLH	LLH	Source	BPA Revised Market Forecast	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Nov	$36.63	**$30.00**	ICE (avg bid / ask)	**Nov-09**	$28.75	$26.38
Dec	$43.50	**$36.98**	HLH = TFS avg; LLH = derived	**Dec-09**	$30.61	$27.41
Q1 - 2010	$42.00	**$36.95**	HLH = TFS avg; LLH = derived	**Jan-10**	$34.13	$29.51
				Feb-10	$34.46	$29.77
				Mar-10	$33.92	$29.16
Q2 - 2010	$32.50	**$21.06**	HLH = TFS avg; LLH = derived	**Apr-10**	$32.95	$28.05
				May-10	$33.93	$24.45
				Jun-10	$34.33	$26.33
Q3 - 2010	$52.50	**$37.29**	HLH = TFS avg; LLH = derived	**Jul-10**	$37.33	$32.18
				Aug-10	$42.48	$35.63
				Sep-10	$42.86	$38.00
Q4 - 2010	$53.50	**$45.77**	HLH = TFS avg; LLH = derived	**Oct-10**	$43.31	$36.85
				Nov-10	$45.36	$40.59
				Dec-10	$48.81	$43.42
Flat Average		**$40.30**				

Port Townsend Revenue Comparison Nov. 2009 - Dec. 2010

Estimated BPA revenues based on the IP rate	$7,104,839
Estimated BPA revenues based on BPA's revised market forecast	**$6,997,512**
Difference between revenue at the IP rate and BPA's revised market forecast	$107,327
Estimated BPA revenues based on sale at Mid-Columbia Power Prices	$8,242,213
Difference between revenues at the IP rate and Mid-C Power Sale at Market Prices	($1,137,374)

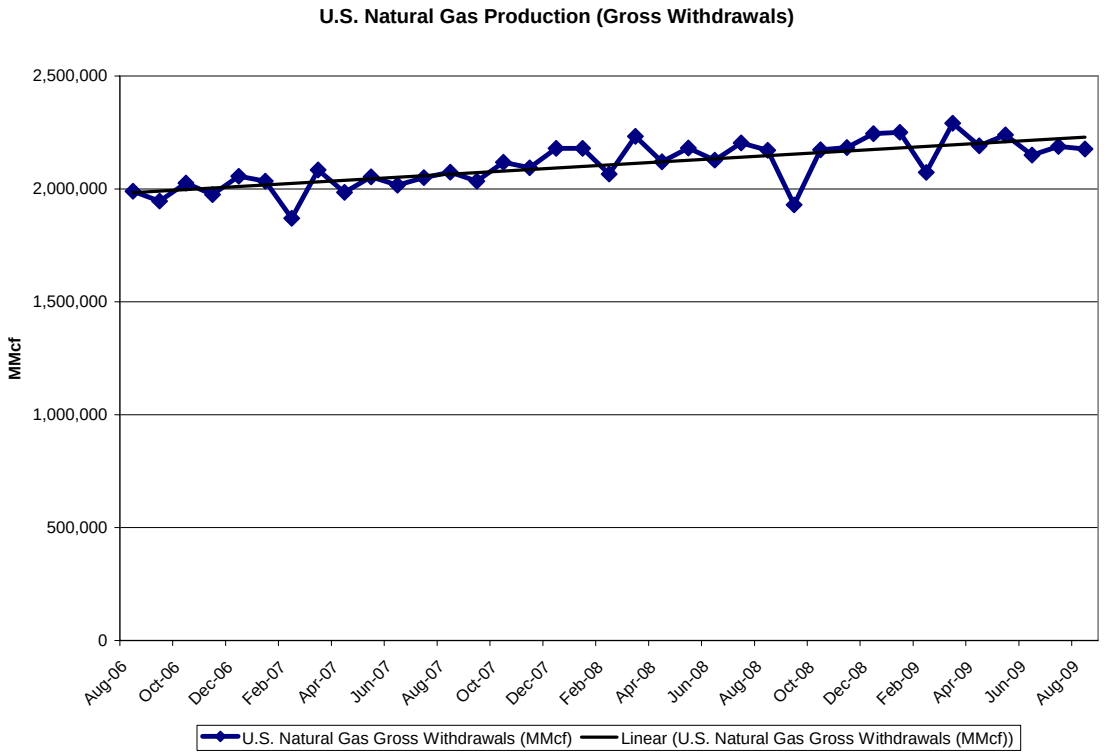
BPA's addition to clarify results provided by Snohomish
BPA's adjustment to values provided by Snohomish

BPA's re-creation of Snohomish's analysis using BPA's market price inputs from TFS and BPA's estimation of TFS LLH market pricing for November 6, 2009 reduces Snohomish's estimate of the difference between revenues at the IP rate and Mid-C power sale at market prices from $2.5 million to $1.1 million. 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 term of the Block Contract fell from $46.78 per MWh to $40.30 per MWh and reduced the cost asserted by Snohomish by more than half. 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 in longer-term public policy decisions.

ATTACHMENT H

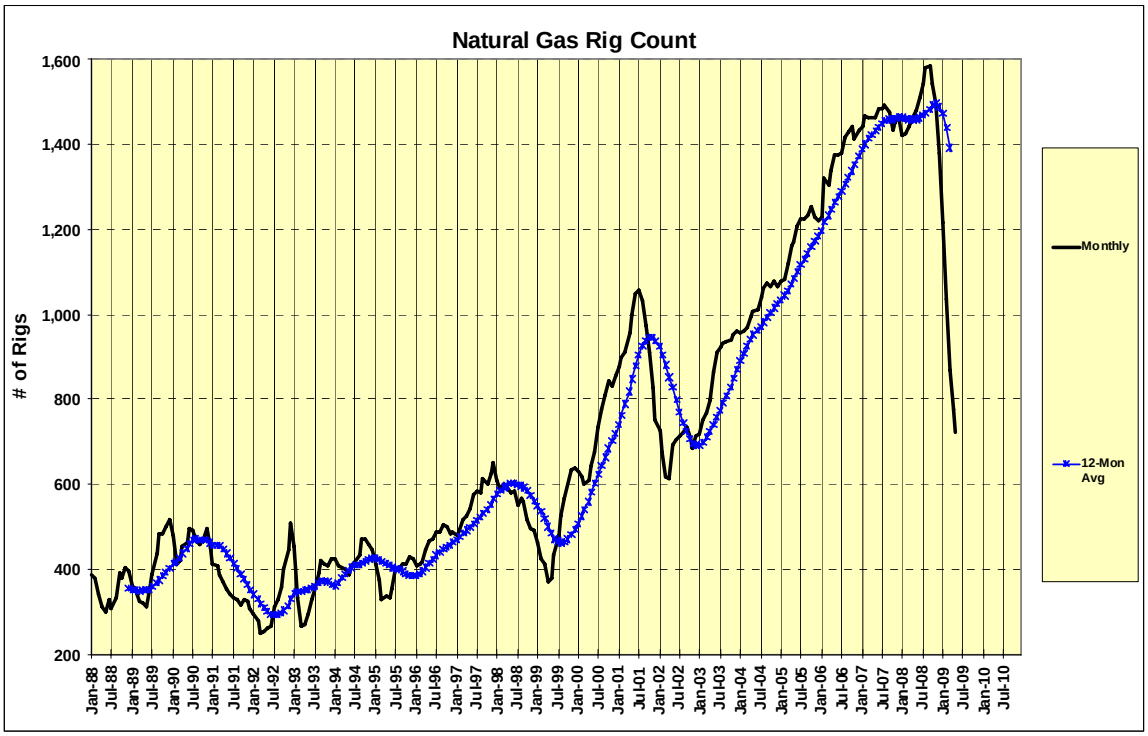
Natural Gas Statistics

Figure 1 – Natural Gas Production



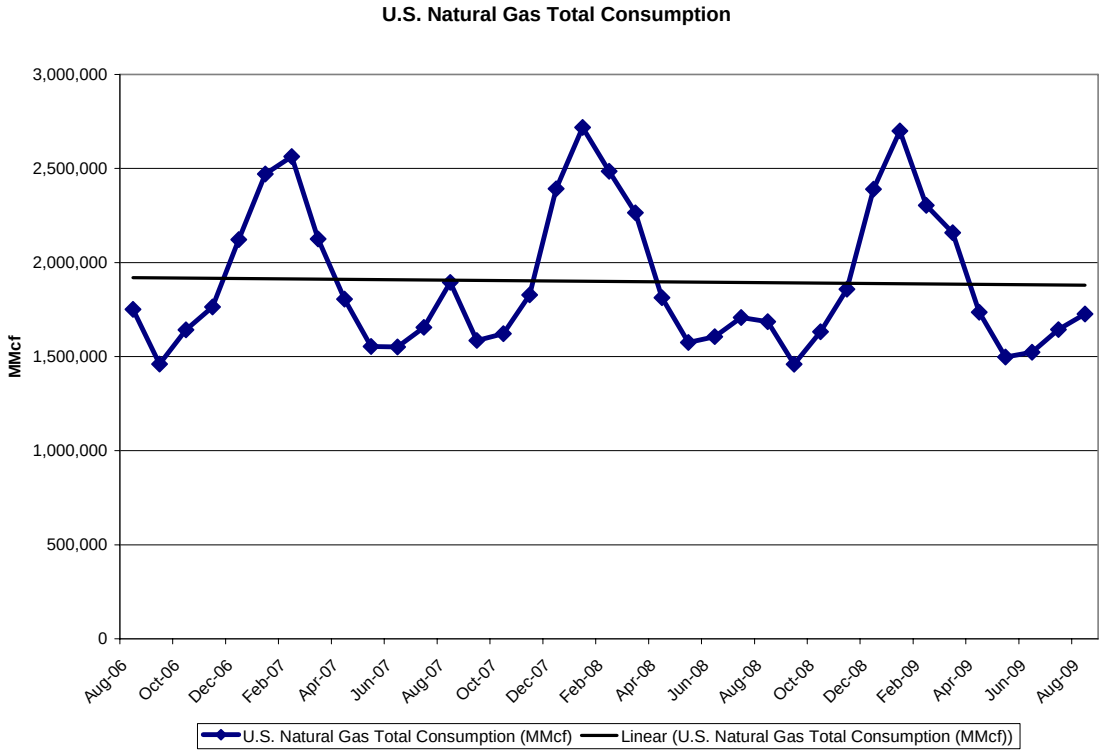
Source: United States Department of Energy, Energy Information Administration, released October 30, 2009.

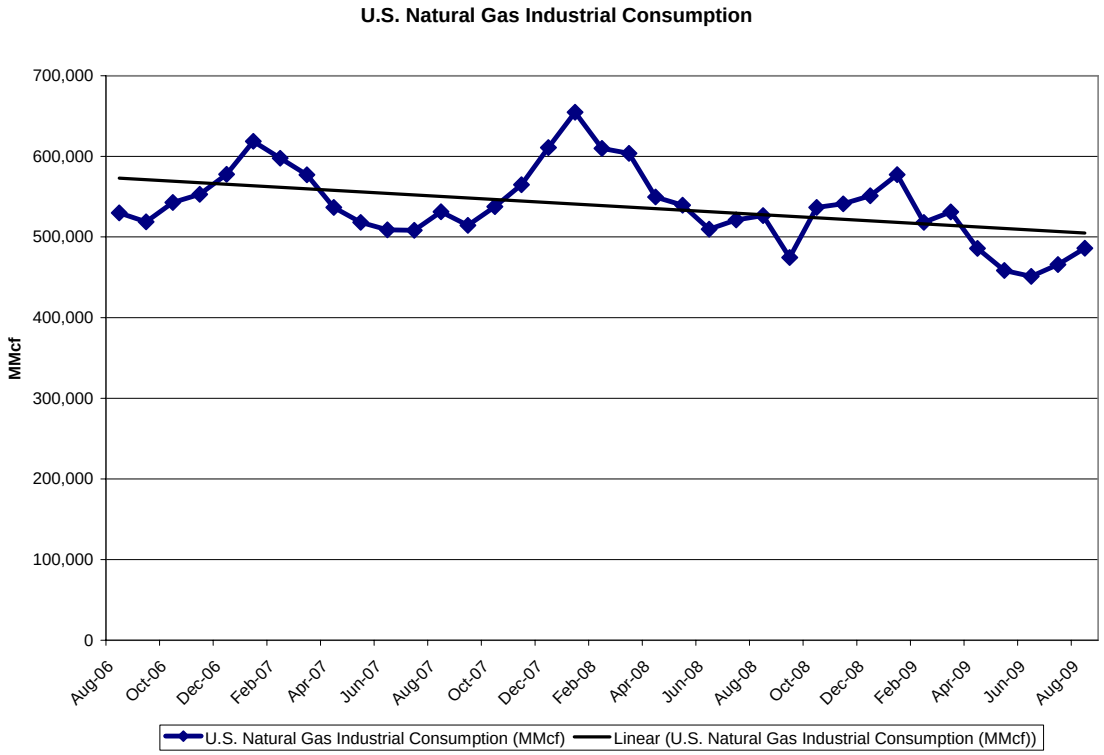
Figure 2 – Natural Gas Rig Count



Source: draft *Resource Program*, Appendix B: Market Uncertainties, Bonneville Power Administration, September 30, 2009, page B-4.

Figure 3 – U.S. Natural Gas Total Consumption and Industrial Consumption





Source: United States Department of Energy, Energy Information Administration, October 30, 2009.

Figure 4 – Natural Gas Storage

Weekly Natural Gas Storage Report

Released: November 5, 2009 at 10:30 A.M. (eastern time) for the Week Ending October 30, 2009.
Next Release: November 13, 2009

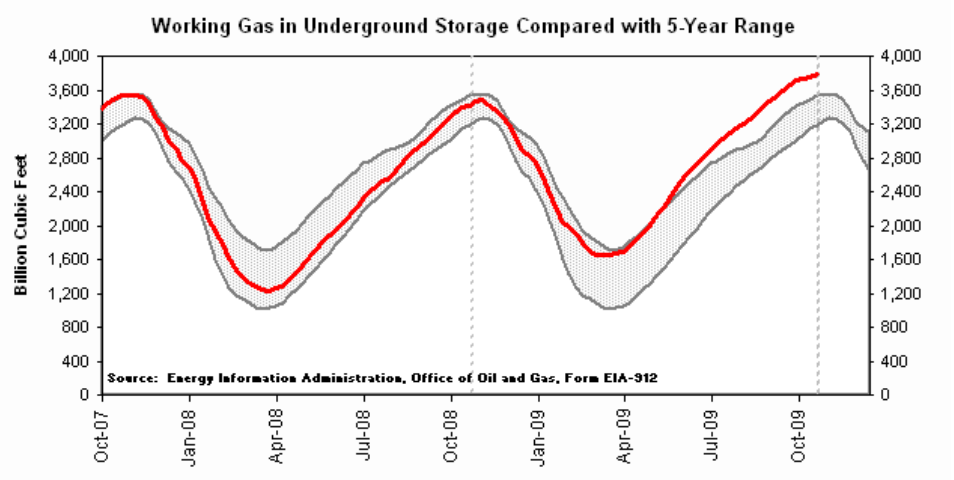
Working Gas in Underground Storage, Lower 48

other formats: Summary TXT CSV

Region	Stocks in billion cubic feet (Bcf)			Historical Comparisons			
	10/30/09	10/23/09	Change	Year Ago (10/30/08)		5-Year (2004-2008) Average	
				Stocks (Bcf)	% Change	Stocks (Bcf)	% Change
East	2,085	2,058	27	2,009	3.8	1,962	6.3
West	514	513	1	461	11.5	450	14.2
Producing	1,189	1,188	1	939	26.6	962	23.6
Total	**3,788**	**3,759**	**29**	**3,409**	**11.1**	**3,374**	**12.3**

Notes and Definitions

Summary
Working gas in storage was 3,788 Bcf as of Friday, October 30, 2009, according to EIA estimates. This represents a net increase of 29 Bcf from the previous week. Stocks were 379 Bcf higher than last year at this time and 414 Bcf above the 5-year average of 3,374 Bcf. In the East Region, stocks were 123 Bcf above the 5-year average following net injections of 27 Bcf. Stocks in the Producing Region were 227 Bcf above the 5-year average of 962 Bcf after a net injection of 1 Bcf. Stocks in the West Region were 64 Bcf above the 5-year average after a net addition of 1 Bcf. At 3,788 Bcf, total working gas is above the 5-year historical range.



Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2004 through 2008.
Source: Form EIA-912, "Weekly Underground Natural Gas Storage Report." The dashed vertical lines indicate current and year-ago weekly periods.

Source: United States Department of Energy, Energy Information Administration, November 5, 2009.