Attachments A – M to

Issues Remanded to Bonneville Power Administration in Pacific Northwest Generating Cooperative v. Department of Energy (*PNGC I*), 580 F.3d 792 (9th Cir. 2009) and Pacific Northwest Generating Cooperative v. Bonneville Power Administration (*PNGC II*), 596 F.3d 1065 (9th Cir. 2010)

ADMINISTRATOR'S RECORD OF DECISION

February 18, 2011

BONNEVILLE
POWER ADMINISTRATION

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http://www.bpa.gov/power/pl/regionaldialogue/06-2005_dsi_rod.pdf

Attachment B - Supplement to Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 – Administrator's Record of Decision

http://www.bpa.gov/power/pl/regionaldialogue/05-31-2006_dsi_rod_supplement.pdf

Attachment C - Contract No. 06PB-11744, Power Sale to Alcoa, Inc. (June 2006)

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Attachment D - Contract No. 06PB-11745, Power Sale to CFAC (June 2006)

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Attachment F - Contract No. 060201, Surplus Firm Power Sales Agreement between Clallam County PUD No. 1 and Port Townsend Paper Corporation

BPA is not a party to Contract No. 060201; therefore this contract was not previously available on the BPA external website. Contract No. 060201 will be available on the external website as an attachment to the Administrator's Final Record of Decision.

Attachment G - Letter to the Region on DSI Lookback Issue (6/10/09)

http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/2009/2009-06-10_DSI_Lookback_Letter.pdf

Attachment H - Amendment No. 1 to Contract No. 06PB-11744

http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/2009/DSI/2009-01-09_DSI-Amendment_afterImplementationTeam_blackline.pdf

Attachment I - Letter to the Region Announcing Delay to the DSI Lookback Process (7/24/09)

http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/2009/2009-07-24_DSI_Lookback_delayed_Letter.pdf

Attachment J - 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

http://www.bpa.gov/corporate/pubs/RODS/2009/2009-11-13_port-Townsend-Power-Sale-Record-of-Decision.pdf

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Attachment M - Administrator's Record of Decision Granting Alcoa's Request to Extend the Initial Period of Alcoa's Power Sales Agreement, Contract No. 10PB-12175

http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/DSI.SHTML

Attachment A

Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 – Administrator's Record of Decision

BONNEVILLE POWER ADMINISTRATION

Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011

Administrator's Record of Decision

June 30, 2005

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I. Scope of DSI Service within Regional Dialogue

Beginning in July 2004, the Bonneville Power Administration (BPA) initiated the Regional Dialogue process as part of its effort, in cooperation with its customers and constituents, to identify and decide issues regarding BPA's power supply role for FY 2007-2011. *See, Bonneville Power Administration's Policy Proposal for Power Supply Role for Fiscal Years 2007-2011* issued July 7, 2004. BPA service to Direct Service Industries (DSIs) has been steadily declining since the pre-1995 period when contracts totaled over 3,000 aMW, to 1995 when contracts were reduced to 2,000 average megawatts (aMW), to 2002 when contracts were reduced to 1,500 aMW (with much less actually delivered in the 2002-2006 period). Over the same period, BPA service to public utilities has grown significantly. Among the issues presented by BPA was whether it should continue the steady ramp-down of service to its DSI customers when existing power supply contracts with those customers expire on Sept. 30, 2006, or whether to eliminate further service. BPA proposed providing up to 500 aMW of service (cumulative) to creditworthy DSIs, at a known and capped cost, where such service would enable continued operation of DSI facilities, thereby maintaining Pacific Northwest jobs.

BPA indicated that, in order to eliminate the market and default risks to BPA associated with a traditional "take-or-pay" physical power sales contract, and to meet the known and capped cost prerequisite for DSI service, its preferred alternative was to provide service benefits to the DSIs financially, by cashing-out, or monetizing, the value of a power sales contract in lieu of physically delivering power. BPA indicated also that it believed it was unlikely that service to the DSIs under the Industrial Firm Power (IP) rate schedule would provide a rate low enough to support economic operation by DSI customers that use BPA power to smelt aluminum. The aluminum smelters would make up over 95 percent of BPA's DSI load under a 500 aMW scenario. The proposal to provide 500 aMW of service benefits to the DSIs represented a continuation in the ramping-down of BPA's role as a supplier of power service to the DSIs.

II. First Phase Regional Dialogue – Administrator's Record of Decision (February 4, 2005)

The culmination of the first phase of the Regional Dialogue process was the *Policy For Power Supply Role For Fiscal Years 2007-2011- Administrator's Record of Decision (*February 4, 2005). In it, BPA decided that for the 2007-2011 period it would continue the ramp-down in DSI service by providing eligible DSI customers some level of service benefits, at a known quantity and capped cost, at rates no lower than rates paid by BPA's public preference customers, and under contractual terms no better than those offered to other customers. That decision is not being revisited in this record of decision. However, in order to provide an opportunity for additional dialogue with (and among) customers, in the hope of achieving any possible consensus for a balanced and durable solution for BPA service to the DSIs, BPA reserved for later decision: (1) the actual level of service benefits it would provide, (2) the eligibility criteria it would apply in determining which DSIs would qualify for such service benefits, and (3) the mechanism or mechanisms it would use to deliver those service benefits. BPA's resolution of these issues is addressed in this record of decision.

III. Report to the Region

On February 4, 2005, BPA sent a letter to customers and constituents describing a public process for additional comment on these reserved DSI service issues, and outlining its straw proposal on each issue. The public process called for a March 1, 2005, open forum hosted by the BPA administrator and an opportunity to file additional written comments by March 11, 2005. BPA suggested a straw proposal that provided up to 500 aMW of service benefits to the DSIs at a capped cost of $40 million a year. BPA noted that this amount of benefits was in line with the level of support many non-DSI customers had indicated in previous comments they were willing to support, and that the proposal struck a reasonable balance between supporting DSI operations and attendant jobs and the need for BPA to contain costs.

With respect to the mechanism to deliver these service benefits, BPA's straw proposal was to provide financial benefits in lieu of a physical power sale. Under this mechanism, BPA would monetize, or convert to cash, the financial value of a physical power sales contract. BPA's straw proposal contemplated a three-way surplus power sales contract between BPA, the DSI and the local public utility in whose service territory the DSI facility is located. The surplus sale, priced as close as possible to the rate charged by BPA to its public preference customers, would be made to the local utility, with the benefits passed on to the DSI customer. BPA stated in the letter that monetizing the power sales transaction enabled it reliably to meet the prerequisite that the cost of serving the DSIs be capped, but that BPA was willing to consider other mechanisms that could possibly also meet this criteria.

Finally, with respect to eligibility criteria, BPA's straw proposal centered on each DSI's creditworthiness, including evidence of each company's ability to operate and create employment during periods of challenging industry and company economics, such as during the current rate period, which has seen high power prices and sustained periods of low aluminum prices. The straw proposal noted that BPA wanted to focus the limited service benefits likely to be available where they had the greatest probability of promoting sustained DSI operations and associated job creation and retention.

BPA received almost 100 written comments from a broad cross-section of customers and constituents, including each of the DSIs, public customer organizations and many individual public utility customers, and individual citizens, including DSI employees and individuals from communities where the DSI facilities are located. In addition, the open forum, which was structured into five separate panel discussions, with questions from the audience, plus a public comment session, was attended by approximately 100 individuals representing the same broad cross-section of customers and constituents described above. Written comments regarding DSI service received in response to both the July 7, 2004, policy proposal, and the February 4, 2005, straw proposal are considered herein, as well as comments from the open forum, which are also highlighted and evaluated in this record of decision.

VI. Issue 1 - Level of Benefits

Parties' Comments

The issue regarding the level of benefits has two distinct but linked components: (1) the amount of service benefits to be provided, either through the delivery of power to the DSIs or through financial benefits (monetization) in lieu of power deliveries; and (2) the maximum cost, including market and credit risk, BPA will incur on behalf of the DSIs to provide such service

benefits. In its July 7, 2004, policy proposal, BPA indicated it was committed to exploring DSI service options that would continue the ramp-down in DSI service benefits to 500 aMW, at a known and capped cost. This proposed level of service was in line with amounts contained in the Northwest Power Planning Council's December 2002 recommendations regarding BPA service to the DSIs in the next rate period, and is in keeping with the long-term ramping-down of BPA service to the DSIs that began when access to the wholesale power markets became available to the companies beginning in the mid-1990s. Since then, BPA's DSI load has dropped by half from historical levels in excess of 3,000 aMW, to approximately 1,500 aMW. While the July 2004 policy proposal itself did not propose a specific cost cap, during the course of meetings and discussions with customers and constituents regarding the policy proposal, BPA indicated it believed the cost of DSI service to BPA and its other customers should be capped at approximately $40 million per year.

Comments On July 2004 Proposal

In response, each DSI commented on the level of service it would like to receive, but generally did not state what each thought other DSIs should receive. While not addressing the cost cap issue directly, each DSI stated or implied that the cost of such service to BPA must necessarily equal the delta, however much that may be, between BPA's lowest-cost rate under the Priority Firm (PF) rate schedule available to BPA's public preference customers (a rate level the DSIs generally argue is necessary to accommodate economic aluminum smelter operations) and the higher-priced market. Alcoa (Alcoa, RD04-0067) stated that prior discussions on limiting service to 100 aMW per smelter would not be sufficient for its Intalco smelter, located in Ferndale, Wash., to operate economically, neither enabling operations nor maintaining jobs. Alcoa asked BPA to provide it 438 aMW, and argued that the 500 aMW amount proposed by BPA is arbitrary. Whatcom County Executive's Office (Whatcom County, RD04-0008), and several Alcoa workers (Flaherty, RD04-0019, Rousseau, RD04-0019 and others) noted their support for 438 aMW to Alcoa. Columbia Falls Aluminum Company (CFAC, RD04-0111), CFAC workers (Keith Haverfield, RD04-0120, Steve Knight, RD04-0076 and others), and the city of Columbia Falls (city of Columbia Falls, RD04-0097) requested 170 aMW to cover half of CFAC's total capacity. CFAC indicated it believed if it could operate at approximately 50 percent capacity "during the tough times" then it could maintain the core of its workforce, suppliers, and other infrastructure elements in anticipation of better market prices for power, aluminum, and alumina. The Montana State Workforce Investment Board (RD04-0063) urged BPA to enable CFAC to "buy power from BPA at a cost-based rate." The CFAC smelter is located in Columbia Falls, Montana.

Evergreen Aluminum (Evergreen, RD04-0075) which was recently acquired by Glencore, and had a contract for only 6 aMW during the 2001-2006 period, requested 120 aMW, enough power to operate its Vancouver, Washington, smelter at approximately 50 percent capacity, thereby maintaining core operations in anticipation of improving market prices. Golden Northwest Aluminum (GNA, RD04-0101) endorsed BPA providing continued service to DSIs after the current contracts expire at the amount of 100 aMW per smelter. This approach would result in 200 aMW of power for GNA, 100 aMW for each of its two smelters, located in Goldendale, Wash., and The Dalles, Ore. Port Townsend Paper (Port Townsend, RD04-0045) asked for continued service for the "smaller than 20 aMW load" at its Port Townsend, Washington, mill at rates comparable to the rates its competitors can purchase BPA power from their local public utility district. The Public Power Council (PPC, RD04-0109) pointed out that

providing 500 aMW was not going to satisfy the DSIs since their stated needs exceed that 500 aMW amount. This comment was borne out by individual DSI requests, which totaled approximately 950 aMW. Aluminum worker comments requested "more than 500" in one instance, and in a couple of cases requests were made for 800-900 aMW (KBAlloys, RD04-0026 and McKinney, RD04-0028).

In other comments, the Industrial Customers of Northwest Utilities (ICNU, RD04-0093), the State of Washington Department of Community, Trade and Economic Development (Washington, RD04-0072), and several workers and citizens (Pike, RD04-0076, Stahlberg, RD04-0076, and others) specifically endorsed the 500 aMW limit. The Northwest Energy Coalition (NWEC, RD04-0110) indicated it would support service to 500-700 aMW of DSI load at some price below market, but asked that BPA consider the costs and benefits of such support relative to BPA's budget proposed for renewables. In addition to specific average megawatt limits, the four state utility commissions and the Eugene Water and Electric Board (EWEB, RD04-0127) expressed support for the principle that benefits be limited and fixed so that the cost to other customers be known and capped. EWEB also reiterated the importance it placed on 500 aMW and a cost of $40 million as absolute limits for DSI service. However, EWEB proposed that BPA serve the DSIs, at a rate discounted to market prices and costs capped at $40 million, only with surplus power from the federal system, and that it not make any augmentation purchases to serve the DSI load. Therefore, under EWEB's proposal any costs incurred would be limited to foregone surplus sales revenues, up to $40 million per year. Western Montana Generation & Transmission (WMG&T, RD04-0076 and RD04-0092) and Lincoln Electric Cooperative (Lincoln, RD04-0100) argued that BPA's proposal needed to be scaled back to 300 aMW. Public Utility District No. 1 of Ferry County (Ferry, RD04-0037) took the position that if BPA was going to acquire any resources to serve DSI load, it should charge the DSIs market prices for the power, so that other customers incur no costs associated with such service. Northwest Requirements Utilities (NRU, RD04-0073), the Western Public Agencies Group (WPAG, RD04-0105), Mason County PUD No.3 (Mason, RD04-0151), and Pacific Northwest Generating Cooperative (PNGC, RD04-0114) similarly expressed qualified support only for no-cost service alternatives.

In its February 4, 2005, straw proposal, BPA continued to propose that it provide up to 500 aMW of service benefits to the DSIs. In addition, BPA expressly proposed to cap the cost of DSI service at $40 million a year. This amount represented a benefit of approximately $10 per megawatt hour (MWh) on a 500 aMW allocation (representing the delta between a rough estimation of BPA's lowest-cost rate in the next rate period, and a snap-shot projection of potential forward market prices during the same period). BPA stated that this amount of benefits was in line with the level of support many non-DSI customers indicated in comments that they were willing to accept, and that it struck a reasonable balance between supporting DSI operations and jobs with BPA's need to contain costs.

Comments on February 2005 Proposal

In response to its straw proposal, BPA received comments and proposals covering a wide range of benefit levels. The DSIs, DSI employees, members of the communities in which DSIs facilities are located, and elected officials representing these areas, argued for a benefit level at least equal to, and in many cases greater than, the levels in BPA's straw proposal. The major organizations representing BPA's public preference customers, as well as individual public preference customers, were generally (though by no means enthusiastically) supportive of BPA's

proposal of up to 500 aMW at a capped cost of $40 million per year, but their support came with conditions attached. The principal condition was that benefits up to these levels be provided only if BPA's lowest-cost public preference rate for the next rate period does not otherwise exceed $27 per MWh (Clark, DSI-069, NRU, DSI-067, PNGC, DSI-088, PPC, DSI-079, Snohomish, DSI-075, Springfield, DSI-076, WREC, DSI-068, Western Montana G&T, DSI-092, WPAG, DSI-090). In addition, many parties made clear they would oppose any amount above the proposed $40 million cap.

Alcoa (DSI-077 and DSI-057) continued to propose that it be provided an amount of physical power equal to its current contract amount (438 aMW). Alcoa commented that it desires to operate its plants continuously and at full capacity, thereby producing aluminum at the lowest possible cost and providing maximum employment and financial benefits to the region. Alcoa indicated that allocating it 438 aMW of power at BPA's lowest-cost rate now would provide a "bridge" while regional long-term service issues are resolved.

Nevertheless, Alcoa indicated it would likely sign a new contract if BPA offered it less than 438 aMW at its lowest cost-based rate, provided contract terms are satisfactory and rates are in a competitive range, and that it would try to operate up to the limitations of that contract amount. However, Alcoa clearly stated the $40 million cap in the straw proposal "was not a viable service option." Using an example assuming a BPA rate of $27 per MWh and a market rate of $45 per MWh, and allocating all 500 aMW to itself, Alcoa concluded that the $40 million cap would allow it to buy down its effective rate by only $9.10 per MWh, to $35.90 per MWh. It asserts this rate level "would almost certainly make the Intalco plant non-competitive, whereas, it is much more likely to be competitive at the assumed [$27 per MWh] average rate." A number of Washington State legislators commented supporting Alcoa's proposal, echoing its argument that BPA's capped straw proposal is wholly inadequate and "puts at risk hundreds of family wage jobs." (Sen. Finkbeiner, DSI-049; *see also*, Reps. Morris and Chopp, DSI-051; Rep. Chandler, *et al.*, DSI-081; Rep. Linville, DSI-082; Sen. Brandland, DSI-050). Numerous Alcoa employees (Dennis Van Beek, DSI-008, L. Engler, DSI-006, and others) submitted comments supporting Alcoa's request for BPA to provide physical power equal to Alcoa's current contract amount, pointing to the direct and indirect jobs that would be provided, the support Alcoa provides the community, and that as a Federal agency BPA should be required to support family wage jobs. Businesses located in the community where Alcoa's Intalco plant is located (Diehl Ford Inc, DSI-028, Peoples Bank, DSI-029, and others), educational and environmental associations (Bellingham Technical College, DSI-013, Nooksack Salmon Enhancement Association, DSI-014, and others) and the mayor of Ferndale, Washington, (City of Ferndale, DSI-016) commented expressing support for Alcoa's proposal. Public Utility District No. 1 of Whatcom County (Whatcom, DSI-071), in whose service territory Alcoa's Intalco smelter is located, stated it supports a service benefit capped at between $40 to $60 million per year, so long as BPA's public preference rate "meets an acceptable target."

Columbia Falls Aluminum (CFAC, DSI-093) proposed a two-part (physical and financial) service benefit totaling 517 aMW. Under the CFAC proposal, 323 aMW of power would be allocated among DSIs that currently have contracts with BPA, each to receive a physical delivery of the lesser of 100 aMW or its current contract amount. *Id.* The balance (194 aMW) would be allocated evenly among CFAC, Alcoa, and GNA, and the value of the allocation monetized (converting the value of the contract to cash based on the difference between the contract price and market prices) up to a limit of $10 per MWh. CFAC's parent, Glencore Ltd., (Glencore, DSI-

085) stated that BPA's stated preference in the straw proposal to monetize a 500 aMW allocation up to a capped amount of $40 million per year "will fail to maintain jobs in the Northwest" given likely market power prices in the next rate period. Glencore stated if BPA adopts a financial transaction capped at $40 million it foresees a "strong likelihood that we will be given no other choice but to shut down" the CFAC smelter.

GNA (DSI-011) commented that it believes BPA should offer to serve the net requirements needed to support full operation of DSI customers, or at least offer to extend service at the current contract amounts through FY 2011. But citing "political realities" and BPA's stated preference to cap the costs of DSI service benefits using a financial transaction, GNA stated it "can accept a properly structured proposal for BPA to provide service benefits equivalent to 500 aMW of power at BPA's average cost." However, GNA argues that BPA should offer 500 aMW of physical power at its lowest-cost rate, or offer financial support that "is truly equivalent" to 500 aMW of power, and therefore not adopt the $40 million cap, since presumably it believes that amount of money is inadequate to do either. GNA stated it needed a minimum of 200 aMW in total to operate one potline each at its Goldendale and Dalles smelters. In additional comments (DSI-083) GNA stated 200 aMW would allow it to maintain "pilot light" operations at each smelter and position it to increase production by leveraging the BPA service when market conditions allow. The United Steel Workers Association Local 8147 (DSI-048), Northwest Energy Coalition (DSI-057), Klickitat PUD (DSI-058), and several GNA employees, steelworkers union representatives Jim Woodward (DSI –057), Gaylan Prescott (DSI-057), and others' comments were supportive of BPA providing 100 aMW per smelter. Gil Hayes (DSI-057), said that BPA needed to re-energize Northwest jobs and Northwest communities, and that BPA should provide 100 aMW per smelter with 20 percent transferable to a company's other smelters. Klickitat PUD (DSI-058), in whose service territory GNA's Goldendale smelter is located, noted that Klickitat County is "in a deep economic recession and needs all the help it can get" to retain the family-wage jobs the smelter provides.

Northwest Requirements Utilities (NRU, DSI-067) proposed BPA provide the DSIs a two-part 500 aMW service benefit comprised entirely of physical power, but only if a $27 per MWh average Priority Firm (PF) rate target is met. NRU proposed that each DSI be provided, presumably under BPA's market-based surplus power rate schedule, an amount of physical power equal to each company's actual purchases during the current rate period, up to 300 aMW in total, thereby maintaining the number of employees at the current levels. In addition, NRU proposes BPA offer an additional 200 aMW of service benefits to DSIs that meet certain qualifying criteria, but irrespective of the amount of power they purchased from BPA during the current rate period. Under the NRU proposal, the cost of service to the DSIs is not capped by the $40 million amount, but rather by its proposed $27 per MWh PF rate cap on a capped 500 aMW amount, with an additional separate cap on the 200 aMW equal to a $10 per MWh differential between the PF rate and market prices. Under its proposal, NRU noted that DSI benefits could exceed $40 million per year on a 500 aMW allocation so long as the $27 per MWh rate cap is not exceeded. Wells Rural Electric Company (Wells, DSI-068) also commented separately supporting NRU's proposal. Snohomish County PUD No. 1, (Snohomish, DSI-075) likewise commented that BPA should not make any firm commitments on expense items until it is assured that it will achieve the rate goal of $27 per MWh, which will not be known until the completion of the rate case. Port Townsend Paper (Port Townsend, DSI-045) commented that it believed it could support the NRU proposal and also noted that it provided 10-times more jobs per megawatt of purchased power than the aluminum smelter DSIs.

The Public Power Council (PPC, DSI-079) also proposed that DSI benefits be capped by the $27 per MWh PF rate target, but also by the $40 million cap, so that DSI benefits could not exceed $40 million even if additional benefits could be provided without breaching the $27 per MWh threshold. PPC stated that a cap is important in order to limit "BPA's (and BPA's customers') liability in the event of another energy crisis." However, PPC also argues that the level of the DSI benefit should fluctuate with any increases in the rate that BPA charges other customers, so that in some cases the annual benefit may be less than $40 million. PPC believes this criteria would provide DSIs with incentive to remain engaged in BPA cost and rate control. Clark County PUD (DSI-069) and Snohomish (DSI-075) commented generally supporting the PPC's proposal with respect to benefit level. On the other hand, NRU's proposal (DSI-067) stated that once a contract containing benefits levels is offered to the DSI, that it should not be adjusted, regardless of subsequent potential changes in BPA's financial position during the rate period.

The Western Public Agencies Group (WPAG, DSI-090) argued that it was "premature to even discuss the prospect of adding costs to BPA's preference customer rate" to serve DSI load when it is not clear BPA will meet its customers' $27 per MWh PF rate target, and that it was skeptical BPA could hold the line on its proposed DSI benefits level. However, WPAG proposed that if BPA was going to serve DSI load, the cost should be capped at a maximum of $40 million per year. The Pacific Northwest Generating Cooperative (PNGC, DSI-088), in addition to echoing other public customers' comment that any DSI service not cause BPA's PF rate for the next rate period to exceed $27 per MWh, also commented that under no circumstances should the cost cap exceed $40 million per year. Springfield Utility Board (SUB, DSI-076) agreed with BPA's straw proposal that service benefits should be based on 500 aMW and capped at $40 million per year, as did Washington State Senators Brown and Poulson (DSI-086). The Washington Department of Community, Trade and Economic Development urged BPA to establish a cap that reflects a balance between costs to other customers and the number of DSI jobs that will be protected (DSI-072).

Cowlitz County PUD (Cowlitz, DSI-070) and the Industrial Customers of Northwest Utilities (ICNU, DSI-084) indicated that the cost of DSI service benefits must be capped at a level that impacts BPA's public preference rate by $0.50 per MWh or less. Northern Wasco PUD (Northern Wasco, DSI-074), in whose service territory GNA's The Dalles smelter is located, indicated that an impact of $1.00 per MWh or less is reasonable. Western Montana Electric Generating and Transmission Cooperative (WMG&T, DSI-092) supports the $40 million cap, and commented that proposals that provide 900 aMW, or that are otherwise cost exorbitant, are unacceptable, but that conversely the "proposal must work for the DSIs or it is not worth pursuing." At the March forum, the representative from the Northwest Power and Conservation Council (DSI-057) took the position that benefits should be capped at $10 per MWh. Portland General Electric (DSI-057) commented at the forum that benefit levels should be set at a level so that other customers are not harmed, but that are sufficient to encourage job creation. Clatskanie People's Utility District (Clatskanie, DSI-087) proposed that benefit levels should be limited through serving the DSIs only with any surplus available from BPA's system, at a rate equivalent to BPA lowest-cost preference rate. Clatskanie notes that benefit levels would likely thereby be limited to power deliveries for only 3 to 4 months a year, with the possibility of zero benefits in some years. Central Lincoln PUD (DSI-066) suggested that BPA should limit the amount of benefits, within the $40 million cap, based on an analysis of "what it takes" for each DSI to stay open and operating.

There were several comments that were not supportive of BPA providing service benefits to the DSIs and that asked BPA to reconsider its earlier decision to offer some amount of service to the DSIs (ICNU, DSI-084; WPAG, DSI-090; Springfield, DSI-076; Benton, DSI-012; PNGC, DSI-057; *et al.*). Benton REA (DSI-012) believes BPA should not provide the DSIs any Federal benefits, and that benefits provided in the past have not made Pacific Northwest aluminum production competitive. Benton suggests BPA provide $20 million to retrain the DSI workforce. WPAG (DSI-090) stated there are "good and substantial" reasons for BPA to reconsider its decision to provide some benefits to the DSIs for the post-2006 period.

Finally, BPA noted at the March forum that a DSI service solution should account for BPA's one remaining small non-smelter DSI, Port Townsend Paper's 17 aMW paper mill load. In response, a number of parties commented that Port Townsend Paper should be treated separately. GNA (DSI-083) commented it supports separate treatment for Port Townsend given its relatively small power requirements (approximately 17 aMW), and because Port Townsend would have been served by its local utility (and paid a PF equivalent rate for its power) but for special historical circumstances that led to its DSI status. Cowlitz PUD (DSI-070) commented similarly, and stated it was not opposed to BPA providing "a modest level" of support directly to Port Townsend or indirectly through its local utility. Whatcom PUD (DSI-071) also supports BPA treating the Port Townsend load distinct from the DSI smelter loads, based on its comparatively small power requirements and unique operating characteristics.

Evaluation and Decision

At the outset, it is important to note that BPA is attempting to craft a compromise that will have a known and relatively small impact on the rates paid by its public preference customers, while still making available to the DSIs a level of service benefits large enough to materially improve the likelihood that power costs to the smelters will be low enough to facilitate smelter operations in times when such operations would otherwise be economically infeasible. However, it is not BPA's goal, nor is it within BPA's ability, to guarantee any particular level of DSI operations, even minimal levels. World aluminum prices, raw materials costs, and the financial health of the companies are beyond BPA's control and play at least as large a role in the feasibility of smelter operations as power prices. Many comments, both at the DSI forum and written comments, recognized this fact.

Additional important context is the fact that the amount of power provided by BPA to the DSIs has dropped from approximately 3,000 aMW a decade ago, to approximately 1,500 aMW under current contracts entered into for the FY 2002-2006 rate period. These contract amounts have also been significantly reduced by, among other things, contract terminations and aluminum company bankruptcies. Only half of the DSI contracts for the FY 2002-2006 period are still in effect, and the totals for power provided under these contracts, excluding the period of time the smelters curtailed load at BPA's request, will average less than 300 aMW. The fact that only 300 aMW of the original 1,500 aMW contracted for under the existing contracts was used is due principally to economic choices by the DSIs, highlighting the fact that BPA's power service decisions are only one variable in the economic and operating decisions the DSIs face. As already noted, BPA is not revisiting its earlier decision to serve some amount of DSI load at a known and capped cost. However, issues raised concerning the manner in which service benefits can or should be delivered are addressed in this record of decision.

While BPA's February 2005 straw proposal for 500 aMW of benefits with a $40 million cap generally set the bounds for the discussion, many proposals ranged higher and lower. Individual DSI proposals, which each company generally describes as the amount needed to maintain base-level operations at their respective smelters, total over 900 aMW. More importantly, the DSIs' proposals are each essentially uncapped. Each company made clear, given expected market power prices for the next rate period, that the $40 million cap was inadequate to facilitate smelter operations at even bare minimum levels. Using Alcoa's example of a delta of $18 per MWh between BPA's lowest-cost rate and the market, the Alcoa proposal would cost BPA approximately $70 million to serve 438 aMW of Alcoa load alone, almost $80 million to serve 500 aMW of DSI load, and over $140 million if the 900 aMW requested was served. Of course, given the inherent volatility of electric power markets, in high markets the delta would be wider, leaving BPA and its customers exposed to even greater costs. Proposals that leave the cost of service to the DSIs uncapped violate the principle already adopted by BPA that the cost of DSI service must be known and capped, and will not be adopted.

The partial and conditional acceptance by public preference customers of the $40 million cost of BPA's straw proposal makes clear that while there is some willingness to pay some part of the cost of providing the DSIs a limited amount of service benefits, there is little or no support by these customers for providing more benefits than proposed in the straw proposal. However, proposals that would reduce or eliminate altogether the 500 aMW and $40 million amounts, which could occur under some circumstances in the proposals by public entities, would likewise reduce or eliminate any reasonable likelihood that BPA service could have a meaningful, positive impact on the DSIs' chances to operate their facilities at even minimal levels during the next rate period. For example, many public customer representative groups, and others, proposed that BPA not provide any service to the DSIs if doing so would potentially increase the PF rate above $27 per MWh. BPA has not commenced the rate case that will establish the PF rate for the next period, so it is not known definitively at this time what that rate will be and it is therefore not feasible to tie the decision on DSI services to the PF rate level ultimately adopted by BPA. However, BPA is mindful that service to the DSIs will come at the expense of higher rates paid by its public preference customers, and is attempting to craft a compromise that balances those costs against providing a meaningful level of service benefits to the DSIs, but a proposal that will result in no DSI service benefits does not provide that balance.

BPA proposed the $40 million cap believing it would, in many expected power markets, provide enough value to the DSIs to close the gap between power market prices and BPA's lowest-cost rate. However, power market prices have significantly increased since the Regional Dialogue began in July 2004. The probability that a $40 million benefit will close the gap on an amount of power required for minimal operations has decreased. Recognizing this, BPA believes the balance between containing costs and providing a meaningful benefit to the DSIs is best achieved by increasing the average megawatt amount provided to 560 aMW, and increasing the cap to $59 million per year. These amounts exclude service by BPA to Port Townsend Paper (adding 17 aMW, for a total of 577 aMW), which as explained below will be treated separately from BPA's aluminum smelter customers. The following discussion and evaluation applies solely to BPA's provision of service benefits to the aluminum smelters. The argument by each of the DSIs is that the $40 million cap amount will be inadequate in light of the level of probable market power prices is supported by steadily upward trend in forward market index prices, and by BPA's own current forward market price snap-shots. The Mid-Columbia (Mid-C) index forward market prices for Fiscal Year (FY) 2006-2009 have continued to rise since the time of BPA's original

proposal in July 2004 and its straw proposal of February 2005, with current flat prices for FY 2007-2009 hovering around $50-$55 per MWh. At these levels, a $40 million cap would allow the DSIs to bring down their effective rate on a 500 aMW allocation to only approximately $40-$45 per MWh, which each has indicated is far too high to allow economic operation, even under robust aluminum market prices. BPA's own snapshot of forward prices for the FY 2007-2009 period likewise suggests that a higher cap is needed to create a reasonable probability of reducing the DSI rate, under most power market scenarios, to levels conducive to economic smelter operations.

A recent price distribution estimation by BPA for FY 2007-2009 flat power (average price of power over all hours of the day every day of the year) indicates that power market prices could be below $38 per MWh more than 30 percent of the time, at or below $42 per MWh approximately 40 percent of the time, and at or below $54 per MWh approximately 60 percent of the time. This means with benefits capped at $59 million (which translates into a $12 per MWh credit), BPA could provide 560 aMW of benefits to the DSI smelters at a theoretical PF-equivalent rate of approximately $30/MWh (bridging the $12 per MWh delta between the PF rate and a $42 per MWh market rate) 40 percent of the time during the rate period. Given this relatively low probability, in the event that BPA delivers service benefits through a financial mechanism (where the cost of supplying the DSI load cannot be achieved within the cost cap) BPA will provide the companies flexibility to spread this benefit over fewer megawatts, down to one-half of the megawatts allocated to the company, further increasing the probability of some smelter operations over a wider spectrum of market power prices. To be clear, BPA is not deciding that the smelters will have unlimited flexibility in terms of the amount of power supply to utilize the proposed financial benefit. Rather, the flexibility will range from the full allocation as the maximum rate of delivery, and the minimum rate of delivery will be one-half of the maximum. With this added flexibility BPA could provide 280 aMW of benefits (one-half of the 560 aMW) at the PF-equivalent rate. This flexibility provides the DSI's the ability to choose, under high market price conditions, to reduce smelter operations to one-half of their allocated amount. This would allow the smelters to double the potential $12 per MWh benefit and allow them (for example) to bridge the $24 per MWh delta between a theoretical $30 per MWh PF rate and a $54 per MWh market rate. Therefore, under the rough estimate of forward power market prices used here, BPA would be able to provide power prices equivalent to expected PF rates to allow a level of smelter operations approximately double current levels almost half the time, and approximately equal to current operating levels 60 percent of the time. BPA believes this level of benefits strikes the right balance between offering an amount of power at a rate low enough to help maintain – and provide opportunities to expand – DSI operations and employment, while keeping rates charged to its public preference customers as low as possible. However, the cap will not be raised further in the event BPA's updated forecast price distribution for the FY 2007-2009 rate period shows even higher market prices, nor will they be updated for changes in the forecast of market prices for the FY 2010-2011 rate case.

The two caps (560 aMW and $59 million) will work in tandem, and provide the maximum benefits that may be provided, but are not a floor level and do not represent the minimum amount of annual service benefits that will be provided to the DSIs. Power deliveries in excess of 560 aMW (or financial benefits based on more than 560 aMWs) will not be provided to the DSIs even if that could be done within the $59 million cap; likewise less than 560 aMW of power will be provided (or financial payments will be based on fewer than 560 aMW) where the $59 million cap would otherwise be breached. BPA believes the capped amounts provide a sufficient amount

of benefits to help sustain DSI operations under most power market conditions. If markets improve so that 560 aMW or equivalent financial benefits can be provided to the DSIs at less than $59 million, then BPA's other customers will have the impacts to their rates reduced by the savings. This is consistent with BPA's goal of enabling the DSIs to obtain enough low-cost power to help maintain minimal levels of smelter operations – other customers will not be asked to pay for more than this. In addition, these caps are annual caps, and benefits not used within a fiscal year, for any reason, will not be carried over into future years. BPA is imposing costs on its other customers beyond the $40 million cap in its straw proposal, and so it is necessary to maintain the annual cap to provide one possibility that the actual cost of the service benefit could be less than $59 million. BPA will ratchet down service benefits to the DSIs if providing the full amount would result in DSIs paying a lower rate than public preference customers. BPA's intent is that no DSI will pay prices that are lower than public preference customers pay for similar power products from BPA.

In addition to power sales contracts for an aggregate 560 aMW of benefits at a capped $59 million cost that BPA will offer to the aluminum company DSIs, BPA will offer, through the local public utility, a 17 aMW surplus power sales contract to Port Townsend Paper Company, under its market based rate schedule (or the IP rate if viable) at a price approximately equivalent to, but in no case less than, its lowest-cost PF rate. BPA is persuaded that Port Townsend's situation is unique among the DSIs and warrants unique treatment. The jobs provided by Port Townsend are over 10-times the number provided per megawatt at the aluminum smelters. By serving Port Townsend as described, BPA will simply be treating Port Townsend the same as similarly situated paper mills located within the Pacific Northwest and served directly by BPA's public preference customers. To be clear, service to Port Townsend is not included in the $59 million cap.

The decision to allocate 577 aMWs to the DSIs, while slightly higher than the original straw proposal of 500 aMW, represents a decrease of over 900 aMW of Federal power service to this customer group compared to the contracts signed by BPA and its DSI customers in 2001, and almost 2,500 aMW compared to contracts signed a decade ago.

Finally, on June 10, 2005, the United States District Court for the District of Oregon issued an injunction that, if sustained on appeal, will likely greatly reduce the amount of water available this summer for hydroelectricity production. The injunction calls for significant additional spill this summer, and BPA estimates the financial impact in the range of $57-81 million. While this record of decision is being issued subsequent to the court's injunction, BPA's evaluation of DSI service issues, and its decision making process on those issues, was completed prior to the injunction. If this injunction is sustained on appeal, and especially if summer spill along the lines ordered in the injunction is made a regular part of river operations, the rate impacts would be of extreme concern, and BPA may seek offsetting cost reductions. However, the injunction is under appeal, and the cost implications for this summer and the next several years are still unclear. A long-term cost increase of this magnitude would presumably have an impact on the DSIs ability to proceed with a take-or-pay contract. Notwithstanding this uncertainty, BPA has decided to issue this DSI service record of decision without specifically accounting for the potential costs impacts of the injunction on BPA's ability to deliver the DSI service benefits contemplated in this record of decision. However, BPA will review this decision prior to contracts being signed pursuant to this ROD based on more current information about the implications of the District Court's decision and its impact on future hydro system operations.

V. Issue 2 - Eligibility and Allocation

Comments on July 2004 Proposal

In its July 2004 Regional Dialogue policy proposal, BPA proposed that any benefits allocated to the DSIs would be targeted to DSIs that are creditworthy and have fully met their obligations under current rate period power sales contracts. However, BPA did not propose how it would allocate benefits among DSIs that otherwise meet any threshold criteria. Most of the comments BPA received in response (and that otherwise supported, or acquiesced to, some level of service to the DSIs) were supportive of BPA's proposed criteria. CFAC (RD04-0111) and Alcoa (RD04-0067) underscored the importance of creditworthiness and noted that they had met the criteria. Evergreen Aluminum (Evergreen, RD04-0075) noted that it too meets the eligibility criteria and has honored the terms of its current BPA contract. The State of Washington Department of Community, Trade and Economic Development (Washington DCTED, 0072), EWEB (RD04-0127), Franklin PUD (RD04-0108), PNGC (RD04-0114), WMG&T (RD04-0092), ICNU (RD04-0093), and Flathead Electric (Flathead, RD04-0048) also endorsed the eligibility principles. Tacoma (RD04-0103) argued against any service to the DSIs, but endorsed BPA's principles for service, including the creditworthiness criteria, if BPA did choose to offer some form of DSI service. While strongly objecting to any service to the DSIs, WPAG (RD-04-0105 and RD04-0150) proposed a number of additional eligibility criteria, including that the DSI had not declared bankruptcy, rejected its power sales contract in a bankruptcy proceeding, or imposed any stranded costs on BPA by "substituting market power for their Federal power supply."

On the other hand, GNA (RD04-0101), which filed for bankruptcy in December 2003, and some GNA employees, discounted the importance of creditworthiness (Mike Keith, RD04-0053 and Mark Pedersen, RD04-0171). GNA commented that a focus on past creditworthiness under the current power sales contract, given recent GNA financial difficulties, would unfairly discount its other previous responsible actions as a regional corporate citizen, and would only harm innocent employees and communities. GNA also stated that BPA has not been financially harmed by GNA's inability to purchase the 236 aMW of power to which it committed to purchase on a take-or-pay basis in its power sales contract, and that BPA has made more revenues from remarketing this power than it would have made if it had made the sales to GNA under the contract.

Comments on February 2005 Proposal

In its February 2005 straw proposal, BPA reiterated that it believed eligibility criteria for service benefits should center on each DSI's creditworthiness. BPA stated it believed the focus on creditworthiness was crucial to directing scarce benefits where they can best enhance the prospects for smelter operations and employment. As such, BPA indicated evidence of each company's ability to operate and create employment during times of difficult industry and company economics, such as experienced during the current contract period, should be a relevant consideration, and suggested an objective measurement of such ability could be the amount of energy used by each DSI during the current rate period to produce aluminum. BPA suggested that the power or financial benefit should only be provided in support of actual DSI operations and employment, and that the DSI must be purchasing and consuming an amount of power in support of production operations to receive any service benefits from BPA. BPA stated it wanted to understand the business plan of each company, and how the business plan explains the ability

of the DSI to operate under the market conditions that existed over the current rate period. In addition, at the March 2005 forum BPA indicated it believed a relevant eligibility consideration would be how, if applicable, each DSI disposed of its windfall remarketing benefits during the 1996-2001 rate period. BPA did not describe the application of the eligibility criteria to any particular company, or make any proposal on whether the eligibility criteria would be used to allocate benefits among companies that otherwise appear to meet the criteria.

Most comments from non-DSI customers and others expressed support that, at a minimum, the DSI must be creditworthy to receive benefits in the form of physical power deliveries. (*E.g.*, Whatcom PUD, DSI-071; ICNU, DSI-084; NRU, DSI-067; PPC, DSI-079; PNGC, DSI-088; WPAG, DSI-090; WMG&T, DSI-092; Wells Rural Electric Company, DSI-068; Clark PUD, DSI-069; Cowlitz PUD, DSI-069; SUB, DSI-076.) A number of comments suggested that BPA apply the same credit requirements as contained in BPA's contracts with its Slice customers. (CFAC, DSI-093; NRU, DSI-067; WPAG, DSI-090; SUB, DSI-076) Taking a different view, the Klickitat County Board of Commissioners (DSI-058) commented that "jobs and local economic benefits created by [the aluminum industry] outweigh any simple credit worthiness test" and that BPA should create a fair allocation process so that all remaining smelters in the region have a chance to succeed.

Some comments suggested additional criteria to qualify for service benefits, including: that the DSI "must have been operating continuously" (ICNU, DSI-084); that the DSI "provide prudential support up to the total amount purchased at the PF rate for the term of the contract" (WMG&T, DSI-092); that the DSI provide information to BPA demonstrating the number and location of jobs it will preserve or create, and anticipated wages (Central Lincoln PUD, DSI-066); that the DSI pre-pay monthly for power to be delivered by BPA (WPAG, DSI-090); that the DSI pay the cost of a put option to ensure that, in the event of a curtailment, the resale of power purchased for the curtailing DSI does not shift costs to other customers (NRU, DSI-067); that the DSI agree not to receive benefits from BPA after September 2011, that it demonstrate that its wages are equal to or better than the industry average, and that it demonstrate a commitment to non-BPA power sources in the long-term (SUB, DSI-076). There was no disagreement with BPA's proposal that the DSI must be purchasing power in support of smelter production in order to receive service benefits from BPA.

GNA (DSI-011 and DSI-057) strongly disagreed with BPA's proposed criteria, stating the criteria "appear to have been structured to favor specific companies instead of focusing on expected viability of smelters" in the upcoming rate period. In particular, GNA is opposed to any criteria that includes an examination of each company's operating performance during the current rate period. GNA argues that BPA's eligibility criteria ignore the dominant role power prices play in smelter viability, that allocating benefits based on eligibility criteria that include past performance will essentially predetermine which of the DSI aluminum smelters succeed or fail, and that "choosing which smelters should succeed or fail and which communities must suffer the attendant economic dislocation is not an appropriate role for BPA." (DSI-011) This comment was echoed by Whatcom PUD (DSI-071) and certain members of Congress (Baird, *et al.*, DSI-057). Likewise, WPAG (DSI-090) rejected any eligibility criteria aside from the DSI being creditworthy, noting that the element of BPA's straw proposal that suggested BPA would evaluate the viability of each DSI's business plan and operating capability would place BPA "in an untenable position" and that BPA should not judge which smelters receive power and which do not. On the other hand, PNGC (DSI-DSI-088), NRU (DSI-067), SUB (DSI-076), and Clark PUD

(DSI-069) argued that having fulfilled prior contractual obligations should be a prerequisite to receiving service benefits. PNGC commented that whether a company has honored its past obligations "is a key concern" in light of the fact that its members and other customers have been required to pick-up the cost of BPA write-offs of uncollectible DSI debt. NRU argues that a distinction should be drawn between those DSIs that are currently operating and those that are shutdown, since the former "have helped to pay BPA's costs during a very difficult period." (DSI-067)

GNA (DSI-011) argued that the most important circumstances influencing smelter operations in the current rate period, such as the price of aluminum and alumina, the volatile cost of electricity, and the value of the dollar, are not predictive of a company's ability to operate in the next period. GNA noted also that it has emerged from bankruptcy having shed most of its debt, and with new "strong, very credit worthy" majority ownership. GNA urged BPA merely to specify the amount of power system benefits it will make available to support actual smelter operations, and provide such benefits (in the form of a financial transaction) to those smelters that do operate in proportion to their actual level of operations. GNA argues its proposal will avoid BPA "tilting the playing field" and better promote job preservation and creation since it will allow the marginal or "swing-smelters" to maintain minimum viable levels of production under virtually all conditions, whereas BPA's eligibility criteria will likely allocate all available benefits to smelters that will operate with or without such benefits, without creating or sustaining jobs. Alternatively, GNA suggests that if BPA does specify allocations for each smelter, that allocating 100 aMW per smelter would be the best way to support some level of operations by each company. Finally, GNA noted in additional written comments that it would support a decision that allocated 500 aMW "on a non-discriminatory basis" and that any BPA allocation "simply needs to give each remaining smelter a chance to succeed." (DSI-083).

Alcoa (DSI-077 and DSI-057) stated that it is a creditworthy company, that it has met all its obligations under "current and past" BPA contracts, and that it "will not bring unfair risks to other customers." (DSI-057) Alcoa consistently stated that it wants 438 aMW of power from BPA and did not propose any other allocation scheme in the face of BPA's straw proposal limiting DSI service benefits to 500 aMW. However, Alcoa argues that spreading limited benefits among several smelters means that "none of the Northwest plants that rely on BPA power will be able to compete in the long run." (DSI-077) It stated that short of extending all DSI contracts in their current amounts, that BPA should allocate whatever amount of power is made available for DSI service to "the plants that will make the best partner for BPA and its customers" *Id.* As noted under Issue 1, a number of Washington State legislators and Alcoa employees (Sen. Finkbeiner, DSI-049; Reps. Morris and Chopp, DSI-051; Rep. Chandler, *et al.*, DSI-081; Rep. Linville, DSI-082; Sen. Brandland, DSI-050; Dennis Van Beek, DSI-008, L. Engler, DSI-006, and others) submitted comments supporting Alcoa's request for BPA to provide physical power equal to Alcoa's current contract amount. Businesses located in the community where Alcoa's Intalco plant is located (Diehl Ford Inc, DSI-028, Peoples Bank, DSI-029, and others), educational and environmental associations (Bellingham Technical College, DSI-013, Nooksack Salmon Enhancement Association, DSI-014, and others) and the Mayor of Ferndale, Washington, (City of Ferndale, DSI-016) commented expressing support for Alcoa's proposal. On the other hand, the mayor of Goldendale, Washington, argues the Alcoa proposal is unfair to smelters located in areas with the highest unemployment, and urges BPA to "just be fair about the allocation." (City of Goldendale, DSI-027).

CFAC proposed, assuming each of the remaining smelter DSIs meets its proposed credit prerequisites (the Slice contract credit requirements), that 323 aMW of the 500 aMW in BPA's straw proposal (plus 17 aMW for Port Townsend) be allocated as physical power deliveries among DSIs that currently have contracts with BPA, each to receive a physical delivery of the lesser of 100 aMW or its current contract amount, for a total of 306 aMW. *Id.* The balance (194 aMW) would be allocated evenly between CFAC, Alcoa, and GNA, and the value of the allocation monetized, up to a capped dollar amount. CFAC proposed that if any allocated benefits are rejected by a company, or if a company cannot meet the credit prerequisites, then those benefits would be reallocated among the remaining smelters pro rata. Whatcom PUD (DSI-071) also supports reallocating unused benefits. PPC (DSI-079) commented that it opposed proposals that would reallocate benefits in the event one or more of the companies could not utilize them, and that benefits should instead be determined on a company-by-company basis, but did not make a specific allocation proposal. Many parties submitting comments did not make specific allocation proposals.

However, several parties did make specific allocation proposals. The cost caps and other rate conditions associated with these allocation proposals, and the mechanisms proposed by parties for delivery of the allocated benefits, are discussed under Issues 1 and 3. In general, however, as noted almost all parties commented that the DSI must be creditworthy to receive an allocation of benefits. NRU (DSI-067) proposed that up to 300 aMW in aggregate be offered to DSIs equal to the amount of power each purchased from BPA in the current rate period. An additional 200 aMW in aggregate would be made available on a pro rata basis. Wells (DSI-068) commented that it agreed with NRU's proposal. WPAG (DSI-090) proposed what is essentially a pro rata allocation formula. Under the WPAG proposal, BPA would request load commitments from all DSIs on a quarterly or semi-annual basis. If the load requests exceeded 500 aMW, BPA could serve the increment above that amount so long as the $40 million annual cost cap was not breached. WMG&T (DSI-092) made a similar pro rata allocation proposal.

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BPA will allocate a share of the 560 aMW of service benefits to each DSI aluminum company for purposes of making an initial offer of service, but the creditworthiness of each DSI, on a going-forward basis, will determine whether BPA executes a contract with a company. In order to protect its financial position to the fullest extent possible, in particular in the case where BPA must purchase some amount of power in the market to provide benefits to the DSIs, BPA will establish and apply uniform creditworthiness criteria. In the event that BPA's credit evaluation of a company concludes credit assurances are required to mitigate BPA's risk from the company's lack of creditworthiness or performance viability, then BPA will require the company to provide performance assurances acceptable to BPA and consistent with the credit assurance provisions contained in the credit agreement by and between BPA and its Slice customers.

Several parties suggested only companies that have met all their obligations under the current power sales contract should be eligible for an allocation of service benefits. The only DSI that has failed to do so is GNA, which filed for bankruptcy protection in December 2003. At the time the bankruptcy petition was filed, GNA had outstanding unpaid balances billed by BPA for take-or-pay damages associated with several power sales contract curtailments. BPA is an unsecured creditor of GNA, and will receive its pro rata share of the distribution to unsecured creditors as provided for in the plan of reorganization approved by the court. The value of the distribution to BPA will be quite small in relation to the amount claimed. Although receiving so

little value is frustrating, a decision to deny GNA an offer of service benefits in the next rate period solely because it filed for bankruptcy protection and failed to pay BPA in full raises difficult questions regarding the policy of the bankruptcy code to afford debtors a fresh start. In addition, such a result would certainly not benefit GNA workers and the communities in which the GNA smelters are located. Nevertheless, GNA (or more accurately the reorganized entity that is its successor) will have to establish its creditworthiness, or post credit assurances acceptable to BPA if that is required, in order for BPA to execute a power sales contract with the company. As noted by several parties, however, if BPA monetizes the value of a company's power sales contract in lieu-of a traditional physical power delivery form of service, then the creditworthiness issue is less important, since the company itself would arrange its own physical power supply, with BPA providing an after-the-fact credit.

Contrary to the comments submitted by GNA and several others as well, BPA continues to believe that a company's record of operation under the current power sales contract is a credible, objective measure of an aluminum smelter's ability to operate in the next rate period on a sustained basis. Nevertheless, BPA is persuaded by the comments of GNA and others that this criteria, in and of itself, is an imperfect measure of that ability and that BPA should strive not to have an assessment of viability predetermine whether a company is offered an allocation of benefits.

BPA has concluded that it is important to allocate now among the companies the amount of service benefits each will be offered in a contract for the FY 2007-2011 period, and each company's past operating performance has played some role in that allocation. A pre-allocation of service benefits from BPA will provide each company with a known power supply base, at a known cost, upon which to make arrangements now for its additional power supply needs in the market. This level of certainty is not available under the various pro-rata allocations proposed by several parties. Pro-rata allocations would necessarily occur much closer to the date of the commencement of service, since it is entirely possible, for any number of reasons, that one or more of the companies may decline BPA's offer of service. While this is just as possible under a pre-allocation, BPA has attempted to equitably allocate the service benefits based on each company's stated minimal needs, and each company's demonstrated ability to operate during the current contract period, which BPA believes are reasonable and objective indications of each company's ability to accept and use the allocated benefits. The pro-rata allocation schemes do not adequately take these factors into account, or account for substantial differences in smelter size and operating characteristics. Given each company's stated minimal requirements and current operating posture, a pro rata allocation that is not determined until later is a less efficient way to allocate these scarce benefits compared to a pre-allocation. Each company's allocation will be based on a combination of its stated minimum requirements and current contract period operating posture. The result is that each company will receive a smaller allocation than it indicated it would like to have, but a larger allocation than each has used under the current power sales contracts. CFAC and Alcoa have chosen to operate their Columbia Falls and Intalco smelters well below capacity and BPA contract amounts, purchasing Federal power, and at times market power, to run approximately one potline at each facility. This represents approximately 70 aMW in the case of CFAC, and approximately 177 aMW in the case of Alcoa. GNA has not operated its Dalles smelter at all during the current contract period, using fewer than 50 aMW of power at its Goldendale smelter for the first 19 months of the current rate period, and none since shutting down operations in April 2003. GNA has curtailed its entire remaining load for the remainder of its contract term. CFAC and Alcoa, and their workers, have made it clear that they

believe that to be successful in the future they will need to have the ability to increase their current production levels. CFAC has requested 171 aMW, and Alcoa has requested 438 aMW. BPA has decided to provide CFAC and Alcoa the opportunity to increase their production by allocating benefits to them that will allow each to potentially increase its production to approximately two potlines at each facility. For CFAC, BPA has decided to provide 140 aMW worth of benefits, for Alcoa BPA has decided to provide 320 aMW worth of benefits. BPA has decided to allocate 100 aMW of benefits to GNA, which will provide the newly reorganized company an opportunity to ramp-up from its current shutdown status to a significant level of smelting and local employment, providing GNA with the "pilot light" it requested. Port Townsend will be provided 17 aMW as previously discussed. BPA will not allocate any benefits to Evergreen Aluminum for the next rate period. Evergreen, which elected in 1996 to reduce its power sales contract relationship with BPA to 10 aMW (an amount reduced further in its current contract to 6 aMW), is currently mothballed and has not operated since December 2000. BPA cannot justify diluting the allocations of the other smelters on the remote possibility that Evergreen will operate during the next rate period. However, Glencore, which owns both the CFAC and Evergreen smelters, will be permitted to reallocate up to 6 aMW of the CFAC allocation to Evergreen to continue to serve Evergreen's ordinary station service needs. No other DSI – current or former – requested service and none will be offered.

BPA has also decided to develop a "use-it-or-lose it" provision in the DSI contracts that will offer an opportunity to permanently reallocate benefits not used by a company over the course of one year. The amounts not used during a current year will result in reducing costs to other Federal power customers and these unused benefits will not be carried over to a future year as part of the reallocation. This provision will reward smelters that successfully operate with the opportunity to acquire unused benefit amounts from other less successful companies, allowing future market conditions to rebalance the benefit levels and allowing companies to potentially increase their initially allocated benefit levels. However, no company will be reallocated an amount of benefits in excess of its current BPA power sales contract. For Alcoa the maximum is 438 aMW, for CFAC the maximum amount is 171 aMW, and for GNA the maximum amount is 236 aMW. The reason for capping the amount any individual DSI may receive to its current contract allocation echoes the reason the benefit caps are ceilings and not floors for benefit levels, and BPA will not ask its public preference customers to help underwrite the operating level of any DSI beyond existing contract levels.

VI. Issue 3 - Delivery Mechanism

In simplest terms, in addressing this issue BPA must resolve how it can best structure the new contracts to deliver 560 aMW of service benefits to the aluminum smelter DSIs without breaching or creating the possibility of breaching the $59 million annual cost cap. The two primary elements to be considered as part of this structure or "delivery mechanism" are the rate schedule that will be employed, and whether benefits will be delivered as: (1) physical power, or (2) the value of a physical contract monetized, based on its relative market value, and paid to the DSIs. As part of its July 2004 proposal, BPA indicated it was examining offering eligible DSI loads a "defined and limited financial incentive to operate" in place of a traditional physical power sale under the Industrial Firm (IP) rate. BPA stated that in order to implement this mechanism for delivering benefits, in which BPA would pay the DSI the difference between the cost of the DSI's market power purchases and the cost to BPA of serving the DSIs in the traditional manner, it would need to be assured that the cost impact on other customers was

"roughly no greater than if BPA had exercised its discretion to serve the DSI customers" directly with physical power deliveries using the IP rate. BPA noted this approach eliminated the take-or-pay risk associated with a physical power sale for both BPA and the DSIs, while providing additional operating flexibility to the companies, and allowing them to make operating decisions in light of the availability of the financial credit from BPA. BPA's principal goals behind this proposal were to eliminate the inherent risk and cost uncertainty associated with augmenting the Federal system to serve DSI load and to minimize the risk of bad debt even in the case of bankruptcy.

Comments on the July 2004 Proposal

A number of comments to the July 2004 proposal addressed the financial incentive concept. While a few parties (WPAG, RD04-0105 and RD04-0150; Columbia River PUD, RD04-0031; NRU RD04-0073), commented that BPA has no legal authority to provide financial benefits to DSIs, or stated a preference for a physical power sale (ICNU, RD04-0093), most parties that commented on this issue were at least open to the financial incentive approach. Alcoa (RD04-0067) and CFAC (RD04-0111) stated a preference for a power sale at a PF-equivalent rate, but CFAC noted it would be open to a financial incentive approach to service, and Alcoa stated it would consider a "fair settlement" of a power sales contract in the form of a financial incentive to operate. However, in arguing for a physical power sale, Alcoa noted BPA "should not expect zero uncertainty" surrounding the cost to serve DSI load with purchased power, and that there were options for mitigating that cost and risk uncertainty. GNA (RD04-0101) expressed support for the concept of monetizing the value of a power sales contract to eliminate the risk to BPA associated with a physical power sale, and proposed an exchange mechanism that might be used to structure such a transaction. Under this exchange, the incentive amount would equal the difference between the market price forecast BPA establishes in the power rate case, and the IP rate that is also set in the rate case. The DSI would offer to "sell" power to BPA at the market price, and BPA would simultaneously "sell" an equal amount of power at the IP rate, but the transaction would be monetized, providing the DSI an amount of money to offset its actual market power purchases.

NWEC (RD04-0110) strongly supported a financial mechanism in lieu of a power sale and noted its similarities to earlier proposals they had made which would encourage smelting during low price periods and discourage it during high price periods. The State of Washington Department of Community, Trade and Economic Development (RD-0072), Springfield (RD04-0106 and RD04-0158), city of Sumas (RD04-0132) and Tacoma (RD04-0103), also endorsed the financial incentive approach to delivering benefits. Flathead Electric (Flathead, RD04-0048) expressed support for the financial incentive if transitioning DSI load to a local utility was not feasible. Northern Wasco (Northern Wasco, RD04-0042) also expressed support for the financial incentive, but noted it would ultimately support a "more prudent" approach if one presented itself. Western Montana G&T (WMG&T, RD04-0092) and Lincoln (RD04-0100) expressed openness to the concept of a capped financial incentive so long as it did not allow any gaming by the DSIs.

Through the various regional dialogue venues some customers began suggesting that perhaps BPA service to DSI load should be delivered via the local utility of each DSI. The rationale behind this idea was essentially two-fold. First, that it would eliminate the DSIs as a separate class of customers, thereby eliminating many of the rate setting and other service complexities that status now presents to BPA and the region. And second, that it would begin the process of moving decision-making regarding service to these large loads into the communities in

which the facilities, and the jobs that go with them, are located. Alcoa (RD04-0067), Whatcom PUD 1 (RD04-0146), Klickitat PUD (RD04-0144), and Flathead (RD04-0048) proposed that BPA be open to serving former DSI loads through their local utilities, but generally did not specify whether they supported monetizing the transaction. Whatcom commented BPA should transition DSI power supply responsibility to the local utilities, thereby allowing BPA to move out of the DSI business and local utilities to support the local economies in which the DSIs operate. Whatcom, Klickitat, and Flathead each have DSI smelters in their service territories. On the other hand, Clark PUD (DSI-069), in whose service territory CFAC's sister smelter Evergreen Aluminum is located, expressed strong objections to participating in any arrangement to serve the smelter load, since it could "be left holding the bag if a DSI did not pay for its power." BPA's investor-owned utility customers (IOUs, RD04-0157) also addressed the issue of BPA service to the DSIs via local utilities, and cautioned BPA that service through the local utility could have "unintended consequences" for BPA's New Large Single Load Policy. PNGC (DSI-088) stated it was "too late in the game" to try and place the DSIs on the same basis as other industrial loads served by local public utilities, and that it was concerned about the risk to the individual utilities in a transaction where they stood between BPA and the DSI.

Comments on the February 2005 Proposal

BPA's February 2005 straw proposal to "provide financial benefits in lieu-of" a physical power sale remained essentially unchanged from the July 2004 proposal. BPA explained that this "mechanism monetizes, or converts to cash, the financial value of a physical power sales contract." BPA's principal rationale for proposing this mechanism remained that it allowed BPA "reliably to meet the requirement that the benefits be capped," while noting that "other mechanisms may meet this requirement as well." However, in place of focusing on the IP rate as the rate schedule vehicle off of which service benefits would be calculated, BPA proposed that one alternative to be considered, and its preferred path, was to structure the transaction as a surplus power sale to the DSIs through the local serving public utility district. BPA explained that this would take the form of a three-party power sales contract, with the first leg of the transaction being a below market surplus power sale by BPA to the local utility under BPA's firm surplus power rate schedule, and the second leg being a re-sale of this surplus by the local utility to the DSI. In order to eliminate the risks to the parties associated with a physical power sale, BPA's proposal contemplated that the value of the transaction would be monetized, the value being the difference between the below market surplus power and the forecasted market price for power. The principal reason for moving away from an IP rate based solution was that it is becoming more clear as BPA prepares for the upcoming power rate case that it is unlikely the IP rate can be established at a level low-enough to even approximate the PF rate.

In response, and in something of a reverse from the leanings of prior comments, most comments reflected a preference for benefits to be delivered through physical power sales. WPAG (DSI-090), Western Montana G&T (DSI-092), Snohomish County PUD (DSI-075), PNGC (DSI-088), Northern Wasco PUD (DSI-074), Klickitat PUD (DSI-064), ICNU (DSI-084), the DSIs, Ferndale community leaders, most Washington State legislators, and numerous DSI employees comments either expressly or impliedly favored a physical power sale over BPA's proposed financial approach. WPAG (DSI-090) argued that any power sales contract that the parties intended ahead of time to monetize was a "sham transaction that is being proposed merely as a pretext to enter into a financial transaction under which BPA would deliver money to the utility rather than power." As an alternative, WPAG proposed that BPA make a power sale

directly to each DSI "at the DSI rate, which would be equal to the PF rate." Western Montana G&T (DSI-092) equated monetizing the value of the power sales contract with a "financial subsidy to industries" and that it did not believe that was good public policy. It agreed the financial transaction had certain benefits, but that it was "a little too tricky" and that a physical power sale to the DSIs would be the superior alternative. It proposed that BPA simply purchase and allocate as much as each DSI requested up to the cost cap, or on a pro rata basis in the case requests exceeded supply, a five-year flat block of power. PNGC (DSI-088) stated that while it understood BPA's rationale for preferring to monetize the transaction and eliminate the risks of a physical transaction, it had concerns about "the legal mechanics" of that approach. It argued a physical power sale is simpler and "provide closer alignment with other customers." Snohomish, DSI-075, proposed that BPA should consider a one-time augmentation of the Federal system by buying-back a portion of the power BPA delivers to Canada pursuant to the Canadian Entitlement to serve the DSIs, thereby avoiding the expense of adding new transmission and facilities in western Washington.

Other commenters were supportive or willing to consider the financial approach over a physical power sale or a combination of the two for a service benefit package, including each of the DSIs. Springfield (DSI-076) argued that a physical power sale would result in higher costs or a loss in surplus revenue, that benefits should be financial only, and based on the difference between the IP rate and the Mid-C index price. The State of Washington, Department of Community, Trade and Economic Development (DSI-072) commented that monetization of a power sale, as proposed by BPA, is the most practical way to implement the DSI benefits. NRU (DSI-067) and CFAC (DSI-057 and DSI-093), each proposed a combination of a base amount of physical power and financial payments based on an additional allocation. The PPC (DSI-079) did not state a preference for a physical or financial approach, but cautioned BPA not to use a delivery mechanism "that relies unduly on BPA's settlement authority," a reference to the monetary settlement of BPA's obligation to provide residential exchange benefits to its investor-owned utility customers, which is currently the subject of litigation.

Evaluation and Decision

BPA's evaluation of this issue is driven by the principle adopted in July 2004 that any service benefits provided to the DSIs in the next rate period must be at a known and capped cost. Service delivery mechanisms that do not meet this principle with a very high degree of certainty create risks the agency cannot afford. Many customers, including the DSIs, have urged BPA to deliver benefits to the DSIs through a traditional physically delivered power sale. At the outset, it is important to note BPA very likely would be required to make market purchases for at least some portion of the 560 aMW (or less subject to the $59 million cap) of physical power service. Meeting the cost cap under a traditional physically delivered power sale at a fixed contract rate presents a number of payment and market risks that must be mitigated, and power supply decisions that must be managed.

Under either physical or financially settled approaches, the determination of how costs associated with serving DSI load will be allocated to other customers' rates is a rate case issue. However, the Slice contracts and rate methodology contemplate costs for serving DSI load during the FY2007-2011 period, and the costs of serving the DSIs will be allocated between Slice and non-Slice customers consistent with applicable legal requirements. It is an essential condition of this decision that costs are shared among all Slice and non-Slice customers.

One risk BPA would face in connection with a physically delivered power sale is the potential default on payment of the contract rate by the DSI. If the DSI fails to pay the contract rate to BPA, then the cap is in jeopardy of being breached during periods when BPA must remarket unused DSI power at prices below the contract rate. For example, assuming a contract rate of $30/MWh and market rate of $42/MWh, BPA would spend the entire cap amount to serve the DSI load for one year. However, for the cap not to be breached each DSI must pay BPA the full contract rate – BPA's service benefit is limited by the cap to $12/MWh in this example. If a DSI fails to take and pay for 150 aMW in a given one-year period, and the market price for power has slipped to below the $30/MWh contract price to $27/MWh, then BPA has breached the cap by the $3/MWh difference times 150 aMW, or approximately $4 million over that one year period. Of course, BPA has also incurred a sunk cost of $16 million on this 150 aMW, or the cost of bridging the delta between the contract rate and the market rate at which it purchased the power for the DSI. This is money that has been wasted in the effort to preserve jobs. To mitigate this risk, in the event BPA elects to directly or indirectly physically deliver power to a company, BPA will apply a rigorous application of credit assurance tools. Corporate guarantees or letters of credit, or some combination, are instruments that can be used to mitigate this risk. BPA could also require the company to post cash-collateral to secure its payment obligations under specified circumstances agreed to in advance.

However, the greater risk associated with a physical power sale is that the cost of market purchases to serve the contracted load will exceed the cap due to rising market power prices. In its last power rate case, BPA projected that service to the DSIs could be achieved with $28 per MWh market purchases, but actual market prices had increased several fold by the time BPA was making system augmentation purchases. These purchases were at rates far higher than the rates charged by BPA for DSI service. The only clear way to eliminate the risk of breaching the cap due to escalating market prices (other than through a block purchase at the beginning of the rate period for the full contract amount at a price at or below the cost cap) would be through a contract provision that excused BPA from providing the DSI with power as soon as BPA had incurred costs equal to the DSI's annual allocated share of the cost cap. But this is impractical for a number of reasons, leaving BPA under some circumstances with residual remarketing risks, and creating too many operating uncertainties for the DSI.

A number of parties supported BPA's straw proposal to deliver benefits through a financial mechanism that monetizes the value of a surplus below-market power sales agreement, up to a capped amount. While the DSIs have expressed a preference for physical power deliveries, they each also stated they were open to the financial approach to delivering benefits, and both CFAC and GNA made specific proposals regarding how the financial approach could be structured. The financial approach has some inherent advantages compared to a physically delivered power sale. First, it provides the only way to meet the cost cap prerequisite with certainty. This is because the financial benefit would be paid after-the-fact based on each DSI demonstrating that it has used power purchased from the market to operate. The exact number of megawatt-hours used is known, as is the market price (whether it is a set forecast price or the price actually paid by the DSI for its market purchases). BPA can therefore calculate and pay benefits with precision up to the cap. There is no market or payment risk because BPA will not have purchased power, which effectively eliminates the take-or-pay risk to both BPA and the DSI. Second, and contrary to the comments expressed by some parties, BPA believes the financial approach is simpler than a physical power sale to administer. The DSIs' creditworthiness and performance viability are substantially reduced as considerations that must

be dealt with, and BPA is not forced to design and execute a physical power supply strategy. Third, the financial approach leaves power purchasing decisions and associated market price volatility risks with the DSIs, which is more consistent with BPA's goal to limit costs and control risks. However, as noted in the comments, for various reasons, many customers are wary of the financial mechanism.

In sum, BPA recognizes there are implementation advantages and challenges associated with each delivery mechanism. However, because of the financial risks inherent in providing a physically delivered power sale and in order to meet the known and capped cost prerequisite, BPA's default delivery mechanism will be to monetize the value of the below-market power sales contract, providing the service benefits through cash payments. However, in light of the strong support by many parties for a physically delivered power sale, BPA will retain an option to provide physically delivered power in-lieu of monetizing the transaction. Whether the physical delivery option is exercised will be based on BPA's evaluation of whether any credit risks of a physically delivered power sale to a company have been adequately mitigated, and whether BPA can supply the DSI load, including locking down any necessary market power purchases, on a fully hedged basis at a cost at or below the cost cap. BPA will have this option under each power sales contract, exercisable by BPA under terms to be determined in the development of the contracts. Absent BPA exercising this option, each power sales contract will be monetized.

Under the default monetization of the power sales contract, payment will be made to the DSI only if it has operated its smelter. Exactly how the payment will be calculated, including any operating level requirements, and how the market price will be established, will be determined through contract negotiation. In addition, the contract will provide that the value of any monetization will be limited to ensure that the DSI is not paying less for power than public utility customers on a dollar per MWh basis. Payments to any DSI will be limited if such payments would cause the DSI's net cost of power (for the portion supported through the BPA transaction) to drop below the flat PF rate equivalent. Consequently, BPA will not provide any benefits for DSI loads at prices at or below BPA's PF rate for an equivalent product. The contracts, which will be offered for regional review and comment for consistency with the above principles, will not contain terms more favorable than those offered other customers.

Because the IP rate does not appear to have a high likelihood of being a viable rate for DSI service in the next rate period, BPA plans to offer power sales contracts in the amounts determined herein as surplus power transactions under its surplus power rate schedule. BPA plans to use firmed secondary surplus as the supply source. BPA will set the price for the sale at $12 per MWh below projected market prices, with the contract price shaped to match each company's load shape. The use of secondary firm surplus as the resource basis for the proposed surplus sale may appear to eliminate some of the cost uncertainty related to serving this load. It does not. BPA's secondary surplus has an opportunity cost value equal to the market value as that secondary is produced. Therefore, the risk of market price volatility associated with this supply source is as great as the price risks associated with market power purchases where BPA physically supplied the DSI load. Pricing the proposed surplus sale at $12 per MWh below the projected market and monetizing the transaction allows BPA to produce a defined value that will not exceed $59 million per year.

In addition, most of the public utilities whose service territory includes a smelter indicated a willingness to partner with BPA and the DSI in a three-party contract arrangement. BPA intends to work with these utilities if they desire to play a role in serving the DSI located in their

community, for the purpose of supporting their local economies. Among other things, BPA will work with the utilities to ensure that they bear minimal financial risk associated with the transaction, be it a purchase and re-sale of surplus power if BPA exercises its option to physically deliver, or the delivery of the equivalent financial value of those surplus transactions under the default mechanism. Some comments cautioned BPA that providing service benefits to the DSIs through the local utilities raised New Large Single Load (NLSL) issues. BPA does not believe DSI service provided as a surplus power sale, transacted through a three-party surplus power contract including the local utility, will violate BPA's NLSL policy. The fundamental distinction between the surplus sales proposed here, and a sale to the public utility to serve new industrial load on a requirements basis, is that the sale here is a discretionary sale that could be made directly by BPA. These contracts do not create new public utility preference load that must be served by BPA at the PF and/or New Resources (NR) rate, the rate typically used to serve new large single loads.

VII. Issue 4 - Credit Support

In its July 2004 proposal BPA sought comment on whether it should pursue offering the DSIs credit support in efforts they may undertake to build energy resources to serve their smelter loads. While credit support could take a number of forms, the most likely would be where BPA would agree in a power sales contract to serve as a back-stop purchaser of the resources output, guaranteeing that cost, including debt service, are paid up to a certain capped amount. While credit support could be structured to cap and limit BPA's absolute cost, it would likely carry significant market and transactional risk that BPA would actually be called upon to make payments under the credit support, up to negotiated limits. BPA did not make any proposal regarding credit support in its February 2005 straw proposal.

Parties' Comments

GNA (GNA, RD04-101) stated that it believes it is appropriate for BPA to provide credit support for generating facilities developed by DSIs to enable transition permanently off the BPA system. It provided some specifics from previous credit support discussions it had undertaken with BPA, and asked that BPA not foreclose the option of credit support. A couple of GNA workers (Keith, RD04-0053 and Geary, RD04-0053) noted their agreement with credit support as an option. Several comments (EWEB, RD04-0127; SUB, RD04-0106, Idaho Falls, RD04-0023; PPC, RD04-0109; ICNU, RD04-0093; and Alcoa, RD04-0067) expressed opposition to credit support. Alcoa underscored that it did not need credit support, and that providing it would be inconsistent with BPA's creditworthiness prerequisite. Alcoa also noted that it did not believe new generation was a viable energy alternative for its facilities given existing natural gas prices. EWEB was concerned that BPA could incur financial exposure beyond the cost of providing DSI service, and the PPC stated it did not think it was BPA's job to act as the DSIs' banker.

Evaluation and Decision

With the exception of GNA and GNA employees, the comments on credit support overwhelmingly opposed BPA providing credit support. Alcoa's comments that the current cost of generating resources are too high for smelting echoes BPA's conclusion that the cost of new resources continues to be much higher than levels needed for profitable smelting. Efficient gas-fired combustion turbines produce power at prices that appear too high to enable economic smelter operations, when viewed in combination with expected natural gas, alumina, and aluminum market prices. BPA is also concerned with the credit risk and potential costs credit

support would entail. GNA's comments included an attachment outlining a proposed credit support deal negotiated with BPA. Based on BPA's analysis of that proposed deal at the time (an analysis that holds true today), BPA does not believe that providing credit support is likely to meet the key principle, established by BPA in connection with previous credit support discussions, that such actions will actually enable aluminum production and maintain Pacific Northwest jobs. Absent a reasonable expectation that this principle can be achieved through credit support, and in light of the weight of comments against credit support, BPA cannot endorse further pursuing credit support at this time.

VIII. Other Issues

There are several other issues not raised specifically by BPA in either the July 2004 or February 2005 proposals, but which were raised by parties in comments. Those issues, to the extent they have not been evaluated above, are briefly discussed and evaluated here.

A few parties questioned whether the DSIs should provide reserves to BPA, including stability reserves. BPA's transmission function is responsible for procuring stability reserves, and the only reserves that BPA's power function would procure from the DSIs are so-called operating reserves. Operating reserves, also sometimes referred to as contingency reserves, allow BPA to interrupt (or curtail), specified amounts of DSI load. The value of operating reserves depends on, among other things, how much notice of interruption is required, how long the load may be interrupted, and how frequently it may be interrupted. Until the current contract that was signed in 2001, operating reserves had been provided by the DSIs, with the cost paid through a downward adjustment to the IP rate. Therefore, BPA paid for reserves whether it used any or not. In general, however, operating reserves can now be purchased more cheaply by BPA in the market when and if needed. CFAC (RD04-0111) requested that reserves, other than stability reserves, be negotiated bilaterally between BPA and the companies. Washington State Representatives Jeff Morris and Frank Chopp (DSI-051) commented that the value of spinning reserves provided by Alcoa was a consideration in Washington providing Alcoa a tax relief package. The current power rate schedule provides that BPA may obtain operating reserves from DSIs at a negotiated price, up to a price cap. The price paid depends on the quality of the reserves provided. BPA has not purchased any operating reserves from the DSIs under the current contracts. However, to ensure such reserves are available if needed and not otherwise available more cheaply in the market, BPA will establish a successor operating reserves provision in the upcoming power rate case along the lines of the current schedule.

Alcoa (DSI-057) proposed something akin to, but fundamentally different from, a standard operating reserve product, which is used to help remedy real-time system emergencies. Alcoa is willing to adopt long-term curtailment of smelter operations to protect BPA and its customers from extreme market rates, provided BPA reimburses Alcoa for the cost of the shutdown. Under Alcoa's proposal, it would curtail operations if wholesale market prices are expected to be above a certain level over a period of time. Alcoa used an example of $150/MWh over a 12-month period. Alcoa indicated this is a valuable "catastrophic insurance" policy that will help protect all BPA customers from "future extreme price excursions." Several Washington State representatives and Alcoa-Ferndale employees (Representatives Bruce Chandler, Jan Shabro, Dan Newhouse, Jim Clements, Mike Armstrong, Doug Ericksen, and Jan Rodne (DSI-081), aluminum employees Terry Easterwood, DSI-003, Marshall Mahala, DSI-024, and others) argue that Alcoa's proposed catastrophic insurance would put a cap on high power costs. Jim Lobdell-PGE (DSI-057), and NWEC (DSI-057) urged BPA to retain interruptible rights. The Washington State

Labor Council, AFL-CIO (DSI-059) comments supported the aluminum industry providing curtailment rights to BPA during periods of severe drought to prevent negative impacts to consumers or threatened fish species and that BPA should provide compensation to the aluminum industry during such curtailments to offset curtailment costs of affected employees, local taxing authorities and to the aluminum companies.

Evaluation and Decision

As described above, BPA will not provide physical power under a contract unless it can completely hedge all risk associated with the cost of that service to the capped amount allocated to the company. Catastrophic insurance is not needed to mitigate the risk Alcoa is describing. Nevertheless, under the option where BPA is serving the load with physical power and market prices are projected to be well above the cost to BPA of serving the load, curtailing a company's operations and remarketing the power may be in the economic best interest of BPA, the company and its employees, and other customers. In the event that BPA opts to provide physically delivered power instead of its financial equivalent, then BPA will require some type of long-term interruption right in the power sales contracts. The terms and conditions of such a right will be developed at the time of contract negotiations. Terms that will need to be negotiated include at what market price the interruption can be triggered, the amount subject to interruption, the length of the interruption, and the amount of reimbursement BPA will provide the DSI for the interruption.

Finally, a few parties suggested that BPA should require the DSIs to agree not to seek service from BPA after FY2011 in exchange for service from BPA in the FY2007-2011 period. BPA service to all its customers post-2011 is the subject of an upcoming regional public process. BPA limited the current Regional Dialogue to service issues in the FY2007-2011 period and, with the exception of the few comments calling for the DSI commitment regarding post-2011 service, parties have not addressed the long-term service issue. BPA wants to hear from all its customers and other interested parties, including the DSIs, regarding continued service by BPA to DSI load post-2011, and so will not condition a service offer for the FY2007-2011 period on a commitment from the DSIs regarding service post-2011.

IX. Decision Summary

Issue 1 – Level of Benefits:

BPA will offer the DSI aluminum smelters 560 aMW of service benefits for the FY2007-2011 period at a capped cost of $59 million per year. BPA will offer Port Townsend Paper Company 17 aMW of service benefits through its local utility at a rate approximately equivalent to, but in no case lower than, the PF rate. BPA will review its decision to supply 560 aMW of benefits at a $59 million capped cost to the aluminum companies for FY2007-2011 after the cost impact of the June 10, 2005, injunction becomes more clear and before final contracts with the DSIs are signed. A decision to reduce the amount of service benefits BPA will provide to the aluminum companies, up to and including a decision not to serve any aluminum smelter load, is possible.

Issue 2 – Eligibility and Allocation:

Of the 560 aMW in service benefits to be provided to the DSI aluminum companies, 320 aMW will be offered to Alcoa, 140 aMW will be offered to CFAC, and 100 aMW will be offered

to GNA. The contracts with the companies will provide for the permanent reallocation of unused benefits to other companies, but no company will be allocated an amount of average annual megawatts above its current contract amount. BPA will execute a power sales contract with a company only if it is creditworthy or provides credit assurances acceptable to BPA.

Issue 3 – Deliver Mechanism:

BPA will make 560 aMW of benefits available for the aluminum smelters and 17 aMW for Port Townsend. This will be accomplished through a secondary surplus power sales contract priced in a manner that, when monetized relative to expected market value, will result in an equivalent financial value of up to $12/MWh for the smelters. This will be the default mechanism for delivery of service benefits to the aluminum companies 2007-2011. The contract will contain a right for BPA to provide physically delivered surplus power in lieu of the financial transaction, if BPA determines it can completely remove all risk associated with market power purchases to serve the contract load at or below the $59 million annual cap. The sales will be made under BPA's surplus rate schedule. BPA will attempt to structure any physically delivered surplus power sale, or its financial equivalent, through the local utility whose service territory includes a smelter to be served.

Issue 4 – Credit Support:

BPA will not pursue credit support at this time.

Issue 5 – Other Issues:

If BPA exercises its option to make physical power deliveries under a contract BPA will require some type of long-term interruption rights. BPA will not condition a service offer for the FY2007-2011 period on a commitment from the DSIs regarding service post-2011.

X. Environmental Compliance

This section of this ROD provides an evaluation of the proposed DSI service for FY 2007-2011 under the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 et seq. The potential environmental effects that could result from BPA providing service to its DSI customers were evaluated in BPA's Business Plan Environmental Impact Statement (EIS) (DOE/EIS-0183, June 1995).

The Business Plan EIS was prepared in response to a need for an adaptive business policy that would allow BPA to be more responsive to the evolving and increasingly competitive wholesale electricity market, while still meeting both its business and public service missions. BPA's Business Plan EIS evaluates six alternative business directions: Status Quo (No Action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. Each of the six alternatives provides policy direction for deciding 19 major policy issues that fall into five broad categories: Products and Services, Rates, Energy Resources, Transmission, and Fish and Wildlife Administration. Business Plan EIS, section 2.4.

Policy options, or modules, were also developed in the EIS to allow variations of the alternatives in four key areas, including DSI service. Business Plan EIS, section 2.1.2. The DSI

modules in the Business Plan EIS include Renew Existing Firm Contracts, Firm Service in Spring Only, Declining Firm Service, and No New Firm Power Sales Contracts. The EIS thus contains analyses of policy modules that consider service to the DSIs ranging from no new contracts to 100-percent firm service. (Business Plan EIS, sections 2.3.1.3 and 2.6.3.3.)

On August 15, 1995, the BPA Administrator issued a Record of Decision (Business Plan ROD) that adopted the Market-Driven alternative from the Business Plan EIS. This alternative was chosen because it more consistently meets the need and purposes identified in the Business Plan EIS than the other alternatives, and best strikes a balance among marketing needs, statutory obligations, and environmental concerns. This alternative also assists BPA in maintaining the financial strength necessary to continue BPA's support for public service benefits. Business Plan ROD, section 6. Although the Declining Firm Service DSI module is intrinsic to the Market-Driven alternative, the other DSI modules are identified as variable elements for this alternative as well. Business Plan EIS, section 2.3.2.

The Business Plan ROD also documented a decision strategy for tiering subsequent business decisions to the Business Plan ROD. (Business Plan EIS, section 1.4; Business Plan ROD, section 8.) For each such decision, as appropriate, the BPA administrator reviews the Business Plan EIS and ROD to determine whether the proposed subsequent decision falls within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. If the action is found to be within the scope of this alternative, the administrator may tier the decision for a proposed action to the Business Plan ROD. Business Plan EIS, section 1.4. BPA's NEPA ROD for its Policy for Power Supply Role for Fiscal Years 2007-2011 (Regional Dialogue), issued on February 4, 2005, is such a tiered ROD.

Recognizing the importance of the DSIs to the Pacific Northwest economy, the administrator's ROD for Regional Dialogue documented the policy decision that BPA would provide eligible Pacific Northwest DSIs some level of Federal power service benefits, at a known but limited quantity and capped cost, in the FY 2007-2011 period. Specific details were to be worked out in a supplemental regional public process. (Regional Dialogue NEPA ROD, page 8.) The NEPA ROD for Regional Dialogue also noted that, whatever level of DSI service was decided, the analysis of the environmental impacts would likely fall within the scope of the Business Plan EIS given the broad range of potential DSI service that was covered by the EIS. (Regional Dialogue NEPA ROD, page 13.)

Based on a review of the Business Plan EIS and ROD, I have determined that BPA's Service to Direct Service Industrial Customers for Fiscal Years 2007-2011 falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD. This service is a direct application of the Market-Driven alternative because it continues the implementation of the module that was intrinsic to the Market-Driven alternative. (Business Plan EIS, section 2.2.3.) Furthermore, since the proposed level of DSI operation is within the range of levels analyzed in the Business Plan EIS, it is not expected to result in significantly different environmental impacts from those examined in the EIS. I therefore have determined that it is appropriated to tier the decision to implement service to BPA's DSI customers for FY 2007-2011 to the Business Plan ROD.

This ROD, which satisfies BPA's requirements under NEPA, will be distributed to interested and affected persons and agencies. The ROD will also be posted on BPA's Web site for the Regional Dialogue, which is www.bpa.gov/power/regionaldialogue. Copies of the

Business Plan, Business Plan EIS, the Business Plan ROD, and Regional Dialogue ROD and additional copies of this ROD are all available from BPA's Public Information Center, P.O. Box 12999, Portland, Oregon 97212. Copies of these documents may also be obtained by using BPA's nationwide toll-free document request line, 1-800-622-4520.

Issued in Portland, Oregon on June 30, 2005

/s/ Stephen J. Wright

Stephen J. Wright
Administrator and Chief Executive Officer
Bonneville Power Administration

Bonneville Power Administration

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Attachment B

Supplement to Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 – Administrator's Record of Decision

SUPPLEMENT TO ADMINISTRATOR'S RECORD OF DECISION ON BONNEVILLE POWER ADMINISTRATION'S SERVICE TO DIRECT SERVICE INDUSTRIAL (DSI) CUSTOMERS FOR FISCAL YEARS 2007-2011

ADMINISTRATOR'S RECORD OF DECISION

Bonneville Power Administration
U.S. Department of Energy

May 31, 2006

Supplement to Administrator's Record of Decision on Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011

I. Background

On February 4, 2005, Bonneville Power Administration (BPA) sent a letter to customers and constituents describing a public process for comments on certain issues related to service by BPA to its remaining direct service industrial (DSI) customers that had not been finally decided in the *Policy For Power Supply Role For Fiscal Years 2007-2011 – Administrator's Record of Decision*, published the same day. The issues on which BPA was seeking additional public comment were: 1) the actual level of service benefits it should provide to the DSIs; 2) the eligibility criteria it should apply in determining which DSIs would qualify for such service benefits; and 3) the mechanism or mechanisms it should use to deliver those service benefits. BPA's letter outlined a straw proposal on each of these issues.

BPA received almost 100 written comments from a broad cross-section of customers, constituents, and private citizens, and held an open forum to discuss these DSI service issues, which was attended by approximately 100 individuals. The culmination of this public process was the publication on June 30, 2005, of *Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 – Administrator's Record of Decision* (DSI ROD).

In the DSI ROD BPA tentatively decided that it would offer a surplus power sales contract to each of its remaining three aluminum company DSI customers, totaling in aggregate 560 aMW, at a capped cost of $59 million per year, and a 17 aMW surplus power sales contract to its one remaining non-aluminum company DSI customer, which would not be subject to the cost cap. The ROD indicated that BPA would attempt to structure the delivery of service benefits through a contractual arrangement that included the public utility in whose service area the DSI is located. The ROD concluded that the default mechanism for providing benefits to the DSI aluminum companies would be financial payments, generated by monetizing the value (relative to expected market prices) of each company's below-market surplus power sales contract, resulting in an equivalent financial value of up to $12/MWh (or $59 million annually) on each megawatt-hour allocated to each aluminum company. Nevertheless, the final decision regarding whether benefits would be provided through these financial payments or through physically delivered power, along with other implementation details, was left to the contract negotiations.

The DSI ROD made clear that the decision to offer contracts to the aluminum companies was expressly contingent on a further review of the cost impacts to BPA associated with an injunction, issued on June 10, 2005, by the United States District Court for the District of Oregon, relating to certain anadromous fish protection measures, and directly impacting the amount of water available to BPA for hydroelectricity

production (the "BiOp Litigation"). BPA stated in the DSI ROD that a final decision to reduce the amount of service benefits to the DSIs, up to and including a decision not to serve any aluminum company load, was possible.

Finally, the DSI ROD stated that following negotiations with the DSIs and the local public utility districts ("Public Utility Partner") whose service territory includes an aluminum smelter, the contracts would be available for public review and comment to ensure consistency between the draft contracts and the principles and decisions contained in the ROD.

II. Draft Prototype Surplus Firm Power Sales Agreement

On November 28, 2005, BPA made available for public review and comment the *Draft Prototype – Block Power Sales Agreement* (Smelter Prototype). The Smelter Prototype is the draft surplus firm power sales contract BPA proposed to deliver service benefits to the DSI aluminum companies during FYs 2007-2011. The Smelter Prototype was the result of several months of negotiations between BPA, the DSIs, and several of the Public Utility Partners. A separate prototype was developed for Port Townsend Paper, and is addressed below at section IV.

The Smelter Prototype is a three-party power sales contract under which BPA makes available for sale to the local Public Utility Partner the amount of surplus firm power allocated by the DSI ROD to the aluminum company DSI located in its service territory.[1] The Public Utility Partner in turn makes an equal amount of power available to the DSI. Because the cost to BPA of physically delivering firm surplus power to the companies during the next rate period (FY 2007-2009) is projected to exceed the $59 million cap established in the DSI ROD, the Smelter Prototype provides that this transaction will be monetized in lieu of physical power deliveries during that three-year period (Smelter Prototype Section 5(a)). The monetization is designed to capture and deliver to the company, within strictly defined limits, the value of the contract, or the difference between the contract rate (a rate deemed equivalent to BPA's Priority Firm rate) and a forecast market price, not to exceed the cap.

Section 6 provides how this monetary benefit is calculated, examples of which are provided in Exhibit D of the Smelter Prototype. In all cases payments are tied to the level of actual smelter operations, capped by each company's firm surplus power allocation under the DSI ROD, with payments made monthly on an after-the-fact basis. In the event that a company is able to operate at or above its full BPA allocation (measured in megawatts), its monetary benefit would be the lesser of the maximum benefits it could receive on each allocated megawatt of operation ($12/MWh), or the difference between a surrogate contract price (assumed to be equivalent to the Priority Firm Power rate) and a

[1] The Public Utility Partners likely will include Flathead Electric (Columbia Falls Aluminum Company); Klickitat County Public Utility District (Golden Northwest Aluminum Holding Company – Goldendale smelter); Northern Wasco Public Utility District (Golden Northwest Aluminum Holding Company – The Dalles smelter); Chelan County Public Utility District (Alcoa – Wenatchee smelter); and Whatcom County Public Utility District (Alcoa – Ferndale smelter).

forecast market price. Consistent with the DSI ROD, the Smelter Prototype requires that each company access at least one-half of its allocated benefits in order to access any benefits; that is, if a company fails to access at least one-half of its benefits in a month (with some limited exceptions), it receives no benefits at all. However, if due to high market power prices or other factors a company operated (measured in megawatts) at less than its full BPA allocation, the Smelter Prototype provides that the company may access the full difference between the equivalent Priority Firm Power rate and the forecast market price, up to a maximum of $24/MWh for each megawatt of operation, as long as its operating level does not fall below one-half.

Section 6 of the Smelter Prototype makes clear that a company is not entitled to benefits from BPA that exceed its actual cost of power, and requires that a company inform BPA if it knows it will not require all its monetized benefits in order to reduce its actual power costs to a level equivalent to the Priority Firm Power rate. Overpayments are set off against future benefits, and BPA may audit a company's power purchase data, including the cost of such purchases.

BPA retained the right to physically deliver firm surplus power for the final two-years (FY 2010-2011) of each contract (Smelter Prototype Section 5(b)). In the event physical power is delivered, the provisions of Section 4 of the contract apply, and the contract rate for such sales would be established by BPA (using its then-effective surplus power rate schedule) at a level no lower than the Priority Firm Power rate for the rate period, and at a cost not in excess of the cost cap established by the DSI ROD. If a company does not wish to assume the take-or-pay risk associated with a physically delivered power sale, or for any other reason, it has the right to terminate the contract pursuant to Section 16(b) prior to its conversion to a physically delivered power sale.

As contemplated by the DSI ROD, the Smelter Prototype also includes provisions for the reallocation of benefit amounts (either monetized benefit amounts or physically delivered power amounts) that a company will likely not be able to access. This is a prospective reallocation of future benefits that is based on a company's failure to access its available benefits over a period of time. Sections 7 and 8 of the Smelter Prototype provide how such amounts are determined, and how they are reallocated. Examples of how benefits could be reallocated are provided in Sections 2 and 3 of Exhibit D of the Smelter Prototype. The purpose of these reallocation provisions is to promote the efficient utilization of benefits provided under these contracts, while still providing the companies with a level of operating flexibility.

In its November 28 letter inviting comment on the Smelter Prototype, BPA noted that steadily rising forward market prices for electric power were eroding the value of the proposed benefits to the companies, and that the DSIs had requested additional flexibilities be built into the contract to allow them to access benefits under a wider range of circumstances. The letter posed the following questions for comment:

- Does the Prototype conform to the decisions and policies contained in the June 30 DSI ROD?

- In light of the fact that when service benefits are monetized each aluminum company DSI may obtain such benefits only if it is operating at certain minimum levels, is the level of operating flexibility provided to the DSIs in the Prototype reasonable? Should DSIs have access to benefits at lower minimum operating levels than discussed in the ROD, or higher levels? Should BPA maintain the $59 million annual limit or should smelters be given additional flexibility to draw benefits early from future fiscal years?

In addition, the November 28 letter noted that the DSI ROD indicated BPA would revisit its decision to offer service to the DSIs once the financial impacts of changes in hydroelectric system operations stemming from the BiOp Litigation were better known. BPA stated that its review of BiOp Litigation impacts would be part of a top-to-bottom review of all BPA costs (the so-called Power Function Review II (PFR II)), but that this review was not scheduled to be completed until April 2006. BPA believed the DSIs needed to know sooner than the conclusion of the PFR II what level of benefits, if any, they could expect from BPA in order to make operating and power purchase decisions, and so BPA indicated it intended to complete its reconsideration of DSI service levels before the overall cost review.

III. Comments and Evaluation on Smelter Prototype

BPA received comments from the Public Power Council (PPC), Umatilla Electric Cooperative, Springfield Utility Board (SUB), Industrial Customers of Northwest Utilities (ICNU), Snohomish County Public Utility District, Pacific Northwest Generating Cooperative (PNGC), each of the DSI aluminum companies (Alcoa, Columbia Falls Aluminum Company (CFAC), and Golden Northwest Aluminum Holding Company (GNAH)), and one private citizen.[2]

At the outset, a number of comments urged BPA to make its final determination with respect to service levels to the DSIs in the context of the PFR II, which was designed to provide a forum for the examination of BPA spending levels and policy

[2] In addition, comments regarding the Smelter Prototype were filed on April 26, 2006, by Columbia Research Corporation (CRC) on behalf of Grays Harbor Public Utility District (Grays Harbor) and Canby Utility. The thrust of those comments challenged BPA's authority to make payments to the DSIs by monetizing the value of the proposed surplus power sales contracts. CRC also commented that BPA should further explain its proposal with respect to Port Townsend. Comments regarding the Smelter Prototype were due to BPA on or before January 4, 2006, and comments on the draft Port Townsend contract were due January 31, 2006. The only DSI issue presented for review and comment in the PFR II process was whether the $59 million annual benefit level was still appropriate in light of the BiOp Litigation. Therefore, CRC's comments regarding the Smelter Prototype and the draft Port Townsend contract were not timely presented to the agency. Nevertheless, the issues raised by CRC are largely repetitive of the issues raised by other parties, which are addressed in this supplement to the DSI ROD, or in the DSI ROD itself. Canby and Grays Harbor, on April 26, 2006, also separately filed identical comments on the Smelter Prototype. Those comments focus on issues regarding audit rights and the possibility of power being physically delivered to the companies in FYs 2010-2011. These comments on the contracts also were untimely filed, but as with CRC's comments, are largely redundant of other timely filed comments, which are addressed herein.

choices impacting power rates. On January 18, 2006, BPA agreed to examine DSI benefit levels as part of that process, and the evaluation in this Supplemental Record takes into account the information and conclusions produced in the PFR II. The PFR II provided additional review of DSI benefit levels in light of more recent information on expected hydro system operations, and a more refined understanding of secondary revenues BPA will achieve during FY 2006.

A. Benefit Level Issues

There are two separate but related questions that BPA posed for comment with respect to benefit levels. The first is whether providing an annual maximum benefit of $59 million (based on an allocation of 560 aMW) to the aluminum companies is appropriate, in light of the cost impacts of the BiOp Litigation and BPA's other spending level commitments. As noted, exploring this question was integrated into the PFR II at the behest of the comments BPA received in the comment period on the DSI contracts. The second is whether, and if so how, the Smelter Prototype should be modified to provide the companies additional flexibilities in accessing benefits. Providing more or less flexibility, in some circumstances, can make it more or less likely that a company will be able to operate and use its benefits. In simplest terms, providing more or less flexibility will likely raise or lower the portion of the $59 million in benefits that can be accessed by the DSIs, and therefore raise or lower the costs borne by BPA's other customers.

1. The $59 Million and 560 aMW Caps

Comments

ICNU commented that the $59 million amount "no longer strikes the correct balance and unnecessarily subsidizes the DSIs." (DS2-007 at 1.) It notes that since BPA issued the DSI ROD additional costs have been imposed on BPA, including approximately $70 million in FY 2005 for additional spill associated with the BiOp Litigation, and that larger cost increases may occur in FY 2006 to pay for additional spill and greater flows. (*Id.* at 2.) ICNU argues that because BPA's proposed Priority Firm Power rate for the FY 2007-2009 rate period represents an increase over the current Priority Firm rate, a "$59 million a year credit to support otherwise uneconomic smelter operations is no longer the right balance." (*Id.*) ICNU argues that its members "overwhelmingly" provide more jobs than the aluminum companies in the region, and that "burdening ICNU's members with these DSI costs is unwarranted." ICNU contends that "under no circumstances" should the benefit level be increased. (*Id.*)

Umatilla Electric Cooperative notes that it did not support the increase in benefits from the straw proposal of $40 million annually to the $59 million annual cap adopted in the DSI ROD, but that it does support "some amount of help for the DSIs." (DS2-001.) SUB commented that given the cost impacts of the BiOp Litigation that the proposed $59 million cap should be halved on a pro-rata basis to $29.9 million, but

that it would also support eliminating altogether benefits to the companies. (DS2-006 at 1.) SUB argues that if BPA does not reduce the benefit level from $59 million then the companies are effectively insulated from the cost impacts of the BiOp Litigation, since those costs will not necessarily be reflected in a higher PF equivalent price in the companies' contracts. (*Id.* at 3.)

PPC (DS2-010) and Snohomish (DS2-008) argued the benefit amount should be reduced to zero based on the BiOp Litigation costs. Short of that, PPC proposed that a reasonable revision would be to link the amount of DSI benefits to events "dramatically affecting" BPA's rates, and that the Smelter Prototype should include a mechanism to adjust benefits in response to present and future costs. PNGC does not address the DSI ROD benefit levels in the context of BiOp Litigation costs or BPA's other program spending requirements, but rather argues that BPA has no statutory authority to offer any benefits of any kind under any circumstances to the DSIs, and should abandon its plan to offer DSI contracts. (DS2-009.) The legal arguments raised by PNGC and by other comments are addressed in section III.C., below.

GNAH argues that its allocation of 100 aMW is too small to allow it to operate given expected near-term forward power market prices, and that its allocation should be increased to a level that is "comparable to what BPA granted Alcoa." (DS2-004 at 2.) For its part, like PNGC, Alcoa argues that BPA's allocation decisions in the DSI ROD are fundamentally at odds with its statutory obligations, and that it constitutes an arbitrary reduction of benefits to the DSIs that assures only that the remaining DSI loads cannot be adequately served. (DS2-005 at 3.) Alcoa proposes that BPA should allocate an amount of power to the DSIs that reflects their aggregated historic load levels, adjusted by "actual DSI loads still capable of being served." Alcoa does not specify how much power it believes this formula would yield to each company, but does argue that BPA is obligated by law to serve any such load at a "fixed, cost-based rate" with firm surplus power that would otherwise be offered out-of-region. (*Id.* at 3-4.)

In addition, Alcoa argues that the energy savings achieved through DSI conservation measures should be considered when determining how much power BPA has to serve DSI load since the conservation is a resource that has been paid for by the DSIs. (*Id.* at 2.) While CFAC argues for certain additional flexibilities that could increase the benefit level above $59 million in any given fiscal year, it states it is not arguing for BPA to increase the total number of dollars provided for in the DSI ROD over the five-year period. (DS2-003.)

Evaluation and Decision

Parties' comments with respect to the appropriate level of benefits in light of the BiOp Litigation were considered as part of the PFR II. At the time comments were due on the DSI ROD, the only BiOp Litigation-related cost that BPA had actually incurred was approximately $75 million related to spill during the summer of 2005. Several comments cite this figure, and note that implementing additional BiOp Litigation costs could cost even more. Since the comment period closed on January 4, BPA has

developed a cost estimate of $60 million for summer 2006 spill required by the BiOp Litigation. After discussion in the PFR II, and examining updated information on expected hydro operations and revenues, BPA decided through the PFR II process not to reduce the maximum DSI benefit level of $59 million based on BiOp Litigation cost impacts. *See Bonneville Power Administration – Power Function Review II Closeout Report* (May 2006).

BPA explained that the original $59 million benefit level was chosen to balance benefits to smelters and smelter communities, with the rate impact on other customers. BPA noted that, had the impact of modified hydro operations on rates been more adverse, it could well have needed to rebalance. However, the information examined in the PFR II process showed that FY 2006 financial results will be at least as good as had been expected when the DSI service decision had originally been proposed. Several comments on the Draft PFR II Closeout Report questioned BPA's proposal to retain the $59 million benefit level, and noted that the positive financial results BPA has experienced over the last year are not necessarily a predictor of the conditions, including secondary revenues, BPA may experience during future years. BPA acknowledges this fact. However, the fact that BPA's revenues vary with market and water conditions has always been an important context for DSI benefit decisions. The purpose behind the reexamination of the $59 million amount was to decide whether the changes in BPA's hydro operations so significantly altered BPA's near-term financial picture, that DSI benefit levels should be changed. BPA delayed the final benefit level decision to gather information about its own operations, and to better understand its near-term financial condition.

The comments in this process made it clear that many of our public utility customers, and their consumers, would rather see their own rates reduced than to pay anything to provide service to the DSIs, largely reinforcing comments they had made previously. These comments highlight the importance of BPA's decision to have a known capped cost on the DSI benefit level, even though DSIs have been equally clear they would like to see higher benefit levels. While the costs of changes to hydro operations have impacted BPA's revenues, BPA concluded in the PFR II process that these costs are not enough to require a change in the balance originally proposed on this issue, and that the maximum benefit level should remain at $59 million per year. Having made the foundational decision, BPA addresses in this supplement to the DSI ROD other benefit level issues raised in comments on the Smelter Prototype.

PPC argued in its comments that a mechanism should be developed in the contract that allows for adjustment of DSI benefits in response to BPA cost levels. (DS2-010 at 2.) The approach offered by PPC would not provide a workable power supply for DSI loads, since they could face a substantial or complete termination of physically or financially delivered benefits, whenever some future unknowable event occurs. BPA does not believe the level of uncertainty this would create is a reasonable contingency to place on any customer's power supply contract. This challenge is compounded in the case of the aluminum companies which already face marginal economic conditions. The DSIs make operating and purchasing decisions extending over long periods of time into the future. It would be difficult for a company to

commit to other long-term purchases required to run its business without a reasonable amount of certainty with respect to the level and duration of service benefits from BPA.

Moreover, the DSI benefit level is effectively subject to reasonably defined adjustments reflecting BPA cost increases, since the companies' benefit level is tied to the Priority Firm Power rate, which in turn will be subject to adjustment (under the cost adjustments proposed by BPA in the pending power rate case), within parameters, reflecting increased BPA costs. Therefore, an increasing Priority Firm Power rate that reduces the spread between that rate and market power prices may reduce the amount of benefits that a company would receive from BPA under the Smelter Prototype, reducing costs to other customers. PPC's proposal will not be adopted, but BPA will continue to ensure that increases in the Priority Firm Power rate impact the benefits DSIs receive, such that higher Priority Firm rates have the potential to reduce the benefits that will be available to the smelters.

GNAH argues that high power market prices are increasing the value of BPA's surplus power, making it feasible for BPA to increase GNAH's allocation to a level that would support minimal operations at its Goldendale smelter "without any significant impact on other customers." (DS2-004 at 2.) GNAH asks that its allocation be increased to a level "comparable" to that of Alcoa, which is 320 aMW, an increase of approximately 200 aMW for GNAH. It is not readily apparent how increasing GNAH's allocation would help it operate in the near term, since it states in its comments that forward power market prices are too high to make market power purchases economical even with a $24/MWh benefit. (DS2-004 at 1.) Furthermore, the PFR II process looked holistically at BPA revenues and budgets, and could have decided to either raise or lower the $59 million benefit cap. BPA decided that the original level still struck a fair balance between the issues raised. This balance is highlighted by the fact that the PPC asked BPA to reduce the cap levels based on a focus on potential increases in BPA *costs*, while GNAH's request to increase benefits is based on potential increases in *revenues*.

As BPA noted in the DSI ROD, BPA is already proposing to allocate over two times as much power to the DSIs as they have chosen to purchase under their current BPA power sales contracts. As more fully explained in the DSI ROD, BPA believes it has struck a fair balance between providing a level of power system benefits to the DSIs, including to GNAH and Alcoa, that will enhance the prospects for smelter operation under a reasonable number of power and aluminum market scenarios, but not substantially increasing the rates to other customers. For these reasons, Alcoa's proposals to "aggregate" DSI historic loads, and to tally historic DSI conservation measures as federal base system resources paid for by the DSIs, all of which apparently would result in an allocation to Alcoa alone of 625 aMW, will not be adopted.

2. Flexibilities

BPA's November 28 letter asked whether the companies should be given more or less flexibility in how they are permitted under the Smelter Prototype to access their

monetized benefits. First, BPA asked whether the minimum operating levels necessary to draw benefits should be increased or decreased. Under the Smelter Prototype the minimum level of operation required to access any benefits is one-half of each company's allocation of surplus firm power. Second, BPA asked if the companies should be given additional flexibility to draw benefits early from future contract years, thereby potentially raising the annual cap in any one year beyond $59 million (but not increasing the total available benefits over the full 5-year contract term).

Some companies argued for two additional flexibilities. In the event that a company is operating at one-half of its surplus firm power allocation, the Smelter Prototype caps the level of payments BPA will make to a company at $24/MWh. Some companies argued, in conjunction with eliminating the minimum operating level condition, that BPA should remove the $24/MWh limit (while maintaining the overall cost cap), allowing reduced operations in higher priced power market. Likewise, some companies argued, again in conjunction with eliminating the minimum operating level condition, that BPA should eliminate the provisions of the Smelter Prototype providing that companies operating at less than certain defined levels over a specified period of time forfeit future benefits.

Comments

CFAC stated that absent additional flexibilities, including the ability to "borrow dollars" from later years it was unlikely its smelter could operate. (DS2-003.) CFAC also argues that BPA should eliminate both the $24/MWh limit and the unused benefit provisions in the Smelter Prototype. CFAC argues the unused benefit provisions penalize a company in future years for actions which result in savings for BPA's other customers in early contract years.

GNAH stated that power market prices are too high for it to operate even with a $24/MWh benefit, but that allowing it to draw benefits early from future years may allow it to operate a portion of one pot-line in FY 2007. (DS2-004.) GNAH notes this would also allow it to protect itself from losing future years' benefits it may otherwise forfeit under the Smelter Prototype's unused benefit provisions. However, GNAH also notes it is not practical for it to operate its Goldendale smelter at below 50 MW (one-half its DSI ROD allocation), and so it does not support modifying the Smelter Prototype to allow companies to collect benefits on operations below the existing one-half minimum criteria, since it believes this will only increase the likelihood that Alcoa, which is more likely to operate at lower levels given its greater maximum allocation, will qualify for a reallocation under the Smelter Prototype at GNAH's expense. However, GNAH's comment presumed that if BPA provided this operating level flexibility, that it would also double the level of benefits available on each megawatt of operation at these reduced levels from $24/MWh at one-half operation to $48/MWh at one-quarter operation.

Alcoa, however, opposes modifying the Smelter Prototype to allow companies to draw benefits forward from future years. (DS2-005 at 6.) Alcoa essentially argues that allowing weaker companies to borrow benefits from future contract years undermines the

unused benefit provisions of the Smelter Prototype, diminishing the amount of future benefits that might otherwise be available to "save" a smelter that is more viable on a long-term basis (citing as an example its Intalco smelter) during periods of high power market prices.

PPC (whose comments Snohomish indicated it generally supported) opposes allowing companies to draw future benefits forward, arguing that they will simply front-load all their benefits into the early years of the contract, and then cease operations. (DS2-010.) PPC argues this fundamentally undermines the balance struck in the DSI ROD between an annual capped level of benefits for each company, and the possibility of rate relief to other customers in the event a company cannot operate within the confines of that cap. ICNU argues that the same principle prohibiting unused benefits to be carried into future years should prohibit borrowing benefits from future years. (DS2-007.) ICNU states that allowing this flexibility violates the "known and capped" benefits principle because it fails to account for the fact the equivalent Priority Firm rate, established under the Smelter Prototype at the beginning of each contract year, serves as one input determining the actual level of benefits a company may receive in a year. In other words, a company could receive more benefits than it would have been entitled to if it had actually collected them in the future year. ICNU also argues that allowing the companies to access benefits at lower operating levels than provided in the Smelter Prototype will only result in a short-term subsidy that supports fewer jobs and reduces the likelihood of long-term DSI survival. Finally, ICNU argues that allowing a company to collect benefits while operating at less than one-half its allocation would effectively "increase the credit" and cause it to exceed the expected Priority Firm Power rate.

For its part, SUB stated it believed the level of flexibility provided by the Smelter Prototype is reasonable, that the minimum operating level required to access benefits should not be adjusted, and that the companies should not have any right to draw benefits early from future contract years. (DS2-006.)

Evaluation and Decision

(a) Minimum Operating Level and $24/MWh Cap

Only CFAC and Alcoa support allowing access to benefits in circumstances where the company is operating at less than one-half of its surplus firm power allocation. GNAH believes providing this additional flexibility, absent also increasing substantially GNAH's allocation, will increase the likelihood GNAH will be forced to forfeit future benefits under the unused benefit provisions of the Smelter Prototype. Each of the companies argued that BPA should also eliminate the $24/MWh limit in conjunction with eliminating or reducing the minimum operating level requirement, which would allow a company to access the full amount of its benefits even if operating at less than one-half of its allocation of surplus firm power. Other comments argued against this additional flexibility, arguing it would undermine the balance struck in the DSI ROD and provide the companies with a power rate effectively below the Priority Firm Power rate.

As explained in the DSI ROD, the principal reason for permitting the DSIs to draw financial benefits even when they operate at less than their full contract allocation – down to as low as one-half that amount, while simultaneously increasing the rate of financial benefit to a maximum of $24/MWh - was to further increase the probability of some smelter operations over a wider spectrum of power market prices. With a capped benefit, as power markets rise, the companies can afford to offset the high cost of fewer megawatts, so this flexibility was seen as important. However, BPA also felt it was important to establish a minimum level of operations in order to encourage the DSIs to work to maintain a level of smelter employment approximately equal to current levels. BPA did not feel it was reasonable to ask other customers to pay the costs associated with DSI benefits in cases where those costs were incurred to support diminishing, as opposed to stable or increasing, levels of smelter employment.

BPA believes it is important to maintain these balances, but does recognize that persistently high forward power market prices could make it difficult for the companies to meet the operating level requirements in the Smelter Prototype. The companies have argued that in these circumstances they might have to operate at levels lower than one-half, and that without the flexibility to receive benefits at lower operating levels they may be forced to shut down all operations now, putting into doubt the likelihood of the smelter's long-term survival. BPA understands that the economics of smelting are made significantly more challenging, due to the high cost of smelter restart, once a smelter shuts down, and that maintaining a reduced operating level may well be a short-term strategy to bridge to a time when operating levels can be increased. BPA is willing to provide the companies with slightly more operating flexibility, but only in a way that concomitantly reduces the overall cost to other customers in the event a company elects to operate at levels below one-half of its full allocation of surplus firm power. Therefore, BPA will reduce the minimum operating requirement to one-quarter of each company's allocation of surplus firm power, but will not adopt the companies' proposal that the Smelter Prototype be modified to provide more than $24/MWh for each megawatt of actual operation. With this change, a company will be able to access benefits if it decides that it makes economic sense for it to operate at levels as low as one-quarter of its allocation, but the overall cost to BPA's other customers will be reduced (though still higher than if the original one-half operating level requirement was retained) since the existing cap of $24/MWh will be paid out on fewer megawatts. BPA believes this approach strikes a fair balance between the business needs expressed by CFAC and Alcoa, as well as the challenges described by GNAH, and the rate concerns expressed in other customers' comments.

The fact that the $24/MWh amount will not be increased addresses the concern raised by GNAH that higher payments, in conjunction with lowering the minimum operating levels, would make it more vulnerable to having its allocation of benefits acquired by another DSI in later years. As structured, when a DSI operates at less than one-half of the megawatt level it has received, it also receives less than the maximum financial benefit that could be available under its contract. But if a company acquires unused benefits of another DSI, and benefit levels are increased above the current maximum of $24/MWh as its load decreased below one-half its new total allocated

amount, this could result in higher financial benefits than the company was entitled to under its initial allocation, without a corresponding increase in operations. Maintaining the $24/MWh maximum eliminates this potential outcome, reducing the incentive to rapidly acquire unused power from GNAH, potentially providing a longer window for GNAH to find a way to start-up operations. In any case, under the Smelter Prototype if a company has unused benefits, the right to that amount of benefits in future years is *either* reallocated to one or more of the other companies operating in excess of their full allocation, *or* eliminated from the 560 aMW amount permanently. So, if GNAH is unable to operate in the early years of the contract its benefits will ultimately be forfeited, whether another company acquires the benefits or not.

(b) Drawing Benefits Forward and Eliminating the Unused Benefits Provisions

To recap, CFAC and GNAH support allowing the companies the flexibility to draw benefits from future years for use in earlier years, and eliminating the unused benefit provisions of the Smelter Prototype. Alcoa and each other party that commented on these issues oppose making either of these changes to the Smelter Prototype.

As BPA reviewed and analyzed the comments it became clear that the approach BPA ultimately decided to take on flexibility was of primary importance to whether the DSI contract would result in smelting operations or not. The companies face forward power market prices, at least during the first two years of the contract, that are at or above the high end of the price distribution projection in the DSI ROD. While disparate solutions were proposed in comments, it was clear that a fundamental need of the companies was for some additional consideration on flexibility. This need was further highlighted by letters that BPA received during its deliberations from political leaders from Montana and Washington State that called on BPA to continue to work on creative approaches that would allow the DSIs to access their benefits.

Although BPA continued to hear about a desire for more flexibility, it had not decided whether to maintain the $59 million benefit level in light of BiOp Litigation costs, since that question was being explored in the PFR II process. Through that process, the rate concerns of the other customers were reiterated. Hearing from both groups of customers also reinforced the need to maintain the principle in the DSI ROD of creating a balance between rate impacts on other customers and the DSI benefit levels offered. For this reason, BPA continued to think about the flexibility in the context of ensuring that any annual benefit cap was maintained. The concept of allowing dollars to be shifted forward between years presented a number of problems, some of which are described in the comments. As PPC notes, an unlimited right to draw benefits forward could result in the companies front loading all their benefits under the contract into the early years, which is contrary to the principle adopted in the DSI ROD that benefits would be capped at $59 million annually. PPC also correctly notes such flexibility would make it almost certain that all the benefits (approximately $300 million over the contract term) would be consumed in the early years, increasing the chance of the smelters closing in the later years.

ICNU correctly notes that the Smelter Prototype establishes an equivalent Priority Firm Power rate each year, and that the annual level of available benefits is established, in part, by that rate. Since it will be unknown what the PF rate will be in the year from which benefits are drawn forward, allowing companies to draw benefits forward could result in an effective "rate" under the contract that is below the Priority Firm rate, contrary to the principle adopted in the DSI ROD that the companies would not get a better deal than the Priority Firm rate. Likewise, the Smelter Prototype provides that a market rate be forecast by the start of each contract year, another factor in establishing the level of available benefits. Allowing a company to pull forward benefits from contract years in which neither the Priority Firm rate nor the forecast market rate are yet established could result in a company receiving benefits that it would not have otherwise been entitled to.

For its part, Alcoa argues that the Smelter Prototype, as structured, properly enhances the long-term prospects of the more viable smelters, by making unused benefits available to those companies that can establish and maintain higher levels of operation at the proposed annual benefit levels. It is true that the DSI ROD contemplated that the reallocation provisions would provide companies that could successfully operate an opportunity to acquire the unused benefits of a less successful company. However, it was also BPA's intent to allocate an amount of benefits, at terms and conditions for their access, that would give each company a reasonable opportunity, under a range of expected power market prices, to increase its operations over current levels.

The principal argument by CFAC and GNAH in support of this flexibility is that current forward market prices for the early years of the contract term are too high for them to operate, even if they can access their full annual benefit. GNAH stated that this flexibility "potentially could" allow it to operate a portion of one pot-line in FY 2007. Operating at some level will also help it reduce the loss of access to benefits under the unused benefits provisions of the Smelter Prototype. CFAC indicated that it needs to be able to shape its monetary benefits in the early years of the contract to close the gap between prevailing forward power market prices and the expected Priority Firm rate. CFAC has stated it will be forced to cease operations completely at the start of the upcoming rate period unless BPA provides this additional flexibility. Under the Smelter Prototype, if CFAC or GNAH fail to operate at all for a period of 12 consecutive months, those companies would likely end up forfeiting all future benefits.

Nevertheless, BPA is not convinced that allowing the companies to move benefit levels between years would lead to a long-term stable result. The comments of both GNAH and CFAC seem to highlight the fact that they are seeking a solution that allows them to hang-on in the short-term, leaving a high likelihood that each would use up its allocated benefits well before the contract expired. This was further highlighted by Alcoa's concerns about having benefits burned-up before they were made available to other smelters, and by the PPC's concern that moving values between years would greatly increase the likelihood that most of the benefits would be consumed. This could ultimately lead to a result where BPA's other customers' rates reflect the full cost of

proposed DSI benefits, but communities see significantly diminished smelting operations and jobs. This result is inconsistent with BPA's intent expressed in the DSI ROD, and will not be adopted.

BPA stated in the DSI ROD that it would not adjust the overall benefit levels based on changing forward power market prices. However, it is becoming clearer as the next rate period approaches that flat forward power market prices, in at least the first two years of the contract, are likely to remain at levels above the high end of the range of the price distribution used by BPA in the DSI ROD. BPA is persuaded that the companies, and in particular CFAC and GNAH, are unlikely to operate in the early years of the contract, absent some additional flexibility in how they access their benefits. The likely result would be that those two companies will forfeit all future benefits under the unused benefits provisions of the contract. This is not the result BPA was aiming to achieve in the DSI ROD. Therefore, BPA is willing to provide a mechanism for additional flexibility to all the companies, in a way that enhances the prospect of smelter operations over the full term of the contract, but that does not create a risk of rate impacts exceeding the $59 million cap, or otherwise substantially erode the other interests addressed in the DSI ROD and the Smelter Prototype.

In the January 18, 2006, posting announcing the decision to reexamine the $59 million benefit level in the PFR II, BPA noted there was a possibility that the DSI decision would be accelerated to meet DSI business needs. Within that context both Alcoa and CFAC each separately approached BPA in late March to indicate that with some additional flexibility from BPA, they could likely make market power purchase decisions that would allow them, in turn, to make firm operating decisions for much or all of the full term of the Smelter Prototype. Specifically, they asked that BPA consider allowing them to lock in a market price equivalent to their power purchases over a multi-year period, thereby providing certainty that they would be reimbursed under the Smelter Prototype, up to the annual cap, for their purchase power expenses. While forward market prices remain relatively high, they have moderated from their highest levels over the past twelve months. As currently structured, the Smelter Prototype resets the amount of benefits available each year based on a forecast of market prices. Each company argued this construct creates a substantial risk for them that the annual market forecast price could be below the price it pays now for a forward-block of power over the same period. They argue this risk prevents them from locking in such purchases now, which could allow them to maintain current levels of operations during most, if not all of FY 2007-2011. They argued that, unless this risk can be mitigated, they will be forced to wait until the beginning of each contract year to make power purchasing decisions. But if the market begins to rise again above current forward prices, the chances of the companies making such purchases later are slim, with the result that smelter operations will likely be shut down. The ability to make longer-term purchases now would also allow the DSIs to spread out the costs of higher and lower market prices in these years, since forward market prices are currently highest in FY 2007, dropping in the out-years of the contract.

Although a key part of the companies' request involved moving up the timing on moving forward with final decisions regarding the level of service benefits, BPA decided to allow the PFR II process to run its course because that process was moving towards conclusion, and would be disrupted by accelerating decisions on DSI service benefits. However, BPA saw merit in exploring the flexibility they requested. As noted, forward market prices for power – while still high – have moderated. In addition, market prices for primary aluminum (the product produced by the smelters) have increased over the past year, but have only marginally improved the economics faced by Northwest smelters since most of the increase is due to an increase in the cost of alumina, the raw product from which aluminum is made. These two factors together have improved the prospects for more stable smelter operations, but it is becoming more apparent that power prices now play the key role in the decision of the Northwest aluminum smelters to operate, or not. BPA believes modifying the contract so that the companies can lock in power prices offers an approach that will significantly increase the likelihood of continuous smelter operations over the term of the contract, but at a cost to BPA that is still within the annual cap on benefits. However, while power market prices have moderated recently, they remain high enough that locking-in the market price in the Smelter Prototype will also lock in the rate impact to other customers near the cost cap established for the DSI benefits. The actual impact of removing the year-by-year test on market prices is unknown, but by locking-in prices near the cost cap other customers will lose a potential rate benefit if market prices drop. BPA remains mindful of the balance that it has worked to strike between DSI benefits and rate impacts on other customers, and believes that a decision to offer the requested flexibility should be accompanied by some other form of rate benefit for its other customers.

Based on these considerations, BPA has decided to provide an option in the contract that allows a company to lock in its power purchases for a minimum of three years, and up to the full five-year term. BPA will use the cost of a company's purchase as the market price in the contract in later years, rather than updating the market price forecast on an annual basis. The DSI will be required to provide documentation that allows BPA to verify its market purchase price within a reasonably short period after exercising the option to lock in. During the time the DSI locks in a purchase price, BPA will continue to compare the actual Priority Firm rate (including all adjustments) with the net rate paid by the DSI (purchase price less the monetary benefits). Payments to the DSI will be reduced if a company's average net power cost over the period is less than the average effective Priority Firm rate. To balance this option with the interests of other customers, BPA will discount the monetary benefits if a DSI chooses to lock in its power price, reducing the maximum monetary benefit by 8% in FY2007-2009. If each company locks in its market price this will result in approximately $15 million of savings to other customers over a three-year period, compared to the case where the companies were entitled to access the full amount of benefits, up to the cap. Given the current markets for power and aluminum, BPA believes this level of discount will still allow a company to execute a multi-year power purchase that will keep some of the plants operating, thus preserving jobs. It is also a number that BPA believes will result in a reasonable probability that actual payments to the DSIs will not exceed the $53 million dollar level of benefits projected in BPA's pending wholesale power rate case to be accessed by the

companies. This will help insure no increase in Priority Firm rates over what is already assumed in the rate case. If a DSI chooses not to exercise the contractual option to lock in its purchase price, the year-by-year calculations for determining benefits will continue to apply. Because the period to lock in a purchase price may exceed three years, BPA will also adjust the contract provisions around the right to convert the monetized power to a physical power sale to align with rights provided to lock in the power price.

Finally, BPA will not modify or eliminate the unused benefits provisions of the Smelter Prototype, as requested by CFAC and GNAH. The provision to lock in power purchase prices provides a significant flexibility for all of the smelters to use. Although the economics of smelting remain challenging in the Northwest, BPA believes that the additional flexibilities adopted here provide a reasonable opportunity for each company to access its benefits. If, even in this context, a DSI is unable to access its benefits within the generous time-lines provided in the Smelter Prototype, BPA continues to believe the unused benefits should be made available, on a timely basis, for another company that has the ability to utilize them.

B. Other Smelter Prototype Provisions

Parties raised a number of other comments regarding specific provisions in the Smelter Prototype, or proposals for additional provisions. Each such comment, or related group of comments, will be presented and evaluated here in turn.

1. Benefit Repayment if Court Holds Payments "Illegal"

Comments

PNGC (DS2-009) commented that there is a "material risk" for BPA that petitioners will prevail on DSI rate and service issues currently pending before the Ninth Circuit Court of Appeals, and that the Smelter Prototype will likewise (or as a consequence of the outcome of those other pending actions) not survive legal challenge. PNGC notes the Prototype does not contain "adequate creditworthiness and credit support provisions" that will allow BPA to recover any "illegal" benefit payments made to the DSIs under the Smelter Prototype in the event the court later voids the contracts.

Evaluation and Decision

By "illegal" payments PNGC suggests that the Ninth Circuit could find BPA lacks statutory authority to serve DSI load, or if it does have such authority that some essential element or elements of the Smelter Prototype is outside that authority, or is otherwise contrary to law, and that the contracts are therefore void. BPA believes the service construct embodied in the DSI ROD and the Smelter Prototype is within the statutory authority of the BPA Administrator, and is a prudent use of the Administrator's discretion to serve DSI load. Even if not, a provision requiring the companies to refund payments in the event the Ninth Circuit holds that the contracts are void is unreasonable under the circumstances.

In the unlikely case the contracts are held void (so that no contract ever existed as a matter of law) and the payments are "illegal," the companies will have little realistic prospect of operating their smelters during the next rate period. Yet they may, at their own risk and expense, have made commitments with respect to operating their facilities, including making market power purchases, in anticipation of benefits being available under the Smelter Prototype. The Smelter Prototype makes clear that the companies may not seek damages against BPA in the event the contract is terminated if successfully challenged on certain grounds, and as discussed below, that language will be modified to be more expansive, as proposed by PPC in its comments. In these circumstances, BPA does not believe it is equitable also to require the companies to refund benefits paid. PNGC's proposal will not be adopted.

2. Audits and Recovering Overpayments

Section 6 of the Smelter Prototype provides that a company is not entitled to monetary benefits in any year in excess of the amount actually incurred to close the gap between its market power costs and the equivalent Priority Firm Power rate. This is the case even if the forecast market price for such contract year, as compared to the equivalent Priority Firm Power rate, would otherwise provide for monetary payments in excess of the company's actual power purchase expense. To prevent a windfall, the Smelter Prototype contains certain audit and repayment provisions, in addition to an affirmative duty on the part of the company to advise BPA if it believes it has procured power at a cost that will require it to access less than the full available monetary benefits to bridge the gap to an equivalent Priority Firm Power rate. However, these issues are largely eliminated if a company elects to lock in its market purchases, as described above. However, even under that scenario refunds could be due in the unlikely event that the company's net power cost falls below the Priority Firm Power rate.

Section 6 also provides BPA with an audit right to confirm a company's power purchase cost. If the company's actual cost was less than the monetary benefits paid to it over the course of the contract year, then such overpayment is netted against any monetary benefits available to the company in the next contract year, or subsequent contract years until fully recovered by such offset. If the contract terminates prior to full recovery of an overpayment through offset, then the company must pay BPA directly. *Id.*

Comments

PPC believes that the repayment construct has certain weaknesses. PPC commented that the companies' self-reporting requirement is inadequate, and that in any case the contract language is unclear regarding what constitutes "knowledge" by the company that its power purchase costs will under-run available monetary benefits during the course of the contract year. In addition, PPC commented that BPA's audit right at the end of each contract year is inadequate since it will allow for potentially substantial overpayments to occur before they are discovered through an audit. PPC notes that this problem is not addressed by the repayment mechanisms since if the DSI fails to operate,

enters bankruptcy, or declines the future benefit without simultaneously terminating the contract (thereby triggering the direct repayment obligation) then BPA may not be able to recover overpaid amounts. PPC recommends that the contract be amended so that BPA conducts quarterly audits of any company receiving benefits, which PPC believes would lead to timely discovery of overpayments, and a greater likelihood of repayment.

PNGC commented that BPA should require the DSIs to provide credit support to insure they repay any overpayments, and that BPA should make a "commitment to vigorously police and enforce repayment" of overpayments. In addition, PNGC commented that the contract should contain specific credit support requirements to address the take-or-pay risk to BPA associated with a physically delivered transaction, and that the current contract language requiring the application of "then-current credit policies," and the reference to the prepayment of damages included at the end of curtailment provisions in Section 4, is insufficient.

Evaluation and Decision

On its face PPC's proposal for quarterly audits appears reasonable, and BPA considered the feasibility of such an approach as it developed the Smelter Prototype. However, a quarterly audit regime raises many difficult implementation problems. The quarterly approach is not practical in light of the seasonal nature of both power prices and the Priority Firm rates that set the amount of benefits that would be available. Market prices may be exactly $24/MWh higher than the Priority Firm Power rate over the course of the year, but within individual quarters the gap will almost certainly be both higher and lower. Breaking the benefit levels into quarterly amounts would greatly complicate the implementation of these benefits since to insure that a company received the amount of annual benefits it was entitled to under the contract, BPA would need to establish balancing or true-up mechanisms, allowing a company to take greater amounts in one quarter and less in other quarters. This would be further complicated by the fact that changes in the Priority Firm Power rate, due to rate adjustments that could occur several times during a year, could cause BPA to have to revisit any quarterly result. BPA does not believe such a regime could be easily or accurately implemented. BPA believes that an annual audit meets the intent of making sure benefit levels do not exceed what a company is entitled to under the contract, while minimizing costly and burdensome administration steps. Ultimately the quarterly approach would increase the cost of implementation, but would not provide BPA with a more accurate picture of whether a company was receiving overpayments.

However, BPA agrees with PPC that the obligation of the companies to notify BPA if it believes its power costs will not require full access to benefits under the contract should be strengthened and clarified. To the extent that a company elects to lock in its market purchases and use the cost as the contract market price, then the company will be required to provide documentation that allows BPA to verify the purchase price within 30 days of providing BPA notice of its decision. A company that does not elect to lock in its market price will be required, within 90-days following the end of each contract year, to provide BPA a written certification by its chief financial officer that the

average annual purchase power cost to serve its total smelter load was equal to or greater than the forward market price established under Section 6, and provide BPA access to contracts, invoices, or other documentation sufficient to substantiate such certification.

PNGC commented that BPA should require each company to post a letter of credit or issue a parental guarantee to cover any possible repayment obligations that are not recovered by BPA through setoff or otherwise. BPA believes the risk of overpayment will be greatly reduced in the event that the companies that operate lock in their power purchases and the contract market price, as BPA expects they will. This is because BPA will know up front the level of benefits that a company will be entitled to. Under the Smelter Prototype as currently structured, BPA makes payments based on a forecasted market price, and does not necessarily know what the companies actually paid for its market power until the end of the contract year, following an audit. Knowing the companies' market power costs up front will allow BPA to monitor on an on-going basis the gap between those costs and the Priority Firm Power rate. This provides a kind of natural hedge against overpayments, allowing BPA to prevent overpayments from ever occurring. Of course, if an overpayment does occur, BPA may setoff the company's repayment obligation against future benefit payments. To the extent no setoff is available, the company is obligated by the Smelter Prototype to pay BPA cash. The chance of overpayments are slim; if one occurs it will likely involve a very small amount of money, and the chances of recovery using the tools already available are high. In BPA's business judgment, the administrative burden associated with securing and maintaining credit instruments to cover the small risk outweighs the very marginal benefit.

Finally, PNGC commented that the Smelter Prototype's provision that "then-current credit policies" will be applied to a company in the event BPA exercises its option to convert to a physical sale in FY 2010-2011, is inadequate. PNGC suggests BPA secure "robust credit support" from the companies now to mitigate the various risks associated with a physically delivered power sale. BPA understands the concern expressed by PNGC, but believes the better business approach is to review a company's credit quality when, and if, BPA decides to convert the transaction to a physical sale. Any credit assurance instruments secured now would likely either require too little (leaving BPA exposed) or too much (burdening the company with unnecessary costs) credit support, since BPA could only guess at the nature and financial scope of the risks involved. Much can happen over the course of three years (the earliest BPA could exercise its option) that can impact a company's risk profile. BPA does not want to lock itself into contract credit support language that may end up being insufficient later, and so PNGC's proposal will not be adopted.

3. Physically Delivered Power and the Cap

Comments

Section 5(b) of the Smelter Prototype gives BPA the option to convert the transaction to a physically delivered power sale for the final two years of the contract.

PPC commented that the Smelter Prototype does not provide sufficient mechanisms to guarantee that the cost cap would not be breached in the event that BPA elects to exercise this option under one or more of the contracts. PPC correctly notes that BPA would face market price risk, which in this case (where BPA is structuring a deal that provides the companies with a $59 million benefit) will arise in circumstances where market prices are more than $12/MWh above the contract rate. This could result either from foregone market sales of BPA surplus being used to serve DSI load at a below market rate, or where BPA must purchase power in the market to serve some or all of the DSI load. PPC recommends that the contract specify that BPA's obligation to serve DSI load with physically delivered power would be limited by the amount of cost (forgone revenue and/or power purchase costs) actually incurred by BPA, up to the $59 million cap.

Alternatively, PPC recommends that the amount of cost incurred by BPA to serve the DSI load be tracked in relation to changing market prices. In either case, PPC recommends that BPA's obligation to deliver power would terminate as soon as the cap is reached, which it describes as "a major part of the deal BPA described when it justified these benefits" to its customers and constituents. PPC notes that any operational uncertainty to the DSIs caused by such a provision is consistent with the principle in the DSI ROD that BPA is not attempting to "guarantee any particular level of DSI operations, even minimal levels." Finally, PPC suggests that before any decision to physically deliver surplus firm power, BPA conduct a public comment process, in which the preference customers could participate. (DS2-010 at 6.)

SUB commented that BPA's option to convert the transaction to physically delivered power "complicates the contract and should be eliminated." (DS2-006 at 4.) Short of that, SUB recommended that the contracts should clarify that any such sale is subject to BPA Transmission Business Lines (TBL) Open Access Tariff, business practices, and applicable records of decision, to avoid what SUB describes as "super-preference" transmission rights. SUB also suggests that the contract clarify that a company may not resell any physically delivered power.

Evaluation and Decision

PPC is correct that BPA concluded in the DSI ROD that it was not prepared to guarantee DSI operations at any price. Rather, the megawatt and dollar caps were established at a level that balanced the competing goals of providing a level of benefits that will provide some opportunity for smelter operations at current or increased levels, at the least cost possible to other customers. PPC's proposal would fundamentally undermine the first goal, inasmuch as none of the companies will base a plan of smelter operations on a power supply that is essentially subject to termination at any given time. Yet there may be scenarios where it is more advantageous for BPA, a company, or both to physically deliver power in lieu of monetizing the transaction. Certainly the companies, and some other parties as well, expressed a strong desire for physically delivered power in the earlier round of comments leading to the DSI ROD. PPC rightly notes that a physically delivered deal more fully hedges the companies against rising market prices. Nevertheless, from BPA's perspective, while monetizing the value of the

contract mitigates the risk of breaching the $59 million cap, physically delivering power to the companies is, in some ways, a simpler proposition.

As BPA stated in the DSI ROD, it will proceed with physically delivering power under the contract only where any credit (default) risks associated with providing a physical supply to a company have been addressed, and where BPA can supply a company's load, including locking down any necessary market supplied purchases, on a fully hedged basis at a cost at or below the cost cap. In circumstances where BPA forecasts that the cost to serve one or more of the companies would not exceed the cap, it is probable that BPA could hedge any risk on the margins of that forecast (and include any costs associated with the hedge against the cap). Absent this, BPA will not exercise its option to physically deliver. Therefore, it is not necessary to adopt the PPC's proposals on this issue. However, BPA will adopt PPC's proposal to conduct a public process before exercising its option to convert to a physically delivered sale. The purpose of the process will be to explain why BPA wants to exercise the option, and how the transaction can be executed such that the cost to BPA will be within the capped cost levels established in the DSI ROD.

It is not clear to BPA what issue SUB is raising in its comment that the Smelter Prototype may create "super-preference" transmission rights for the companies. Section 4(g) makes clear that the DSIs are responsible for securing transmission service to get the power to their facilities. The language in section 4(g) stating that BPA would take actions necessary to facilitate the delivery of power to the DSI consistent with whatever transmission services the DSI secures, is standard language contained in most of BPA's Subscription power sales contracts. The manner in which the DSI secures transmission services from the TBL, and how that service is provided, is subject to the same tariff and other rules and regulations applicable to every other customer of TBL, and nothing in the Smelter Prototype does, or can, alter that. Therefore, SUB's proposed language appears to be superfluous, and will not be included in the final contract.

With respect to SUB's comment that language should be added that the DSI is prohibited from reselling physically delivered surplus firm power, Section 4 of the Smelter Prototype already expressly provides that all physically delivered surplus firm power provided by BPA under the contract "is solely for service to Total Plant Load." In addition, Section 4(e) specifies how a company may curtail its load, including that any such curtailed load is remarketed by BPA, not the company. Therefore, SUB's proposed language appears to be superfluous, and will not be included in the final contract.

4. Interruption Rights

Comments

Section 4(i) of the Smelter Prototype gives BPA a one-time right, on 90-days prior notice, to interrupt power deliveries to a company for a period of not less than 6 or more than 12 months, provided it anticipates that the average market prices for a flat

block of power will exceed $125/MWh over the period of the proposed curtailment. In exchange, the company will be paid $24/MWh for amounts interrupted.

PPC commented that this interruption right is "wholly insufficient as a DSI benefit risk-mitigation strategy." PPC believes the notice period should be shortened so BPA could interrupt the load sooner in a high-priced market, and that BPA should not be obligated to resume deliveries if market prices remain at such high levels. (DS2-10 at 5.) PPC also commented that the $24/MWh payment, some or all of which must be used to compensate employees, provides an inappropriate windfall for those employees. PPC reasons that in such a high-priced market it is unlikely that the companies would be operating their smelters, and that BPA should not be paying employees "under conditions in which the DSIs are not viable." PPC recommends that BPA delete the interruption right from the contract, and instead "focus on enforcing the cap on its actual costs."

Evaluation and Decision

PPC misconstrues the purpose of the interruption right. It was not intended to be, and therefore is not designed as, a risk mitigation tool. As BPA stated in the DSI ROD, and reaffirmed above, it will not exercise its option to physically deliver surplus firm power to a company unless it has fully hedged all risk that the cost of serving DSI load will exceed the cost cap. If BPA is not able to put positions in place that will allow it to meet this test, then it will not move to exercise its option to convert to physical delivery. That is the baseline from which the interruption right was devised, the purpose of which is to give BPA the opportunity to take advantage of a prolonged high price market.

With respect to the $24/MWh payment, PPC's comments fail to take into account that if BPA is delivering power to a company on a take-or-pay basis, at a fixed cost that incorporates the benefit, then the company is likely indifferent to the market price for power. Each company has been allocated an amount of BPA surplus firm power to enable a reasonable level of smelter operations, without additional market power. Therefore, if BPA elects to interrupt the company's BPA-supplied power, there is no reason to presume it will be for a period of time that the company would not have otherwise operated its smelter. A company may terminate the contract in response to BPA exercising its option to commence physical deliveries. If a company elects to accept the take-or-pay obligation associated with physical deliveries, then presumably it will have determined that operating its smelter was otherwise economically desirable. In these circumstances the payment to the company for the interruption of its load is appropriate, and would not provide a windfall to workers.

5. Termination

Comments

Section 16(a) of the Smelter Prototype provides that BPA may terminate the contract without liability in the event BPA is legally prohibited from recovering from its Slice customers DSI service benefit costs allocated to those customers by BPA. PPC

notes that the legality of BPA's collection of money from preference customers for payments to the DSIs during the current rate period is being challenged in the Ninth Circuit by various parties, including a challenge by PNGC to the DSI ROD. (DS2-010 at 7.) PPC also comments that Section 11(b) of the Smelter Prototype, which specifies that the uncontrollable force provision of the contract is not applicable during periods when the transaction is monetized, should be amended to make an exception for court orders.

Evaluation and Decision

In the event any of the pending challenges to BPA's fundamental authority to serve DSI load are successful, one likely result would be that the Smelter Prototype would be *void ab initio* and not enforceable by or against BPA. That would not be the case in a more narrow action by Slice customers challenging their obligation to pay for the costs associated with DSI service under the Smelter Prototype. Nevertheless, PPC's comment regarding Section 16(a) is well taken, and the provision will be amended to clarify that the contract will terminate without liability to BPA if a court issues a final, unappealable order that expressly prohibits or has the effect of preventing BPA from performing its obligations under the contract. With this change, it is not clear that PPC's recommended change to Section 11(b) is either necessary or appropriate. If a court holds that providing benefits to the companies is beyond BPA's authority, that will trigger the termination of the contract (both by operation of law and pursuant to the language amending Section 16). Stating that it would also constitute an uncontrollable force event is therefore not necessary, and may create an ambiguity regarding the enforceability of the contract.

C. Legal Issues

Comments

Some parties raised legal issues in their comments. PPC raises three such issues. First, PPC comments that the Smelter Prototype does not include a mechanism for recovering from the DSIs costs that exceed the section 7(b)(2) rate ceiling. PPC states that section 7(b)(2) requires BPA to either make some provision in the contract to do so, or to otherwise "make certain that it can collect these amounts from some source" other than the Priority Firm Power rate. (DS2-010 at 6.) Likewise, Snohomish commented that the Smelter Prototype "appears to be contrary to several provisions of existing law" including the section 7(b)(2) rate test. PPC next comments that the Smelter Prototype "sets and guarantees the DSIs a rate outside of the [section] 7(i) rate-setting process." (*Id.* at 7.) PPC states it believes the rate construct contained in the contract should be determined in a rate case. Finally, PPC questions whether BPA can "sidestep" section 5(d)(1)(A) of the Northwest Power Act, which provides that sales to the DSIs pursuant to that section shall provide a portion of reserves for firm power loads within the region, simply due to the fact that the sale in this case is a surplus power sale.

PNGC comments that BPA failed in either the Regional Dialogue record of decision or the DSI ROD to "identify any legal authority" for providing benefits by

monetizing the value of the contract, for selling physically delivered surplus power at "heavily discounted rates" to the companies, or for charging its preference customers the costs associated with providing these benefits. (DS2-009 at 1.) PNGC notes that some of these issues, and other issues regarding service by BPA to the DSIs, are currently pending before the Ninth Circuit in *Golden Northwest Aluminum, et al. v. BPA*, Nos. 03-73426 *et al.* (consolidated cases) (*"Golden Northwest"*). PNGC states that if the court accepts its arguments in that case, then BPA cannot "enter into 'sleeving' or conduit arrangements with cooperating preference customer distribution utilities to do indirectly what it is unlawful to do directly." (DS2-009 at 2.) Snohomish also commented that it believes BPA has no statutory authority to provide "financial subsidies of the type proposed" in the Smelter Prototype, but does state that it is in the discretion of BPA to serve DSI load. (DS2-008.)

PNGC comments that BPA has failed to offer the surplus power being allocated to the companies in the Smelter Prototype to its preference and priority customers, and that the contracts "constituted administrative allocations of surplus power" in violation of public preference. PNGC notes that to the extent the contracts operate as power sales to the local public utility partner, that "it is obvious that BPA is providing service for customers that are new large single loads of those utilities." Finally, PNGC argues that the Smelter Prototype reflects "discriminatory and preferential treatment" for the local public utility partner. They argue that other public preference customers have similarly situated industrial load that could benefit from the benefits provided through the Smelter Prototype, but that even if it were lawfully able to do so, BPA could not reasonably offer similar contracts to other similarly situated parties.

For its part, Alcoa comments that BPA's own estimates show it will have sufficient surplus in 2006 through 2008 to serve all of the 560 aMW allocated to the companies in the DSI ROD, and that under average water conditions BPA will have large amounts of surplus power for the full five-year term of the Smelter Prototype. (DS2-005.) Alcoa argues that section 5(d) of the Northwest Power Act expressly establishes for the DSIs "a statutory right to power." As such, if there is surplus available that is unclaimed by BPA's public preference customers, Alcoa reasons, because of its status as a regional preference customer under the Pacific Northwest Consumer Power Preference Act, 16 U.S.C. § 837, *et seq.*, (Regional Preference Act), that it is entitled to that surplus power, physically delivered, at "a fixed, cost-based rate."

Alcoa argues that if BPA is unwilling to deliver surplus power at cost directly to the companies, then it should, similar to the service construct contemplated for Port Townsend, serve aluminum company load based on a sale of BPA power at the Priority Firm rate to the public utilities adjacent to the aluminum smelters, including a reasonable margin for those utilities. Alcoa implies, without actually arguing, that BPA may not discriminate between the companies. Citing section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s, Alcoa argues that BPA's power sales contracts should encourage the most widespread use of federal power, at the lowest rates possible consistent with sound business principles, and on fair and reasonable terms and conditions. Alcoa states that the "fair and reasonable terms" clause is similar to the "just, fair, and reasonable"

standard (presumably in the Federal Power Act, 16 U.S.C. § 824d(a)), which "has been held to prohibit discrimination in rates." (DS2-005 at 5.) Finally, Alcoa cites a clause in section 5(a) of the Bonneville Project Act (16 U.S.C. §§ 832, 832d) directing the Administrator to include terms and conditions in contracts with its utility customers that insure rates for resale that are "reasonable and nondiscriminatory."

Evaluation and Decision

BPA disagrees with the PPC that the Smelter Prototype must contain a provision that would allow BPA to allocate a portion of any section 7(b)(2) trigger costs to the companies, or that some other provision must be made to insure public preference customers do not bear such costs through the Priority Firm Power rate. First, BPA's final decisions with regard to the 7(b)(2) rate test, including how any trigger costs will be allocated, will be contained in BPA's 2007 Wholesale Power Rate Case final Record of Decision. BPA also disagrees with the premise of PPC's comment that section 7(b)(2) "puts a ceiling on the amounts that BPA can collect from its preference customers through rates." (DS-010 at 6.) As preference customers have previously admitted in briefing in *Golden Northwest*, the rate test does not provide an absolute rate cap for preference customers. Ultimately, if there are no non-preference loads to allocate such costs to, then such costs are allocated to the Priority Firm rate, consistent with BPA's overarching obligation under section 7(a)(1) of the Northwest Power Act to recover its costs. This issue, however, can be resolved only in BPA's power rate hearings under section 7(i) of the Northwest Power Act.

Furthermore, BPA historically has not allocated any part of the trigger amount under 7(b)(3) to surplus power sales. The Smelter Prototype, a three-party surplus firm power sale by BPA to a public preference customer, with a resale to the DSI, falls squarely into that category. This is true even in cases where BPA has made surplus sales directly to DSI customers under its surplus power rate schedule, which can reflect market prices. Consequently, there is no power sale to the DSIs that any trigger amount can be allocated to, and PPC's proposal will not be adopted.

PPC next argues that the "rate construct" in the Smelter Prototype should be established in a formal rate proceeding. Again, the rate construct in the Smelter Prototype is a negotiated rate established under BPA's existing surplus power rate schedule. Both BPA's existing surplus rate schedule (the Firm Power Products and Services schedule or "FPS"), and its proposed successor, each of which themselves will have been established pursuant to a section 7(i) rate proceeding, provide BPA with the ability to negotiate a contract rate, or rate formula, such as the one in the Smelter Prototype. Notwithstanding the complexity of the Smelter Prototype, the fundamental term in the contract is a formula for the payment of cash, or the delivery of firm power, each based, in part, on a rate equivalent to the Priority Firm Power rate.

It is neither legally required, nor practically possible, for BPA to conduct a section 7(i) rate proceeding every time it executes a power sales deal at a negotiated price under its surplus power rate schedule. In addition, it is worth noting that the proposal for

service to the DSIs for the FY 2007-2011 period, including the amount of benefits (in the form of a rate discounted to market), has been subject to a public review process that is, in many ways, as rigorous as any rate proceeding. A formal rate proceeding is not legally required for BPA to negotiate a rate within an established rate schedule in a surplus power sales contract, and in this case in particular, would add little or nothing to the record already developed regarding the benefit levels established in the DSI ROD, and this supplement thereto. PPC's proposal will not be adopted.

Finally, PPC raised the issue whether section 5(d)(1)(A) of the Northwest Power Act requires the DSIs to provide reserves to BPA, even though BPA is not making a traditional direct sale to the DSIs under the Industrial Firm Power rate, pursuant to sections 5(d) and 7(c) of the Act. Historically, BPA's right to interrupt or curtail service to DSI load provided BPA with valuable stability (transmission system) and operating (power system) reserves. DSI smelter load in particular could provide reserves to BPA due to its interruptible nature. However, these reserves were not provided for free, and section 7(c)(3) of the Act provides that the DSIs are to be compensated for the value of the reserves they provide to BPA through a credit to the Industrial Firm Power rate.

However, both section 5(d)(1)(A) and section 7(c)(3) contemplate sales under, and a credit to, the Industrial Firm Power rate. It is BPA's position that the reserves requirement in section 5(d)(1)(A) does not apply in the event BPA is serving DSI load with surplus power under sections 5(f) and 7(f) of the Act. In fact, BPA has never procured reserves from the DSIs under surplus power sales contracts with the DSIs.

Moreover, beginning with the 2002 Wholesale Power Rate Case and related DSI Subscription contracts, BPA ceased crediting the Industrial Firm Power rate for the value of reserves, and has not procured reserves from the DSIs under their Subscription contracts. DSI contracts since that time have been firm, take-or-pay contracts, without provision for interruption by BPA. This is due primarily to changes in the wholesale power markets which allow BPA to procure needed reserves cheaper and more reliably from other sources. In lieu of a fixed credit to the Industrial Firm Power rate, in the 2002 rate case, through the so-called Supplemental Contingency Reserves Adjustment, BPA established a cap on the amount it could pay a company in the event it wished to procure reserves from a DSI through negotiation. This approach was proposed, adopted, and has been implemented by BPA without objection, and the DSIs have provided no reserves under their Subscription contracts. *See 2002 Final Power Rate Proposal – Administrator's Record of Decision*, WP-02A-02, Part 3, at 15-36. BPA is proposing the same approach in its 2007 rate proceeding. Of course, for at least the first three years of the Smelter Prototype, BPA will monetize the contract, so no power will flow from BPA's system to the DSIs. As a consequence, there are no reserves that can be provided. Nevertheless, there is no apparent reason why BPA could not apply, either directly or by way of guidelines, the cap and criteria in the Supplemental Contingency Reserves Adjustment provision to any reserves it wishes to procure from a willing DSI in the FY 2010-2011 period, in the event the contract is converted to physical delivery.

PNGC raises fundamental issues regarding BPA's authority to provide service to the DSIs in the manner contemplated under the Smelter Prototype. As it notes, some of these issues are currently pending before the Ninth Circuit in the *Golden Northwest* case. PNGC's argument that BPA may not allocate to its public preference customers any costs of serving DSI load is pending before the court in *Golden Northwest*. That case has been briefed and oral argument was held on November 16, 2005. Because BPA has already articulated its position on this issue in *Golden Northwest*, and a decision by the court is pending, BPA will not directly address that issue here.

PNGC also questions whether BPA may provide the benefits of a "heavily discounted" surplus power sales contract to the DSIs, either by monetizing the value of the contract or by supplying physical power at a below-market price. This appears to be raised as a separate issue from the cost allocation issue described above, but is similar insofar as the "cost" of any below market surplus power sale, at least theoretically, means that other customers' rates will be higher than they otherwise could have been absent the below market sale. In fact, PNGC does not appear to argue, in any of its comments regarding BPA's service to the DSIs, that BPA may not enter into a surplus power sales contract with a DSI customer, but rather only that it may not do so at a below market price.

BPA believes it is beyond reasonable dispute that it has the statutory authority under section 5(f) to enter into a firm surplus power sales contract with a DSI customer, and that such sales may be priced at below market rates under BPA's surplus power rate schedule. Since 1996 alone, BPA has entered into dozens of firm surplus power transactions directly with DSI customers under the FPS-96 rate schedule. *See Kaiser Aluminum & Chemical v. Bonneville Power Administration,* 261 F.3d 843, 847-48 (9th Cir. 2001)(noting a number of FPS-96 transactions between BPA and DSI companies), *see also Portland General Electric Co. v. Johnson*, 754 F.2d 1475 (9th Cir. 1985)(approving sales to DSIs under BPA's nonfirm surplus power rate schedule). Apart from referencing its position in *Golden Northwest* that BPA may not charge public preference customer rates for any costs associated with serving DSI load, PNGC does not provide any legal analysis in its comment to support its suggestion that BPA may not otherwise enter into a below-market surplus transaction with a DSI; however, if the totality of PNGC's argument is that BPA cannot do so because any costs associated with such a transaction would necessarily be borne by public preference customers, then BPA's response is contained in its brief in *Golden Northwest*.

PNGC also questions BPA's legal authority to monetize the value of the contracts and make payments to the companies in lieu of delivering the surplus firm power. BPA's business rationale for its preference to monetize the transactions was discussed at length in the DSI ROD. As explained there, the fundamental reason for electing to default to monetization is that it is the best way to mitigate the market and default risks associated with a traditional take-or-pay firm surplus power sale to the DSIs. If BPA has the authority to enter into a surplus firm power sales contract (directly or indirectly) with a DSI customer (and no party has disputed that it does), and if BPA may price that contract under its surplus power rate schedule at a below-market price, then BPA believes it

follows that the Administrator has the authority to structure the transaction to achieve the lowest possible cost to BPA and its other customers.

There is no statutory prohibition against BPA fulfilling a contractual obligation under a power sales agreement by making a financial payment to a counterparty in lieu of delivering power. In fact, there is precedent for doing so both in other BPA power sales contracts, and in the wholesale power industry in general. BPA's program to buy-back its power sales obligations to certain customers in lieu of delivering energy, including with many of its DSI customers, during the west coast energy crisis in 2001, is one example. Another is found in the so-called "sale and exchange" agreements BPA has with California public and investor-owned utility customers, which contain "cash-out" provisions that give the parties the flexibility to make cash payments in lieu of providing energy. Another is found in the Northwest Power Act, where Congress established the Residential Exchange Program, which provides for BPA to buy higher priced power from regional utilities, and to "offer, in exchange, to sell an equivalent amount of electric power" to those utilities for resale to their residential customers. 16 U.S.C. § 839c(c)(1) (section 5(c)). Even though the language of the Act contemplates an actual power sale by BPA to the IOUs, in implementing section 5(c) in 1981 BPA determined that it was more economic and administratively efficient, while still carrying out the Congressional purposes in section 5(c), to monetize the exchange. BPA has always monetized exchange benefits provided to the IOUs, while retaining the right to provide physical power, pursuant to the terms of the applicable Residential Exchange Program contracts, settlements, and policies. Just as BPA is authorized by section 5(c) to provide the IOUs physically delivered power, but has always chosen to monetize the transaction in order to implement the program at the lowest cost, BPA is also authorized to enter into power sales agreements with the DSIs and monetize the transaction (while retaining the option, absent a DSI lock-in, to deliver physical power in the final two years of the agreement) in order to mitigate the financial risks inherent in a power sale to the companies, providing the benefits at a known and capped cost.

In addition, it is common electric utility industry practice to monetize a power delivery obligation rather than actually deliver the energy. Long-term power sales and exchange contracts frequently include provisions that specifically provide the option to cash out an energy delivery under specific circumstances. It is understood that there are times, over the life of a contract, when it is not feasible to deliver power. In those circumstances, a cash-out provision allows the party delivering the power to simply pay the other party the current value of the energy and forego delivery. Some type of predetermined market indexed formula price is commonly how the value is determined. For utilities that trade power to serve load, and that are constantly balancing their portfolio, replacing the undelivered energy is not difficult. In standard commodity trading, where there is no specific cash-out provision, the parties will mutually agree to monetize a delivery when the power cannot be delivered by one party or received by the other. The cash-out payment is designed to cover the purchase cost of the power. The DSI contract utilizes the same monetization approach. BPA elected to provide the DSI's with 560 aMW. To avoid the uncertainty surrounding power deliveries, BPA chose to provide the financial value of the energy to the DSIs, rather than the energy. BPA is

determining the value of the energy to the DSIs through a formula price, taking into account both market prices and BPA rates.

PNGC also argues the Smelter Prototype violates public customers' statutory preference and priority right to federal power. But public preference only applies in the case of a competing demand for Federal power between a public preference customer and a non-public preference customer. Preference applies to all BPA power sold, but it also applies only to the extent that a customer making a competing request has a need for the power to meet its Pacific Northwest energy requirement. If a public utility already has its regional firm load met, and has no firm resources other than hydro used for its loads that are higher cost than BPA's Priority Firm Power, then under section 1(f) of the Northwest Preference Act and section 9(c) of the Northwest Power Act, it has no energy requirement for federal power that could be met by a competing request for a BPA sale. Moreover, BPA's sales of surplus power to one public customer over another are discretionary and BPA may choose not to sell to one public utility while selling to another. *See City of Santa Clara v. Andrus,* 572 F.2d 660 (9th Cir. 1978). Here the sale proposed is to another public utility. The Smelter Prototype is a three-party contract, and BPA is selling surplus power under the contract directly to a public preference customer for resale, and not directly to the DSIs. Public preference is not implicated. In addition, the fact that the transaction is structured to serve DSI load, albeit through a local public utility, does not in any way undermine public preference rights. The Public Utility Partners to the Smelter Prototype have elected to participate in serving the load of the smelters located in their service territories, eliminating any possible public preference issues.

Moreover, even if BPA had elected to make these sales directly to the DSIs, it is not clear that any of BPA's public preference customers would have any practical financial incentive to step in front of the transaction. BPA's statutory obligation under sections 5(a) and (b) of the Northwest Power Act is to serve the net firm power loads of its public preference customers, and to meet the energy requirement of its regional customers as that requirement is defined under section 1(f) of the Regional Preference Act and 9(c) of the Northwest Power Act, as discussed above. BPA is not required to sell power to a public customer solely for the purpose of the customer's arbitrage of the power by resale on the market, particularly when that power can be made available to serve other regional load. BPA made clear in its *Policy For Power Supply Role For Fiscal Years 2007-2011 – Administrator's Record of Decision* (February 2005), that it will meet the net requirements of its public preference customers, at its lowest-cost Priority Firm Power rates, for the FY 2007-2011 period. Because the public preference customers' full net requirements (as defined by statute and any applicable contractual provisions) will be satisfied, BPA also has the statutory authority, but not requirement, to make surplus firm power available to its DSI customers.

PNGC next argues that if this is a sale to a public preference customer for resale to the DSI, then the transaction is for service to a new large single load. The Northwest Power Act definition of "new large single load" includes an existing facility (such as a DSI smelter), which was not served by a public utility prior to passage of the Act, and

which will result in an "increase in the requirements" of the public utility, of ten average megawatts or more, in a consecutive twelve-month period. 16 U.S.C. § 839a(13)(B). PNGC believes the surplus firm power contracts contemplated here would constitute service to a new large single load, and, presumably, must therefore be priced at the rate applicable to such loads, which is the New Resource Firm Power rate. PNGC is incorrect. The DSI loads to be placed on the local Public Utility Partner are not new large single loads, because they will not cause an "increase in the requirements" placed on BPA by those local public utilities under section 5(b) of the Northwest Power Act. Rather, these are discretionary sales by BPA that are "surplus to [the Administrator's] obligations incurred pursuant to [section 5(b)]" and will be made under section 5(f) of the Northwest Power Act. 16 U.S.C. § 839c(f). Neither the new large single load provisions in the Act, nor BPA's policies on new large single loads, have any application in this case.

Finally, PNGC argues that the Smelter Prototype reflects "discriminatory and preferential treatment" of the local Public Utility Partner. It notes that many other public preference customers have industrial load in their service territories that could benefit from the deal contemplated in the Smelter Prototype. It is not clear if PNGC is arguing that the alleged discriminatory and preferential treatment is not only inequitable, but also illegal. BPA presumes PNGC means both. However, BPA disagrees that the deal proposed under the Smelter Prototype is discriminatory or preferential in the first instance, let alone inequitably or illegally (or in the parlance of the Federal Power Act, which does not apply to BPA's power sales, "unduly") discriminatory and preferential. Notwithstanding the fact that BPA service to its DSI customers is discretionary, the remaining DSI companies retain their status as a class of industries that are uniquely situated as eligible to receive direct power service from BPA. Because other industrial customers are not similarly situated to the DSIs, there is no basis upon which to allege that a benefit conferred upon the DSIs by BPA through their local public utility (which could be directly conferred) constitutes preferential treatment for the DSI or the local utility partner. *See Association of Public Utility Customers, et al. v. Bonneville Power Administration*, 126 F.3d 1158, 1171 (9th Cir. 1997) ("*APAC*") (rejecting argument that BPA discriminated in favor of the DSIs for purposes of providing transmission service because the DSIs and industrial customers of public utilities are not "similarly situated").

In any case, the Ninth Circuit has held that public preference does not require that all preference customers be treated equally. *City of Santa Clara v. Andrus*, 572 F.2d 660 (9th Cir. 1978) (interpreting preference clause in the Reclamation Project Act of 1939, 43 U.S.C. § 485h(c)). There is no other non-discrimination standard applicable to BPA's surplus power sales, and the courts will not apply such a standard where Congress has not made one expressly applicable. *See Southern California Edison v. Jura*, 909 F.2d 339, 343 (9th Cir. 1990) (court refused to apply a nondiscrimination standard to BPA's extra-regional nonfirm energy rates where Congress did not expressly provide for one, but had "expressly prohibited discrimination or 'undue' discrimination in other very similar administrative contexts" including section 205(b) of the Federal Power Act, 16 U.S.C. §§ 791a, 824d); *APAC*, 126 F.3d at 1172 (finding "there is no antidiscrimination standard

that applies to BPA's provision of wheeling services to the DSIs but not to APAC's members.")

Alcoa's legal arguments place it on the other end of the spectrum from PNGC. While PNGC argues that BPA has no authority to offer a below-market surplus power sales contract to the DSIs, Alcoa argues that BPA is not only authorized, but required by BPA's enabling statutes to do so. Alcoa appears to argue that its alleged "right" to power service from BPA at a cost-based rate is established by section 5(d) of the Northwest Power Act, and through its status as a regional customer under the Regional Preference Act. 16 U.S.C. § 837, *et seq*. BPA's position with respect to its discretion, but not obligation, to serve the DSIs under section 5(d) of the Northwest Power Act was articulated in *Golden Northwest*. BPA would add here only that the Ninth Circuit has stated that BPA "is not obligated to sell any power to direct service industrial customers" under section 5(d). *M-S-R Public Power Agency v. Bonneville Power Administration*, 297 F.2d 833, 837 (9th Cir. 2002).

Alcoa correctly notes that BPA projected in its 2007 Wholesale Power Rate Case initial proposal that, under average water conditions, the Federal power system will produce substantial amounts of surplus power in the FY 2007-2009 period. *See Wholesale Power Rate Development Study Documentation*, WP-07-E-BPA-05A, Vol. 1, at 129, Table 3.6.2. However, the basis for Alcoa's conclusion that BPA is obligated by statute to use a portion of this projected surplus to provide Alcoa "power service at a fixed, cost-based rate" is not clear. Presumably, by "fixed, cost-based rate" Alcoa is arguing that it is entitled by statute to a surplus power sales contract, physically delivered, and priced at a rate equivalent to BPA's lowest-cost Priority Firm Power rate. But beyond referencing the Regional Preference Act, Alcoa does not provide any statutory support for this position. Section 1(c) of the Regional Preference Act defines "surplus energy as:

> . . . electric energy generated at Federal hydroelectric plants in the Pacific Northwest which would otherwise be wasted because of the lack of a market therefore in the PNW at any established rate.

16 U.S.C. § 837(c). Section 9(c) of the Northwest Power Act clarified that definition to mean:

> . . . electric energy for which there is no market in the Pacific Northwest at any rate established for the disposition of such energy . . .

16 U.S.C. § 839f(c). The language in section 9(c) made it clear that the phrase "any established rate" used in section 1(c) of the Regional Preference Act meant more precisely "any rate for the disposition of such energy." Rates for the disposition of surplus energy are established pursuant to section 7(f) of the Northwest Power Act. Currently, the Firm Power Products and Services (FPS-96) rate schedule is the applicable schedule for such sales, and BPA is proposing FPS-07 as its successor for the next rate period. *See 2007 Wholesale Power Rate Schedules and General Rate Schedule*

Provisions, WP-07-E-BPA-07, at 57. Power is sold under the FPS schedules at rates mutually agreed to by BPA and the purchaser. BPA may, but is not obligated, to sell surplus power under the FPS schedules to any party, including Alcoa, at a rate equivalent to any of its posted, cost-based rates.

Alcoa appears to argue that because (in its view) it is entitled to a power sales contract under section 5(d) of the Northwest Power Act, that it is entitled to a cost-based rate also, and attempts to distinguish the Ninth Circuit's holding in *Kaiser Aluminum & Chemical Corporation v. Bonneville Power Administration*, 261 F.3d 843 (9th Cir. 2001), which upheld BPA's refusal to sell surplus firm power to the DSIs at the Industrial Firm Power (IP-96) rate. But section 5(d) does not provide Alcoa with a right to a power sales contract, and so Alcoa's attempt to distinguish *Kaiser* on the grounds that there it had "relinquished" its section 5(d) contract is irrelevant. Alcoa is not entitled to a power sales contract as a matter of right under section 5(d) of the Northwest Power Act. The Ninth Circuit in *M-S-R* supported this position. BPA may make surplus power sales to DSI customers, including Alcoa, but it is not obligated to price such sales at a rate equivalent to its lowest cost Priority Firm Power rate, or any other cost-based rate. The Ninth Circuit in *Kaiser* supported this position.

Finally, Alcoa argues that BPA should not discriminate against it and the other smelter companies vis-à-vis Port Townsend, which BPA is proposing to offer (through its Public Utility Partner) a supply of physically delivered surplus firm power priced approximately equivalent to the Priority Firm Power rate. Alcoa cites section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s, and section 5(a) of the Bonneville Project Act, 16 U.S.C. § 832d. It is unclear whether Alcoa is arguing that the alleged discrimination is merely inequitable, or that it is also illegal. In any case, BPA believes it is neither. Some provisions in BPA's enabling statutes do expressly prohibit undue discrimination by the Administrator. For example, section 6 of the Transmission System Act requires BPA to make transmission capacity in excess of BPA's requirements available to all utilities on a fair and nondiscriminatory basis. 16 U.S.C. § 838d. As noted above, however, no such standard exists with respect to the formulation of rates for discretionary sales of power by BPA to the DSIs, and the courts will not apply such a standard where Congress has not made one expressly applicable. *Jura*, 909 F.2d 339; *APAC*, 126 F.3d 1158. In addition to *Jura*, the Ninth Circuit in *Aluminum Company of America v. Bonneville Power Administration*, 903 F.2d 585 (9th Cir. 1989), in discussing the applicability of section 825s of the Flood Control Act to the establishment of extra-regional nonfirm rates, held that "no 'fair and reasonable' standard is applicable to BPA ratemaking." *Id.* at 591. Alcoa's reliance on section 5(a) of the Bonneville Project Act, 16 U.S.C. § 832d, is also unavailing. Section 5(a), in part, specifies that contracts for the sale of energy by BPA to utilities that resell such energy to the general public shall contain terms and conditions "as the [A]dministrator may deem necessary, desirable or appropriate" to effectuate the purposes of the Act, and to insure that resale by such utilities to ultimate consumers shall be at rates which are "reasonable and nondiscriminatory." Of course, this provision says nothing about rates for the sale of wholesale energy by BPA to *its* customers, including sales of surplus energy, because BPA's power rates are governed by separate, specific statutory provisions. As noted,

there are no nondiscrimination standards applicable to BPA ratemaking, and BPA is not otherwise unduly discriminating against the aluminum company DSIs with respect to the delivery of power during the FY 2007-2011 period.

BPA acknowledges that it is treating Port Townsend differently. But the massive difference in the quantities of energy involved in serving DSI smelter load (560 aMW), compared to Port Townsend (17 aMW), and the comparative cost and financial risk associated with each, justifies the different treatment. Assuming a difference between BPA's lowest-cost Priority Firm Power rate and market prices over the term of the next rate period of $30/MWh, the cost to BPA of serving the Port Townsend load will be approximately $4.5 million each year. If BPA were to offer the same deal to the smelter companies, the cost to BPA would be approximately $147 million per year, or $88 million more per year than BPA proposed in the DSI ROD. In the event the delta between the Priority Firm Power rate and market prices grows, the cost to BPA would increase. The cost associated with this risk, while not insignificant with respect to the 17 aMW deal for Port Townsend, is manageable. However, for every $5/MWh increase in the market price, if BPA were obligated to physically deliver energy to the smelter companies (and was not otherwise able to hedge all the market risk) BPA's costs to serve 560 aMW would increase by $25 million per year. Even if a standard prohibiting undue discrimination or preferential treatment applied, the higher costs and risks associated with service to the aluminum companies, as compared to Port Townsend, fully justifies the different treatment of the two.

In addition, as described more fully below, Clallam Public Utility District, Port Townsend's Public Utility Partner, will be purchasing surplus firm power from BPA under a two-party contract with BPA, and reselling the energy to Port Townsend under a separate two-party agreement. Clallam's obligation to pay BPA under the BPA/Clallam surplus firm power agreement is not contingent on Clallam receiving payment from Port Townsend under the Clallam/Port Townsend Agreement. Given the strength of Clallam's credit compared to Port Townsend, the counterparty risks to BPA associated with physically delivering energy under the contract are mitigated. However, given the much larger amounts of power being made available to the aluminum companies under the Smelter Prototypes, it is not reasonable to expect those companies' Public Utility Partners, unlike Clallam, to manage the counterparty risk directly. BPA's proposal for the sale of surplus firm power (through the Public Utility Partners) to the aluminum companies, pursuant to the terms in the Smelter Prototype, is both fair and reasonable.

IV. Port Townsend

BPA's proposal in the DSI ROD was to offer Port Townsend 17 aMW of surplus firm power at a price approximately equivalent to, but in no case less than, its lowest-cost Priority Firm Power rate. The DSI ROD contemplated a sale by BPA to the local utility (Clallam), and a resale by Clallam to Port Townsend. BPA proposed to provide physical power for the reasons discussed immediately above. On December 22, 2005, BPA made available for public review and comment a two-party, and a three-party version of a surplus firm power sales contract to deliver power to Port Townsend. Because BPA

proposed to provide physical power, without any option to monetize the transaction, the draft contract form is simpler than the Smelter Prototype. Comments were due on or before January 31, 2006.

The only party to comment was ICNU. (PT-001.) ICNU did not comment on the contract itself, but rather urged BPA to reconsider offering any benefits to Port Townsend at all. ICNU argued that it is "highly inappropriate and an abuse of BPA's discretion" to offer Port Townsend a below market rate, since it may be lower than rates paid by ICNU member entities that are competitors of Port Townsend. In a letter to BPA dated July 14, 2005 (after publication of the DSI ROD), ICNU made a similar point, and suggested to BPA that a "better result would be to charge Port Townsend the [Priority Firm] rate plus a typical utility margin in line with the provisions of the [Northwest] Power Act." In its response to ICNU dated August 17, 2005, BPA noted that Port Townsend is not directly interconnected with BPA's transmission system, is not served off the distribution system of Clallam PUD (or any other local distribution utility) and, in fact, owns and maintains several miles of 115 kv transmission line and two substations, infrastructure that is typically utility owned. Therefore, Port Townsend directly pays costs that typically would be reflected in charges or rates paid to the local utility.

Nevertheless, BPA stated it would consider reflecting some or all of the typical industrial margin adopted by BPA in the 2007 wholesale power rate case, if it appeared that the costs incurred by Port Townsend, including any charges assessed by Clallam, were less than the margin. BPA will work with Clallam and Port Townsend to insure that the total cost of power paid by Port Townsend, taking into account any margin-type costs incurred by it directly, is not less than the Priority Firm Power rate, plus the typical industrial margin, thereby addressing ICNU's discrimination concern. To that end, the BPA/Clallam contract will provide that the rates for surplus firm power sold by BPA to Clallam shall be set equal to the corresponding Priority Firm Power rate, plus the typical industrial margin used to establish the Industrial Firm Power rate.

V. Conclusion

For the foregoing reasons:

- While the costs of changes to hydro operations have impacted BPA's revenues, BPA concluded in the PFR II process that these costs are not enough to require a change in the balance originally proposed on benefit levels, and that the maximum benefit level should remain at $59 million per year. Consistent with its decision in the DSI ROD, BPA will not provide benefits that bring the DSIs' power costs below the Priority Firm Power rate, and BPA will administer the contracts and adjust the benefits provided so that the effective power price paid by the DSI does not drop below the Priority Firm Power rate.

- BPA will reduce the minimum operating requirement to one-quarter of each company's allocation of surplus firm power, but will not adopt the companies'

proposal that the Smelter Prototype be modified to provide more than $24/MWh for each megawatt of actual operation.

- Companies will not be permitted to shift benefits between contract years.

- Companies will be given the option to lock in the contract market price for a minimum of three years, up to the full five year contract term. If a company elects to exercise this option its monetary benefit levels will be reduced by 8% in FY2007-2009.

- A company exercising the lock-in option will be required to provide documentation that allows BPA to verify the purchase price within 30 days of providing BPA notice of its decision. A company that does not elect to lock in its market price will be required, within 90-days following the end of each contract year, to provide BPA a written certification by its chief financial officer that the average annual purchase power cost to serve its total smelter load was equal to or greater than the forward market price established under Section 6, and provide BPA access to contracts, invoices, and other documentation necessary to substantiate such certification.

- The unused benefit provisions will not be amended or eliminated.

- BPA won't require companies to post credit instruments before signing a contract.

- A provision will not be included requiring a company to repay any benefits due to a subsequent court order holding the contracts void.

- BPA will exercise its option to physically deliver power under the contract (unless the company has exercised its option to lock in the contract market price) only where any credit (default) risks associated with providing a physical supply to a company have been addressed, and where BPA can supply a company's load, including locking down any necessary market supplied purchases, on a fully hedged basis at a cost at or below the cost cap. Prior to exercising its option (if available) BPA will conduct a public process. The purpose of the public process will be to explain why BPA wants to exercise the option, and how the transaction can be executed such that the cost to BPA will be within the capped cost levels established in the DSI ROD.

- BPA's interruption right in the Smelter Prototype won't be amended or eliminated.

- Section 16 will be amended to clarify that the contract will terminate without liability to BPA if a court issues a final, unappealable order that expressly prohibits or has the effect of preventing BPA from performing its obligations under the contract.

Issued in Portland, Oregon on May 31, 2006

/s/ Stephen J. Wright

_____

Stephen J. Wright
Administrator and Chief Executive Officer
Bonneville Power Administration

Attachment C

Contract No. 06PB-11744, Power Sale to Alcoa, Inc. (June 2006)

Attachment D

Contract No. 06PB-11745, Power Sale to CFAC (June 2006)

Contract No. 06PB-11744

BLOCK POWER SALES AGREEMENT
executed by the
BONNEVILLE POWER ADMINISTRATION
and
ALCOA INC.
and
PUBLIC UTILITY DISTRICT NO. 1 OF WHATCOM COUNTY, WASHINGTON

AUTHENTICATED

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Exhibit A	Surplus Firm Power Rate
Exhibit B	Additional Products, Services, and Special Provisions
Exhibit C	BPA Power Business Line Scheduling Provisions
Exhibit D	Examples
Exhibit E	Maximum Allocation, Minimum Allocation, and Demand Entitlement
Exhibit F	Determination of Forecast Market Price and Equivalent PF

This BLOCK POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), Alcoa Inc. (Alcoa), and Public Utility

District No. 1 of Whatcom County, Washington (Whatcom). Alcoa is a corporation organized under the laws of the State of Pennsylvania. Whatcom is a public utility district organized under the laws of the State of Washington. BPA, Alcoa, and Whatcom are sometimes referred to in the singular as "Party" or in the plural as "Parties."

RECITALS

On June 30, 2005, BPA issued a record of decision titled "Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011." On May 31, 2006, BPA issued a supplement to the record of decision. The record of decision and its supplement together constitute and are referred to herein as the Administrator's ROD.

This Agreement implements the decisions contained in the Administrator's ROD.

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision making activities of BPA's power business from the administrative and decision making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA, Alcoa and Whatcom agree:

1. TERM

This Agreement, when signed by the Parties, shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to section 16 below. All obligations incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principle place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

(b) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, CY 2007 begins October 1, 2006, and continues through September 30, 2007.

(c) "Demand Entitlement" means, during periods when this Agreement operates as a physical Surplus Firm Power sale, the megawatt (MW) amount each

hour that Whatcom shall purchase from PBL, and that Alcoa shall purchase from Whatcom, as specified in Exhibit E.

(d) "Equivalent PF" means the applicable average Priority Firm Rate at 100 percent load factor, as determined pursuant to Exhibit F.

(e) "Escrow Account" means the specific account established pursuant to the provisions in section 9(b) below for receipt of funds from BPA and transfer of funds by Whatcom to Alcoa.

(f) "Forecast Market Price" means the annual forecast market price for power at 100 percent load factor, as determined pursuant to the procedures in Exhibit F or, if Alcoa has selected an option pursuant to subsection 5(c) or subsections 5(c) and 5(d), then as determined by the average purchase price paid by Alcoa during the Option Period.

(g) "FY 07-09 Rate Period" means the wholesale power rate period that begins on October 1, 2006, and continues through September 30, 2009.

(h) "FY 10-11 Rate Period" means the wholesale power rate period that begins on October 1, 2009, and continues through September 30, 2011.

(i) "MB Monthly Payment" means the monthly Monetary Benefit payment that is available during each month, as calculated in section 6(c)(4) below.

(j) "MB Rate" means the rate in dollars per megawatt-hour ($/MWh) used to calculate MB Monthly Payments pursuant to section 6(c) below. The MB Rate is determined by subtracting Equivalent PF from Forecast Market Price, and shall not exceed $24/MWh.

(k) "Maximum Allocation" means, for the purpose of determining MB Monthly Payments, the maximum average megawatt (aMW) amount that may be used to determine a MB Monthly Payment. The Maximum Allocation is shown in Exhibit E.

(l) "Maximum MB Monthly Payment" means the amount calculated in section 6(c)(3) below.

(m) "Minimum Allocation" means, for the purpose of determining MB Monthly Payments, the minimum aMW amount that may be used to determine a MB Monthly Payment. The Minimum Allocation is equal to one-fourth of the Maximum Allocation.

(n) "Monetary Benefits" means monetary payments made by BPA to Whatcom for the account of Alcoa under this Agreement, as determined pursuant to the provisions in section 6 below.

(o) "Monthly Plant Load" means a monthly aMW amount equal to the Total Plant Load for each month divided by the number of hours in each such month.

(p) "Monthly Purchase Deficiency" means the monthly amount(s) of Surplus Firm Power not purchased due to a curtailment, as such amount(s) may be adjusted pursuant to section 4(e)(1) below.

(q) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(r) "Option Benefits" means the MB Monthly Payments under the options provided for in section 5(c) and 5(d), including UBA amounts if Alcoa chooses to establish Monetary Benefits pursuant to the provisions to include UBA in Option Benefits as specified in section 8(a)(4) below.

(s) "Option Period" means the combined period(s) of the option(s) specified in the provisions of section 5(c) and 5(d) selected by Alcoa to establish MB Monthly Payments

(t) "Other DSIs" means aluminum smelters other than Alcoa that have executed an agreement substantially in the form of this Agreement.

(u) "Points of Measurement" means the interconnection points between BPA, Alcoa, and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(v) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL to Whatcom, and where Surplus Firm Power shall be made available by Whatcom to Alcoa's transmission provider.

(w) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(x) "Region" means the definition established for "Region" in the Northwest Power Act.

(y) "Surplus Firm Power" means electric power that PBL shall make continuously available to Whatcom, and which Whatcom shall make continuously available to Alcoa, under this Agreement.

(z) "Total Plant Load" means the amount of electric energy in megawatt-hours (MWh) consumed during each month at Alcoa's production facilities. A detailed description of Alcoa's production facilities, including station service requirements and metering equipment, is described in Exhibit B.

(aa) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(bb) "Unused Benefit Amount" or "UBA" means either: (1) an aMW amount determined pursuant to section 7(a) during any period in which Monetary Benefits are provided, or (2) a MW amount determined pursuant to section 7(b) during any period in which this Agreement operates as a physical Surplus Firm Power sale.

3. APPLICABLE RATES

(a) **Applicable Rate for Purchases by Whatcom**
Purchases by Whatcom under this Agreement are subject to the Firm Power Products and Services (FPS) rate schedule or its successor, and the General Rate Schedule Provisions (GRSP). Purchases under the FPS rate schedule are established as follows:

If this Agreement operates as a physically delivered Surplus Firm Power sale pursuant to section 4 below, then section 4(a) below and Exhibit A, Surplus Firm Power Rate, identify Surplus Firm Power amounts, rates, and billing entitlements subject to the FPS rate schedule. If the Surplus Firm Power sale is monetized, then the provisions of section 6 below establish the applicable FPS rate.

(b) **Applicable Rate for Purchases by Alcoa**
Purchases by Alcoa under this Agreement are subject to the applicable rate schedule developed by Whatcom for such purchases. The rates and billing entitlements specified in such rate schedule shall be equal to those rates billed to Whatcom by BPA under this Agreement, FPS rate schedule and GRSPs, as specified in Exhibit A.

4. POWER SALE PROVISIONS

This section 4 only applies when this Agreement operates as a physically delivered Surplus Firm Power sale. In this event, the Monetary Benefit provisions in section 6 shall not apply. All physically delivered Surplus Firm Power provided by PBL under this section 4 is solely for service to Total Plant Load.

(a) **Power Sale by PBL to Whatcom**

(1) **Hourly Amounts**
PBL shall make available and Whatcom shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**

The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes Whatcom's HLH and LLH Energy Entitlements with respect to this Agreement.

(b) **Power Sale by Whatcom to Alcoa**

(1) **Hourly Amounts**
Whatcom shall make available and Alcoa shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**
The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes Alcoa's HLH and LLH Energy Entitlements.

(c) **Unauthorized Increase Charge**
Alcoa shall not intentionally schedule in excess of the amount specified in section 4(b)(1) above. However, in the event that an excess amount is scheduled due to error, then such amounts taken by Alcoa from Whatcom at the Points of Receipt in excess of the amounts specified in section 4(b)(2) above shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and Alcoa shall not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement. Any Unauthorized Increase Charge shall be billed by BPA in accordance with the billing procedures described in section 9(a) below. Any Surplus Firm Power used by Whatcom or Alcoa for any other purpose shall be subject to the Unauthorized Increase Charge.

(d) **Curtailment**
If Alcoa curtails Total Plant Load in whole or in part, then Alcoa may request take-or-pay mitigation for purchases under section 4(b) above pursuant to section 4(e) below.

(e) **Take-or-Pay Mitigation for Curtailments**
If Alcoa chooses to curtail its purchase obligation, then the following terms and conditions shall apply:

(1) **Notice of Curtailment**
Alcoa shall provide written notice to PBL and Whatcom at least three (3) Business Days in advance of a curtailment. Such notice shall specify the monthly amounts of power to be curtailed and the duration of the curtailment. The election to curtail such power, and the amount and duration of such curtailment, may not be changed without PBL's consent. PBL's sale to Whatcom shall be reduced by the amount of power curtailed, and Whatcom shall not be assessed any damages or

incur any liability as a result of any such reduction. The Monthly Purchase Deficiency will be reduced by any reduction to the Demand Entitlement pursuant to section 7(b)(2) below.

(2) **Calculation of Damages**

Alcoa shall pay directly to BPA damages for each Monthly Purchase Deficiency equal to the amount by which the reasonable market value of such Monthly Purchase Deficiency is less than the price of the applicable rate specified in Exhibit A. For purposes of calculating damages under this section 4(e)(2), the Monthly Purchase Deficiency(s) shall be reduced by any reduction of Demand Entitlement under section 7(b)(3), effective on the date any such reduction becomes effective. No later than 60 days following the end of each Contract Year, PBL shall, for each month of the previous Contract Year, calculate the reasonable market value for each Monthly Purchase Deficiency during such Contract Year. Reasonable market value and calculation of damages shall be determined as follows.

(A) No later than 3 Business Days prior to the commencement of a curtailment under this section 4(e), Alcoa may obtain one or more transactable quotes for all or a portion of such power from a third party. The transactable quote may be for any length of time and curtailment amount. Each quote shall be deemed equal to the reasonable market value of such power to which the quote applies for the purpose of calculating damages under this section 4(e)(2). BPA may, but shall not be obligated to, resell the curtailed power to the third party, retain the power, or dispose of the power as it chooses. Alcoa shall allow PBL at least 4 hours during normal business hours to decide whether or not to transact under such quote.

(B) BPA shall determine, by any reasonable method, the reasonable market value of the portion of each Monthly Purchase Deficiency for which Alcoa has not obtained a transactable quote. The reasonable market value shall be adjusted to reflect volume and BPA transmission costs associated with remarketing each such portion of the Monthly Purchase Deficiency, regardless of whether each such portion is actually remarketed.

(C) BPA shall bill Alcoa and Alcoa shall directly pay BPA damages for such Contract Year equal to the amount by which the sum of the product of (1) each Monthly Purchase Deficiency and (2) the applicable rate specified in Exhibit A that BPA would have charged each month if the power had been taken under this Agreement, exceeds the sum of the product of (1) each Monthly Purchase Deficiency and (2) the reasonable market value in each month. Amounts for damages under section

4(e)(2)(A) and section 4(e)(2)(B) may only be netted within a Contract Year. If a transactable quote for a curtailment or portion of a curtailment extends into a future Contract Year, then the total amounts associated with such quote will be netted in the Contract Year in which the curtailment or portion of curtailment associated with such quote begins. BPA is not obligated to pay Alcoa the difference when the reasonable market value exceeds the applicable rate in Exhibit A.

It is expressly agreed to by the Parties that BPA shall not be obligated to enter into replacement transactions to determine or collect damages under this section 4(e)(2).

It is also expressly agreed that BPA will apply its then-current applicable credit policies if damages are due under this section 4(e)(2), and such policies may include an obligation to prepay for damages.

(f) **Scheduling**

All Surplus Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit C, BPA Power Business Line Scheduling Provisions. The procedures for scheduling described in Exhibit C are the standard utility procedures followed by BPA for power transactions between PBL and other utilities or entities in the Region that require scheduling.

(g) **Delivery**

(1) **Transmission Service for Surplus Firm Power**

This Agreement does not provide transmission services for, or include the delivery of, Surplus Firm Power by BPA to Whatcom, or by Whatcom to Alcoa. Alcoa shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Surplus Firm Power (Wheeling Agreement). PBL and Alcoa agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power to Alcoa, consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(2) **Liability for Delivery**

Alcoa waives any claims against PBL and Whatcom arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. Neither Whatcom nor PBL shall be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event shall any Party be liable under this Agreement to any other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for transfer service.

(3) **Points of Receipt**

PBL shall make Surplus Firm Power available to Whatcom, and Whatcom shall make Surplus Firm Power available to Alcoa under this Agreement at Points of Receipt solely for the purpose of Alcoa scheduling transmission to points of delivery for service to Alcoa's Total Plant Load. Alcoa shall schedule, if scheduling is necessary, such Surplus Firm Power solely for use by its Total Plant Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to Whatcom and Alcoa no later than October 1, 2008.

If required by the Wheeling Agreement, when PBL designates such Points of Receipt, PBL shall provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under Alcoa's Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount of Surplus Firm Power specified in sections 4(a) and 4(b) above. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of a nonfirm Point of Receipt to provide Surplus Firm Power to Whatcom for the account of Alcoa, but notwithstanding section 4(g)(2) above, PBL shall reimburse Alcoa for any additional costs or production losses incurred by Alcoa due to its compliance with such request.

(4) **Transmission Losses**

PBL shall provide Alcoa the transmission losses between the Points of Receipt and Alcoa's points of delivery for Surplus Firm Power, at no additional charge. Such losses shall be provided at Points of Receipt as established under section 4(g)(3) above, and under the terms and conditions as defined in the transmission provider's tariff.

(h) **Measurement**

(1) Amounts of Surplus Firm Power taken are deemed equal to the amount scheduled by Alcoa under section 4(f) above or an amount of power as measured at Points of Measurement, as appropriate.

(2) Alcoa shall provide reasonable notice to PBL and Whatcom prior to changing control areas.

(i) **Interruption Rights**

PBL shall have a one-time right during the term of this Agreement to interrupt deliveries of a portion of the Surplus Firm Power hereunder pursuant to the following provisions. PBL may interrupt a portion of Surplus Firm Power deliveries if PBL anticipates, in its sole and exclusive discretion, that average forward market prices for a flat block of power will exceed

$125/MWh during an interruption period to be specified by PBL in a written notice. In this event, PBL shall consult with Alcoa and Whatcom prior to providing such written notice. If PBL decides to interrupt, then it will provide 90 days advance written notice to Alcoa and Whatcom that specifies the amount of Surplus Firm Power to be interrupted and the associated interruption period; *provided, however,* that a minimum of 6 aMW will not be subject to any such interruption. Unless the Parties mutually agree otherwise, such interruption period shall extend for a minimum of 6 months and for a maximum of 12 months, regardless of the level of actual market prices during an interruption period. In the event of an interruption, BPA shall pay Whatcom, and Whatcom shall in turn pay Alcoa, $24/MWh for amounts interrupted. Payments shall be made pursuant to section 9(b) below. Payments to Alcoa under this section 4(i) shall be used first to compensate Alcoa's employees employed at the time of an interruption under this section 4(i) by providing each such employee, at the election of Alcoa, either (1) the opportunity to work a regular work week (40 hours) at regular wage and benefit rates, or (2) special supplemental benefits such that the employee's effective after-tax income (including any available unemployment income) will be equal to what the employee's income would have been working a regular work week, plus all benefits the employee would have received, had the employee been working a regular 40-hour work week. BPA shall have the right to conduct an audit to verify compliance with this section 4(i). If there is an interruption under this section 4(i), then the portion of Demand Entitlement interrupted shall be treated as if taken for purposes of section 7(b)(1)(A) and shall not be subject to the take-or-pay provisions in sections 4(a) and 4(b).

(j) **Modification of Whatcom's Obligations**

(1) Whatcom shall have no obligation to purchase any power from BPA under this Agreement except for such power that Alcoa is obligated to and does purchase from Whatcom under this Agreement. Whatcom shall have no obligation to make available to Alcoa any power under this Agreement except for such power that BPA is obligated to and does make available to Whatcom under this Agreement. Notwithstanding anything in this Agreement to the contrary, if the obligation of BPA to make available power to Whatcom or the obligation of Alcoa to purchase power from Whatcom are modified for any reason, including but not limited to curtailment, interruption or any change to the Demand Entitlement, then Whatcom's corresponding obligation to make power available to Alcoa and/or to purchase power from BPA shall be modified to the same extent.

(2) Whatcom's obligation to purchase power from BPA and Whatcom's obligation to make power available to Alcoa are contingent upon Alcoa performing its corresponding obligation's under this Agreement to purchase power from Whatcom and upon BPA performing its corresponding obligation to make power available to Whatcom. Whatcom's obligations under this Agreement to BPA and Alcoa shall

be excused and reduced to the extent of any nonperformance by Alcoa or BPA of their corresponding obligations under this Agreement to Whatcom.

5. BPA AND ALCOA OPTIONS

(a) **Monetary Benefits for the FY 07-09 Rate Period**
BPA has determined that, during the FY 07-09 Rate Period, in order to meet the cost caps described in the Administrator's ROD with certainty, it will monetize the physically delivered Surplus Firm Power sale obligation; provided, however, if Alcoa chooses an option specified in section 5(c) or 5(d) and/or 8(a)(4) below, then the physically delivered Surplus Firm Power sale obligation will be monetized for the entire Option Period. As such, BPA will make any MB Monthly Payments during the FY 07-09 Rate Period, the FY 10-11 Rate Period or the CY 2011 period, as applicable, subject to the provisions of section 5(c), 5(d), and 6 below.

(b) **BPA Option for the FY 10-11 Rate Period and the CY 2011 period**
PBL shall have the option to discontinue Monetary Benefits after the FY 07-09 Rate Period and to revert to a physically delivered Surplus Firm Power sale for the FY 10-11 Rate Period or for the CY 2011 period. This option is not applicable to the portion of MB Monthly Payments which Alcoa has chosen to lock in under section 5(c), 5(d), and/or 8(a)(4). If PBL chooses to exercise this option, then BPA shall provide written notice to Alcoa and Whatcom no later than October 1, 2008. In this event, the provisions of section 6 below shall not apply to that portion of Monetary Benefits that have reverted to a physically delivered Surplus Firm Power sale during the period this option is applicable, and this Agreement will operate in whole or in part as a physically delivered Surplus Firm Power sale, subject to the provisions of section 4 above, unless Alcoa elects to terminate this Agreement pursuant to section 16(b) below. In addition, in the event of a physical power sale, BPA will require Alcoa to provide performance assurances, consistent with BPA's then-current applicable credit policies.

Prior to exercising this option BPA shall conduct a public process providing an opportunity for customers to comment on the merits of exercising the option.

(c) **Alcoa Option for CY 2007-2009, CY 2007-2010 or CY 2007-2011**
Alcoa shall have a one time option to establish its MB Monthly Payments for CY 2007-2009, CY 2007-2010, or CY 2007-2011 pursuant to this section 5(c). If this option is selected by Alcoa, then the lower of the Forward Flat-Block Price Forecast, in effect on the date Alcoa provides written notice pursuant to this section 5(c), or the average purchase price paid for power to serve Alcoa's Total Plant Load during the Option Period shall establish the Forecast Market Price when calculating Alcoa's MB Monthly Payments as specified in section 6 below. The power purchase contracts entered into by Alcoa shall cover the full term of the Option Period and, except for UBA amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit

calculation during the Option Period. If Alcoa chooses to exercise this option, then Alcoa shall provide written notice to BPA and Whatcom no later than September 30, 2006, specifying the CY 2007-2009, CY 2007-2010 or CY 2007-2011 period for which it has selected this option. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice Alcoa shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate Alcoa's MB Monthly Payments for this option.

(d) **Alcoa Option for CY 2010-2011 and CY 2011**
Provided Alcoa exercised either the CY 2007-2009 option or the CY 2007-2010 option specified in section 5(c) Alcoa shall also have a one time option to establish its MB Monthly Payments for the remainder of the Agreement. If Alcoa selects this option, then the lower of the Forward Flat-Block Price Forecast, in effect on the date Alcoa provides written notice pursuant to this section 5(d), or the average purchase price paid for power to serve Alcoa's Total Plant load during the Option Period shall establish the Forecast Market Price when calculating Alcoa's MB Monthly Payment specified in section 6 below. The power purchase contracts entered into by Alcoa shall cover the full term of the Option Period and, except for UBA amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit calculation during the Option Period. If Alcoa chooses to exercise this option, then Alcoa shall provide written notice to BPA and Whatcom no later than September 30, 2007. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice, Alcoa shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate Alcoa's MB Monthly Payments for this option.

6. MONETARY BENEFIT PROVISIONS

This section 6 only applies when the physically delivered Surplus Firm Power sale is monetized. The provisions in section 4 shall not apply to Monetary Benefits.

(a) **Determination of Forecast Market Price and Equivalent PF for each CY or Option Period**
PBL shall determine the Forecast Market Price and Equivalent PF for each CY, using the procedures described in Exhibit F: provided, however, if Alcoa selects any option specified in section 5(c) or 5(d), then the Forward Market Price shall be determined as specified in the option(s) selected by Alcoa during the Option Period.

(b) **Determination of Monthly Plant Load**
No later than five (5) Business Days following the end of each month, PBL shall determine the Monthly Plant Load for each such month.

(c) **Determination of MB Monthly Payments**
Except as provided for in section 6(c)(5) below, the procedures described in Exhibit F and the following procedure, as described in sections 6(c)(1) through 6(c)(4), shall be used to determine the MB Monthly Payment for each month.

(1) Except as provided in section 6(c)(5), if the Monthly Plant Load is less than the Minimum Allocation during any month (Deficient Month), then the MB Monthly Payment for that month is $0.

(2) If the Monthly Plant Load is equal to or greater than the Maximum Allocation during any month, then the Monthly Plant Load shall be deemed equal to the Maximum Allocation for that month.

(3) The Maximum MB Monthly Payment for each month is determined by the following equation:

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh or MB Rate);

provided, however, during the FY 07-09 Rate Period MB Monthly Payments for Option Benefits shall be determined by the following equation;

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh x 0.92 or MB Rate).

(4) The MB Monthly Payment for each month shall be the lesser of the Maximum MB Monthly Payment determined pursuant to section 6(c)(3) above or the amount determined by the following equation:

MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate)

(5) Alcoa may exercise the following one-time option. If Alcoa desires to exercise its one-time option pursuant to this section 6(c)(5), then Alcoa shall provide written notice to PBL and Whatcom that it will increase smelting load as of a date specified by Alcoa in such notice (Start Date). Then, for the remainder of the month that includes the Start Date and the following 2 months, the MB Monthly Payment shall be determined by the following equation:

MB Monthly Payment = (Total Plant Load) x MB Rate

Each MB Monthly Payment determined under this section 6(c)(5) shall not exceed the Maximum MB Monthly Payment.

(6) In addition to other limitations specified in the Agreement, Alcoa is only entitled to Monetary Benefits which when subtracted from the amount equal to its power costs to serve its Total Plant Load during the CY, does not reduce its power cost below the Equivalent PF multiplied by such total amount of power. If at any time during a Contract Year Alcoa knows it has procured power at a cost that will result in less than the full Monetary Benefits to reach the Equivalent PF, then Alcoa shall notify BPA of such cost and BPA shall reduce its payments accordingly for the remainder of the Contract Year.

This paragraph applies only for periods other than the Option Period, except with respect to acquired UBA not included in Option Benefits. Within 90 days following the end of each CY, BPA shall have the right to request: 1) Access to contracts, invoices or other documentation reasonably necessary for BPA to verify that purchases by Alcoa of power equal to the sum of Alcoa's Total Plant Loads for such CY and the cost of such purchases; and/or 2) A written certification from Alcoa's CFO of power purchases by Alcoa used to serve the sum of Alcoa's Total Plant Loads for such CY and the cost of such purchases. Alcoa shall provide BPA access to such contracts and documentation for such power purchases, subject to reasonable conditions to maintain the confidentiality of such information. If the difference between the cost of such purchases and their cost calculated as if they had been priced at the Equivalent PF is less than the sum of the Monetary Benefits that were paid to Alcoa for such CY, then Alcoa shall owe BPA such difference (Overpayment). BPA shall notify Alcoa of any such Overpayment and will reduce the total Monetary Benefits in the CY following the CY in which the Overpayment occurred by the amount of such Overpayment. If the Overpayment exceeds Monetary Benefits available during that following CY, then any unrecovered Overpayment will carryover to reduce Monetary Benefits in subsequent years until fully recovered.

If, upon termination of this Agreement, an Overpayment occurred for the CY prior to such termination, then, within 90 days following the end of such CY, BPA shall invoice Alcoa and Alcoa shall pay BPA such Overpayment within 20 days of receipt of such invoice.

(7) Notwithstanding anything to the contrary in this Agreement, in no case shall the annual Monetary Benefit total exceed the Monetary Benefit Limit specified in Exhibit E of this Agreement.

(d) **Examples**
Section 1 of Exhibit D contains several illustrative examples of the calculation of MB Monthly Payments, using a variety of assumptions.

7. DETERMINATION OF UNUSED BENEFIT AMOUNTS

The following procedures shall be used to determine UBA.

(a) **Determination of Unused Benefit Amounts During Periods When Surplus Firm Power Sale is Monetized**
This section 7(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Beginning in October 2007, and following each month thereafter, PBL shall track the amount of Monetary Benefit that Alcoa has taken during each of the preceding 12 months.

(2) In order to retain its Maximum Allocation, Alcoa must, for at least one month during the preceding 12 months, have received the Maximum MB Monthly Payment. If this condition has not been satisfied, then the Maximum Allocation shall be reduced.

(3) Alcoa shall retain the highest monthly percentage of the available benefits that it accessed during the previous 12 months. As such, Alcoa's Maximum Allocation shall be reduced by the percentage of the available benefits, rounded to the nearest aMW, that were not accessed during the month that set the highest monthly percentage. The amount of aMW from this calculation becomes an Unused Benefit Amount or UBA.

(4) In the event of an UBA, PBL shall provide written notice to Alcoa and Whatcom that Alcoa's Maximum Allocation shall be reduced by the UBA. Such reductions shall become effective at 2400 hours on the last day of the month in the month the notice is provided (Date of Maximum Allocation Reduction). Alcoa understands and agrees that it will not have an option to re-acquire UBA that it has lost for one month following the Date of Maximum Allocation Reduction and that Other DSIs may acquire the UBA. BPA shall unilaterally revise Exhibit E, effective on the Date of Maximum Allocation Reduction, to reflect the reduced Maximum Allocation. BPA shall also provide notice of the availability of the UBA to the Other DSIs.

(b) **Determination of Unused Benefit Amounts During Periods When the Surplus Firm Power Sale Is Physically Delivered**
This section 7(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) In order to assure its right to retain its Demand Entitlement, as specified in Exhibit E, Alcoa must, for at least one month during the preceding 12 months, have either (A) taken Surplus Firm Power equal to its Demand Entitlement during all hours of such month, or (B) taken the maximum Monetary Benefit available to it during such month. If this condition has not been satisfied, then the Demand Entitlement may be reduced.

(2) If the condition in section 7(b)(1) has not been satisfied, then BPA shall calculate the following for each of the previous 12 months:

(A) the percentage of the available Monetary Benefit received by Alcoa, and (B) the percentage of the Demand Entitlement taken by Alcoa. BPA may reduce the Demand Entitlement to the highest of such percentages multiplied by the Demand Entitlement, and rounded to the nearest MW. The MW amount of such reduction becomes an UBA.

(3) In the event of an UBA resulting from section 7(b)(2), PBL shall provide written notice to Alcoa and Whatcom that the Demand Entitlement may be reduced by the UBA. If all or a portion of such UBA is acquired by the Other DSIs pursuant to section 8(b) below, then the Demand Entitlement shall be reduced by the amount of UBA so acquired. Any such reduction shall become effective at 2400 hours on the last day of the month prior to the month that UBA has been acquired by the Other DSIs (Date of Demand Entitlement Reduction). BPA shall unilaterally revise Exhibit E, effective on the Date of Demand Entitlement Reduction, to reflect the reduced Demand Entitlement. If UBA made available under this section 7(b)(3) is not acquired by Alcoa or the Other DSIs within 6 months following the date such UBA became available, then BPA may, but shall not be obligated to, revise Exhibit E unilaterally to reduce the Demand Entitlement by the UBA not acquired.

(4) If an UBA results from a termination of this Agreement pursuant to section 16(b) below, then the entire Demand Entitlement becomes an UBA as of the effective date specified in section 16(b) below. BPA shall provide notice of the availability of any UBA that becomes available under this section 7(b)(4) to the Other DSIs pursuant to the notice provisions in section 7(b)(3) above. The Other DSIs may acquire this UBA pursuant to section 8(b) below.

(5) If Alcoa provides PBL and Whatcom written notice of curtailment under section 4(e)(1) and UBA will result during the term of such curtailment by operation of sections 7(b)(1) and 7(b)(2), then for purposes of sections 7(b)(2) and 7(b)(3), the UBA that would result during the term of the curtailment shall become UBA upon commencement of the curtailment.

(c) **Examples**
Section 2 of Exhibit D contains several illustrative examples of the determination of UBA, using a variety of assumptions.

8. OPTION TO ACQUIRE UNUSED BENEFIT AMOUNTS

The following procedures shall be used to acquire UBA.

(a) **Option to Acquire Unused Benefit Amounts During Periods When the Physically Delivered Surplus Firm Power Sale is Monetized**
This section 8(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Unless Alcoa provides written notice to PBL and Whatcom that it has chosen not to acquire UBA, available UBA amounts will be added to Alcoa's Maximum Allocation, to the extent that doing so will increase the MB Monthly Payment it will receive for each month.

(2) During months when increases in Monthly Plant Load by Alcoa and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to Alcoa and other DSIs, based on Maximum Allocation.

(3) BPA shall unilaterally revise Exhibit E to reflect the addition of acquired UBA in Alcoa's Maximum Allocation and Monetary Benefit Limit.

(4) If Alcoa has selected an Option Period under section 5(c) above, Monetary Benefits for the acquired UBA will not be included in calculations for Option Benefits and instead will be calculated separately under 6(c) above using the current Forecast Market Price as established under the provisions of Exhibit F of the Agreement unless and until Alcoa notifies BPA it will include the acquired UBA in the calculations to establish the MB Monthly Payments for the remainder of the Option Period. If this option is selected, then the purchase price used as the Forecast Market Price in the calculation of the Option Benefits shall be based on a megawatt hour weighted average of: i) the average purchase price previously used to calculate the Option Benefits, and ii) the average purchase price for acquired UBA, provided that the average purchase price for acquired UBA shall be limited by the Forecast Market Price in effect at the time Alcoa notifies BPA it will exercise this option.

If Alcoa chooses to exercise this option, then Alcoa shall provide written notice to BPA and Whatcom of the purchase price for the power purchased to serve the acquired UBA. For purposes of calculating MB Monthly Payments, the starting date of the purchase shall be the beginning of the month following the notice. Power purchases under this option must begin no later than 6 months following the effective date of the revision to Exhibit E for such acquired UBA. The provisions of section 6(c)(6) shall not apply to these UBA amounts during the Option Period. Instead, within 30 days of providing its power purchase notice, Alcoa shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate Alcoa's MB Monthly Payments for this option.

(5) UBA amounts that remain available and unused for 6 months following the Date of Reduction shall be zeroed out and will no longer be available to Alcoa or the Other DSIs during the term of this Agreement.

(b) **Option to Acquire Unused Benefit Amounts During Periods When the Surplus Firm Power is Physically Delivered**
This section 8(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) Following receipt of a notice provided under section 7(b)(3) above, Alcoa shall provide written notice to PBL and Whatcom of the amount of UBA it wishes to purchase, if any.

(2) UBA amounts requested pursuant to section 8(b)(1) above will be added to the Demand Entitlement, effective on the first day of the month following receipt of the notice provided under section 8(b)(1) above.

(3) When requests for UBA by Alcoa and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to Alcoa and other DSIs, based on Demand Entitlement.

(4) BPA shall unilaterally revise Exhibit E, effective on the date determined in 8(b)(2), to reflect an increase to the Demand Entitlement by the amount of acquired UBA.

(5) Any UBA acquired pursuant to this section 8(b) that remains unused after 6 months following the date specified in 8(b)(2) above will no longer be available to Alcoa or the Other DSIs. Amounts of Total Plant Load during such 6-month period that are less than the increased Demand Entitlement shall become an unused UBA. Such unused UBA shall be considered a Monthly Purchase Deficiency for each month of the remaining term of this Agreement, and Alcoa shall be subject to damages pursuant to section 4(e)(2) above.

(c) Any increased: (1) Maximum Allocation under section 8(a) above; or (2) Demand Entitlement under section 8(b) above shall not exceed 438 MW.

(d) Section 3 of Exhibit D contains several illustrative examples of the acquisition of UBA, using a variety of assumptions.

9. BILLING AND PAYMENT

(a) **Billing and Payment Provisions During Power Sale**
If, pursuant to section 5(b) above, BPA provides written notice that this Agreement will operate as a physically delivered Surplus Firm Power sale during the FY 10-11 Rate Period or the CY 11 period, then no later than March 1, 2009, the Parties shall amend this section 9(a) to include billing and payment provisions for: (1) the physically delivered Surplus Firm Power sale by PBL to Whatcom; and (2) the power sale by Whatcom to Alcoa.

(b) **Billing and Payment When Monetary Benefits Provided**

(1) **Escrow Account**
BPA and Whatcom shall establish an Escrow Account, in accordance with the laws governing Whatcom, for MB Monthly Payments and any interruption payments pursuant to section 4(i). BPA shall make payments into the Escrow Account, but only Whatcom shall have the ability to effect withdrawals from the Escrow Account for payment to Alcoa.

(2) **Payments into the Escrow Account**
Within five Business Days after the end of each month, BPA will review Alcoa's metered load measurements to determine if the Monthly Plant Load for the month is equal to or exceeds the Minimum Allocation.

Within eight Business Days following the end of the month, BPA shall transfer an amount equal to the MB Monthly Payment, and any interruption payments pursuant to section 4(i) above, into the Escrow Account.

(3) **Payments from the Escrow Account**
Within 12 business days following the end of the month, Whatcom shall effect the transfer of all BPA monthly payment amounts received into Escrow Account pursuant to this Agreement to Alcoa.

(4) **Escrow Account Safeguard**
Whatcom shall treat the Escrow Account in accordance with the terms of this Agreement and the agreement setting up the Escrow Account and not as property of Whatcom. Whatcom shall effect the release of such funds from the Escrow Account pursuant only to the escrow instructions consistent with this Agreement that BPA and Whatcom shall develop and provide to the escrow agent. Except to the extent Whatcom has failed to effect transfer of funds from the Escrow Account pursuant to the escrow instructions developed with BPA, Whatcom shall not be liable under any circumstances for the funds deposited by BPA into the Escrow Account, and BPA and Alcoa waive and release Whatcom from any and all claims, liability or damages that could arise from any loss, payment or lack of payment of such funds in the Escrow Account.

(c) **General Terms**

(1) Limitation on Whatcom's Payment Obligations
Notwithstanding anything in this Agreement to the contrary, Whatcom shall have no obligation under any circumstances to pay to BPA any amounts under this Agreement, FPS rate schedule and GRSPs except for such amounts that Whatcom has received from Alcoa under this Agreement, and Whatcom shall have no obligation under any circumstances to pay to Alcoa any amounts under this

Agreement except for such amounts that BPA paid into the Escrow Account under this Agreement and that are available for transfer to Alcoa.

(2) **Payment for Whatcom's Administrative Costs**
Notwithstanding anything in this Agreement to the contrary, to the extent that Whatcom incurs any expenses, fees, charges or costs of any kind not otherwise addressed in this Agreement, including but not limited to, attorneys fees, arising from Whatcom's development of and performance under this Agreement, Whatcom may bill Alcoa and Alcoa shall pay Whatcom for any such costs in addition to the cost of power delivered from Whatcom to Alcoa. Amounts that Alcoa pays Whatcom pursuant to this paragraph 9(c)(2) shall not be treated as amounts Whatcom has received from Alcoa for purposes of determining the limit on Whatcom's payment obligation to BPA under paragraph 9(c)(1) above.

10. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 10.

If to Alcoa:

Alcoa Inc.
6200 Malaga-ALCOA Highway
Malaga, WA 98828-9782
Attn: Jack A. Speer
Northwest Vice President,
Government and Energy Affairs
Phone: 509-663-9331
FAX: 509-663-9200
E-Mail: Jack.speer@alcoa.com

If to PBL:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
Attn: Mark E. Miller
Account Executive
Phone: 503-230-4003
FAX: 503-230-3681
E-Mail: memiller@bpa.gov

If to Whatcom:

Whatcom County PUD No. 1
1705 Trigg Road
Ferndale, Washington 98248
Attn: Brian Walters
Power Resources and Contract
Manager
Phone: 360-384-4288, ext. 25
FAX: 360-384-4849
E-Mail: brianwalters@pudwhatcom.org

11. UNCONTROLLABLE FORCES

(a) **Uncontrollable Forces Provisions During Surplus Firm Power Sale**
If, during the FY 10-11 Rate Period, this Agreement operates as a physical Surplus Firm Power Sale, then the following provisions shall apply; *provided however,* that UBA determinations pursuant to section 7 and acquisitions of UBA pursuant to section 8 shall not be subject to Uncontrollable Forces under this section 11(a).

PBL shall not be in breach of its obligation to provide Surplus Firm Power to Whatcom and Whatcom shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. Similarly, Whatcom shall not be in breach of its obligation to provide Surplus Firm Power to Alcoa and Alcoa shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable

Force that prevents that Party from performing its obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to Alcoa's facilities, including but not limited to unplanned maintenance outages;

(2) any unplanned curtailment or interruption, failure or imminent failure of Alcoa's production or transmission facilities, including but not limited to unplanned maintenance outages;

(3) any planned transmission or distribution outage that affects either Alcoa or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(4) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however*, that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(5) floods, earthquakes, or other natural disasters; and

(6) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Parties as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

All Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

(b) **Uncontrollable Forces Provisions During Periods When Monetary Benefit is Provided**
During periods when the Surplus Firm Power sale is monetized, Alcoa understands and agrees that there are no events that will be considered Uncontrollable Forces under this Agreement.

12. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal law. Disputes arising out of this Agreement that are not otherwise subject to the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit are subject to the Contract Disputes Act, 41 USC 601, et seq.

(b) If a dispute arises under any provision of this Agreement, the Parties shall, within 14 business days following the initiation of a dispute, make a good faith effort to negotiate a resolution of such dispute before initiating the mediation provisions in section 12(c) below.

(c) If the Parties are unable to agree following negotiation pursuant to section 12(b) above, then either Party may request, in writing, to mediate the dispute. The Parties shall seek to reach agreement upon a mediator. In the event that they are unable to agree, then a mediator shall be selected by U.S. Arbitration and Mediation of Oregon. The Parties shall have 30 days from the date a Party initiated mediation to reach agreement before initiating litigation. BPA and Alcoa shall each pay one half of the expenses of any mediation between or among the Parties.

(d) During a contract dispute or contract issue between or among Parties arising out of this Agreement, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impractical. The Parties reserve the right to seek judicial resolution of any dispute arising out of this Agreement.

13. STATUTORY PROVISIONS

(a) **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. Whatcom, together with other customers in the Region, shall have priority to BPA power, consistent with such provisions.

(b) **Limitation on Resale**
Whatcom shall not resell Surplus Firm Power, as defined in this Agreement, to any entity except Alcoa.

(c) **BPA Appropriations Refinancing Act**
The BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110

Stat. 1321, 1350, is incorporated by reference and is a material term of this Agreement.

14. STANDARD PROVISIONS

(a) **Amendments**

No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**

Alcoa may assign this Agreement upon 90 days prior written notice, but only to a successor-in-interest that has acquired ownership, through purchase or merger, of Alcoa's facilities that are served, in whole or in part, with power or Monetary Benefits provided under this Agreement, and then only if such assignee expressly agrees in writing to be bound by the terms of this Agreement. In the event of such assignment, BPA will apply its then current credit policies to determine whether it will require security or assurances from the assignee to secure performance of assignee's obligations under this Agreement. Monetary Benefits under this Agreement are not transferable for use at other aluminum smelters. Such Monetary Benefits shall only be available for eligible production facilities referred to in Exhibit B of this Agreement, subject to any limitations specifically established in Exhibit B.

(c) **Information Exchange and Confidentiality**

The Parties shall provide each other with any information that is reasonably required, and requested by any Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling, and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of 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 obligation 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.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement among the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement among the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers**
Any waiver at any time by any Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's New Large Single Load Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by Alcoa or Whatcom to such policy, nor shall it be construed to be a waiver of the right of Alcoa or Whatcom to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.

(j) **Hold Harmless**
BPA and Alcoa assume all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. BPA and Alcoa shall indemnify and hold the other Parties harmless from any liability arising from such act or negligence.

15. LIMITATION OF LIABILITY OF WHATCOM AND HOLD HARMLESS

BPA and Alcoa agree to and hereby do waive any suit, claim, demand or cause of action of any kind in law and equity which they may have or may assert against Whatcom arising out of this Agreement, except to enforce Whatcom's obligations pursuant to this Agreement (i) to effect transfer of Escrow Account funds pursuant to section 9(b) of this Agreement, and (ii) to pay such amounts received from Alcoa to BPA in the amount of payments received by Whatcom from Alcoa pursuant to section 9(a) of this Agreement as may be amended pursuant to section 9(a) of this Agreement.

In no event or any circumstance shall Whatcom be liable for special punitive, indirect, incidental or consequential losses or damages of any kind whatsoever (including but not limited to lost profits), even if Whatcom has been advised of the likelihood of such loss or damage and regardless of the form of action.

Furthermore, BPA and Alcoa agree to share equally any payment necessary to indemnify, hold harmless and reimburse Whatcom for damages and/or any reasonable costs, other than Whatcom's implementation and administrative costs billable to Alcoa under section 9 of this Agreement, including, but not limited to, reasonable attorney fees, incurred by Whatcom as a direct or indirect result of its participation in this Agreement.

BPA's and Alcoa's agreement to indemnify and hold harmless Whatcom pursuant to this section 15 shall survive the termination of this Agreement until extinguished by any applicable statue of limitations.

16. TERMINATION

(a) BPA may terminate this Agreement on 30 days written notice to the other Parties in the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order preventing or prohibiting BPA from recovering under the Slice Agreements or its Slice rate schedules that portion of BPA's cost of service associated with this Agreement allocated by BPA to such Slice Agreements or Slice rate schedules. BPA shall diligently litigate any action challenging its ability to assess such costs. Neither Alcoa nor Whatcom shall be entitled to any damages for such termination and hereby expressly waives any right to seek such damages.

(b) If, pursuant to section 5(b) above, BPA provides written notice to convert the payment of Monetary Benefit to a physical Surplus Firm Power Sale during the CY 2010-2011 period or the CY 2011period, then Alcoa may terminate this Agreement by providing written notice to Whatcom and BPA no later than November 1, 2008. The effective date of any such termination shall be 2400 hours on the September 30 immediately preceding the effective date of such conversion. In this event, the Demand Entitlement becomes an UBA as of the effective date specified in this section 16(b), and shall be offered to Other DSIs pursuant to section 7(b)(4) above.

(c) In the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final order that declares or renders this Agreement void

or otherwise unenforceable, no Party shall be entitled to any damages or restitution of any nature, in law or equity, from any other Party, and each Party hereby expressly waives any right to seek such damages.

(d) Whatcom may terminate its obligations under this Agreement upon 30 days written notice to the other Parties if there is an Event of Default by Alcoa. An Event of Default shall mean the failure of Alcoa to pay when due the reimbursements owed by Alcoa to Whatcom under sections 9(c)(2), 12(c), 14(j) and/or 15 if payment is not remedied within 30 Business Days after written notice. In the event of such termination by Whatcom, BPA and Alcoa will establish a mutually agreeable alternative means to effectuate the payments and the acquisition of BPA power by Alcoa provided for in this Agreement.

17. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

ALCOA INC.

By /S/ ALAN CRANSBERG

Name Alan Cransberg
(Print/Type)

Title President, Global Mfg.

Date June 19, 2006

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ MARK E. MILLER
Account Executive

Name Mark E. Miller
(Print/Type)

Date June 9, 2006

PUBLIC UTILITY DISTRICT NO. 1 OF
WHATCOM COUNTY, WASHINGTON

By /S/ STEPHAN JILK

Name Stephan Jilk
(Print/Type)

Title General Manager

Date June 13, 2006

Exhibit A
SURPLUS FIRM POWER RATE

If BPA chooses to exercise its option, pursuant to section 5(b) of the body of this Agreement, to sell physically delivered Surplus Firm Power under this Agreement during the FY 10-11 Rate Period, then BPA shall unilaterally revise this Exhibit A, effective on October 1, 2009, to include the specific rates and charges that will apply to the physically delivered Surplus Firm Power sale. The cost to BPA to provide such physically delivered Surplus Firm Power will not exceed the cost caps as described in the Administrator's ROD.

Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS

1. DESCRIPTION OF ALCOA's PRODUCTION FACILITIES, STATION SERVICE REQUIREMENTS, AND METERING EQUIPMENT

Production Facilities: are Alcoa's aluminum smelting facilities served from the Government's Intalco Substation, where the 13.8 kilovolt (kV) facilities of BPA and Alcoa are connected. If Alcoa requests a Companion Contract pursuant to section 2 of this Exhibit B for its Wenatchee smelter, located at Wenatchee, Washington, the portion of the Wenatchee smelter load that has been traditionally served with purchases from Chelan PUD will be excluded from Alcoa's Total Plant Load and the cost of these purchases will be excluded from the calculation of Monetary Benefits under this Agreement.

Metering Equipment: used to measure energy usage of Alcoa's facilities at the Government's Intalco Substation in the 13.8 kV circuits over which such electric power and energy flows.

Alcoa agrees to allow PBL access to all hourly load measurements of its Production Facilities necessary to administer this Agreement.

2. SECOND CONTRACT RIGHT

At any time during the term of this contract Alcoa may request a contract to serve the Wenatchee smelter. BPA shall offer Alcoa and the Utility that shall serve the Wenatchee smelter a contract (Companion Contract) with the same terms and conditions as this contract, but with the eligible production facilities at the Wenatchee smelter incorporated and with the following revisions, which revisions shall also simultaneously be incorporated into this contract:

Section 6(c)(1) of this Agreement shall be replaced with the following:

> "Alcoa shall have the right to transfer Maximum Allocation amounts among this Agreement and a Companion Contract entered into between BPA, Alcoa, and another utility as specified in Exhibit E of this Agreement. If the total Monthly Plant Load plus the total Monthly Plant Load of the Companion Contract is less than ¼ of the Total Maximum Allocation during any month (Deficient Month), then the MB Monthly Payment for that month is $0."

Exhibit E shall be replaced with the following:

"Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT

1. **MAXIMUM AND MINIMUM ALLOCATIONS**
During periods when Monetary Benefit payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefit Limit amounts are as follows:

Maximum Allocation:	320 aMW
Minimum Allocation:	80 aMW
Monetary Benefit Limit:	$33,638,400/CY (Leap Year $92,160 greater.)

Total Maximum Allocation shall be equal to the summation of Maximum Allocation amounts specified in this Exhibit E and in the Companion Contract:

Total Maximum Allocation: 320 aMW

2. **DEMAND ENTITLEMENT**
During periods when this Agreement operates as a physical Surplus Firm Power sale pursuant to section 4 of the body of this Agreement, the Demand Entitlement shall be as follows:

Demand Entitlement: 320 MW

Total Demand Entitlement shall equal the summation of Demand Entitlement amounts specified in this Exhibit B and in the Companion Contract:

Total Demand Entitlement: 320 aMW

3. **MAXIMUM ALLOCATION AND DEMAND ENTITLEMENT TRANSFERS**
Alcoa may transfer amounts of Maximum Allocation and amounts of Demand Entitlement among this Agreement and a Companion Contract as specified in this Exhibit E. The total of Alcoa's Maximum Allocation amounts and Demand Entitlement amounts specified in these contracts may not exceed Alcoa's Total Maximum Allocation or Total Demand Entitlement. Alcoa shall provide both BPA and Whatcom at least 7 days advance written notice of the effective date of such transfers. The effective date must be the first day of a month. BPA shall revise this Exhibit E to reflect such changes to Maximum Allocation, Minimum Allocation, and/or Demand Entitlement.

4. **REVISIONS**
BPA shall unilaterally revise this Exhibit E to reflect changes to Maximum Allocation, Total Maximum Allocation, Minimum Allocation, and/or Demand Entitlement and Total Demand Entitlement under this Agreement, except as provided for in section 3 of this Exhibit E."

3. REVISIONS

This Exhibit B shall be revised upon mutual agreement of the Parties to reflect any new products, services, and special provisions that may be added during the term of this Agreement.

Effective December 15, 2003

Exhibit C
BPA POWER BUSINESS LINE SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

Unless otherwise specified in this Exhibit C, all transactions shall be scheduled in accordance with the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC). The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power products bought or sold under this Agreement. All provisions apply equally to all BPAP Counter Parties (as defined in section 2 below) and their authorized scheduling agents. Transmission scheduling arrangements are provided under separate agreements/provisions with the designated transmission provider.

2. DEFINITIONS

(a) **After the Fact**: The process of reconciling all transactions, Schedules, and accounts after they have occurred.

(b) **APOD**: Alternate Point Of Delivery. Any point other than the POD specified in a Confirmation Agreement or other contract to which this Exhibit C applies.

(c) **BPAP**: Bonneville Power Administration Power Business Line.

(d) **BPAP Counter Party**: A PSE (Purchasing Selling Entity, as defined by NERC) that has contracted to purchase from BPAP or sell to BPAP electric power products.

(e) **COB**: California-Oregon Border or COI (California-Oregon Intertie). Consists of the Pacific AC Intertie (PACI or Malin) and 3rd AC Intertie (3A or Captain Jack) transmission lines to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(f) **NOB**: Nevada-Oregon Border. Consists of the Pacific DC Intertie (PDCI or Celilo) transmission line to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(g) **POD**: Point of Delivery, as defined by NERC.

(h) **Preschedule Day**: Preschedule Day is in accordance with WECC practice and variations are identified in the WECC calendar to allow for Holidays, WECC meetings, etc.

(i) **Prescheduling**: The process (verbally and in writing) of establishing and balancing (checking out) schedules on the Preschedule Day.

(j) **Real-Time Scheduling**: Any new or modified Transaction that occurs after prescheduling is completed.

(k) **Schedule**: The planned Transaction approved and accepted by all counterparties and Control Areas involved in the Transaction.

3. COORDINATION: GENERAL, CONTROL AREA, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS

(a) General Requirements

(1) BPAP shall have the right to revise and replace this Exhibit C: (1) in the event that scheduling procedures are changed due to agreement among scheduling parties in the WECC; (2) to comply with rules or orders issued by the Federal Energy Regulatory Commission (FERC) or NERC, or (3) to implement changes reasonably necessary for BPAP to administer its power scheduling function in a more efficient manner.

(2) BPAP and each BPAP Counter Party must have necessary staff available during both parties' Prescheduling, Real-Time Scheduling, and After the Fact check out processes, including the completion of the NERC Etag.

(3) All transactions shall be stated in the Pacific Prevailing Time (PT), beginning with the 0100 hour ending.

(4) BPAP and each BPAP Counter Party shall notify each other of changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time Scheduling, After the Fact, or scheduling agents, etc.).

(b) Prescheduling Requirements

(1) Information Required For Any Preschedule

(A) When the NERC Tag is prepared, the BPAP Counter Party purchasing from BPAP shall use commercially reasonable efforts to ensure the BPAP Confirmation Agreement contract number is included within the generation/load segment, in the XML "Contract Number" element of the Etag.

(B) Transactions to or from COB must identify the use of either Malin or Captain Jack.

(2) **Preschedule Coordination**
Final hourly Schedules must be submitted by each BPAP Counter Party to BPAP for the next day(s) transactions by 1100 PT of each Preschedule Day, unless otherwise agreed. After 1100 PT Preschedules can be accepted if mutually agreed to by BPAP and the BPAP Counter Party, and the Preschedules are accepted by the transmission provider(s).

(c) **Real-Time Scheduling Requirements**

(1) BPAP Counter Parties may not make real-time changes to the schedules unless such changes are allowed under specific Confirmation Agreements or other contracts to which this Exhibit C applies, and by mutual agreement.

(2) If real-time changes to the schedule become necessary and are allowable as described in section 3(c)(1) above, the requesting BPAP Counter Party must submit requests for such changes no later than specified in the contract or BPAP Confirmation Agreement. Emergency schedule changes (including mid-hour changes) will be handled in accordance with WECC procedures.

(3) Multi-hour changes to the schedule shall specify an "hour beginning" and an "hour ending" and shall not be stated as "until further notice."

(d) **After the Fact Reconciliation Requirements**
Each BPAP Counter Party agrees to reconcile all transactions, Schedules, and accounts following the end of each month (within the first 10 calendar days of the next month).

Exhibit D
EXAMPLES

I. EXAMPLES OF THE CALCULATION OF MONETARY BENEFIT PAYMENTS

Following are examples of the calculation of Monetary Benefit payments pursuant to section 6 of the body of this Agreement.

Example No. 1: Calculation of MB Rate, Maximum MB Monthly Payment, and MB Monthly Payment.

Demand Entitlement	250	aMW
Hours in the Month Equals	744	

Difference Between Forecast Market Price and Equvalent PF	MB Rate	Maximum MB Payment	Minimum Load (aMW) to Receive Maximum MB Monthly Payment
$26.00	$24.00	$2,232,000	125.0000
$25.00	$24.00	$2,232,000	125.0000
$24.00	$24.00	$2,232,000	125.0000
$23.00	$24.00	$2,232,000	130.4348
$22.00	$24.00	$2,232,000	136.3636
$21.00	$24.00	$2,232,000	142.8571
$20.00	$24.00	$2,232,000	150.0000
$19.00	$19.00	$2,232,000	157.8947
$18.00	$18.00	$2,232,000	166.6667
$17.00	$17.00	$2,232,000	176.4706
$16.00	$16.00	$2,232,000	187.5000
$15.00	$15.00	$2,232,000	200.0000
$14.00	$14.00	$2,232,000	214.2857
$13.00	$13.00	$2,232,000	230.7692
$12.00	$12.00	$2,232,000	250.0000
$11.00	$11.00	$2,046,000	250.0000
$10.00	$10.00	$1,860,000	250.0000
$9.00	$9.00	$1,674,000	250.0000
$8.00	$8.00	$1,488,000	250.0000
$7.00	$7.00	$1,302,000	250.0000
$6.00	$6.00	$1,116,000	250.0000
$5.00	$5.00	$930,000	250.0000
$4.00	$4.00	$744,000	250.0000
$3.00	$3.00	$558,000	250.0000
$2.00	$2.00	$372,000	250.0000
$1.00	$1.00	$186,000	250.0000
$0.00	$0.00	$0	0.0000

Example No. 2: Difference between Forecast Market Price and Equivalent PF exceeds $24/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$2,235,000	$2,160,000	$2,232,000	$2,232,000	$2,016,000	$2,232,000

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$2,157,000	$2,232,000	$2,160,000	$2,232,000	$2,232,000	$2,160,000

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ 2,235,000	63,000	84.6	**Yes**	$ 1,512,000
November	45,000	$ 2,160,000	61,000	84.7	**Yes**	$ 1,464,000
December	46,500	$ 2,232,000	60,000	80.6	**Yes**	$ 1,440,000
January	46,500	$ 2,232,000	44,500	59.8	**No**	$ -
February	42,000	$ 2,016,000	40,500	60.3	**No**	$ -
March	46,500	$ 2,232,000	45,000	60.5	**No**	$ -
April	44,938	$ 2,157,000	44,000	61.2	**No**	$ -
May	46,500	$ 2,232,000	46,000	61.8	**No**	$ -
June	45,000	$ 2,160,000	60,000	83.3	**Yes**	$ 1,440,000
July	46,500	$ 2,232,000	80,000	107.5	**Yes**	$ 1,920,000
August	46,500	$ 2,232,000	90,000	121.0	**Yes**	$ 2,160,000
September	45,000	$ 2,160,000	97,500	135.4	**Yes**	$ 2,160,000
		26,280,000	731,500			$ 12,096,000

In this example the DSI is entitled to the Maximum MB Monthly Payment each month that the actual monthly load equals or exceeds the Minimum Allocation. January through May monthly loads were less than the Minimum Allocation Requirement, and the MB Monthly Payments equal zero.

Example No. 3: Difference between Forecast Market Price and Equivalent PF equals $18/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 2,235,000	$ 2,160,000	$ 2,232,000	$ 2,232,000	$ 2,016,000	$ 2,232,000

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 2,157,000	$ 2,232,000	$ 2,160,000	$ 2,232,000	$ 2,232,000	$ 2,160,000

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement	Maximum MB Payment	Monthly Plant Load (MWh)	Actual Monthly Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ 2,235,000	63,000	84.6	**Yes**	$ 1,134,000
November	45,000	$ 2,160,000	61,000	84.7	**Yes**	$ 1,098,000
December	46,500	$ 2,232,000	60,000	80.6	**Yes**	$ 1,080,000
January	46,500	$ 2,232,000	44,500	59.8	**No**	$ -
February	42,000	$ 2,016,000	40,500	60.3	**No**	$ -
March	46,500	$ 2,232,000	45,000	60.5	**No**	$ -
April	44,938	$ 2,157,000	44,000	61.2	**No**	$ -
May	46,500	$ 2,232,000	46,000	61.8	**No**	$ -
June	45,000	$ 2,160,000	60,000	83.3	**Yes**	$ 1,080,000
July	46,500	$ 2,232,000	80,000	107.5	**Yes**	$ 1,440,000
August	46,500	$ 2,232,000	90,000	121.0	**Yes**	$ 1,620,000
September	45,000	$ 2,160,000	97,500	135.4	**Yes**	$ 1,755,000
		26,280,000	731,500			$ 9,207,000

In this example the DSI is entitled to the Maximum MB Monthly Payment only September. January thru May MB Monthly Payments equal zero because the DSI failed to meet the Minimum Allocation requirement. For the remaining months an MB Monthly Payment equal to the actual monthly load multiplied by the MB Rate ($18.00/MWh) was paid.

Example No. 4: Difference between Forecast Market Price and Equivalent PF equals $8/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 1,490,000	$ 1,440,000	$ 1,488,000	$ 1,488,000	$ 1,344,000	$ 1,488,000

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ 1,438,000	$ 1,488,000	$ 1,440,000	$ 1,488,000	$ 1,488,000	$ 1,440,000

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement Minus	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ 1,490,000	63,000	84.6	**Yes**	$ 504,000
November	45,000	$ 1,440,000	61,000	84.7	**Yes**	$ 488,000
December	46,500	$ 1,488,000	60,000	80.6	**Yes**	$ 480,000
January	46,500	$ 1,488,000	44,500	59.8	**No**	$ -
February	42,000	$ 1,344,000	40,500	60.3	**No**	$ -
March	46,500	$ 1,488,000	45,000	60.5	**No**	$ -
April	44,938	$ 1,438,000	44,000	61.2	**No**	$ -
May	46,500	$ 1,488,000	46,000	61.8	**No**	$ -
June	45,000	$ 1,440,000	60,000	83.3	**Yes**	$ 480,000
July	46,500	$ 1,488,000	80,000	107.5	**Yes**	$ 640,000
August	46,500	$ 1,488,000	90,000	121.0	**Yes**	$ 720,000
September	45,000	$ 1,440,000	97,500	135.4	**Yes**	$ 780,000
		17,520,000	731,500			$ 4,092,000

In this example, January through May the MB Monthly Payment equals zero because the DSI failed to meet the Minimum Allocation requirement. In the remaining months the MB Monthly Payment equals actual monthly load multiplied by the MB Rate ($8.00/MWh).

Example No. 5: Equivalent PF is greater than the Forecast Market Price and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

	October	November	December	January	February	March
Hours in the Month	745	720	744	744	672	744
Market Forecast (FBPF)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ -	$ -	$ -	$ -	$ -	$ -
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ -	$ -	$ -	$ -	$ -	$ -

	April	May	June	July	August	September
Hours in the Month	719	744	720	744	744	720
Market Forecast (FBPF)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Equivalent PF	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00	$ 32.00
Maximum MB Rate	$ -	$ -	$ -	$ -	$ -	$ -
Demand Entitlement - MW	250	250	250	250	250	250
Maximum MB Monthly Pmt	$ -	$ -	$ -	$ -	$ -	$ -

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	Meets Minimum Load Requirement?	MB Monthly Payment
October	46,563	$ -	63,000	84.6	Yes	$ -
November	45,000	$ -	61,000	84.7	Yes	$ -
December	46,500	$ -	60,000	80.6	Yes	$ -
January	46,500	$ -	44,500	59.8	No	$ -
February	42,000	$ -	40,500	60.3	No	$ -
March	46,500	$ -	45,000	60.5	No	$ -
April	44,938	$ -	44,000	61.2	No	$ -
May	46,500	$ -	46,000	61.8	No	$ -
June	45,000	$ -	60,000	83.3	Yes	$ -
July	46,500	$ -	80,000	107.5	Yes	$ -
August	46,500	$ -	90,000	121.0	Yes	$ -
September	45,000	$ -	97,500	135.4	Yes	$ -
		-	731,500			$ -

In this example the Forecast Market Price is less than the Equivalent PF so there are no MB Monthly Payments made to the DSI.

II. EXAMPLES OF THE DETERMINATION OF UNUSED BENEFIT AMOUNTS

Following are examples of the determination of Unused Benefit Amounts pursuant to section 7 of the body of this Agreement.

Example No. 1: DSI's operation without any UBA made available at the end of the 12 month period. Maximum Allocation equals 250 aMW and the MB Rate equals $18/MWh.

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	MB Monthly Payment	Maximun MB Monthly Payment Paid?	Percentage MB Payment Accessed
April	44,938	$ 2,157,000	130,000	180.8	$ 2,157,000	Yes	100.00%
May	46,500	$ 2,232,000	100,000	134.4	$ 1,800,000	-- No --	80.65%
June	45,000	$ 2,160,000	100,000	138.9	$ 1,800,000	-- No --	83.33%
July	46,500	$ 2,232,000	89,000	119.6	$ 1,602,000	-- No --	71.77%
August	46,500	$ 2,232,000	81,000	108.9	$ 1,458,000	-- No --	65.32%
September	45,000	$ 2,160,000	90,000	125.0	$ 1,620,000	-- No --	75.00%
October	46,563	$ 2,235,000	88,000	118.1	$ 1,584,000	-- No --	0.00%
November	45,000	$ 2,160,000	92,000	127.8	$ 1,656,000	-- No --	76.67%
December	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
January	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
February	42,000	$ 2,016,000	105,000	156.3	$ 1,890,000	-- No --	93.75%
March	46,500	$ 2,232,000	116,000	155.9	$ 2,088,000	-- No --	93.55%
		26,280,000.0	1,221,000		21,795,000		

No UBA is made available at the end of this 12month period because the DSI received a Maximum MB Monthly Payment in April but one more month without accessing the Maximum MB Monthly Payment will result in UBA; up to 6 percent of this DSI Maximum Allocation may be made available to the Other DSIs.

Example No. 2: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $18/MWh.

	Minimum Load Requirement	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	MB Monthly Payment	Maximun MB Monthly Payment Paid?	Percentage MB Payment Accessed
April	44,938	$ 2,157,000	100,000	139.1	$ 1,800,000	-- No --	83.45%
May	46,500	$ 2,232,000	100,000	134.4	$ 1,800,000	-- No --	80.65%
June	45,000	$ 2,160,000	100,000	138.9	$ 1,800,000	-- No --	83.33%
July	46,500	$ 2,232,000	89,000	119.6	$ 1,602,000	-- No --	71.77%
August	46,500	$ 2,232,000	81,000	108.9	$ 1,458,000	-- No --	65.32%
September	45,000	$ 2,160,000	90,000	125.0	$ 1,620,000	-- No --	75.00%
October	46,563	$ 2,235,000	88,000	118.1	$ 1,584,000	-- No --	0.00%
November	45,000	$ 2,160,000	92,000	127.8	$ 1,656,000	-- No --	76.67%
December	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
January	46,500	$ 2,232,000	115,000	154.6	$ 2,070,000	-- No --	92.74%
February	42,000	$ 2,016,000	105,000	156.3	$ 1,890,000	-- No --	93.75%
March	46,500	$ 2,232,000	116,000	155.9	$ 2,088,000	-- No --	93.55%
		26,280,000.0	1,191,000		21,438,000		

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (93.75%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.9375 = 234.375 rounded to 234 aMW). UBA that will be made available to the Other DSIs is 250 aMW minus 234 aMW, 16 aMW.

Example No. 3: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $12/MWh.

	Minimum Load Requirement Minus	Maximum MB Monthly Payment	Actual Monthly Load (MWh)	Monthly Plant Load (aMW)	MB Monthly Payment	Maximum MB Monthly Payment Paid?	Percentage MB Payment Accessed
April	44,938	$ 2,157,000	100,000	139.1	$ 1,200,000	– No –	55.63%
May	46,500	$ 2,232,000	100,000	134.4	$ 1,200,000	– No –	53.76%
June	45,000	$ 2,160,000	100,000	138.9	$ 1,200,000	– No –	55.56%
July	46,500	$ 2,232,000	89,000	119.6	$ 1,068,000	– No –	47.85%
August	46,500	$ 2,232,000	81,000	108.9	$ 972,000	– No –	43.55%
September	45,000	$ 2,160,000	90,000	125.0	$ 1,080,000	– No –	50.00%
October	46,563	$ 2,235,000	88,000	118.1	$ 1,056,000	– No –	0.00%
November	45,000	$ 2,160,000	92,000	127.8	$ 1,104,000	– No –	51.11%
December	46,500	$ 2,232,000	115,000	154.6	$ 1,380,000	– No –	61.83%
January	46,500	$ 2,232,000	115,000	154.6	$ 1,380,000	– No –	61.83%
February	42,000	$ 2,016,000	105,000	156.3	$ 1,260,000	– No –	62.50%
March	46,500	$ 2,232,000	116,000	155.9	$ 1,392,000	– No –	62.37%

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (62.50%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.62.50 = 156.25 rounded to 156 aMW). UBA that will now be made available to the Other DSIs is 250 aMW minus 156 aMW, 94 aMW.

III. EXAMPLES OF THE ACQUISITION OF UNUSED BENEFIT AMOUNTS

Following are examples of the acquisition of Unused Benefit Amounts pursuant to section 8 of the body of this Agreement.

Example No. 1: Maximum Allocation increases of two DSI who both increased operation to acquire nearly all available UBA (94 aMW).

	DSI-A Maximum Allocation	DSI-B Maximum Allocation	UBA Available aMW	UBA Acquired by DSI-A	UBA Acquired by DSI-B
April	140	100	94	50	39
May	190	139	5	0	0
June	190	139	5	0	0
July	190	139	5	0	0
August	190	139	5	0	0
September	190	139	5	0	0
October	190	139	0	0	0
November	190	139	0	0	0
December	190	139	0	0	0
January	190	139	0	0	0
February	190	139	0	0	0
March	190	139	0	0	0

In this example DSI-A was allocated 50 aMW and DSI-B was allocated 39 aMW. The new Demand Entitlement for DSI-A is 190 aMW and 139 aMW for DSI-B. The remaining 5 aMW of UBA was never acquired and after September was not available to any DSIs.

Example No. 2: Same as Example #1 except DSI-A has a contractually limited Maximum Allocation of 171 aMW.

	DSI-A Maximum Allocation	DSI-B Maximum Allocation	UBA Available aMW	UBA Acquired by DSI-A	UBA Acquired by DSI-B
April	140	100	94	31	39
May	171	139	24	0	0
June	171	139	24	0	0
July	171	139	24	0	0
August	171	139	24	0	0
September	171	139	24	0	0
October	171	139	0	0	0
November	171	139	0	0	0
December	171	139	0	0	0
January	171	139	0	0	0
February	171	139	0	0	0
March	171	139	0	0	0

In this example DSI-A's Demand Entitlement was limited to 171 aMW. DSI-A was allocated 31 aMW and DSI-B was allocated its 39 aMW of UBA. Available UBA was 24 aMW through September but because none was acquired during this period it was no longer available to any DSIs afterward.

Example No. 3: Maximum Allocation of two DSIs increased over 2-month period with full amount of UBA (94 aMW) allocated.

	DSI-A Maximum Allocation	DSI-B Maximum Allocation	UBA Available aMW	UBA Acquired by DSI-A	UBA Acquired by DSI-B
April	140	100	94	0	45
May	140	145	49	24	25
June	164	170	0	0	0
July	164	170	0	0	0
August	164	170	0	0	0
September	164	170	0	0	0
October	164	170	0	0	0
November	164	170	0	0	0
December	164	170	0	0	0
January	164	170	0	0	0
February	164	170	0	0	0
March	164	170	0	0	0

In this example DSI-B increased its load in April sufficient to acquire 45 aMW of the available UBA, resulting in its Maximum Allocation increasing from 100 aMW to 145 aMW beginning with May. Both DSIs increased load sufficiently for the remaining UBA to be allocated during May, increasing DSI-A's Maximum Allocation to 164 aMW and DSI-B's Maximum Allocation to 170 aMW.

Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT

1. **MAXIMUM AND MINIMUM ALLOCATIONS**
During periods when Monetary Benefit payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefit Limit amounts are as follows:

Maximum Allocation:	320 aMW
Minimum Allocation:	80 aMW
Monetary Benefit Limit:	$33,638,400/CY (Leap Year $92,160 greater.)

2. **DEMAND ENTITLEMENT**
During periods when this Agreement operates as a physical Surplus Firm Power sale pursuant to section 4 of the body of this Agreement, the Demand Entitlement shall be as follows:

Demand Entitlement:	320 MW

3. **REVISIONS**
BPA shall unilaterally revise this Exhibit E to reflect changes to Maximum Allocation, Minimum Allocation, Monetary Benefit Limit, and/or Demand Entitlement.

Exhibit F
DETERMINATION OF FORECAST MARKET PRICE AND EQUIVALENT PF

1. DETERMINATION OF FORECAST MARKET PRICE

Prior to the beginning of each Contract Year, the following provisions shall be used to determine the Forecast Market Price.

(a) **Definitions**

(1) **"2007-2011 Agreements"** means the agreements between BPA and each PNW IOU that provide for among other things, the determination of the Forward Flat-Block Price Forecast for each year, 2007 through 2011.

(2) **"FBPF Exhibit"** means the exhibit titled "Determination of Forward Flat-Block Price Forecast For Contract Years 2007 through 2011, which is attached to each of the 2007-2011 Agreements.

(3) **"Forward Flat-Block Price Forecast"** or **"FBPF"** means the Forward Flat-Block Price Forecast developed from time to time under the 2007-2011 Agreements.

(4) **"Forward Price Data Agreement"** means BPA Contract No. 04PB-11534 among BPA and the PNW IOUs.

(5) **"PNW Investor-Owned Utility"** or **"PNW IOU"** means each of the following investor-owned utilities (and its investor-owned utility successors and assigns) that serves residential and small farm customers in the Pacific Northwest: Puget Sound Energy, Inc., PacifiCorp, Portland General Electric Company, Avista Corporation, Idaho Power Company, and NorthWestern Energy Division of NorthWestern Corporation.

(b) **Determination of Forecast Market Price**

(1) BPA has contracted with a qualified third party (QTP) pursuant to the FBPF Exhibit to determine the Forward Flat-Block Price Forecast for each Contract Year, 2007 through 2011.

(2) During four consecutive quarters prior to the beginning of each Contract Year, 2007 through 2011, the QTP surveys certain eligible data providers (EDPs) that have signed contracts in the form of Exhibit A to the Forward Price Data Agreement.

(3) The first quarterly survey for CY 2007 is conducted during Q1 of calendar year 2005 (January 2005-March 2005). The last quarterly survey for CY 2007 is conducted during Q4 of calendar year 2005 (October 2005-December 2005). The same procedure is followed for CY 2008 through 2011 but the quarters surveyed change to calendar

years 2006 through 2009, respectively. Each quarterly survey results in an FBPF for the upcoming CY. The average of the four quarterly FBPFs is the FBPF that is used to calculate benefits under the 2007-2011 Agreements.

(4) For the purpose of determining Monetary Benefit pursuant to section 6 of the body of this Agreement, the Forecast Market Price shall be equal to the FBPF established for Q4 of each calendar year for the upcoming CY. For example, the FBPF for Q4 of calendar year 2005 shall be the Forecast Market Price for CY 2007.

The Forecast Market Price for CY 2007 is $67.75/MWh.

2. DETERMINATION OF EQUIVALENT PF

Prior to the beginning of each CY, BPA will calculate the initial Equivalent PF for each such CY and, if applicable, for the Option Period.

(a) For Monetary Benefits not included in Option Benefits the Equivalent PF shall be equal to the actual cost, in $/MWh, to purchase 1 MW during every hour of the CY at the PF Rate (including but not limited to the effect of any adjustments, surcharges, dividends or true-ups) divided by the number of hours in the CY.

(b) For Monetary Benefits included in Option Benefits the Equivalent PF for the Option Period shall be the weighted average of the Equivalent PF for each CY included in whole or part within the Option Period calculated as follows: (i) For each CY within the Option Period, a CY Total Plant Load will be calculated by summing the monthly Total Plant Loads for each month of the CY that falls within the Option Period. For this calculation monthly Total Plant Load shall be limited to the Maximum Allocation, less UBA amounts not included in Option Benefits, and will be deemed equal to zero if the monthly Total Plant load is less than the Minimum Allocation. (ii) Each CY Total Plant Load for each CY from step i will then be multiplied by the Equivalent PF for the corresponding CY. (iii) The sum of the numbers calculated in step ii will then be divided by the sum of the CY Total Plant Loads from step i for the entire Option Period to derive the Equivalent PF for the Option Period. For purposes of this calculation, if the Option Period extends beyond CY 2009, BPA will deem the Equivalent PF Rate equal to a rate that results in an MB Rate, for periods beyond the CY 2009, equal to $24/MWh until BPA's initial proposal is published for the FY 10-11 Rate Period. When the initial proposal for FY 10-11 Rate Period is published the Equivalent PF used in this calculation for CY 2010 and CY 2011 will be established according to 2(c) below.

(c) Each time any adjustment, surcharge, dividend or true-up to the PF Rate is proposed by BPA in writing (which may be before the date such change will actually be applied to the PF Rate), BPA will adjust the Equivalent PF and the MB Rate and MB Monthly Payments for the remaining months of such CY or Option Period. Such adjustment will take into consideration the

Monetary Benefits provided to date and the PF Rate adjustment to provide an end-of-CY or end of Option Period total Monetary Benefit to which Alcoa is entitled. If such recalculation indicates that BPA has paid Alcoa more in Monetary Benefits than the amount to which Alcoa is entitled, then BPA will reduce the MB Monthly Payments to Alcoa over the next following three months (if full recovery of the amount is not possible in the 3-month period BPA may invoice Alcoa for the remaining amount), by the amount needed to recover the overpayment. If adjustments, surcharges, and true-ups are established after the CY or Option Period ends, then BPA will calculate the final Equivalent PF rate for each such CY or Option Period, and adjustments to Monetary Benefit will be applied in the following CY.

(d) If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by Alcoa to BPA, then BPA shall invoice Alcoa for such payment within 90 days following the end of such final CY. Such payment shall be made by Alcoa within 20 days following the receipt of such invoice. If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by BPA to Alcoa, then BPA shall pay Alcoa no later than 90 days following the end of such final CY.

3. REVISIONS

BPA shall have the unilateral right to revise this Exhibit F to reflect the Forecast Market Price and Equivalent PF for each CY after CY 2007 calculated pursuant to this Exhibit F. Any changes to the procedure used to determine Forecast Market Price or Equivalent PF may only be made upon mutual agreement of the Parties.

Contract No. 06PB-11745

AUTHENTICATED

BLOCK POWER SALES AGREEMENT
executed by the
BONNEVILLE POWER ADMINISTRATION
and
COLUMBIA FALLS ALUMINUM COMPANY, LLC
and
FLATHEAD ELECTRIC COOPERATIVE, INC.

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Exhibit A	Surplus Firm Power Rate
Exhibit B	Additional Products, Services, and Special Provisions
Exhibit C	BPA Power Business Line Scheduling Provisions
Exhibit D	Examples
Exhibit E	Maximum Allocation, Minimum Allocation, and Demand Entitlement
Exhibit F	Determination of Forecast Market Price and Equivalent PF

This BLOCK POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), COLUMBIA FALLS ALUMINUM

COMPANY, LLC (CFAC), and FLATHEAD ELECTRIC COOPERATIVE, INC. (Flathead). CFAC is a corporation organized under the laws of the State of Delaware. Flathead is a nonprofit corporation organized under the laws of the State of Montana. BPA, CFAC, and Flathead are sometimes referred to in the singular as "Party" or in the plural as "Parties."

RECITALS

On June 30, 2005, BPA issued a record of decision titled "Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011." On May 31, 2006, BPA issued a supplement to the record of decision. The record of decision and its supplement together constitute and are referred to herein as the Administrator's ROD.

This Agreement implements the decisions contained in the Administrator's ROD.

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision making activities of BPA's power business from the administrative and decision making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA, CFAC and Flathead agree:

1. TERM

This Agreement, when signed by the Parties, shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to section 16 below. All obligations incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principle place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

(b) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, CY 2007 begins October 1, 2006, and continues through September 30, 2007.

(c) "Demand Entitlement" means, during periods when this Agreement operates as a physical Surplus Firm Power sale, the megawatt (MW) amount each

hour that Flathead shall purchase from PBL, and that CFAC shall purchase from Flathead, as specified in Exhibit E.

(d) "Equivalent PF" means the applicable average Priority Firm Rate at 100 percent load factor, as determined pursuant to Exhibit F.

(e) "Escrow Account" means the specific account established pursuant to the provisions in section 9(b) below for receipt of funds from BPA and transfer of funds by Flathead to CFAC.

(f) "Forecast Market Price" means the annual forecast market price for power at 100 percent load factor, as determined pursuant to the procedures in Exhibit F or, if CFAC has selected an option pursuant to subsection 5(c) or subsections 5(c) and 5(d), then as determined by the average purchase price paid by CFAC during the Option Period.

(g) "FY 07-09 Rate Period" means the wholesale power rate period that begins on October 1, 2006, and continues through September 30, 2009.

(h) "FY 10-11 Rate Period" means the wholesale power rate period that begins on October 1, 2009, and continues through September 30, 2011.

(i) "MB Monthly Payment" means the monthly Monetary Benefit payment that is available during each month, as calculated in section 6(c)(4) below.

(j) "MB Rate" means the rate in dollars per megawatt-hour ($/MWh) used to calculate MB Monthly Payments pursuant to section 6(c) below. The MB Rate is determined by subtracting Equivalent PF from Forecast Market Price, and shall not exceed $24/MWh.

(k) "Maximum Allocation" means, for the purpose of determining MB Monthly Payments, the maximum average megawatt (aMW) amount that may be used to determine a MB Monthly Payment. The Maximum Allocation is shown in Exhibit E.

(l) "Maximum MB Monthly Payment" means the amount calculated in section 6(c)(3) below.

(m) "Minimum Allocation" means, for the purpose of determining MB Monthly Payments, the minimum aMW amount that may be used to determine a MB Monthly Payment. The Minimum Allocation is equal to one-fourth of the Maximum Allocation.

(n) "Monetary Benefits" means monetary payments made by BPA to Flathead for the account of CFAC under this Agreement, as determined pursuant to the provisions in section 6 below.

(o) "Monthly Plant Load" means a monthly aMW amount equal to the Total Plant Load for each month divided by the number of hours in each such month.

(p) "Monthly Purchase Deficiency" means the monthly amount(s) of Surplus Firm Power not purchased due to a curtailment, as such amount(s) may be adjusted pursuant to section 4(e)(1) below.

(q) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(r) "Option Benefits" means the MB Monthly Payments under the options provided for in section 5(c) and 5(d), including UBA amounts if CFAC chooses to establish Monetary Benefits pursuant to the provisions to include UBA in Option Benefits as specified in section 8(a)(4) below.

(s) "Option Period" means the combined period(s) of the option(s) specified in the provisions of section 5(c) and 5(d) selected by CFAC to establish MB Monthly Payments

(t) "Other DSIs" means aluminum smelters other than CFAC that have executed an agreement substantially in the form of this Agreement.

(u) "Points of Measurement" means the interconnection points between BPA, CFAC, and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(v) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL to Flathead, and where Surplus Firm Power shall be made available by Flathead to CFAC's transmission provider.

(w) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(x) "Region" means the definition established for "Region" in the Northwest Power Act.

(y) "Surplus Firm Power" means electric power that PBL shall make continuously available to Flathead, and which Flathead shall make continuously available to CFAC, under this Agreement.

(z) "Total Plant Load" means the amount of electric energy in megawatt-hours (MWh) consumed during each month at CFAC's production facilities. A detailed description of CFAC's production facilities, including station service requirements and metering equipment, is described in Exhibit B.

(aa) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(bb) "Unused Benefit Amount" or "UBA" means either: (1) an aMW amount determined pursuant to section 7(a) during any period in which Monetary Benefits are provided, or (2) a MW amount determined pursuant to section 7(b) during any period in which this Agreement operates as a physical Surplus Firm Power sale.

3. APPLICABLE RATES

(a) **Applicable Rate for Purchases by Flathead**
Purchases by Flathead under this Agreement are subject to the Firm Power Products and Services (FPS) rate schedule or its successor, and the General Rate Schedule Provisions (GRSP). Purchases under the FPS rate schedule are established as follows:

If this Agreement operates as a physically delivered Surplus Firm Power sale pursuant to section 4 below, then section 4(a) below and Exhibit A, Surplus Firm Power Rate, identify Surplus Firm Power amounts, rates, and billing entitlements subject to the FPS rate schedule. If the Surplus Firm Power sale is monetized, then the provisions of section 6 below establish the applicable FPS rate.

(b) **Applicable Rate for Purchases by CFAC**
Purchases by CFAC under this Agreement are subject to the applicable rate schedule developed by Flathead for such purchases. The rates and billing entitlements specified in such rate schedule shall be equal to those rates billed to Flathead by BPA under this Agreement, FPS rate schedule and GRSPs, as specified in Exhibit A.

4. POWER SALE PROVISIONS

This section 4 only applies when this Agreement operates as a physically delivered Surplus Firm Power sale. In this event, the Monetary Benefit provisions in section 6 shall not apply. All physically delivered Surplus Firm Power provided by PBL under this section 4 is solely for service to Total Plant Load.

(a) **Power Sale by PBL to Flathead**

(1) **Hourly Amounts**
PBL shall make available and Flathead shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**

The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes Flathead's HLH and LLH Energy Entitlements with respect to this Agreement.

(b) **Power Sale by Flathead to CFAC**

(1) **Hourly Amounts**
Flathead shall make available and CFAC shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**
The Demand Entitlement multiplied by: (A) the number of HLH; and (B) the number of LLH in the applicable month establishes CFAC's HLH and LLH Energy Entitlements.

(c) **Unauthorized Increase Charge**
CFAC shall not intentionally schedule in excess of the amount specified in section 4(b)(1) above. However, in the event that an excess amount is scheduled due to error, then such amounts taken by CFAC from Flathead at the Points of Receipt in excess of the amounts specified in section 4(b)(2) above shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and CFAC shall not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement. Any Unauthorized Increase Charge shall be billed by BPA in accordance with the billing procedures described in section 9(a) below. Any Surplus Firm Power used by Flathead or CFAC for any other purpose shall be subject to the Unauthorized Increase Charge.

(d) **Curtailment**
If CFAC curtails Total Plant Load in whole or in part, then CFAC may request take-or-pay mitigation for purchases under section 4(b) above pursuant to section 4(e) below.

(e) **Take-or-Pay Mitigation for Curtailments**
If CFAC chooses to curtail its purchase obligation, then the following terms and conditions shall apply:

(1) **Notice of Curtailment**
CFAC shall provide written notice to PBL and Flathead at least three (3) Business Days in advance of a curtailment. Such notice shall specify the monthly amounts of power to be curtailed and the duration of the curtailment. The election to curtail such power, and the amount and duration of such curtailment, may not be changed without PBL's consent. PBL's sale to Flathead shall be reduced by the amount of power curtailed, and Flathead shall not be assessed any damages or

incur any liability as a result of any such reduction. The Monthly Purchase Deficiency will be reduced by any reduction to the Demand Entitlement pursuant to section 7(b)(2) below.

(2) **Calculation of Damages**
CFAC shall pay directly to BPA damages for each Monthly Purchase Deficiency equal to the amount by which the reasonable market value of such Monthly Purchase Deficiency is less than the price of the applicable rate specified in Exhibit A. For purposes of calculating damages under this section 4(e)(2), the Monthly Purchase Deficiency(s) shall be reduced by any reduction of Demand Entitlement under section 7(b)(3), effective on the date any such reduction becomes effective. No later than 60 days following the end of each Contract Year, PBL shall, for each month of the previous Contract Year, calculate the reasonable market value for each Monthly Purchase Deficiency during such Contract Year. Reasonable market value and calculation of damages shall be determined as follows.

(A) No later than 3 Business Days prior to the commencement of a curtailment under this section 4(e), CFAC may obtain one or more transactable quotes for all or a portion of such power from a third party. The transactable quote may be for any length of time and curtailment amount. Each quote shall be deemed equal to the reasonable market value of such power to which the quote applies for the purpose of calculating damages under this section 4(e)(2). BPA may, but shall not be obligated to, resell the curtailed power to the third party, retain the power, or dispose of the power as it chooses. CFAC shall allow PBL at least 4 hours during normal business hours to decide whether or not to transact under such quote.

(B) BPA shall determine, by any reasonable method, the reasonable market value of the portion of each Monthly Purchase Deficiency for which CFAC has not obtained a transactable quote. The reasonable market value shall be adjusted to reflect volume and BPA transmission costs associated with remarketing each such portion of the Monthly Purchase Deficiency, regardless of whether each such portion is actually remarketed.

(C) BPA shall bill CFAC and CFAC shall directly pay BPA damages for such Contract Year equal to the amount by which the sum of the product of (1) each Monthly Purchase Deficiency and (2) the applicable rate specified in Exhibit A that BPA would have charged each month if the power had been taken under this Agreement, exceeds the sum of the product of (1) each Monthly Purchase Deficiency and (2) the reasonable market value in each month. Amounts for damages

under section 4(e)(2)(A) and section 4(e)(2)(B) may only be netted within a Contract Year. If a transactable quote for a curtailment or portion of a curtailment extends into a future Contract Year, then the total amounts associated with such quote will be netted in the Contract Year in which the curtailment or portion of curtailment associated with such quote begins. BPA is not obligated to pay CFAC the difference when the reasonable market value exceeds the applicable rate in Exhibit A.

It is expressly agreed to by the Parties that BPA shall not be obligated to enter into replacement transactions to determine or collect damages under this section 4(e)(2).

It is also expressly agreed that BPA will apply its then-current applicable credit policies if damages are due under this section 4(e)(2), and such policies may include an obligation to prepay for damages.

(f) **Scheduling**

All Surplus Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit C, BPA Power Business Line Scheduling Provisions. The procedures for scheduling described in Exhibit C are the standard utility procedures followed by BPA for power transactions between PBL and other utilities or entities in the Region that require scheduling.

(g) **Delivery**

(1) **Transmission Service for Surplus Firm Power**

This Agreement does not provide transmission services for, or include the delivery of, Surplus Firm Power by BPA to Flathead, or by Flathead to CFAC. CFAC shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Surplus Firm Power (Wheeling Agreement). PBL and CFAC agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power to CFAC, consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(2) **Liability for Delivery**

CFAC waives any claims against PBL and Flathead arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. Neither Flathead nor PBL shall be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event shall any Party be liable under this Agreement to any other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for transfer service.

(3) **Points of Receipt**
PBL shall make Surplus Firm Power available to Flathead, and Flathead shall make Surplus Firm Power available to CFAC under this Agreement at Points of Receipt solely for the purpose of CFAC scheduling transmission to points of delivery for service to CFAC's Total Plant Load. CFAC shall schedule, if scheduling is necessary, such Surplus Firm Power solely for use by its Total Plant Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to Flathead and CFAC no later than October 1, 2008.

If required by the Wheeling Agreement, when PBL designates such Points of Receipt, PBL shall provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under CFAC's Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount of Surplus Firm Power specified in sections 4(a) and 4(b) above. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of a nonfirm Point of Receipt to provide Surplus Firm Power to Flathead for the account of CFAC, but notwithstanding section 4(g)(2) above, PBL shall reimburse CFAC for any additional costs or production losses incurred by CFAC due to its compliance with such request.

(4) **Transmission Losses**
PBL shall provide CFAC the transmission losses between the Points of Receipt and CFAC's points of delivery for Surplus Firm Power, at no additional charge. Such losses shall be provided at Points of Receipt as established under section 4(g)(3) above, and under the terms and conditions as defined in the transmission provider's tariff.

(h) **Measurement**

(1) Amounts of Surplus Firm Power taken are deemed equal to the amount scheduled by CFAC under section 4(f) above or an amount of power as measured at Points of Measurement, as appropriate.

(2) CFAC shall provide reasonable notice to PBL and Flathead prior to changing control areas.

(i) **Interruption Rights**
PBL shall have a one-time right during the term of this Agreement to interrupt deliveries of a portion of the Surplus Firm Power hereunder pursuant to the following provisions. PBL may interrupt a portion of Surplus Firm Power deliveries if PBL anticipates, in its sole and exclusive discretion,

that average forward market prices for a flat block of power will exceed $125/MWh during an interruption period to be specified by PBL in a written notice. In this event, PBL shall consult with CFAC and Flathead prior to providing such written notice. If PBL decides to interrupt, then it will provide 90 days advance written notice to CFAC and Flathead that specifies the amount of Surplus Firm Power to be interrupted and the associated interruption period; *provided, however,* that a minimum of 6 aMW will not be subject to any such interruption. Unless the Parties mutually agree otherwise, such interruption period shall extend for a minimum of 6 months and for a maximum of 12 months, regardless of the level of actual market prices during an interruption period. In the event of an interruption, BPA shall pay Flathead, and Flathead shall in turn pay CFAC, $24/MWh for amounts interrupted. Payments shall be made pursuant to section 9(b) below. Payments to CFAC under this section 4(i) shall be used first to compensate CFAC's employees employed at the time of an interruption under this section 4(i) by providing each such employee, at the election of CFAC, either (1) the opportunity to work a regular work week (40 hours) at regular wage and benefit rates, or (2) special supplemental benefits such that the employee's effective after-tax income (including any available unemployment income) will be equal to what the employee's income would have been working a regular work week, plus all benefits the employee would have received, had the employee been working a regular 40-hour work week. BPA shall have the right to conduct an audit to verify compliance with this section 4(i). If there is an interruption under this section 4(i), then the portion of Demand Entitlement interrupted shall be treated as if taken for purposes of section 7(b)(1)(A) and shall not be subject to the take-or-pay provisions in sections 4(a) and 4(b).

(j) **Modification of Flathead's Obligations**

(1) Flathead shall have no obligation to purchase any power from BPA under this Agreement except for such power that CFAC is obligated to and does purchase from Flathead under this Agreement. Flathead shall have no obligation to make available to CFAC any power under this Agreement except for such power that BPA is obligated to and does make available to Flathead under this Agreement. Notwithstanding anything in this Agreement to the contrary, if the obligation of BPA to make available power to Flathead or the obligation of CFAC to purchase power from Flathead are modified for any reason, including but not limited to curtailment, interruption or any change to the Demand Entitlement, then Flathead's corresponding obligation to make power available to CFAC and/or to purchase power from BPA shall be modified to the same extent.

(2) Flathead's obligation to purchase power from BPA and Flathead's obligation to make power available to CFAC are contingent upon CFAC performing its corresponding obligation's under this Agreement to purchase power from Flathead and upon BPA performing its corresponding obligation to make power available to Flathead.

Flathead's obligations under this Agreement to BPA and CFAC shall be excused and reduced to the extent of any nonperformance by CFAC or BPA of their corresponding obligations under this Agreement to Flathead.

5. BPA AND CFAC OPTIONS

(a) **Monetary Benefits for the FY 07-09 Rate Period**
BPA has determined that, during the FY 07-09 Rate Period, in order to meet the cost caps described in the Administrator's ROD with certainty, it will monetize the physically delivered Surplus Firm Power sale obligation; provided, however, if CFAC chooses an option specified in section 5(c) or 5(d) and/or 8(a)(4) below, then the physically delivered Surplus Firm Power sale obligation will be monetized for the entire Option Period. As such, BPA will make any MB Monthly Payments during the FY 07-09 Rate Period, the FY 10-11 Rate Period or the CY 2011 period, as applicable, subject to the provisions of section 5(c), 5(d), and 6 below.

(b) **BPA Option for the FY 10-11 Rate Period and the CY 2011 period**
PBL shall have the option to discontinue Monetary Benefits after the FY 07-09 Rate Period and to revert to a physically delivered Surplus Firm Power sale for the FY 10-11 Rate Period or for the CY 2011 period. This option is not applicable to the portion of MB Monthly Payments which CFAC has chosen to lock in under section 5(c), 5(d), and/or 8(a)(4). If PBL chooses to exercise this option, then BPA shall provide written notice to CFAC and Flathead no later than October 1, 2008. In this event, the provisions of section 6 below shall not apply to that portion of Monetary Benefits that have reverted to a physically delivered Surplus Firm Power sale during the period this option is applicable, and this Agreement will operate in whole or in part as a physically delivered Surplus Firm Power sale, subject to the provisions of section 4 above, unless CFAC elects to terminate this Agreement pursuant to section 16(b) below. In addition, in the event of a physical power sale, BPA will require CFAC to provide performance assurances, consistent with BPA's then-current applicable credit policies.

Prior to exercising this option BPA shall conduct a public process providing an opportunity for customers to comment on the merits of exercising the option.

(c) **CFAC Option for CY 2007-2009, CY 2007-2010 or CY 2007-2011**
CFAC shall have a one time option to establish its MB Monthly Payments for CY 2007-2009, CY 2007-2010, or CY 2007-2011 pursuant to this section 5(c). If this option is selected by CFAC, then the lower of the Forward Flat-Block Price Forecast, in effect on the date CFAC provides written notice pursuant to this section 5(c), or the average purchase price paid for power to serve CFAC's Total Plant Load during the Option Period shall establish the Forecast Market Price when calculating CFAC's MB Monthly Payments as specified in section 6 below. The power purchase contracts entered into by CFAC shall cover the full term of the Option Period and, except for UBA

amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit calculation during the Option Period. If CFAC chooses to exercise this option, then CFAC shall provide written notice to BPA and Flathead no later than September 30, 2006, specifying the CY 2007-2009, CY 2007-2010 or CY 2007-2011 period for which it has selected this option. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice CFAC shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate CFAC's MB Monthly Payments for this option.

(d) **CFAC Option for CY 2010-2011 and CY 2011**
Provided CFAC exercised either the CY 2007-2009 option or the CY 2007-2010 option specified in section 5(c) CFAC shall also have a one time option to establish its MB Monthly Payments for the remainder of the Agreement. If CFAC selects this option, then the lower of the Forward Flat-Block Price Forecast, in effect on the date CFAC provides written notice pursuant to this section 5(d), or the average purchase price paid for power to serve CFAC's Total Plant load during the Option Period shall establish the Forecast Market Price when calculating CFAC's MB Monthly Payment specified in section 6 below. The power purchase contracts entered into by CFAC shall cover the full term of the Option Period and, except for UBA amounts subject to section 8(a)(4), shall be for all power included in the Monetary Benefit calculation during the Option Period. If CFAC chooses to exercise this option, then CFAC shall provide written notice to BPA and Flathead no later than September 30, 2007. In such event, the provisions of section 6(c)(6) shall not apply to Monetary Benefits subject to this option during the Option Period. Within 30 days of providing such notice, CFAC shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate CFAC's MB Monthly Payments for this option.

6. MONETARY BENEFIT PROVISIONS

This section 6 only applies when the physically delivered Surplus Firm Power sale is monetized. The provisions in section 4 shall not apply to Monetary Benefits.

(a) **Determination of Forecast Market Price and Equivalent PF for each CY or Option Period**
PBL shall determine the Forecast Market Price and Equivalent PF for each CY, using the procedures described in Exhibit F: provided, however, if CFAC selects any option specified in section 5(c) or 5(d), then the Forward Market Price shall be determined as specified in the option(s) selected by CFAC during the Option Period.

(b) **Determination of Monthly Plant Load**
No later than five (5) Business Days following the end of each month, PBL shall determine the Monthly Plant Load for each such month.

(c) **Determination of MB Monthly Payments**

Except as provided for in section 6(c)(5) below, the procedures described in Exhibit F and the following procedure, as described in sections 6(c)(1) through 6(c)(4), shall be used to determine the MB Monthly Payment for each month.

(1) Except as provided in section 6(c)(5), if the Monthly Plant Load is less than the Minimum Allocation during any month (Deficient Month), then the MB Monthly Payment for that month is $0.

(2) If the Monthly Plant Load is equal to or greater than the Maximum Allocation during any month, then the Monthly Plant Load shall be deemed equal to the Maximum Allocation for that month.

(3) The Maximum MB Monthly Payment for each month is determined by the following equation:

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh or MB Rate);

provided, however, during the FY 07-09 Rate Period MB Monthly Payments for Option Benefits shall be determined by the following equation;

Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in month)) x (lesser of $12/MWh x 0.92 or MB Rate).

(4) The MB Monthly Payment for each month shall be the lesser of the Maximum MB Monthly Payment determined pursuant to section 6(c)(3) above or the amount determined by the following equation:

MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate)

(5) CFAC may exercise the following one-time option. If CFAC desires to exercise its one-time option pursuant to this section 6(c)(5), then CFAC shall provide written notice to PBL and Flathead that it will increase smelting load as of a date specified by CFAC in such notice (Start Date). Then, for the remainder of the month that includes the Start Date and the following 2 months, the MB Monthly Payment shall be determined by the following equation:

MB Monthly Payment = (Total Plant Load) x MB Rate

Each MB Monthly Payment determined under this section 6(c)(5) shall not exceed the Maximum MB Monthly Payment.

(6) In addition to other limitations specified in the Agreement, CFAC is only entitled to Monetary Benefits which when subtracted from the amount equal to its power costs to serve its Total Plant Load during the CY, does not reduce its power cost below the Equivalent PF multiplied by such total amount of power. If at any time during a Contract Year CFAC knows it has procured power at a cost that will result in less than the full Monetary Benefits to reach the Equivalent PF, then CFAC shall notify BPA of such cost and BPA shall reduce its payments accordingly for the remainder of the Contract Year.

This paragraph applies only for periods other than the Option Period, except with respect to acquired UBA not included in Option Benefits. Within 90 days following the end of each CY, BPA shall have the right to request: 1) Access to contracts, invoices or other documentation reasonably necessary for BPA to verify that purchases by CFAC of power equal to the sum of CFAC's Total Plant Loads for such CY and the cost of such purchases; and/or 2) A written certification from CFAC's CFO of power purchases by CFAC used to serve the sum of CFAC's Total Plant Loads for such CY and the cost of such purchases. CFAC shall provide BPA access to such contracts and documentation for such power purchases, subject to reasonable conditions to maintain the confidentiality of such information. If the difference between the cost of such purchases and their cost calculated as if they had been priced at the Equivalent PF is less than the sum of the Monetary Benefits that were paid to CFAC for such CY, then CFAC shall owe BPA such difference (Overpayment). BPA shall notify CFAC of any such Overpayment and will reduce the total Monetary Benefits in the CY following the CY in which the Overpayment occurred by the amount of such Overpayment. If the Overpayment exceeds Monetary Benefits available during that following CY, then any unrecovered Overpayment will carryover to reduce Monetary Benefits in subsequent years until fully recovered.

If, upon termination of this Agreement, an Overpayment occurred for the CY prior to such termination, then, within 90 days following the end of such CY, BPA shall invoice CFAC and CFAC shall pay BPA such Overpayment within 20 days of receipt of such invoice.

(7) Notwithstanding anything to the contrary in this Agreement, in no case shall the annual Monetary Benefit total exceed the Monetary Benefit Limit specified in Exhibit E of this Agreement.

(d) **Examples**
Section 1 of Exhibit D contains several illustrative examples of the calculation of MB Monthly Payments, using a variety of assumptions.

7. DETERMINATION OF UNUSED BENEFIT AMOUNTS

The following procedures shall be used to determine UBA.

(a) **Determination of Unused Benefit Amounts During Periods When Surplus Firm Power Sale is Monetized**
This section 7(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Beginning in October 2007, and following each month thereafter, PBL shall track the amount of Monetary Benefit that CFAC has taken during each of the preceding 12 months.

(2) In order to retain its Maximum Allocation, CFAC must, for at least one month during the preceding 12 months, have received the Maximum MB Monthly Payment. If this condition has not been satisfied, then the Maximum Allocation shall be reduced.

(3) CFAC shall retain the highest monthly percentage of the available benefits that it accessed during the previous 12 months. As such, CFAC's Maximum Allocation shall be reduced by the percentage of the available benefits, rounded to the nearest aMW, that were not accessed during the month that set the highest monthly percentage. The amount of aMW from this calculation becomes an Unused Benefit Amount or UBA.

(4) In the event of an UBA, PBL shall provide written notice to CFAC and Flathead that CFAC's Maximum Allocation shall be reduced by the UBA. Such reductions shall become effective at 2400 hours on the last day of the month in the month the notice is provided (Date of Maximum Allocation Reduction). CFAC understands and agrees that it will not have an option to re-acquire UBA that it has lost for one month following the Date of Maximum Allocation Reduction and that Other DSIs may acquire the UBA. BPA shall unilaterally revise Exhibit E, effective on the Date of Maximum Allocation Reduction, to reflect the reduced Maximum Allocation. BPA shall also provide notice of the availability of the UBA to the Other DSIs.

(b) **Determination of Unused Benefit Amounts During Periods When the Surplus Firm Power Sale Is Physically Delivered**
This section 7(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) In order to assure its right to retain its Demand Entitlement, as specified in Exhibit E, CFAC must, for at least one month during the preceding 12 months, have either (A) taken Surplus Firm Power equal to its Demand Entitlement during all hours of such month, or (B) taken the maximum Monetary Benefit available to it during such month. If this condition has not been satisfied, then the Demand Entitlement may be reduced.

(2) If the condition in section 7(b)(1) has not been satisfied, then BPA shall calculate the following for each of the previous 12 months:

(A) the percentage of the available Monetary Benefit received by CFAC, and (B) the percentage of the Demand Entitlement taken by CFAC. BPA may reduce the Demand Entitlement to the highest of such percentages multiplied by the Demand Entitlement, and rounded to the nearest MW. The MW amount of such reduction becomes an UBA.

(3) In the event of an UBA resulting from section 7(b)(2), PBL shall provide written notice to CFAC and Flathead that the Demand Entitlement may be reduced by the UBA. If all or a portion of such UBA is acquired by the Other DSIs pursuant to section 8(b) below, then the Demand Entitlement shall be reduced by the amount of UBA so acquired. Any such reduction shall become effective at 2400 hours on the last day of the month prior to the month that UBA has been acquired by the Other DSIs (Date of Demand Entitlement Reduction). BPA shall unilaterally revise Exhibit E, effective on the Date of Demand Entitlement Reduction, to reflect the reduced Demand Entitlement. If UBA made available under this section 7(b)(3) is not acquired by CFAC or the Other DSIs within 6 months following the date such UBA became available, then BPA may, but shall not be obligated to, revise Exhibit E unilaterally to reduce the Demand Entitlement by the UBA not acquired.

(4) If an UBA results from a termination of this Agreement pursuant to section 16(b) below, then the entire Demand Entitlement becomes an UBA as of the effective date specified in section 16(b) below. BPA shall provide notice of the availability of any UBA that becomes available under this section 7(b)(4) to the Other DSIs pursuant to the notice provisions in section 7(b)(3) above. The Other DSIs may acquire this UBA pursuant to section 8(b) below.

(5) If CFAC provides PBL and Flathead written notice of curtailment under section 4(e)(1) and UBA will result during the term of such curtailment by operation of sections 7(b)(1) and 7(b)(2), then for purposes of sections 7(b)(2) and 7(b)(3), the UBA that would result during the term of the curtailment shall become UBA upon commencement of the curtailment.

(c) **Examples**
Section 2 of Exhibit D contains several illustrative examples of the determination of UBA, using a variety of assumptions.

8. OPTION TO ACQUIRE UNUSED BENEFIT AMOUNTS

The following procedures shall be used to acquire UBA.

(a) **Option to Acquire Unused Benefit Amounts During Periods When the Physically Delivered Surplus Firm Power Sale is Monetized**
This section 8(a) only applies when the physically delivered Surplus Firm Power sale is monetized.

(1) Unless CFAC provides written notice to PBL and Flathead that it has chosen not to acquire UBA, available UBA amounts will be added to CFAC's Maximum Allocation, to the extent that doing so will increase the MB Monthly Payment it will receive for each month.

(2) During months when increases in Monthly Plant Load by CFAC and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to CFAC and other DSIs, based on Maximum Allocation.

(3) BPA shall unilaterally revise Exhibit E to reflect the addition of acquired UBA in CFAC's Maximum Allocation and Monetary Benefit Limit.

(4) If CFAC has selected an Option Period under section 5(c) above, Monetary Benefits for the acquired UBA will not be included in calculations for Option Benefits and instead will be calculated separately under 6(c) above using the current Forecast Market Price as established under the provisions of Exhibit F of the Agreement unless and until CFAC notifies BPA it will include the acquired UBA in the calculations to establish the MB Monthly Payments for the remainder of the Option Period. If this option is selected, then the purchase price used as the Forecast Market Price in the calculation of the Option Benefits shall be based on a megawatt hour weighted average of: i) the average purchase price previously used to calculate the Option Benefits, and ii) the average purchase price for acquired UBA, provided that the average purchase price for acquired UBA shall be limited by the Forecast Market Price in effect at the time CFAC notifies BPA it will exercise this option.

If CFAC chooses to exercise this option, then CFAC shall provide written notice to BPA and Flathead of the purchase price for the power purchased to serve the acquired UBA. For purposes of calculating MB Monthly Payments, the starting date of the purchase shall be the beginning of the month following the notice. Power purchases under this option must begin no later than 6 months following the effective date of the revision to Exhibit E for such acquired UBA. The provisions of section 6(c)(6) shall not apply to these UBA amounts during the Option Period. Instead, within 30 days of providing its power purchase notice, CFAC shall provide BPA access to contracts, invoices, or other documents reasonably necessary for BPA to verify the purchase price of power used to calculate CFAC's MB Monthly Payments for this option.

(5) UBA amounts that remain available and unused for 6 months following the Date of Reduction shall be zeroed out and will no longer be available to CFAC or the Other DSIs during the term of this Agreement.

(b) **Option to Acquire Unused Benefit Amounts During Periods When the Surplus Firm Power is Physically Delivered**
This section 8(b) only applies when the Surplus Firm Power sale is physically delivered.

(1) Following receipt of a notice provided under section 7(b)(3) above, CFAC shall provide written notice to PBL and Flathead of the amount of UBA it wishes to purchase, if any.

(2) UBA amounts requested pursuant to section 8(b)(1) above will be added to the Demand Entitlement, effective on the first day of the month following receipt of the notice provided under section 8(b)(1) above.

(3) When requests for UBA by CFAC and Other DSIs exceed the amount of UBA available, UBA will be allocated pro rata to CFAC and other DSIs, based on Demand Entitlement.

(4) BPA shall unilaterally revise Exhibit E, effective on the date determined in 8(b)(2), to reflect an increase to the Demand Entitlement by the amount of acquired UBA.

(5) Any UBA acquired pursuant to this section 8(b) that remains unused after 6 months following the date specified in 8(b)(2) above will no longer be available to CFAC or the Other DSIs. Amounts of Total Plant Load during such 6-month period that are less than the increased Demand Entitlement shall become an unused UBA. Such unused UBA shall be considered a Monthly Purchase Deficiency for each month of the remaining term of this Agreement, and CFAC shall be subject to damages pursuant to section 4(e)(2) above.

(c) Any increased: (1) Maximum Allocation under section 8(a) above; or (2) Demand Entitlement under section 8(b) above shall not exceed 171 MW.

(d) Section 3 of Exhibit D contains several illustrative examples of the acquisition of UBA, using a variety of assumptions.

9. BILLING AND PAYMENT

(a) **Billing and Payment Provisions During Power Sale**
If, pursuant to section 5(b) above, BPA provides written notice that this Agreement will operate as a physically delivered Surplus Firm Power sale during the FY 10-11 Rate Period or the CY 11 period, then no later than March 1, 2009, the Parties shall amend this section 9(a) to include billing and payment provisions for: (1) the physically delivered Surplus Firm Power sale by PBL to Flathead; and (2) the power sale by Flathead to CFAC.

(b) **Billing and Payment When Monetary Benefits Provided**

(1) **Escrow Account**
BPA and Flathead shall establish an Escrow Account, in accordance with the laws governing Flathead, for MB Monthly Payments and any interruption payments pursuant to section 4(i). BPA shall make payments into the Escrow Account, but only Flathead shall have the ability to effect withdrawals from the Escrow Account for payment to CFAC.

(2) **Payments into the Escrow Account**
Within five Business Days after the end of each month, BPA will review CFAC's metered load measurements to determine if the Monthly Plant Load for the month is equal to or exceeds the Minimum Allocation.

Within eight Business Days following the end of the month, BPA shall transfer an amount equal to the MB Monthly Payment, and any interruption payments pursuant to section 4(i) above, into the Escrow Account.

(3) **Payments from the Escrow Account**
Within 12 business days following the end of the month, Flathead shall effect the transfer of all BPA monthly payment amounts received into the Escrow Account pursuant to this Agreement to CFAC.

(4) **Escrow Account Safeguard**
Flathead shall treat the Escrow Account in accordance with the terms of this Agreement and the agreement setting up the Escrow Account and not as property of Flathead. Flathead shall effect the release of such funds from the Escrow Account pursuant only to the escrow instructions consistent with this Agreement that BPA and Flathead shall develop and provide to the escrow agent. Except to the extent Flathead has failed to effect transfer of funds from the Escrow Account pursuant to the escrow instructions developed with BPA, Flathead shall not be liable under any circumstances for the funds deposited by BPA into the Escrow Account, and BPA and CFAC waive and release Flathead from any and all claims, liability or damages that could arise from any loss, payment or lack of payment of such funds in the Escrow Account.

(c) **General Terms**

(1) Limitation on Flathead's Payment Obligations
Notwithstanding anything in this Agreement to the contrary, Flathead shall have no obligation under any circumstances to pay to BPA any amounts under this Agreement, FPS rate schedule and GRSPs except for such amounts that Flathead has received from CFAC under this Agreement, and Flathead shall have no obligation under any circumstances to pay to CFAC any amounts under this

Agreement except for such amounts that BPA paid into the Escrow Account under this Agreement and that are available for transfer to CFAC.

(2) **Payment for Flathead's Administrative Costs**
Notwithstanding anything in this Agreement to the contrary, to the extent that Flathead incurs any expenses, fees, charges or costs of any kind not otherwise addressed in this Agreement, including but not limited to, attorneys fees, arising from Flathead's development of and performance under this Agreement, Flathead may bill CFAC and CFAC shall pay Flathead for any such costs in addition to the cost of power delivered from Flathead to CFAC. Amounts that CFAC pays Flathead pursuant to this paragraph 9(c)(2) shall not be treated as amounts Flathead has received from CFAC for purposes of determining the limit on Flathead's payment obligation to BPA under paragraph 9(c)(1) above.

10. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 10.

If to CFAC:

Columbia Falls Aluminum Company, LLC
40 Lake Bellevue, Suite 100
Bellevue, WA 98005
Attn: James D. Stromberg
Power Manager
Phone: 425-450-4010
FAX: 425-450-5569
E-Mail: Stromberg_cfac@att.net

If to PBL:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
Attn: Scott K. Wilson – PT-5
Account Executive
Phone: 503-230-7638
FAX: 503-230-3681
E-Mail: skwilson@bpa.gov

If to Flathead:

Flathead Electric Cooperative, Inc.
2510 U.S. Highway 2 East
Kalispell, MT 59901
Attn: Ken A. Sugden
General Manager
Phone: 406-751-4401
FAX: 406-756-6617
E-Mail: fec@flatheadelectric.com

11. UNCONTROLLABLE FORCES

(a) **Uncontrollable Forces Provisions During Surplus Firm Power Sale**
If, during the FY 10-11 Rate Period, this Agreement operates as a physical Surplus Firm Power Sale, then the following provisions shall apply; *provided however*, that UBA determinations pursuant to section 7 and acquisitions of UBA pursuant to section 8 shall not be subject to Uncontrollable Forces under this section 11(a).

PBL shall not be in breach of its obligation to provide Surplus Firm Power to Flathead and Flathead shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. Similarly, Flathead shall not be in breach of its obligation to provide Surplus Firm Power to CFAC and CFAC shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its obligations under this

Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to CFAC's facilities, including but not limited to unplanned maintenance outages;

(2) any unplanned curtailment or interruption, failure or imminent failure of CFAC's production or transmission facilities, including but not limited to unplanned maintenance outages;

(3) any planned transmission or distribution outage that affects either CFAC or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(4) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however*, that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(5) floods, earthquakes, or other natural disasters; and

(6) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Parties as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

All Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

(b) **Uncontrollable Forces Provisions During Periods When Monetary Benefit is Provided**
During periods when the Surplus Firm Power sale is monetized, CFAC understands and agrees that there are no events that will be considered Uncontrollable Forces under this Agreement.

12. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal law. Disputes arising out of this Agreement that are not otherwise subject to the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit are subject to the Contract Disputes Act, 41 USC 601, et seq.

(b) If a dispute arises under any provision of this Agreement, the Parties shall, within 14 business days following the initiation of a dispute, make a good faith effort to negotiate a resolution of such dispute before initiating the mediation provisions in section 12(c) below.

(c) If the Parties are unable to agree following negotiation pursuant to section 12(b) above, then either Party may request, in writing, to mediate the dispute. The Parties shall seek to reach agreement upon a mediator. In the event that they are unable to agree, then a mediator shall be selected by U.S. Arbitration and Mediation of Oregon. The Parties shall have 30 days from the date a Party initiated mediation to reach agreement before initiating litigation. BPA and CFAC shall each pay one half of the expenses of any mediation between or among the Parties.

(d) During a contract dispute or contract issue between or among Parties arising out of this Agreement, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impractical. The Parties reserve the right to seek judicial resolution of any dispute arising out of this Agreement.

13. STATUTORY PROVISIONS

(a) **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. Flathead, together with other customers in the Region, shall have priority to BPA power, consistent with such provisions.

(b) **Limitation on Resale**
Flathead shall not resell Surplus Firm Power, as defined in this Agreement, to any entity except CFAC.

(c) **BPA Appropriations Refinancing Act**
The BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110

Stat. 1321, 1350, is incorporated by reference and is a material term of this Agreement.

14. STANDARD PROVISIONS

(a) **Amendments**
No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
CFAC may assign this Agreement upon 90 days prior written notice, but only to a successor-in-interest that has acquired ownership, through purchase or merger, of CFAC's facilities that are served, in whole or in part, with power or Monetary Benefits provided under this Agreement, and then only if such assignee expressly agrees in writing to be bound by the terms of this Agreement. In the event of such assignment, BPA will apply its then current credit policies to determine whether it will require security or assurances from the assignee to secure performance of assignee's obligations under this Agreement. Monetary Benefits under this Agreement are not transferable for use at other aluminum smelters. Such Monetary Benefits shall only be available for eligible production facilities referred to in Exhibit B of this Agreement, subject to any limitations specifically established in Exhibit B.

(c) **Information Exchange and Confidentiality**
The Parties shall provide each other with any information that is reasonably required, and requested by any Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling, and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of 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 obligation 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.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement among the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement among the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers**
Any waiver at any time by any Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's New Large Single Load Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by CFAC or Flathead to such policy, nor shall it be construed to be a waiver of the right of CFAC or Flathead to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.

(j) **Hold Harmless**
BPA and CFAC assume all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. BPA and CFAC shall indemnify and hold the other Parties harmless from any liability arising from such act or negligence.

15. LIMITATION OF LIABILITY OF FLATHEAD AND HOLD HARMLESS

BPA and CFAC agree to and hereby do waive any suit, claim, demand or cause of action of any kind in law and equity which they may have or may assert against Flathead arising out of this Agreement, except to enforce Flathead's obligations pursuant to this Agreement (i) to effect transfer of Escrow Account funds pursuant to section 9(b) of this Agreement, and (ii) to pay such amounts received from CFAC to BPA in the amount of payments received by Flathead from CFAC pursuant to section 9(a) of this Agreement as may be amended pursuant to section 9(a) of this Agreement.

In no event or any circumstance shall Flathead be liable for special punitive, indirect, incidental or consequential losses or damages of any kind whatsoever (including but not limited to lost profits), even if Flathead has been advised of the likelihood of such loss or damage and regardless of the form of action.

Furthermore, BPA and CFAC agree to share equally any payment necessary to indemnify, hold harmless and reimburse Flathead for damages and/or any reasonable costs, other than Flathead's implementation and administrative costs billable to CFAC under section 9 of this Agreement, including, but not limited to, reasonable attorney fees, incurred by Flathead as a direct or indirect result of its participation in this Agreement.

BPA's and CFAC's agreement to indemnify and hold harmless Flathead pursuant to this section 15 shall survive the termination of this Agreement until extinguished by any applicable statue of limitations.

16. TERMINATION

(a) BPA may terminate this Agreement on 30 days written notice to the other Parties in the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order preventing or prohibiting BPA from recovering under the Slice Agreements or its Slice rate schedules that portion of BPA's cost of service associated with this Agreement allocated by BPA to such Slice Agreements or Slice rate schedules. BPA shall diligently litigate any action challenging its ability to assess such costs. Neither CFAC nor Flathead shall be entitled to any damages for such termination and hereby expressly waives any right to seek such damages.

(b) If, pursuant to section 5(b) above, BPA provides written notice to convert the payment of Monetary Benefit to a physical Surplus Firm Power Sale during the CY 2010-2011 period or the CY 2011period, then CFAC may terminate this Agreement by providing written notice to Flathead and BPA no later than November 1, 2008. The effective date of any such termination shall be 2400 hours on the September 30 immediately preceding the effective date of such conversion . In this event, the Demand Entitlement becomes an UBA as of the effective date specified in this section 16(b), and shall be offered to Other DSIs pursuant to section 7(b)(4) above.

(c) In the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final order that declares or renders this Agreement void

or otherwise unenforceable, no Party shall be entitled to any damages or restitution of any nature, in law or equity, from any other Party, and each Party hereby expressly waives any right to seek such damages.

(d) Flathead may terminate its obligations under this Agreement upon 30 days written notice to the other Parties if there is an Event of Default by CFAC. An Event of Default shall mean the failure of CFAC to pay when due the reimbursements owed by CFAC to Flathead under sections 9(c)(2), 12(c), 14(j) and/or 15 if payment is not remedied within 30 Business Days after written notice. In the event of such termination by Flathead, BPA and CFAC will establish a mutually agreeable alternative means to effectuate the payments and the acquisition of BPA power by CFAC provided for in this Agreement.

17. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

COLUMBIA FALLS ALUMINUM COMPANY, LLC

By **/S/ STEPHEN J. KNIGHT**

Name **Stephen J. Knight**
(Print/Type)

Title **Vice President**

Date **June 12, 2006**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By **/S/ SCOTT K. WILSON**
Account Executive

Name Scott K. Wilson
(Print/Type)

Date **June 9, 2006**

FLATHEAD ELECTRIC COOPERATIVE, INC.

By **/S/ KENNETH A. SUGDEN**

Name **Kenneth A. Sugden**
(Print/Type)

Title **General Manager**

Date **June 14, 2006**

Exhibit A
SURPLUS FIRM POWER RATE

If BPA chooses to exercise its option, pursuant to section 5(b) of the body of this Agreement, to sell physically delivered Surplus Firm Power under this Agreement during the FY 10-11 Rate Period, then BPA shall unilaterally revise this Exhibit A, effective on October 1, 2009, to include the specific rates and charges that will apply to the physically delivered Surplus Firm Power sale. The cost to BPA to provide such physically delivered Surplus Firm Power will not exceed the cost caps as described in the Administrator's ROD.

Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS

1. DESCRIPTION OF CFAC's PRODUCTION FACILITIES, STATION SERVICE REQUIREMENTS, AND METERING EQUIPMENT

Production Facilities: are CFAC's aluminum smelting and other facilities served from the Government's Conkelley Substation, where the 13.8 or 230 kilovolt (kV) facilities of BPA and CFAC are connected.

In addition to the production facilities identified above, CFAC's Total Plant Load may include, at CFAC's sole option, up to six (6) MW of service to the Evergreen Aluminum's (Evergreen) facility served from the Government's Alcoa Substation, where the 13.8 kV facilities of BPA and Evergreen are connected. When establishing CFAC's Total Plant Load the Evergreen portion shall be limited to the lesser of actual energy usage or 6 MW per hour.

Metering Equipment: used to measure energy usage of the CFAC facility and the Evergreen facility located in the Government's Conkelley Substation and Alcoa Substation in the 13.8 kV circuits over which such electric power and energy flows.

CFAC agrees to allow PBL access to all hourly load measurements of its Production Facilities necessary to administer this Agreement.

2. REVISIONS

This Exhibit B shall be revised upon mutual agreement of the Parties to reflect any new products, services, and special provisions that may be added during the term of this Agreement.

Effective December 15, 2003

Exhibit C
BPA POWER BUSINESS LINE SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

Unless otherwise specified in this Exhibit C, all transactions shall be scheduled in accordance with the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC). The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power products bought or sold under this Agreement. All provisions apply equally to all BPAP Counter Parties (as defined in section 2 below) and their authorized scheduling agents. Transmission scheduling arrangements are provided under separate agreements/provisions with the designated transmission provider.

2. DEFINITIONS

(a) **After the Fact**: The process of reconciling all transactions, Schedules, and accounts after they have occurred.

(b) **APOD**: Alternate Point Of Delivery. Any point other than the POD specified in a Confirmation Agreement or other contract to which this Exhibit C applies.

(c) **BPAP**: Bonneville Power Administration Power Business Line.

(d) **BPAP Counter Party**: A PSE (Purchasing Selling Entity, as defined by NERC) that has contracted to purchase from BPAP or sell to BPAP electric power products.

(e) **COB**: California-Oregon Border or COI (California-Oregon Intertie). Consists of the Pacific AC Intertie (PACI or Malin) and 3rd AC Intertie (3A or Captain Jack) transmission lines to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(f) **NOB**: Nevada-Oregon Border. Consists of the Pacific DC Intertie (PDCI or Celilo) transmission line to California. N to S indicates that the energy is flowing on the transmission path North to South. S to N indicates energy is flowing on the transmission path South to North.

(g) **POD**: Point of Delivery, as defined by NERC.

(h) **Preschedule Day**: Preschedule Day is in accordance with WECC practice and variations are identified in the WECC calendar to allow for Holidays, WECC meetings, etc.

(i) **Prescheduling**: The process (verbally and in writing) of establishing and balancing (checking out) schedules on the Preschedule Day.

(j) **Real-Time Scheduling**: Any new or modified Transaction that occurs after prescheduling is completed.

(k) **Schedule**: The planned Transaction approved and accepted by all counterparties and Control Areas involved in the Transaction.

3. COORDINATION: GENERAL, CONTROL AREA, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS

(a) General Requirements

(1) BPAP shall have the right to revise and replace this Exhibit C: (1) in the event that scheduling procedures are changed due to agreement among scheduling parties in the WECC; (2) to comply with rules or orders issued by the Federal Energy Regulatory Commission (FERC) or NERC, or (3) to implement changes reasonably necessary for BPAP to administer its power scheduling function in a more efficient manner.

(2) BPAP and each BPAP Counter Party must have necessary staff available during both parties' Prescheduling, Real-Time Scheduling, and After the Fact check out processes, including the completion of the NERC Etag.

(3) All transactions shall be stated in the Pacific Prevailing Time (PT), beginning with the 0100 hour ending.

(4) BPAP and each BPAP Counter Party shall notify each other of changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time Scheduling, After the Fact, or scheduling agents, etc.).

(b) Prescheduling Requirements

(1) Information Required For Any Preschedule

(A) When the NERC Tag is prepared, the BPAP Counter Party purchasing from BPAP shall use commercially reasonable efforts to ensure the BPAP Confirmation Agreement contract number is included within the generation/load segment, in the XML "Contract Number" element of the Etag.

(B) Transactions to or from COB must identify the use of either Malin or Captain Jack.

(2) **Preschedule Coordination**
Final hourly Schedules must be submitted by each BPAP Counter Party to BPAP for the next day(s) transactions by 1100 PT of each Preschedule Day, unless otherwise agreed. After 1100 PT Preschedules can be accepted if mutually agreed to by BPAP and the BPAP Counter Party, and the Preschedules are accepted by the transmission provider(s).

(c) **Real-Time Scheduling Requirements**

(1) BPAP Counter Parties may not make real-time changes to the schedules unless such changes are allowed under specific Confirmation Agreements or other contracts to which this Exhibit C applies, and by mutual agreement.

(2) If real-time changes to the schedule become necessary and are allowable as described in section 3(c)(1) above, the requesting BPAP Counter Party must submit requests for such changes no later than specified in the contract or BPAP Confirmation Agreement. Emergency schedule changes (including mid-hour changes) will be handled in accordance with WECC procedures.

(3) Multi-hour changes to the schedule shall specify an "hour beginning" and an "hour ending" and shall not be stated as "until further notice."

(d) **After the Fact Reconciliation Requirements**
Each BPAP Counter Party agrees to reconcile all transactions, Schedules, and accounts following the end of each month (within the first 10 calendar days of the next month).

Exhibit D
EXAMPLES

I. EXAMPLES OF THE CALCULATION OF MONETARY BENEFIT PAYMENTS

Following are examples of the calculation of Monetary Benefit payments pursuant to section 6 of the body of this Agreement.

Example No. 1: Calculation of MB Rate, Maximum MB Monthly Payment, and MB Monthly Payment.

Demand Entitlement	250	aMW
Hours in the Month Equals	744	

Difference Between Forecast Market Price and Equvalent PF	MB Rate	Maximum MB Payment	Minimum Load (aMW) to Receive Maximum MB Monthly Payment
$26.00	$24.00	$2,232,000	125.0000
$25.00	$24.00	$2,232,000	125.0000
$24.00	$24.00	$2,232,000	125.0000
$23.00	$24.00	$2,232,000	130.4348
$22.00	$24.00	$2,232,000	136.3636
$21.00	$24.00	$2,232,000	142.8571
$20.00	$24.00	$2,232,000	150.0000
$19.00	$19.00	$2,232,000	157.8947
$18.00	$18.00	$2,232,000	166.6667
$17.00	$17.00	$2,232,000	176.4706
$16.00	$16.00	$2,232,000	187.5000
$15.00	$15.00	$2,232,000	200.0000
$14.00	$14.00	$2,232,000	214.2857
$13.00	$13.00	$2,232,000	230.7692
$12.00	$12.00	$2,232,000	250.0000
$11.00	$11.00	$2,046,000	250.0000
$10.00	$10.00	$1,860,000	250.0000
$9.00	$9.00	$1,674,000	250.0000
$8.00	$8.00	$1,488,000	250.0000
$7.00	$7.00	$1,302,000	250.0000
$6.00	$6.00	$1,116,000	250.0000
$5.00	$5.00	$930,000	250.0000
$4.00	$4.00	$744,000	250.0000
$3.00	$3.00	$558,000	250.0000
$2.00	$2.00	$372,000	250.0000
$1.00	$1.00	$186,000	250.0000
$0.00	$0.00	$0	0.0000

Example No. 2: Difference between Forecast Market Price and Equivalent PF exceeds $24/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example the DSI is entitled to the Maximum MB Monthly Payment each month that the actual monthly load equals or exceeds the Minimum Allocation. January through May monthly loads were less than the Minimum Allocation Requirement, and the MB Monthly Payments equal zero.

Example No. 3: Difference between Forecast Market Price and Equivalent PF equals $18/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example the DSI is entitled to the Maximum MB Monthly Payment only September. January thru May MB Monthly Payments equal zero because the DSI failed to meet the Minimum Allocation requirement. For the remaining months an MB Monthly Payment equal to the actual monthly load multiplied by the MB Rate ($18.00/MWh) was paid.

Example No. 4: Difference between Forecast Market Price and Equivalent PF equals $8/MWh and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation.

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example, January through May the MB Monthly Payment equals zero because the DSI failed to meet the Minimum Allocation requirement. In the remaining months the MB Monthly Payment equals actual monthly load multiplied by the MB Rate ($8.00/MWh).

Example No. 5: Equivalent PF is greater than the Forecast Market Price and the DSI's operation varies from less than its Minimum Allocation to its Maximum Allocation

Forecast of Maximum MB Monthly Payment for CY

Equivalent PF subject to same adjustments established for the PF rate.

CY MB Monthly Payments, Demand Entitlement Equals 250 MW

In this example the Forecast Market Price is less than the Equivalent PF so there are no MB Monthly Payments made to the DSI.

II. EXAMPLES OF THE DETERMINATION OF UNUSED BENEFIT AMOUNTS

Following are examples of the determination of Unused Benefit Amounts pursuant to section 7 of the body of this Agreement.

Example No. 1: DSI's operation without any UBA made available at the end of the 12 month period. Maximum Allocation equals 250 aMW and the MB Rate equals $18/MWh.

No UBA is made available at the end of this 12month period because the DSI received a Maximum MB Monthly Payment in April but one more month without accessing the Maximum MB Monthly Payment will result in UBA; up to 6 percent of this DSI Maximum Allocation may be made available to the Other DSIs.

Example No. 2: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $18/MWh.

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (93.75%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.9375 = 234.375 rounded to 234 aMW). UBA that will be made available to the Other DSIs is 250 aMW minus 234 aMW, 16 aMW.

Example No. 3: DSI's operation with UBA resulting at the end of the 12-month period. Maximum Allocation/Demand Entitlement equals 250 aMW and the MB Rate equals $12/MWh.

In this example, the Maximum MB Monthly Payment was not accessed any month over the past 12 months. The DSI's Maximum Allocation times the highest percentage accessed (62.50%) over the pass 12 months rounded to the nearest aMW establishes its new Maximum Allocation (250 aMW * 0.62.50 = 156.25 rounded to 156 aMW). UBA that will now be made available to the Other DSIs is 250 aMW minus 156 aMW, 94 aMW.

III. EXAMPLES OF THE ACQUISITION OF UNUSED BENEFIT AMOUNTS

Following are examples of the acquisition of Unused Benefit Amounts pursuant to section 8 of the body of this Agreement.

Example No. 1: Maximum Allocation increases of two DSI who both increased operation to acquire nearly all available UBA (94 aMW).

In this example DSI-A was allocated 50 aMW and DSI-B was allocated 39 aMW. The new Demand Entitlement for DSI-A is 190 aMW and 139 aMW for DSI-B. The remaining 5 aMW of UBA was never acquired and after September was not available to any DSIs.

Example No. 2: Same as Example #1 except DSI-A has a contractually limited Maximum Allocation of 171 aMW.

In this example DSI-A's Demand Entitlement was limited to 171 aMW. DSI-A was allocated 31 aMW and DSI-B was allocated its 39 aMW of UBA. Available UBA was 24 aMW through September but because none was acquired during this period it was no longer available to any DSIs afterward.

Example No. 3: Maximum Allocation of two DSIs increased over 2-month period with full amount of UBA (94 aMW) allocated.

In this example DSI-B increased its load in April sufficient to acquire 45 aMW of the available UBA, resulting in its Maximum Allocation increasing from 100 aMW to 145 aMW beginning with May. Both DSIs increased load sufficiently for the remaining UBA to be allocated during May, increasing DSI-A's Maximum Allocation to 164 aMW and DSI-B's Maximum Allocation to 170 aMW.

Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT

1. **MAXIMUM AND MINIMUM ALLOCATIONS**
During periods when Monetary Benefit payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefit Limit amounts are as follows:

Maximum Allocation:	140 aMW
Minimum Allocation:	35 aMW
Monetary Benefit Limit:	$14 ,716,800/CY (Leap Year $40,320 greater.)

2. **DEMAND ENTITLEMENT**
During periods when this Agreement operates as a physical Surplus Firm Power sale pursuant to section 4 of the body of this Agreement, the Demand Entitlement shall be as follows:

Demand Entitlement:	140 MW

3. **REVISIONS**
BPA shall unilaterally revise this Exhibit E to reflect changes to Maximum Allocation, Minimum Allocation, Monetary Benefit Limit, and/or Demand Entitlement.

Exhibit F
DETERMINATION OF FORECAST MARKET PRICE AND EQUIVALENT PF

1. DETERMINATION OF FORECAST MARKET PRICE

Prior to the beginning of each Contract Year, the following provisions shall be used to determine the Forecast Market Price.

(a) **Definitions**

(1) **"2007-2011 Agreements"** means the agreements between BPA and each PNW IOU that provide for among other things, the determination of the Forward Flat-Block Price Forecast for each year, 2007 through 2011.

(2) **"FBPF Exhibit"** means the exhibit titled "Determination of Forward Flat-Block Price Forecast For Contract Years 2007 through 2011, which is attached to each of the 2007-2011 Agreements.

(3) **"Forward Flat-Block Price Forecast"** or **"FBPF"** means the Forward Flat-Block Price Forecast developed from time to time under the 2007-2011 Agreements.

(4) **"Forward Price Data Agreement"** means BPA Contract No. 04PB-11534 among BPA and the PNW IOUs.

(5) **"PNW Investor-Owned Utility"** or **"PNW IOU"** means each of the following investor-owned utilities (and its investor-owned utility successors and assigns) that serves residential and small farm customers in the Pacific Northwest: Puget Sound Energy, Inc., PacifiCorp, Portland General Electric Company, Avista Corporation, Idaho Power Company, and NorthWestern Energy Division of NorthWestern Corporation.

(b) **Determination of Forecast Market Price**

(1) BPA has contracted with a qualified third party (QTP) pursuant to the FBPF Exhibit to determine the Forward Flat-Block Price Forecast for each Contract Year, 2007 through 2011.

(2) During four consecutive quarters prior to the beginning of each Contract Year, 2007 through 2011, the QTP surveys certain eligible data providers (EDPs) that have signed contracts in the form of Exhibit A to the Forward Price Data Agreement.

(3) The first quarterly survey for CY 2007 is conducted during Q1 of calendar year 2005 (January 2005-March 2005). The last quarterly survey for CY 2007 is conducted during Q4 of calendar year 2005 (October 2005-December 2005). The same procedure is followed for CY 2008 through 2011 but the quarters surveyed change to calendar

years 2006 through 2009, respectively. Each quarterly survey results in an FBPF for the upcoming CY. The average of the four quarterly FBPFs is the FBPF that is used to calculate benefits under the 2007-2011 Agreements.

(4) For the purpose of determining Monetary Benefit pursuant to section 6 of the body of this Agreement, the Forecast Market Price shall be equal to the FBPF established for Q4 of each calendar year for the upcoming CY. For example, the FBPF for Q4 of calendar year 2005 shall be the Forecast Market Price for CY 2007.

The Forecast Market Price for CY 2007 is $67.75/MWh.

2. DETERMINATION OF EQUIVALENT PF

Prior to the beginning of each CY, BPA will calculate the initial Equivalent PF for each such CY and, if applicable, for the Option Period.

(a) For Monetary Benefits not included in Option Benefits the Equivalent PF shall be equal to the actual cost, in $/MWh, to purchase 1 MW during every hour of the CY at the PF Rate (including but not limited to the effect of any adjustments, surcharges, dividends or true-ups) divided by the number of hours in the CY.

(b) For Monetary Benefits included in Option Benefits the Equivalent PF for the Option Period shall be the weighted average of the Equivalent PF for each CY included in whole or part within the Option Period calculated as follows: (i) For each CY within the Option Period, a CY Total Plant Load will be calculated by summing the monthly Total Plant Loads for each month of the CY that falls within the Option Period. For this calculation monthly Total Plant Load shall be limited to the Maximum Allocation, less UBA amounts not included in Option Benefits, and will be deemed equal to zero if the monthly Total Plant load is less than the Minimum Allocation. (ii) Each CY Total Plant Load for each CY from step i will then be multiplied by the Equivalent PF for the corresponding CY. (iii) The sum of the numbers calculated in step ii will then be divided by the sum of the CY Total Plant Loads from step i for the entire Option Period to derive the Equivalent PF for the Option Period. For purposes of this calculation, if the Option Period extends beyond CY 2009, BPA will deem the Equivalent PF Rate equal to a rate that results in an MB Rate, for periods beyond the CY 2009, equal to $24/MWh until BPA's initial proposal is published for the FY 10-11 Rate Period. When the initial proposal for FY 10-11 Rate Period is published the Equivalent PF used in this calculation for CY 2010 and CY 2011 will be established according to 2(c) below.

(c) Each time any adjustment, surcharge, dividend or true-up to the PF Rate is proposed by BPA in writing (which may be before the date such change will actually be applied to the PF Rate), BPA will adjust the Equivalent PF and the MB Rate and MB Monthly Payments for the remaining months of such CY or Option Period. Such adjustment will take into consideration the

Monetary Benefits provided to date and the PF Rate adjustment to provide an end-of-CY or end of Option Period total Monetary Benefit to which CFAC is entitled. If such recalculation indicates that BPA has paid CFAC more in Monetary Benefits than the amount to which CFAC is entitled, then BPA will reduce the MB Monthly Payments to CFAC over the next following three months (if full recovery of the amount is not possible in the 3-month period BPA may invoice CFAC for the remaining amount), by the amount needed to recover the overpayment. If adjustments, surcharges, and true-ups are established after the CY or Option Period ends, then BPA will calculate the final Equivalent PF rate for each such CY or Option Period, and adjustments to Monetary Benefit will be applied in the following CY.

(d) If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by CFAC to BPA, then BPA shall invoice CFAC for such payment within 90 days following the end of such final CY. Such payment shall be made by CFAC within 20 days following the receipt of such invoice. If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by BPA to CFAC, then BPA shall pay CFAC no later than 90 days following the end of such final CY.

3. REVISIONS

BPA shall have the unilateral right to revise this Exhibit F to reflect the Forecast Market Price and Equivalent PF for each CY after CY 2007 calculated pursuant to this Exhibit F. Any changes to the procedure used to determine Forecast Market Price or Equivalent PF may only be made upon mutual agreement of the Parties.

Attachment E

Contract No. 06PB-11694, Power Sale to Clallam PUD for Service at Port Townsend
(September 2006)

Contract No. 06PB-11694

AUTHENTICATED

SURPLUS FIRM POWER SALES AGREEMENT
executed by the
BONNEVILLE POWER ADMINISTRATION
and
PUBLIC UTILITY DISTRICT NO. 1
OF CLALLAM COUNTY, WASHINGTON

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Exhibit A Surplus Firm Power Rate
Exhibit B Additional Products, Services, and Special Provisions
Exhibit C Points of Measurement for Total Metered Load

This SURPLUS FIRM POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and PUBLIC UTILITY DISTRICT NO. 1 OF CLALLAM COUNTY, WASHINGTON (Clallam). Clallam is a public utility district organized under the laws of the State of Washington. BPA and Clallam are sometimes referred to in the singular as "Party" or in the plural as "Parties".

RECITALS

The Administrator is authorized under the Northwest Power Act to sell surplus power. BPA projects it will have surplus power available for sale during the term of this Agreement.

BPA will sell and Clallam will purchase an amount of surplus power on a firm basis under this Agreement for resale by Clallam to Port Townsend Paper Corporation (Port Townsend) under a separate agreement.

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision making activities of BPA's power business from the administrative and decision making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA and Clallam agree:

1. TERM

This Agreement shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to section 14 below. All liabilities incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, Contract Year 2007 begins October 1, 2006, and continues through September 30, 2007.

(b) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.O. 96-501.

(c) "Point of Measurement" means the Port Townsend Meter No. 2871 in Port Townsend's New Mill Substation, which is the point where Total Metered Load is measured.

(d) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL to Clallam.

(e) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(f) "Priority Firm Rate" means the Priority Firm Rate demand, energy, load variance and all other charges applicable to the purchase by Clallam of firm power from BPA under its PSC during each rate period during the term of this Agreement, including any and all Cost Recovery Adjustment Clauses (CRACs), NFB Adjustments, Emergency NFB Surcharges, Dividend Distribution Clauses (DDCs), and any other charges, surcharges,

adjustments and rebates, but excluding the Low Density Discount and the Conservation Rate Credit.

(g) "Region" means the definition established for "Region" in the Northwest Power Act.

(h) "Surplus Firm Power" means electric power that PBL shall make available to Clallam under this Agreement.

(i) "Surplus Firm Power" means electric power that PBL shall make available to Clallam under this Agreement.

(j) "Total Metered Load" means the total amount of electric energy consumed during a given time period at Port Townsend's production facilities, located on Mill Road, Port Townsend, Washington, as measured at the Point of Measurement.

(k) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

3. SALE AND PURCHASE OF SURPLUS FIRM POWER AND RELATIONSHIP TO THE POWER SALES CONTRACT

(a) **Sale and Purchase of Surplus Firm Power**
BPA agrees to make available to Clallam at the Point of Receipt amounts of Surplus Firm Power, and Clallam agrees to purchase and pay for the amounts of Surplus Firm Power made available to Clallam at the Point of Receipt, all pursuant to the terms and conditions set forth in this Agreement.

(b) **Relationship to the Power Sales Contract**
Clallam also purchases power from BPA pursuant to Contract No. 00PB-12051, Full Service Power Sales Agreement (PSC), executed by the Parties on October 17, 2000, as it may be amended or replaced. If any provision of this Agreement conflicts with a specific provision in the PSC, as it may be amended or replaced, then for the purposes of this Agreement, this Agreement shall control.

4. APPLICABLE RATES

Purchases by Clallam under this Agreement are subject to the WP-07 Firm Power Products and Services (FPS) rate schedule or its successor and the General Rate Schedule Provisions.

Exhibit A, Surplus Firm Power Rate, identifies rates, and billing determinants applicable to purchases of Surplus Firm Power under this Agreement, and is incorporated by reference as if fully set forth in this Agreement.

5. POWER SALE PROVISIONS

All Surplus Firm Power provided by PBL under this Agreement is solely for service to Total Metered Load. Total Metered Load shall only be served with power purchased under this Agreement except for amounts of power that Clallam and BPA agree can be used to serve a portion of Total Metered Load in order to reduce the amount of Unauthorized Increase (UAI) charges that Clallam would otherwise be subject to for deliveries under this Agreement. The Surplus Firm Power provided under this Agreement is intended to support a corresponding wholesale power sale by Clallam to Port Townsend. Power amounts provided under this Agreement are not included in Clallam's Total Retail Load for any purpose under the PSC, including without limitation qualification for or the amount of benefits Clallam may receive under the Low Density Discount.

(a) **Demand**

The monthly megawatt (MW) amount that is measured during the hour of BPA's Generation System Peak establishes billing determinant for Clallam's Demand for Total Metered Load under this Agreement.

(b) **HLH and LLH Energy**

The monthly amounts of HLH and LLH energy, as measured at the Point of Measurement, establish Clallam's HLH and LLH Energy for service to Total Metered Load under this Agreement.

6. SCHEDULING

The Parties shall amend this Agreement as needed if any transmission tariff or regulatory agency requires or recommends changes that PBL decides to accept, which PBL determines require power scheduling provisions be made a part of this Agreement.

7. DELIVERY

(a) **Transmission Service for Contracted Power**

This Agreement does not provide transmission services for, or include the delivery of, Surplus Firm Power to Clallam. Clallam shall be responsible for arranging to have Port Townsend modify existing or execute one or more wheeling agreements with a transmission supplier for the delivery of Surplus Firm Power (Wheeling Agreement). The Parties agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power consistent with the terms, notice, and the time limits contained in the Wheeling Agreements.

(b) **Liability for Delivery**

Clallam waives any claims against PBL arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. PBL shall not be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event will either Party be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership.

(c) **Points of Receipt**

PBL shall make Surplus Firm Power available to Clallam under this Agreement at Points of Receipt solely for the purpose of scheduling transmission to points of delivery to Port Townsend Paper. Clallam shall have Port Townsend schedule, if scheduling is necessary, such Surplus Firm Power solely for service to Total Metered Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, specified Points of Receipt in a written notice to Port Townsend on July 26, 2000.

If required by the Wheeling Agreement, PBL will provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under Port Townsend's Wheeling Agreement (provide however if the firm points of Receipt are not available, that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts shall not exceed the amount reasonably necessary for PBL to provide Surplus Firm Power under this Agreement. At any time PBL may request the use of nonfirm Points of Receipt to provide Surplus Firm Power to Clallam. Notwithstanding section 7(b) above, PBL shall reimburse Clallam for any additional costs incurred due to compliance with such request, if any such costs are passed through to Clallam from Port Townsend's Wheeling Agreement.

(d) **Transmission Losses**

PBL shall provide Clallam the losses for Surplus Firm Power between the Points of Receipt and Clallam's system for Surplus Firm Power, at no additional charge. Such losses will be provided at Points of Receipt as established under section 7©, and under the terms and conditions as defined in the transmission provider's tariff.

(e) **Clallam Network Transmission Agreement**

The Parties acknowledge that this Agreement is not intended to be and does not constitute a resource under Service Agreement no. 01TX-10410 (Network Transmission Agreement) by and between Clallam and TBL, and that notwithstanding anything in this Agreement to the contrary Clallam may not use its Network Transmission Agreement to deliver any power under this Agreement or from any other resource to Port Townsend's Total Metered Load.

8. MEASUREMENT

Clallam authorizes PBL to use metering data as PBL determines is necessary to plan, schedule, and bill for power. Clallam agrees to authorize TBL to provide Clallam's metering data directly to PBL subject to any restrictions imposed by the Federal Energy Regulatory Commission (FERC). All Points of Measurement are shown in Exhibit C, Points of Measurement. Clallam agrees to provide reasonable notice to PBL prior to changing control areas.

9. BILLING AND PAYMENT

(a) **Billing**

PBL shall bill Clallam monthly, consistent with applicable BPA rates, including the GRSPs and the provisions of this Agreement for the Surplus Firm Power provided to Clallam in the preceding month or months under this Agreement. PBL may send Clallam an estimated bill followed by a final bill. PBL shall send all bills on the bill's issue date either electronically or by mail, at Clallam's option. If electronic transmittal of the entire bill is not practical, PBL shall transmit a summary electronically, and send the entire bill by mail.

(b) **Payment**

Payment of all bills, whether estimated or final, must be received by BPA on the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. If payment has been made on an estimated bill before receipt of a final bill for the same month, Clallam shall pay only the amount by which the final bill exceeds the payment made for the estimated bill. PBL shall provide Clallam the amounts by which an estimated bill exceeds a final bill through either a check or as a credit on the subsequent month's bill. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal, plus 4 percent; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received. Clallam shall pay by electronic funds transfer using BPA's established procedures, and may elect to have bills under this Agreement consolidated with those rendered under the PSC.

(c) **Disputed Bills**

In case of a billing dispute, Clallam shall note the disputed amount and pay its bill in full by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to late payment charges provided above. If Clallam is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate used to determine the interest is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received by BPA.

(d) **Payments Hereunder Not Conditional on Payments by Port Townsend**

Payment of any bill under this Agreement by Clallam is not conditional on payment of any amount due by Port Townsend to Clallam for power provided by Clallam to meet Port Townsend.

10. UNCONTROLLABLE FORCES

PBL shall not be in breach of its obligation to provide Surplus Firm Power to Clallam and Clallam shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(a) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to Clallam's facilities, including but not limited to unplanned maintenance outages;

(b) any unplanned curtailment or interruption, failure or imminent failure of Clallam's or Port Townsend's production or transmission facilities, including but not limited to unplanned maintenance outages;

(c) any planned transmission or distribution outage that affects either Clallam or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(d) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however,* that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(e) floods, earthquakes, or other natural disasters; and

(f) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Party as soon as practicable of that Party's inability to meet to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify

any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

Both Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

11. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by e-mail; (c) by United States Mail; (d) by a nationally recognized delivery service; or (e) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 11.

If to Clallam:

Public Utility District No. 1 of Clallam County, Washington
P.O. Box 1090
Port Angeles, WA 98362-0212
Attn: Fred Mitchell
Telecommunications & Power Resources Manager
Phones: 360-565-3235
FAX: 360-687-5139
E-Mail: fredm@clallampud.net

If to PBL:

Bonneville Power Administration

Attn: Charles W. Forman, Jr. – PSW- 6
Account Executive
Phone: 503-230-3432
FAX: 503-230-3242
E-Mail: cformanjr@bpa.gov

12. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal Law. Final actions subject to section 9(e) of the Northwest Power Act are not subject to binding arbitration and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. Clallam reserves the right to seek judicial resolution of any dispute arising under this Agreement that is not subject to arbitration under this section 12. For purposes of this section 12, BPA policy means any written document adopted by BPA as a final action in a decision record or record of decision that establishes a policy of general application, or makes a determination under an applicable statute. If either Party asserts that a dispute is excluded from arbitration under this section 12, either Party may apply to the Federal court having jurisdiction for an order determining

whether such dispute is subject to arbitration under this section 12.

(b) Any contract dispute or contract issue between the Parties arising out of this Agreement, except for disputes that are excluded through section 12(a) above, shall be subject to binding arbitration. The Parties shall make a good faith effort to resolve such disputes before initiating arbitration proceedings. During arbitration, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

(c) Any arbitration shall take place in Portland, Oregon, unless the parties agree otherwise. The International Institute for Conflict Prevention and Resolution's arbitration procedures for commercial arbitration, Non-Administered Arbitration Rules (CPR Rules), shall be used for each dispute; **provided, however,** that: (1) the Parties shall have the discovery rights provided in the Federal Rules of Civil Procedure unless the Parties agree otherwise; and (2) for claims of $1 million or more, each arbitration shall be conducted by a panel of three neutral arbitrators. The Parties shall select the arbitrators from a list containing the names of 15 qualified individuals supplied by the International Institute for Conflict Prevention and Resolution. If the Parties cannot agree upon three arbitrators on the list within 20 business days, the Parties shall take turns striking names from the list of proposed arbitrators. The Parties shall take turns striking names from the list of proposed arbitrators. The Party initiating the arbitration shall take the first strike. This process shall be repeated until three arbitrators remain on the list, and those individuals shall be designated as the arbitrators. For disputes involving less than $1 million, a single neutral arbitrator shall be selected consistent with section 6 of the CPR Rules.

(d) Except for arbitration awards which declare the rights and duties of the Parties under this Agreement, the payment of monies shall be the exclusive remedy available in any arbitration proceeding. Under no circumstances shall specific performance be an available remedy against either Party. The arbitration award shall be final and binding on both Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrators may be entered by any court having jurisdiction thereof.

(e) Each Party shall be responsible for its own costs of arbitration, including legal fees. The arbitrators may apportion all other costs of arbitration between the Parties in such manner as they deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

13. STANDARD PROVISIONS

(a) **Amendments**
No oral or written amendment, rescission, waiver, modification, or other

change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. BPA may assign this Agreement to another Federal agency to which BPA's statutory duties have been transferred. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld. BPA shall consider any request for assignment consistent with applicable BPA statutes. Clallam may not transfer or assign this Agreement to any of its retail customers.

(c) **Information Exchange and Confidentiality**
The Parties shall provide each other with any information that is reasonably required, and requested by either Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of 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 obligation 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.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement between the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement

in the event of a conflict.

(f) **Third-Party Beneficiaries**
Port Townsend is an intended third-party beneficiary of BPA's obligation under the terms of this Agreement to provide Surplus Firm Power to Clallam, and Clallam's obligation under the terms of this Agreement to pay for such power. Except as provided in the preceding sentence, this Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement

(g) **Waivers**
Any waiver at any time by either Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's NLSL Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by Clallam to such policy, nor shall it be construed to be a waiver of the right of Clallam to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless such term is determined to be material to this Agreement, or is not severable from all other provisions of this Agreement by such court.

(j) **Hold Harmless**
Each Party assumes all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. Each Party shall indemnify and hold the other Party harmless from any liability arising from such act or negligence.

(k) **BPA Appropriations Refinancing Act**
The Parties agree that the BPA Refinancing Section of the omnibus Consolidated Recisions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110 Stat. 1321, 1350, as stated in the United States Code on the date this Agreement is signed by the Parties, is incorporated by reference and is a material term of this Agreement. The Parties agree that this provision and the incorporated text shall be included in subsequent agreements between the Parties, as a material term through at least September 30, 2011.

14. TERMINATION

(a) BPA may terminate this Agreement on 30 days written notice to Clallam in the event the Ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order preventing or prohibiting BPA from recovering under the Slice Agreements or its Slice rate schedules that portion of BPA's cost of service associated with this Agreement allocated by BPA to such Slice Agreements or Slice rate schedules. BPA shall diligently litigate any action challenging its ability to assess such costs. Clallam shall not be entitled to any damages for such termination and Clallam hereby expressly waives any right to seek such damages.

(b) In the event the ninth Circuit Court of Appeals or other court of competent jurisdiction issues a final, unappealable order that declares or renders this Agreement void or otherwise unenforceable, Clallam shall not be entitled to any damages of any nature, in law or equity, from BPA. Clallam hereby expressly waives any right to seek such damages from BPA.

(c) PBL may terminate this Agreement if Clallam fails to pay any bill due to BPA within 5 business days after its Due Date.

(d) PBL may terminate or suspend this Agreement on 5 days written notice to Clallam if Port Townsend fails to pay any bill due to BPA within 5 business days after its Due Date.

15. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

PUBLIC UTILITY DISTIRCT NO. 1 OF CLALLAM COUNTY, WASHINGTON

By /S/ **MICHAEL MCINNES**

Name Michael McInnes
(Print/Type)

Title Interim General Manager

Date **September 13, 2006**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ **CHUCK FORMAN, JR.**
Account Executive

Name Charles W. Forman, Jr.
(Print/Type)

Date **August 22, 2006**

(W:PSW\PM\AE_Forman\CL_Clallam\Surplus Firm PSC\CL_06PB-11694_20060821_Final.doc)8/21/06

Exhibit A
SURPLUS FIRM POWER RATE

The firm Power Products and Services rate (FPS-07), or its successor, shall apply to the Surplus Firm Power purchased by Clallam under this Agreement and shall be priced as set forth below:

1. No later than thirty (30) days prior to the effective date of rates, charges or rebates, BPA shall unilaterally revise Table 1 of this Exhibit 1 of this Exhibit A to specify the demand, energy and other rates, charges or rebates that shall apply to the sale of Surplus Firm Power.

   HLH and LLH energy rates for Surplus Firm Power shall be set equal to the corresponding Priority Firm Rate, including any CRACs or DDCs, for energy plus the typical industrial margin used to establish the Industrial Firm Power Rate in BPA's most recently concluded wholesale power rate proceeding in which the typical industrial margin was established. For the WP-07 rate proceeding, the typical industrial margin is $0.57 per megawatt hour.

   The demand and other charges or rebates for Surplus Firm Power shall be set equal to the corresponding Priority Firm Rates, including any CRACs or DDCs if applicable, for demand and other charges or rebates.

2. The monthly load variation charge paid by Clallam for Surplus Firm Power shall be calculated using the sum of the Total Metered load and the amount of energy (in megawatt-hours) generated by Port Townsend's onsite co-generation during each month.

3. Unless otherwise agreed to by the Parties, if Total Metered Load exceeds 17 annual average megawatts (aMW) during a Contract Year, then the amount in excess of 17 annual aMW shall be billed at the UAI charge for energy applicable to any unauthorized increase for September of the Contract Year in which such exceedence occurred.

4. If an Emergency NFB Surcharge (Surcharge), or its successor, is triggered under the Priority Firm Rate, BPA shall establish, for the period the Surcharge is in effect, a dollar per megawatt hour surcharge applicable to Total Metered Load that BPA expects will result in an amount of additional revenue equal to the additional revenue it would have received if: (a) sales under this Agreement were subject to the Surcharge; and (b) the amount of Total Metered Load during the period the Surcharge is in effect was equal to the amount of Total Metered Load during the preceding Contract Year. The dollar per megawatt hour surcharge calculated pursuant to this section 4 will not be charged for any month during which there are no deliveries to Clallam of Surplus Firm Power under this Agreement.

Exhibit A, Table 1 Surplus Firm Power Rates August 17, 2006				
Month	**HLH Rate ($/MWh)**	**LLH Rate ($/MWh)**	**Demand Rate $/kW-Month**	**Load Variation Rate ($/MWh)**
October	30.27	22.33	1.94	0.47
November	32.25	23.67	2.08	0.47
December	33.63	24.83	2.18	0.47
January	28.64	20.87	1.85	0.47
February	29.23	21.07	1.88	0.47
March	27.16	20.06	1.75	0.47
April	25.52	18.50	1.64	0.47
May	21.41	14.98	1.36	0.47
June	19.44	10.59	1.25	0.47
July	23.81	17.58	1.53	0.47
August	27.78	20.75	1.79	0.47
September	28.66	23.11	1.85	0.47

Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS

1. **MONTHLY CO-GENERATION AMOUNTS**
   No later than three business days following the end of each month, Clallam shall provide or cause Port Townsend to provide to BPA in writing or by e-mail the total monthly amount of Port Townsend's onsite co-generation.

2. **REVISIONS**
   This Exhibit B shall be revised upon mutual agreement of the Parties to reflect any new products, services, and special provisions that may be added during the term of this Agreement.

Exhibit C
POINTS OF MEASUREMENT FOR TOTAL METERED LOAD

Transmission Point of Delivery (Voltage) **Point of Metering (Metering Voltage)**	**Metering Location**	**Manner of Service**
Fairmount Transmission Point of Delivery (115 kV)		
Pt. Town New Mill Out Meter No. 2871 (115 kV)	Port Townsend Paper	Direct – BPA to Clallam

Attachment F

Contract No. 060201, Surplus Firm Power Sales Agreement between Clallam County PUD No. 1 and Port Townsend Paper Corporation

Contract No. 060201

SURPLUS FIRM POWER SALES AGREEMENT

executed by the

PORT TOWNSEND PAPER CORPORATION

and

PUBLIC UTILITY DISTRICT NO. 1
OF CLALLAM COUNTY, WASHINGTON

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This SURPLUS FIRM POWER SALES AGREEMENT ("Agreement") is executed by the PORT TOWNSEND PAPER Corporation ("Purchaser"), a Washington State corporation, and the PUBLIC UTILITY DISTRICT NO. 1 OF CLALLAM COUNTY, WASHINGTON ("Clallam"), a public utility district organized under the laws of the State of Washington. Purchaser and Clallam are sometimes referred to in the singular as "Party" or in the plural as "Parties".

RECITALS

Clallam is a public utility district authorized by law to sell electric power and energy at retail and wholesale within and without Clallam County, Washington, and which purchases the bulk of its electric power and energy for resale from the Bonneville Power Administration ("BPA").

Purchaser is a pulp and paper mill located adjacent to Port Townsend, Washington, which is by statute a direct service industrial customer of the BPA, and which has purchased the electric power and energy needed to operate its pulp and paper mill from BPA and wheeling services for such power and energy from Clallam.

On June 30, 2005, the BPA Administrator signed a record of decision titled "Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011" (Administrator's Record of Decision) in which it decided to make 17 aMW of Surplus Firm Power available to Purchaser through Clallam.

Pursuant to the BPA Record of Decision, Clallam has signed a Surplus Firm Power Agreement (Contract No. 06PB-11694) with BPA to acquire surplus power to be used exclusively to serve the Purchaser's mill load, in addition to and separate from the firm power Clallam purchases from BPA under its Full Requirements Power Sales Agreement (Contract No. 00PB-12051).

Purchaser and Clallam agree as follows:

1. **TERM**

   This Agreement, when signed by the Parties, shall become effective on October 1, 2006, and shall continue in effect through September 30, 2011, unless terminated earlier pursuant to sections 9 or 14 below. All obligations incurred hereunder shall be preserved until satisfied.

2. **DEFINITIONS**

   Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are as defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs) then in effect.

   (a) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, Contract Year 2007 begins October 1, 2006, and continues through September 30, 2007.

   (b) "Point of Delivery" means the point where the system of Clallam and the Federal Columbia River Transmission System ("FCRPS") interconnect.

   (c) "Point of Measurement" means the Port Townsend Meter No. 2871 in Port Townsend's New Mill Substation, which is the point where Total Metered Load is measured.

(d) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Surplus Firm Power shall be made available by PBL.

(e) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(f) "Priority Firm Rate" means the Priority Firm Rate demand, energy, load variance and all other charges applicable to the purchase by Clallam of firm power from BPA under its PSC during each rate period during the term of this Agreement, including any and all Cost Recovery Adjustment Clauses (CRACs), NFB Adjustments, Emergency NFB Surcharges, Dividend Distribution Clauses, and any other charges, surcharges, adjustments and rebates,

(g) "Surplus Firm Power" means electric power that Clallam shall purchase from PBL and shall make continuously available to Purchaser under this Agreement.

(h) "Surplus Firm Power Agreement" means the agreement (Contract No. 06PB-11694) for the sales and purchase of surplus power from BPA to Clallam, which surplus power can only be resold at wholesale to Purchaser.

(i) "Surplus Firm Power Rate" means the rate established pursuant to Exhibit A of this Agreement for the sale of Surplus Firm Power from Clallam to Purchaser under this Agreement.

(j) "Total Metered Load" means the total amount of electric energy delivered by Clallam to Purchaser in any month as measured at the Point of Measurement.

(k) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

3. SALE AND PURCHASE OF POWER

Clallam agrees to make available to Purchaser at the Point of Delivery amounts of Surplus Firm Power, and Purchaser agrees to purchase and pay for the amounts of such Surplus Firm Power, all pursuant to the terms and conditions set forth in this Agreement.

4. APPLICABLE RATES

(a) Purchaser shall pay Clallam for the amounts of Surplus Firm Power provided to Purchaser at the Point of Delivery pursuant to this Agreement at rates established from time to time by the Board of Commissioners of Clallam

and as set forth in Exhibit A (Surplus Firm Power Rates). Such Surplus Firm Power Rates will be set as follows:

Monthly Charge = BPA Surplus Firm Power Rate Charges + Other Costs + Taxes

Where:
"BPA Surplus Firm Power Rate Charges" consists of any and all charges applicable to the purchase of Surplus Firm Power by Clallam from BPA under the Surplus Firm Power Agreement that appear on the Clallam's BPA power bill during the applicable month, including without limitation all costs, charges, surcharges, adjustment charges and penalties, and conditions of service as set forth in the applicable General Rate Schedule Provisions.

"Other Costs" are $0.94/ Mwh plus any increase in dues resulting from the inclusion of Surplus Firm Power sales under this Agreement in the calculation of dues (compared to such dues absent such Surplus Firm Power sales) for any association or organization to which Clallam is a member, or becomes a member.

"Taxes" means all federal, state and local applicable to or arising out of this Agreement, all as determined by the Clallam.

A sample calculation of a Monthly Charge is set forth in Exhibit B.

(b) No later than twenty (20) days prior to the first day of each BPA rate period during the term of this Agreement, Clallam shall unilaterally revise Exhibit A to set out the demand, energy and other charges that shall apply to the sale of Surplus Firm Power under this Agreement during such rate period; *provided however*, that during each such rate period Clallam may unilaterally revise Exhibit A as frequently as necessary to reflect any changes in the charges to Clallam under Surplus Firm Power Agreement, as well as changes to Clallam's Other Costs.

(c) The monthly load variation charge paid by Purchaser for Surplus Firm Power purchased under this Agreement shall be calculated using the sum of the Total Metered Load and the amount of energy (in megawatt-hours) generated by Port Townsend's onsite co-generation during each month.

(d) Unless otherwise agreed to by the Parties, if Total Metered Load exceeds 17 annual average megawatts (aMW) during a Contract Year, then the amount in excess of 17 annual aMW shall be billed at the Unauthorized Increase Charge ("UAI") for energy applicable to any unauthorized increase for September of the Contract Year in which such exceedence occurred.

5. POWER SALE PROVISIONS

All Surplus Firm Power provided by Clallam to Purchaser under this Agreement is solely for service to Total Metered Load. Total Metered Load shall only be served with power purchased under this Agreement except for amounts of power that Clallam may agree can be used to serve a portion of Total Metered Load in order to reduce the amount of UAI Charges to which Purchaser would otherwise be subject. Power amounts provided under this Agreement are not included in Clallam's Total Retail Load under the BPA Power Sales Contract, Contract No. 00PB-0051, for any purpose whatsoever.

(a) **Demand**

The monthly megawatt (MW) amount that is measured at the Point of Measurement during the hour of BPA's Generation System Peak establishes the billing determinant for Purchaser's Demand for Total Metered Load under this Agreement.

(b) **HLH and LLH Energy**

The monthly amounts of HLH and LLH energy, as measured at the Point of Measurement, establishes Purchaser's HLH and LLH Energy for service to Total Metered Load under this Agreement.

6. SCHEDULING

The Parties shall amend this Agreement as needed if any transmission tariff or regulatory agency requires or recommends changes that PBL decides to accept, which PBL determines require power scheduling provisions be made a part of this Agreement.

7. DELIVERY

(a) **Transmission Service for Surplus Firm Power**

Purchaser shall execute, one or more wheeling agreements with TBL for the delivery of Surplus Firm Power (Wheeling Agreement) between the Point of Receipt and the Point of Delivery, and shall pay any and all costs due under such Wheeling Agreement. The Parties agree to take such actions as may be necessary to facilitate the delivery of Surplus Firm Power to the Point of Delivery consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

The delivery of Surplus Firm Power from the Point of Delivery and the Point of Measurement is provided by a separate agreement between Purchaser and Clallam, Contract No. 970401 (Wheeling Agreement). All terms and conditions applicable to such delivery are set forth in the Wheeling Agreement.

(b) **Liability for Delivery**

Purchaser waives any claims against Clallam arising under this Agreement for non-delivery of power to any points beyond the applicable Points of Receipt, except as otherwise provided in the Wheeling Agreement. Clallam shall not be liable for any third-party claims related to the delivery or non-

delivery of power after it leaves the Points of Receipt. In no event will either Party be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership.

(c) **Points of Receipt**
The Surplus Firm Power sold by Clallam to Purchaser pursuant to this Agreement shall be made available to Purchaser at Points of Receipt solely for the purpose of scheduling transmission to Points of Delivery, unless otherwise provided. Purchaser shall schedule, if scheduling is necessary, such Surplus Firm Power solely for service to Total Metered Load.

8. MEASUREMENT
All Points of Measurement are shown in Exhibit C, Points of Measurement.

9. BILLING AND PAYMENT

(a) **Deposit**
Purchaser shall deposit with the District an amount equal to the highest estimated monthly bill within five (5) days of signing this agreement. Deposit will be used towards payment of final amounts owed under this agreement. No interest credit will be provided to the Purchaser.

(b) **Billing**
Clallam shall bill Purchaser monthly, consistent with applicable rates set forth in Exhibit A and the provisions of this Agreement for the Surplus Firm Power provided by Clallam to Purchaser. Clallam will send Purchaser an estimated bill by the fifteenth (15th) day of each month for the expected service to Purchaser during the following calendar month. Within ten (10) days of receipt by Clallam of the final bill for each month from BPA under its Surplus Firm Power Agreement with BPA, Clallam will issue to Purchaser either (i) a final bill for the amount by which the costs of Surplus Firm Power service to Purchaser provided under this Agreement exceeded the estimated bill for such month, or (ii) a check payable to Purchaser for the amount by which the estimated bill for Surplus Firm Power Service to Purchaser for such month exceeded the costs of Surplus Firm Power service provided to Purchaser provided under this Agreement during such month. Clallam shall send all bills on the bill's issue date either electronically or by mail, at Clallam's option.

(c) **Payment**
Payment of all estimated bills will be made in four (4) equal payments by Purchaser on or before the 1st, 7th, 14th, and 21st days of the month for which the estimated bill was issued (Due Dates). Payment of all bills, whether estimated or final, must be received by the Due Date. If the Due Date is a Saturday, Sunday or Federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal, plus 4 percent;

by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received. Purchaser shall pay by electronic funds transfer using established procedures.

(d) **Disputed Bills**

In case of a billing dispute, Purchaser shall note the disputed amount and pay its bill in full by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to late payment charges provided above. If Purchaser is entitled to a refund of any portion of the disputed amount, then Clallam shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate used to determine the interest is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received by Clallam.

(e) **Termination for Non-Payment**

If Purchaser fails to pay in full any estimated or final bill by the applicable Due Date, such unpaid amount and the applicable late payment charge shall be considered overdue and Clallam shall have the right, at its sole option and without notice to the Purchaser, to suspend deliveries of Surplus Firm Power under this Agreement on and after the third (3rd) calendar day after the applicable Due Date. If Purchaser has not paid in full such unpaid amount and the applicable late payment charge by tenth (10th) calendar day after the applicable Due Date, Clallam shall have the right, at its sole option and without notice to the Purchaser, to terminate this Agreement. In the event of a termination of this Agreement pursuant to this section 9, Purchaser shall not be entitled to any damages for such termination and Purchaser hereby expressly waives any right to seek such damages. Upon such termination, all liabilities accrued prior to the date of such termination shall be preserved until satisfied.

If Purchaser pays in full the unpaid amount and the applicable late payment charge on or before the tenth (10th) calendar day after the applicable Due Date, Clallam will restore deliveries of Surplus Firm Power under this Agreement on the condition that in addition to any payments required under Section 9(a), Purchaser shall: (i) Deposit with Clallam in the form of cash (or other form of surety acceptable to Clallam) an amount set by Clallam to equal the sum of the two largest monthly payment made by Purchaser under this Agreement in the preceding twelve (12) months; and (ii) an executed letter agreement acceptable to Clallam giving Clallam the right to access and use such amount for purposes of curing any payment due by Purchaser to Clallam that is not received by Clallam on or before the applicable Due Date.

(f) **Remedies Cumulative**

The remedies set forth in this Section 9 are cumulative, and are in addition to any judicial or other remedies available to Clallam for failure of Purchaser to pay amounts due and owing under this Agreement.

10. UNCONTROLLABLE FORCES

Clallam shall not be in breach of its obligation to provide Surplus Firm Power to Purchaser and Purchaser shall not be in breach of its obligation to purchase Surplus Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(a) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Surplus Firm Power to Purchaser's facilities, including but not limited to unplanned maintenance outages;

(b) any unplanned curtailment or interruption, failure or imminent failure of Clallam's or Port Townsend's production or transmission facilities, including but not limited to unplanned maintenance outages;

(c) any planned transmission or distribution outage that affects either Clallam or BPA which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(d) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however*, that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved;

(e) floods, earthquakes, or other natural disasters;

(f) terrorists, or acts of war; and

(g) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic

hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Parties as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

All Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

11. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Any Party may change its address for notices by giving notice of such change consistent with this section 7.

If to Clallam:	If to Purchaser :
Public Utility District No. 1 of Clallam County, Washington P.O. Box 1090 Port Angeles, WA 98362-0212 Attn: General Manager Phone: 360-452-9771 FAX: 360-452-9338	Port Townsend Paper Corporation 100 Mill Road Port Townsend, Washington 98368 Attn: Bruce McComas Phone: 360-379-2158 FAX: 360-385-0355 E-Mail: brucem@ptpc.com

12. GOVERNING LAW

This Agreement shall be interpreted consistent with and governed by Washington state law.

13. STANDARD PROVISIONS

(a) **Amendments**

No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**

This Agreement is binding on any successors and assigns of the Parties. Neither Party may transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld.

(c) **Information Exchange and Confidentiality**

The Parties shall provide each other with any information that is reasonably required, and requested by either Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information.

(d) **Entire Agreement**

This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**

The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement between the Parties unless otherwise specified herein. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **Third-Party Beneficiaries**

This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers**

Any waiver at any time by either Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **Hold Harmless**

Each Party assumes all liability for injury or damage to persons or property arising from the act or negligence of its own employees, agents, members of governing bodies, or contractors. Each Party shall indemnify and hold the other Party harmless from any liability arising from such act or negligence.

(i) **Collection of Amounts Due; Enforcement**
In the event that Clallam uses the services of an attorney in attempting to collect any amounts due under this Agreement, or to enforce the terms hereof or of any agreements related to this Agreement, Purchaser, its successors and assigns, shall repay Clallam, on demand, all costs and expenses so incurred, including reasonable attorney's fees, including those costs, expenses and attorney's fees incurred after the filing by or against the Purchaser of any proceeding under any chapter of the United States Bankruptcy Code [including but not limited to proceeding related to 11 U.S.C. §365, §366 and §362, plan confirmation, claims resolution or litigation] or similar federal or state statute, including receiverships governed by state law, and whether incurred in connection with the involvement of Clallam as a creditor in such proceedings or otherwise.

14. TERMINATION

The Surplus Firm Power being sold to Purchaser under this Agreement is being purchased by Clallam from BPA under the Surplus Firm Power Agreement. If for any reason the Surplus Firm Power Agreement is terminated by BPA, Clallam may terminate this Agreement on the date the Surplus Firm Power Agreement is terminated. Clallam will endeavor to give Purchaser as much prior written notice of such termination as is practicable under the circumstances, but any failure by Clallam to provide such written notice shall not limit or delay the right of Clallam to terminate this Agreement pursuant to this section 14. In the event of a termination of this Agreement pursuant to this section 14, Purchaser shall not be entitled to any damages for such termination and Purchaser hereby expressly waives any right to seek such damages.

15. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

PUBLIC UTILITY DISTIRCT NO. 1 OF CLALLAM COUNTY, WASHINGTON	Port Townsend Paper
By Michael McInnes	By Bruce McComas
Name Michael McInnes *(Print / Type)*	Name Bruce McComas *(Print / Type)*
Title Interim General Manager	Title General Manager
Date 9-13-06	Date 9/12/06

Exhibit A
SURPLUS FIRM POWER RATE

Surplus Firm Power Rates Updated September 8, 2006				
Month	**HLH Rate ($/MWh)**	**LLH Rate ($/MWh)**	**Demand Rate $/kW-Month**	**Load Variation Rate ($/MWh)**
October	31.21	23.27	1.94	0.47
November	33.19	24.61	2.08	0.47
December	34.57	25.77	2.18	0.47
January	29.58	21.81	1.85	0.47
February	30.17	22.01	1.88	0.47
March	28.10	21.00	1.75	0.47
April	26.46	19.44	1.64	0.47
May	22.35	15.92	1.36	0.47
June	20.38	11.53	1.25	0.47
July	24.75	18.52	1.53	0.47
August	28.72	21.69	1.79	0.47
September	29.60	24.05	1.85	0.47

Exhibit B
Sample Estimated Bill Calculation

Purchase Capacity	17	MW
Codenia's Capacity	6	MW
Heavy Load Hours (HLH)	400	hrs
Light Load Hours (LLH)	344	hrs
Total	744	hrs

[redacted]

Bill Calculation

Heavy Load Hour Energy

		400	hrs
X		17	MW
		6,800	MWh
X		34.57	$/MWh
	$	235,076.00	

Light Load Hour Energy

		344	hrs
X		17	MW
		5,848	MWh
X		25.77	$/MWh
	$	150,702.96	

Demand

		17	MW
X		2.18	$/KW-Month
	$	37,060.00	

Load Variation

		744	hrs
X		23	MW
		17,112	MWh
X		0.47	$/MWh
	$	8,042.64	

Sub-Total Month Cost		$	430,881.60
Taxes (estimated)			
Public Utility Tax	3.87%	$	16,675.12
Privelage Tax	2.14%	$	9,220.87
Total Including Tax		**$**	**456,777.59**

Exhibit C
POINTS OF METERING FOR LOADS

Transmission Point of Delivery (Voltage) Point of Metering (Metering Voltage)	Metering Location	Manner of Service
Pt Town New Mill Out Meter No. 2871 (115 kV)	Port Townsend Paper	Direct – B to C

Attachment G

Letter to the Region on DSI Lookback Issue (6/10/09)

Department of Energy

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

EXECUTIVE OFFICE

June 10, 2009

In reply refer to: A-7

To Regional Customers, Stakeholders, and Other Interested Parties:

On December 17, 2008, the United States Court of Appeals for the Ninth Circuit (the court) issued its opinion in *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, 550 F.3d 846 (9th Cir. 2008) (*PNGC*), a case involving the challenge by certain parties to Bonneville Power Administration's (BPA's) FY 2007 – 2011 direct service industrial customer (DSI) service construct and contracts.

Among other holdings, the court granted the petitions challenging BPA's statutory authority to offer the DSIs energy at rates below both the Industrial Firm (IP) power rate and the market rate. *PNGC*, at 882. Since the *PNGC* decision was issued, BPA's preference utility customers have argued that as a consequence of this holding the DSIs received more benefits during the 25-month period preceding the court's opinion (Lookback Period) than BPA was authorized by statute to provide them, and that the excess must be recovered by BPA from the DSIs. For its part, BPA's DSI customer Alcoa, Inc. (Alcoa) has argued that if BPA had applied the IP rate as required by *PNGC*, then it would have received significantly more monetary benefits during the Lookback Period and, therefore, Alcoa is entitled to recoup those additional payments.

In addressing the contention by certain preference utility petitioners that the damages waiver provision in the contracts was void and that BPA must recover overpayments from the DSIs, the court held as follows:

> The question of contractual interpretation before us is whether, if the agreements are partially invalidated, BPA is permitted to seek restitution, not whether it is 'requir[ed]' to do so. Whether BPA intended to retain the flexibility to seek *or* forgo repayment, depending on (a) the DSIs' 'commitments with respect to operating their facilities,' and (b) BPA's interest in still making sales of physical power to them, is an issue the agency did not address in the Supplemental ROD.

Id. (emphasis in original). The court then remanded to BPA "to determine in the first instance the applicability and construction of the severability clause, the damage waiver, and the physical power sale option in light of our holdings here." *Id.*

Therefore, the threshold issues before BPA on remand are whether, as a matter of law and in view of the holdings in *PNGC*,

1) BPA is permitted under the applicable contracts to seek repayment from the aluminum company DSIs Alcoa and Columbia Falls Aluminum Company (CFAC) for any overpayments of monetary benefits during the Lookback Period;

2) Alcoa is permitted to seek additional payments from BPA for the Lookback Period; and

3) BPA is permitted to seek additional payments directly from Port Townsend Paper Company (or indirectly through the Public Utility District No. 1 of Clallam County) for any undercharges for power delivered to Clallam by BPA for the benefit of Port Townsend, both during the Lookback Period and subsequently.

BPA will commence a bifurcated process to address these issues. In the first part, in early July, BPA plans to issue a draft record of decision on the remanded contract issue outlined above, *i.e.*, "the applicability and construction of the severability clause, the damage waiver, and the physical power sale option." Written comments on the draft record of decision must then be filed with BPA in early August 2009. BPA plans to issue a final record of decision regarding the remanded contract issue in late September. In the event BPA's final decision with respect to the remanded contract issue is that, as a matter of law, payments to or from BPA (Lookback Amounts) are precluded, that finding will constitute the Administrator's final decision and no further proceedings will be necessary.

However, in the event BPA's decision in the final record of decision is that the payment to or from BPA of a Lookback Amount is not precluded, then BPA will commence the second part of the process to determine whether, and in what amount, BPA or a DSI is entitled to a Lookback Amount. This second part of the bifurcated process, if necessary, will commence with a workshop, the date and time of which will be announced, if necessary, following release of the final record of decision. The purpose of the workshop will be to discuss whether parties believe it would be necessary to undertake a formal hearing in order to create a record with respect to whether, and in what amount, BPA or a DSI is entitled to a Lookback Amount, or whether such a record could be adequately created through an informal process, including one or more workshops and/or the submission of written arguments and evidence to BPA and other parties.

All parties should keep in mind that litigation is ongoing in the Ninth Circuit that could result in orders that have a bearing on the outcome of this process. The court is still reviewing its original decision pursuant to the filing of petitions for rehearing filed by Port Townsend Paper and BPA. Thus, the mandate has not yet issued and the court is free to change its opinion until that time. Also, the court is reviewing challenges to the contract amendment providing service to Alcoa through FY09. It is possible, then, that the timing of events under this process might have to be adjusted to accommodate any decisions of the court relevant to the Lookback determination.

Most importantly, BPA will not issue its final determination on the applicability of the damage waiver, severability clause, and power sale option on the date specified above if the mandate in the original *PNGC* case has not issued prior to that date. In that event, BPA will issue a notice to the parties describing BPA's intentions with regard to the adjusted timing of events that may be necessary to complete this process.

/s/ Stephen J. Wright

Stephen J. Wright
Administrator and Chief Executive Officer

Attachment H

Amendment No. 1 to Contract No. 06PB-11744

Amendment No. 1
Contract No. 06PB-11744

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

ALCOA INC.

and

PUBLIC UTILITY DISTRICT NO. 1 OF WHATCOM COUNTY, WASHINGTON

This AMENDMENT to the BLOCK POWER SALES AGREEMENT is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), Alcoa, Inc. (Alcoa), and Public Utility District No. 1 of Whatcom County, Washington (Whatcom) (the Parties). Alcoa is a corporation organized under the laws of the State of Pennsylvania. Whatcom is a public utility district organized under the laws of the State of Washington.

This Amendment No. 1 (Amendment) suspends and replaces for the period January 1, 2009, through September 30, 2009 (Amendment Period) Block Power Sales Agreement No. 06PB-11744 (Agreement) by and between BPA, Alcoa, and Whatcom. Pursuant to this Amendment, Whatcom's obligations under the Agreement are excused during the Amendment Period, and no new or substitute obligations are imposed on or undertaken by Whatcom pursuant to this Amendment a) during the Amendment Period, or b) under the Agreement for any period prior to or after the Amendment Period.

On December 17, 2008, the United States Court of Appeals for the Ninth Circuit (Court) filed its opinion in Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration (December Opinion) that held, among other things, that certain provisions of the Agreement are invalid. As a consequence of the December Opinion, BPA halted Monetary Benefit payments under the Agreement.

This Amendment provides for a replacement monetized power sale to Alcoa during the Amendment Period and for the month of December 2008, in a manner and amount that is consistent with the December Opinion.

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. BPA understands the December

Opinion to prohibit payments by BPA to Alcoa that would exceed the difference between the Industrial Firm Power (IP) rate, and BPA's forecasted wholesale market price.

In lieu of delivering firm power to Alcoa at the IP rate during the Amendment Period, BPA will monetize the value of a physically delivered firm power sale at the IP rate, with such value calculated as the difference between the IP rate applicable to the Amendment Period and BPA's forecasted wholesale market price for the Amendment Period. BPA's decision to monetize this transaction is based, in part, on a desire to avoid the risks associated with making the relatively large wholesale market power purchases BPA would be required to undertake, in a short period of time, to serve Alcoa's currently operating load, together with the uncertainty that Alcoa will continue operating at existing levels for the duration of the Amendment Period, given current uncertain economic conditions. Monetization will allow BPA to provide benefits to Alcoa (and obligate BPA to incur expenditures) only in the event Alcoa operates its smelter facility, thereby protecting BPA from making wholesale market purchases that could be both unnecessary in the event Alcoa does not operate, and more expensive than anticipated if actual market prices exceed BPA's current market forecast.

This transaction will be structured as a simultaneous purchase and sale, whereby BPA will be deemed to purchase power from Alcoa during the Amendment Period, in an amount equal to Alcoa's then operating load, at prices equivalent to BPA's currently forecasted wholesale market price for the Amendment Period, and to simultaneously sell back such power to Alcoa at the IP rate. As noted, in lieu of actual power deliveries by either party, the transaction will be monetized.

To summarize, this Amendment adjusts the rate that Alcoa shall pay for power under the Agreement during the Amendment Period to the IP rate, and adjusts the payment made under the monetized transaction to an amount equal to the difference between the IP rate and BPA's forecasted market price for the Amendment Period, which represents the forecasted price that BPA would otherwise pay to acquire power if it were to physically serve Alcoa.

In addition, this Amendment provides for a recalculation (and reduction) of benefits that would have been paid to Alcoa for smelter operation in December 2008, so that such payments will conform with the December Opinion. BPA has calculated a Monetary Benefit payment for December based on 1) BPA's forecasted wholesale market price for the month of December 2008 for purchases made by BPA prior to December 2008, 2) the IP rate in effect for December 2008, and 3) Alcoa's December 2008 operating level.

In addition, the Parties have agreed to modify the provisions regarding the determination of unused benefits under the Agreement to take into account Alcoa's minimum operating level through the Amendment Period. This Amendment is intended to survive the expiration of the Amendment Period. This modification is designed to encourage operation of Alcoa's facilities through the period of increased power production due to fisheries operations on the Federal Columbia River Power System.

This Amendment allows BPA to provide service to Alcoa while it fully considers the December Opinion, including treatment of the payments made to Alcoa under the Agreement prior to the Court's ruling, and the ramifications for service to Alcoa during the final two years of the Agreement (October 1, 2009, through September 30, 2011) following the termination of this Amendment. This Amendment is not intended, and shall not be interpreted, to establish any precedent or to waive any rights or arguments by BPA, Alcoa, or Whatcom regarding the legal rights and obligations of any or all of them under the December Opinion, including but not limited to the manner or amount of service provided by BPA to Alcoa either prior to the December Opinion or after the expiration of this Amendment. The provisions are intended to provide temporary service to Alcoa on terms that BPA, Alcoa, and Whatcom believe adhere to the Court's holdings regarding BPA's authority, while affording the Parties a period of time to negotiate a long term replacement to the Agreement that also is consistent with the December Opinion.

The Parties agree:

1. **EFFECTIVE DATE**
This Amendment shall take effect on January 1, 2009, following execution by the Parties (Effective Date). This Agreement may be executed in counterparts, and upon execution by each Party, each executed counterpart shall have the same force and effect as an original instrument and as if each Party had signed the same instrument.

2. **AMENDMENT OF AGREEMENT**
Each provision of the Agreement is incorporated by reference into this Amendment, except the Parties hereby amend such provisions as follows:

(a) Section 2 of the Agreement (Definitions) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following; except that sections 2(j) and 2(n) shall be used for purposes of establishing Unused Benefit Amounts under the Agreement for the period October 1, 2009 through September 30, 2011 when calculating benefits during the period from December 1, 2008 through September 30, 2009:

"2. **DEFINITIONS**
Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedule(s), including the General Rate Schedule Provisions (GRSPs).

(a) "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principle place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

(b) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, CY 2007 begins October 1, 2006, and continues through September 30, 2007.

(c) "Demand Entitlement" means during the period when this Agreement operates as a physical Industrial Firm Power sale, the megawatt (MW) amount each hour that Alcoa shall purchase from BPA, as specified in Exhibit E.

(d) "Equivalent IP" means the applicable average Industrial Firm Power Rate at 100 percent load factor, as determined pursuant to Exhibit F.

(e) "Escrow Account" means the specific account established pursuant to the provisions in section 9(b) below for receipt of funds from BPA and transfer of funds by Whatcom to Alcoa.

(f) "Forecast Market Price" means the forecast market price for power at 100 percent load factor for the period from January 1, 2009 though September 30, 2009, as specified in Exhibit F.

(g) "FY 07-09 Rate Period" means the wholesale power rate period that begins on October 1, 2006, and continues through September 30, 2009.

(h) "FY 10-11 Rate Period" means the wholesale power rate period that begins on October 1, 2009, and continues through September 30, 2011.

(i) "Industrial Firm Power" means electric power that PBL makes continuously available to Alcoa under this Amendment except during periods when BPA exercises its interruption rights pursuant to section 4(i) below.

(j) "Interim Maximum MB Monthly Payment" means the Demand Entitlement times the hours in the month times the MB Rate.

(k) "MB Monthly Payment" means the monthly Monetary Benefit payment that is available during each month, as calculated in section 6(c)(2) below.

(l) "MB Rate" means the rate in dollars per megawatt-hour ($/MWh) used to calculate MB Monthly Payments pursuant to section 6(c) below. The MB Rate is determined by subtracting Equivalent IP from Forecast Market Price.

(m) "Maximum Allocation" means, for the purpose of determining MB Monthly Payments, the maximum average megawatt (aMW) amount that may be used to determine a MB Monthly Payment. The Maximum Allocation is shown in Exhibit E.

(n) "Maximum MB Monthly Payment" means the Interim Maximum MB Monthly Payment.

(o) "Minimum Allocation" means, for the purpose of determining MB Monthly Payments, the minimum aMW amount that may be used to determine a MB Monthly Payment.

(p) "Monetary Benefits" means monetary payments made by BPA to Alcoa under this Amendment, as determined pursuant to the provisions in section 6 below.

(q) "Monthly Plant Load" means a monthly aMW amount equal to the Total Plant Load for each month divided by the number of hours in each such month.

(r) "Monthly Purchase Deficiency" means the monthly amount(s) of Industrial Firm Power not purchased due to a curtailment, as such amount(s) may be adjusted pursuant to section 4(d)(1) below.

(s) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(t) "Other DSIs" means aluminum smelters other than Alcoa that have executed an agreement substantially in the form of this Agreement.

(u) "Points of Measurement" means the interconnection points between BPA, Alcoa, and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(v) "Point of Receipt" means the points of interconnection on the transmission provider's transmission system where Industrial Firm Power shall be made available by PBL to Alcoa's transmission provider.

(w) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(x) "Region" means the definition established for "Region" in the Northwest Power Act.

(y) "Total Plant Load" means the amount of electric energy in megawatt-hours (MWh) consumed during each month at Alcoa's production facilities. A detailed description of Alcoa's production facilities, including station service requirements and metering equipment, is described in Exhibit B.

(z) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(aa) "Unused Benefit Amount" or "UBA" means either: (1) an aMW amount determined pursuant to section 7(a) during any period in which Monetary Benefits are provided, or (2) a MW amount determined pursuant to section 7(b) during any period in which this Agreement operates as a physical Industrial Firm Power sale."

(b) Section 3 of the Agreement (Applicable Rates) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"3. **APPLICABLE RATES**

Purchases by Alcoa under this Agreement are subject to the Industrial Firm Power (IP) rate schedule, IP-07R, or its successor, and the General Rate Schedule Provisions (GRSP). Billing determinants for any purchases will be included in the rate schedule. Purchases under the IP rate schedule are established as follows:

If this Amendment operates as a physically delivered Industrial Firm Power sale pursuant to section 4 below, then section 4(a) below and the Industrial Firm Power rate schedule apply. If the Industrial Firm Power sale is monetized, then the provisions of section 6 below shall establish the applicable Equivalent IP rate."

(c) Section 4 of the Agreement (Power Sales Provisions) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"4. **Power Sales Provisions**

This section 4 only applies when this Agreement operates as a physically delivered Industrial Firm Power sale. In this event, the Monetary Benefit provisions in section 6 shall not apply. All physically delivered Industrial Firm Power provided by PBL under this section 4 is solely for service to Total Plant Load.

(a) **Power Sale by PBL to Alcoa**

(1) **Hourly Amounts**

PBL shall make available and Alcoa shall purchase the Demand Entitlement each hour. The Demand Entitlement is specified in Exhibit E.

(2) **HLH and LLH Energy Entitlements and Demand Entitlement**

The Demand Entitlement multiplied by: (A) the number of HLH, and (B) the number of LLH in the applicable month establishes Alcoa's HLH and LLH Energy Entitlements with respect to this Amendment.

(b) **Unauthorized Increase Charge**

Alcoa shall not intentionally schedule in excess of the amount specified in section 4(a)(1) above. However, in the event that an excess amount is scheduled due to error, then such amounts taken by Alcoa at the Points of Receipt in excess of the amounts specified in section 4(a) above shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and Alcoa shall not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement. Any Unauthorized Increase Charge shall be billed by BPA in accordance with the billing procedures described in section 9(a) below. Any Industrial Firm Power used by Alcoa for any other purpose shall be subject to the Unauthorized Increase Charge.

(c) **Curtailment**

If Alcoa curtails Total Plant Load in whole or in part, then Alcoa may request take-or-pay mitigation for purchases under section 4(a) above pursuant to section 4(d) below.

(d) **Take-or-Pay Mitigation for Curtailments**

If Alcoa chooses to curtail its purchase obligation, then the following terms and conditions shall apply:

(1) **Notice of Curtailment**

Alcoa shall provide written notice to PBL at least three (3) Business

Days in advance of a curtailment. Such notice shall specify the monthly amounts of power to be curtailed and the duration of the curtailment. The election to curtail such power, and the amount and duration of such curtailment, may not be changed without PBL's consent. PBL's sale shall be reduced by the amount of power curtailed. The Monthly Purchase Deficiency will be reduced by any reduction to the Demand Entitlement pursuant to section 7(b)(2) below.

(2) **Calculation of Damages**

Alcoa shall pay directly to BPA damages for each Monthly Purchase Deficiency equal to the amount by which the reasonable market value of such Monthly Purchase Deficiency is less than the price of the applicable rate specified in Exhibit A. For purposes of calculating damages under this section 4(d)(2), the Monthly Purchase Deficiency(s) shall be reduced by any reduction of Demand Entitlement under section 7(b)(3), effective on the date any such reduction becomes effective. No later than 60 days following September 30, 2009, PBL shall, for each month of the previous Contract Year, calculate the reasonable market value for each Monthly Purchase Deficiency during such period. Reasonable market value and calculation of damages shall be determined as follows.

(A) No later than 3 Business Days prior to the commencement of a curtailment under this section 4(d), Alcoa may obtain one or more transactable quotes for all or a portion of such power from a third party. The transactable quote may be for any length of time and curtailment amount. Each quote shall be deemed equal to the reasonable market value of such power to which the quote applies for the purpose of calculating damages under this section 4(d)(2). BPA may, but shall not be obligated to, resell the curtailed power to the third party, retain the power, or dispose of the power as it chooses. Alcoa shall allow PBL at least 4 hours during normal business hours to decide whether or not to transact under such quote.

(B) BPA shall determine, by any reasonable method, the reasonable market value of the portion of each Monthly Purchase Deficiency for which Alcoa has not obtained a transactable quote. The reasonable market value shall be adjusted to reflect volume and BPA transmission costs associated with remarketing each such portion of the Monthly Purchase Deficiency, regardless of whether each such portion is actually remarketed.

(C) BPA shall bill Alcoa and Alcoa shall directly pay BPA damages for such period equal to the amount by which the sum of the product of (1) each Monthly Purchase Deficiency and

(2) the applicable rate specified in Exhibit A that BPA would have charged each month if the power had been taken under this Agreement, exceeds the sum of the product of (1) each Monthly Purchase Deficiency and (2) the reasonable market value in each month. Amounts for damages under section 4(d)(2)(A) and section 4(d)(2)(B) may only be netted within a Contract Year. BPA is not obligated to pay Alcoa the difference when the reasonable market value exceeds the applicable Industrial Firm Power rate.

It is expressly agreed to by the Parties that BPA shall not be obligated to enter into replacement transactions to determine or collect damages under this section 4(d)(2).

It is also expressly agreed that BPA will apply its then-current applicable credit policies if damages are due under this section 4(d)(2), and such policies may include an obligation to prepay for damages.

(e) **Scheduling**

All Industrial Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit C, BPA Power Business Line Scheduling Provisions. The procedures for scheduling described in Exhibit C are the standard utility procedures followed by BPA for power transactions between PBL and other utilities or entities in the Region that require scheduling.

(f) **Delivery**

(1) **Transmission Service for Industrial Firm Power**

This Agreement does not provide transmission services for, or include the delivery of, Industrial Firm Power by BPA to Alcoa. Alcoa shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Industrial Firm Power (Wheeling Agreement). PBL and Alcoa agree to take such actions as may be necessary to facilitate the delivery of Industrial Firm Power to Alcoa, consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(2) **Liability for Delivery**

Alcoa waives any claims against PBL arising under this Amendment for nondelivery of power to any points beyond the applicable Points of Receipt. PBL shall not be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event shall any Party be liable under this Agreement to any other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply

regardless of whether or not this Amendment provides for transfer service.

(3) **Points of Receipt**
PBL shall make Industrial Firm Power available to Alcoa under this Amendment at Points of Receipt solely for the purpose of Alcoa scheduling transmission to points of delivery for service to Alcoa's Total Plant Load. Alcoa shall schedule, if scheduling is necessary, such Industrial Firm Power solely for use by its Total Plant Load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to Alcoa no later than January 1, 2009.

If required by the Wheeling Agreement, when PBL designates such Points of Receipt, PBL shall provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under Alcoa's Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount of Industrial Firm Power specified in sections 4(a) above. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of a nonfirm Point of Receipt to provide Industrial Firm Power to Alcoa, but notwithstanding section 4(f)(2) above, PBL shall reimburse Alcoa for any additional costs or production losses incurred by Alcoa due to its compliance with such request.

(4) **Transmission Losses**
PBL shall provide Alcoa the transmission losses between the Points of Receipt and Alcoa's points of delivery for Industrial Firm Power, at no additional charge. Such losses shall be provided at Points of Receipt as established under section 4(f)(3) above, and under the terms and conditions as defined in the transmission provider's tariff.

(g) **Measurement**

(1) Amounts of Industrial Firm Power taken are deemed equal to the amount scheduled by Alcoa under section 4(e) above or an amount of power as measured at Points of Measurement, as appropriate.

(2) Alcoa shall provide reasonable notice to PBL prior to changing control areas.

(h) **Interruption Rights**
PBL shall have a one-time right during the term of this Amendment to interrupt deliveries of a portion of the Industrial Firm Power

hereunder pursuant to the following provisions. PBL may interrupt a portion of Industrial Firm Power deliveries if PBL anticipates, in its sole and exclusive discretion, that average forward market prices for a flat block of power will exceed $125/MWh during an interruption period to be specified by PBL in a written notice. In this event, PBL shall consult with Alcoa prior to providing such written notice. If PBL decides to interrupt, then it will provide 30 days advance written notice to Alcoa that specifies the amount of Industrial Firm Power to be interrupted and the associated interruption period; *provided, however,* that a minimum of 6 aMW will not be subject to any such interruption. Unless the Parties mutually agree otherwise, such interruption period shall extend for a minimum of 6 months and for a maximum of the duration of this Amendment, regardless of the level of actual market prices during an interruption period. In the event of an interruption, BPA shall pay Alcoa, $24/MWh for amounts interrupted. Payments shall be made pursuant to section 9(b) below. Payments to Alcoa under this section 4(h) shall be used first by Alcoa to compensate Alcoa's employees employed at the time of an interruption under this section 4(h) by providing each such employee, at the election of Alcoa, either (1) the opportunity to work a regular work week (40 hours) at regular wage and benefit rates, or (2) special supplemental benefits such that the employee's effective after-tax income (including any available unemployment income) will be equal to what the employee's income would have been working a regular work week, plus all benefits the employee would have received, had the employee been working a regular 40-hour work week. BPA shall have the right to conduct an audit to verify compliance with this section 4(h). If there is an interruption under this section 4(h), then the portion of Demand Entitlement interrupted shall be treated as if taken for purposes of section 7(b)(1)(A) and shall not be subject to the take-or-pay provisions in sections 4(a).

(i) **Modification of Whatcom's Obligations**

The Parties agree Whatcom shall have no obligation to purchase any power from BPA under this Amendment. The Parties agree Whatcom shall have no obligation to make available to Alcoa any power under this Amendment."

(d) Section 5 of the Agreement (BPA and Alcoa Options) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"5. **BPA Monetary Benefit Option**

BPA has determined that, during the period of this Amendment, in order to minimize the cost risks of supplying Industrial Firm Power, the Parties will monetize the physically delivered Industrial Firm Power sale obligation. As such, BPA will make any MB Monthly

Payments during the period of this Amendment, subject to the provisions of section 6 below."

(e) Section 6 of the Agreement (Monetary Benefit Provisions) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"**6. MONETARY BENEFIT PROVISIONS**

This section 6 only applies when the physically delivered Industrial Firm Power sale is monetized. The provisions in section 4 shall not apply to Monetary Benefits.

(a) **Determination of Forecast Market Price and Equivalent IP**

PBL has determined the Forecast Market Price and Equivalent IP for the period of this Amendment as specified in Exhibit F.

(b) **Determination of Monthly Plant Load**

No later than five (5) Business Days following the end of each month, PBL shall determine the Monthly Plant Load for each such month.

(c) **Determination of MB Monthly Payments**

The determinations described in Exhibit F and the following procedure as described in section 6(c)(1) through section 6(c)(3) shall be used to determine the MB Monthly Payment for each month.

(1) The Minimum Allocation shall not affect payment of the MB Monthly Payment.

(2) The MB Monthly Payment for each month shall be the amount determined by the following equation:

MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate).

(3) Notwithstanding anything to the contrary in this Amendment, in no case shall the Monetary Benefits accrued during the period from December 1, 2008 through September 30, 2009, exceed the Monetary Benefit Limit specified in Exhibit E of this Amendment.

(d) **Recalculated Monetary Benefits Payment**

BPA shall pay Alcoa a Monetary Benefit equal to the Monthly Plant Load times the number of hours in the month times $14.26/MWh to monetize deliveries of Industrial Firm Power

for the Monthly Plant Load during the month of December 2008.

(f) Section 7(a)(2) and section 7(a)(3) of the Agreement shall be replaced by the following when calculating benefits accessed under section 7(a)(3) for the period from December 1, 2008, through September 30, 2009 and such benefits accessed, or deemed to be accessed, shall be used for purposes of establishing Unused Benefit Amounts under the Agreement for the period October 1, 2009, through September 30, 2011:

"(2) In order to retain its Maximum Allocation, Alcoa must, for at least one month during the preceding 12 months, have received the Maximum MB Monthly Payment. If this condition is not satisfied, then the Maximum Allocation shall be reduced; provided however, if the Monthly Plant Load is either equal to or greater than 160 aMW for all months through June 30, 2009, or equal to or greater than 80 aMW for all months during the term of this Amendment, Alcoa shall be deemed to have received the Maximum MB Monthly Payment for each month of the period from January 1, 2009, through September 30, 2009.

(3) Alcoa shall retain the highest monthly percentage of the available benefits that it accessed during the previous 12 months. As such, Alcoa's Maximum Allocation shall be reduced by the percentage of the available benefits, rounded to the nearest aMW, that were not accessed during the month that set the highest monthly percentage of benefits accessed. The amount of aMW from this calculation becomes an Unused Benefit Amount or UBA."

(g) Section 9(b) of the Agreement (Billing and Payment When Monetary Benefit Payments Provided) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"(b) **Payment of Interim Monetary Benefits Provided**
Within five Business Days after the end of each month, BPA will review Alcoa's metered load measurements to determine the Monthly Plant Load for the month.

Within eight Business Days following the end of the month, BPA shall transfer an amount to Alcoa to pay the MB Monthly Payment, except that the payment under section 6(d) above shall be made on the later of eight Business Days following the end of the month or eight Business Days following execution of this Amendment by both Parties."

(h) Section 11 of the Agreement (Uncontrollable Forces) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"11. UNCONTROLLABLE FORCES

(a) **Uncontrollable Forces Provisions During Industrial Firm Power Sale**

If this Agreement operates as a physical Industrial Firm Power Sale, then the following provisions shall apply; *provided however,* that UBA determinations pursuant to section 7 and acquisitions of UBA pursuant to section 8 shall not be subject to Uncontrollable Forces under this section 11(a).

"Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Industrial Firm Power to Alcoa's facilities, including but not limited to unplanned maintenance outages;

(2) any unplanned curtailment or interruption, failure or imminent failure of Alcoa's production or transmission facilities, including but not limited to unplanned maintenance outages;

(3) any planned transmission or distribution outage that affects either Alcoa or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(4) strikes or work stoppage, including the threat of imminent strikes or work stoppage; *provided, however*, that nothing contained in this provision shall be construed to require any Party to settle any strike or labor dispute in which it may be involved.

(5) floods, earthquakes, or other natural disasters; and

(6) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of any Party shall not constitute an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify the other Party as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force shall notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

All Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

(b) **Uncontrollable Forces Provisions During Periods When A Monetary Benefit is Provided**
During periods when the Industrial Firm Power sale is monetized, Alcoa understands and agrees that there are no events that will be considered Uncontrollable Forces under this Agreement."

(i) Section 13(b) of the Agreement (Limitation on Resale) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the following:

"(b) **Limitation on Resale**
Alcoa shall not resell Industrial Firm Power."

(j) Section 16(c) of the Agreement is deleted for the period from the December 1, 2008 through September 30, 2009.

(k) Exhibit A of the Agreement (Surplus firm Power Rate) shall be inoperative for the period from the Effective Date through September 30, 2009.

(l) Exhibit B of the Agreement (Additional Products, Services, and Special Provisions) shall be inoperative for the period from the Effective Date

through September 30, 2009 and replaced by the attached Revision No. 1 of Exhibit B.

(m) Revision No. 1 of Exhibit E of the Agreement (Maximum Allocation, Minimum allocation, and Demand Entitlement) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the attached Revision No. 2 of Exhibit E.

(n) Exhibit F of the Agreement (Determination of Forecast Market Price and Equivalent PF) shall be inoperative for the period from the Effective Date through September 30, 2009 and replaced by the attached Revision No. 1 of Exhibit F.

3. SIGNATURES

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

ALCOA, INC.

By _____

Name _____
(Print/Type)

Title _____

Date _____

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Administrator

Name _____
(Print/Type)

Date _____

PUBLIC UTILITY DISTRICT NO. 1 OF
WHATCOM COUNTY, WASHINGTON

By _____

Name _____

Title _____

Date _____

Revision No. 1 of Exhibit B
ADDITIONAL PRODUCTS, SERVICES, AND SPECIAL PROVISIONS
(Amendment No.1 of Contract No. 06PB-11744)
Effective on the Effective Date

1. DESCRIPTION OF ALCOA's PRODUCTION FACILITIES, STATION SERVICE REQUIREMENTS, AND METERING EQUIPMENT

Production Facilities: are Alcoa's aluminum smelting facilities served from the Government's Intalco Substation, where the 13.8 kilovolt (kV) facilities of BPA and Alcoa are connected.

Metering Equipment: used to measure energy usage of Alcoa's facilities at the Government's Intalco Substation in the 13.8 kV circuits over which such electric power and energy flows.

Alcoa agrees to allow PBL access to all hourly load measurements of its Production Facilities necessary to administer this Agreement.

Revision No. 2, Exhibit E
MAXIMUM ALLOCATION, MINIMUM ALLOCATION, AND DEMAND ENTITLEMENT
(Amendment No.1 of Contract No. 06PB-11744)
Effective on the Effective Date

1. MAXIMUM AND MINIMUM ALLOCATIONS

During periods when Monetary Benefits payments are provided pursuant to section 6 of the body of this Agreement, the Maximum Allocation, Minimum Allocation, and Monetary Benefits Limit amounts are as follows:

Maximum Allocation:	Demand Entitlement
Minimum Allocation:	0 aMW
Monetary Benefits Limit:	$31,899,596

2. DEMAND ENTITLEMENT

The Demand Entitlement shall be as follows:

- Demand Entitlement: The average Total Plant Load from December 1, 2008, through December 17, 2008.

3. REVISIONS

BPA shall not revise this Revision No. 2 of Exhibit E to reflect changes to Maximum Allocation, Minimum Allocation, Monetary Benefits Limit, and/or Demand Entitlement for the period it is in effect.

Revision No.1 of Exhibit F
DETERMINATION OF FORECAST MARKET PRICE AND EQUIVALENT IP
(Amendment No.1 of Contract No. 06PB-11744)
Effective on the Effective Date

1. DETERMINATION OF FORECAST MARKET PRICE

The Forecast Market Price for the period from January 1, 2009 through September 30, 2009 shall be $48.05/ MWh.

2. DETERMINATION OF EQUIVALENT IP

The initial Equivalent IP for the period from January 1, 2009 through September 30, 2009 shall be $32.70/MWh.

(a) Each time any adjustment, surcharge, dividend or true-up to the IP Rate is proposed by BPA in writing (which may be before the date such change will actually be applied to the PF Rate), BPA will adjust the Equivalent IP and the MB Rate and MB Monthly Payments for the remaining months of such CY. Such adjustment will take into consideration the Monetary Benefits provided to date and the IP Rate adjustment to provide an end-of-CY total Monetary Benefit to which Alcoa is entitled. If such recalculation indicates that BPA has paid Alcoa more in Monetary Benefits than the amount to which Alcoa is entitled, then BPA will reduce the MB Monthly Payments to Alcoa over the next following three months (if full recovery of the amount is not possible in the 3-month period BPA may invoice Alcoa for the remaining amount), by the amount needed to recover the overpayment. If adjustments, surcharges, and true-ups are established after the CY, then BPA will calculate the final Equivalent IP rate for such portion of the CY and adjustments to Monetary Benefit will be applied in the following CY.

(b) If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by Alcoa to BPA, then BPA shall invoice Alcoa for such payment within 90 days following the end of such final CY. Such payment shall be made by Alcoa within 20 days following the receipt of such invoice. If, upon termination of this Agreement, a true-up or other adjustment following the end of the final CY results in a payment owed by BPA to Alcoa, then BPA shall pay Alcoa no later than 90 days following the end of such final CY.

3. REVISIONS

BPA shall have the unilateral right to revise this Exhibit F to reflect changes in Equivalent IP for CY 2009 calculated pursuant to this Exhibit F. Any changes to the procedure used to determine Equivalent IP may only be made upon mutual agreement of the Parties.

Attachment I

Letter to the Region Announcing Delay to the DSI Lookback Process (7/24/09)

Department of Energy

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

EXECUTIVE OFFICE

July 24, 2009

In reply refer to: A-7

To Regional Customers, Stakeholders, and Other Interested Parties:

On June 10, 2009, the Bonneville Power Administration (BPA) issued a letter indicating it would commence a bifurcated process to address Lookback issues that arose as part of the Ninth Circuit's remand in *Pacific Northwest Generating Cooperative, et al. v. Bonneville Power Administration*, 550 F.3d 846 (9th Cir. 2008) (*PNGC*). The suit challenges the validity of BPA's FY 2007 – 2011 direct-service industrial customer (DSI) service construct and contracts. The June 10 announcement indicated that, in early July, BPA planned to issue a draft record of decision, pursuant to the Court's instructions, on "the applicability and construction of the severability clause, the damage waiver, and the physical power sale option."

BPA's original announcement reflects BPA's view, as well as the view of a number of interested parties, that BPA should act as promptly as reasonably possible in resolving issues related to the Lookback. However, BPA also acknowledged that the timing of events under this process might have to be adjusted to accommodate any decisions of the court relevant to the Lookback determination.

In this light, BPA has reconsidered its earlier announcement. The court is still reviewing its original decision pursuant to the filing of petitions for rehearing filed by the Port Townsend Paper Company and BPA. Also, oral arguments were recently completed on an expedited basis in the court's review of challenges to the contract amendment providing service to Alcoa through FY09. Thus, the case is still within the Court's original and continuing jurisdiction, no mandate has been issued, and the court is free to change its opinion until it issues a mandate. It would be unfortunate indeed if BPA were to issue a draft ROD on the DSI Lookback only to have the Court issue an opinion, or opinions, shortly thereafter that have a material effect on BPA's consideration of the salient issues.

Due to this uncertainty, BPA has determined that it would be prudent to delay issuing the draft record of decision until no earlier than 30 days after the mandate issues in *PNGC* or December 1, 2009. In the meantime, BPA will continue to evaluate pertinent issues and await the Court's final determination in the hope that the Court will provide some degree of finality in the near future.

If you have additional questions about this issue, please call Mark Symonds at (503) 230-3027 or Heidi Helwig of the Public Affairs Office at (503) 230-3458.

Sincerely,

//s// Allen Burns

Allen Burns
Acting Deputy Administrator

bcc:

S. Wright – A-7
A. Burns – D-7
C. Brannon – DK-7
CCIS Authentication – KSC-4
R. Roach – L-7
J. Wright – LP-7
S. Cannady – PT-5
H. Clark – PTL-5
L. Kitchen – PTL-5
Official File – PTL-5

HClark:sgc:3662:7/23/2009 (W-PTL-5-W:\P\PT\PTL\DSI_recent_KEEP\Letter to region - delay in DSI Lookback - 072009.doc)

Attachment J

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

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

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

BONNEVILLE POWER ADMINISTRATION

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BONNEVILLE POWER ADMINISTRATION
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

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

---

[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:

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[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

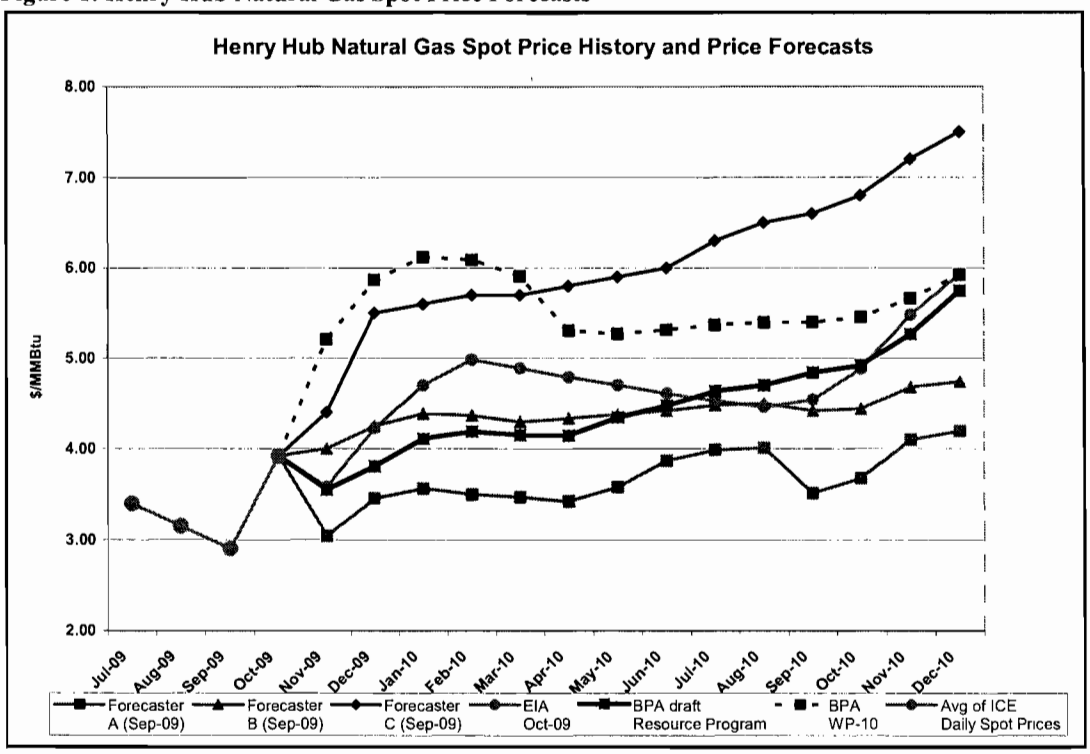


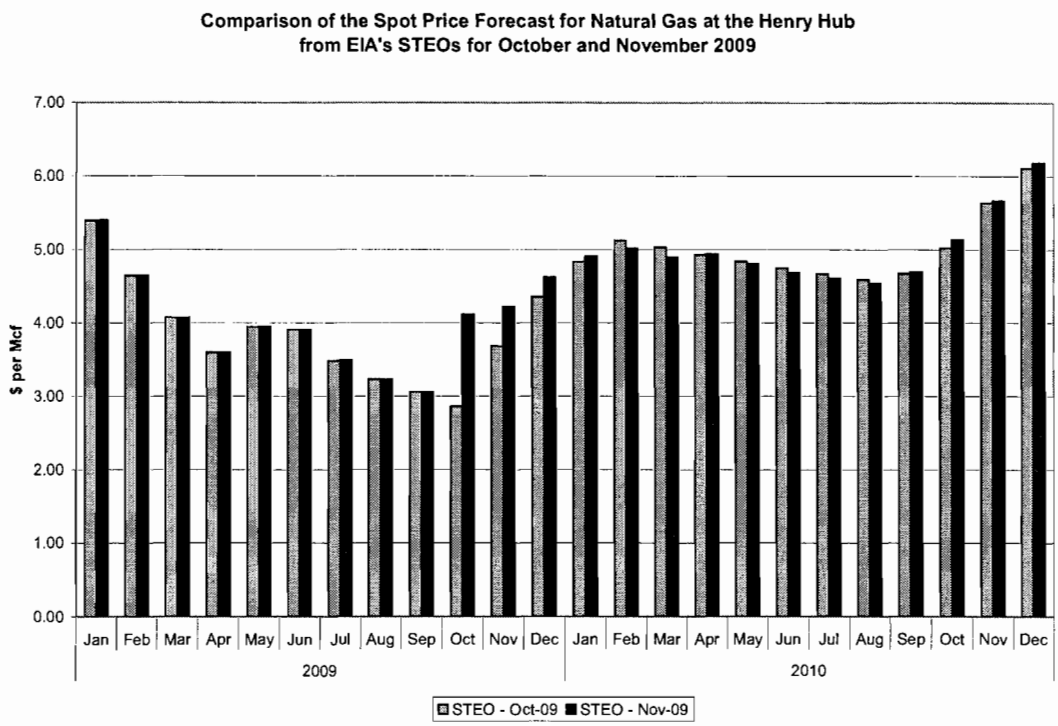
Figure 1 demonstrates that recent spot market prices for natural gas at the Henry Hub have been in the range of $3 to $4 per MMBtu from July to October 2009. This illustration also demonstrates that the forecasts of three other industry experts are $4 per MMBtu or less in November 2009 – the starting 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

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[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

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[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

ALCOA

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.*

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

ALCOA

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.

Power reserves

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.

Michael C. Dotten
13643 Melrose Place
Lake Oswego, OR 97035
Telephone (503) 882-4937
Facsimile (503) 636-9015
E-Mail: mcdotten@msn.com

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

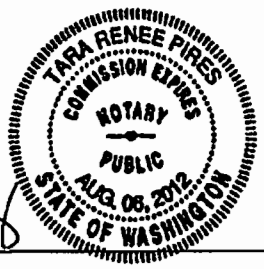
during the term of the Block Power Sales Agreement (October 2006 through September 2011) that it would have had BPA provided Alcoa with physical power at a correctly calculated IP rate.

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
Legal Contact Email: mcdotten@msn.com

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	$11,621,618	$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	$3,182,978	$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	$32,398,816	$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	47.28	$ 10,127,164	$ -	$ -	$10,127,164	$47.28	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	$ 7,876,915	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	$ 14,248,280	$ -	$ -	$14,248,280	$68.70	32.15	$ 6,666,624	36.55	$7,578,656
	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	36.66	$ 7,858,066	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	38.68	$ 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	47.18	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	47.81	54.05	$ 10,481,528	$ -	$ -	$10,481,528	$54.05	40.70	$ 7,876,915	13.35	$2,564,613
	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	38.88	$ 7,858,066	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	38.68	$ 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	Overpaymei $/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

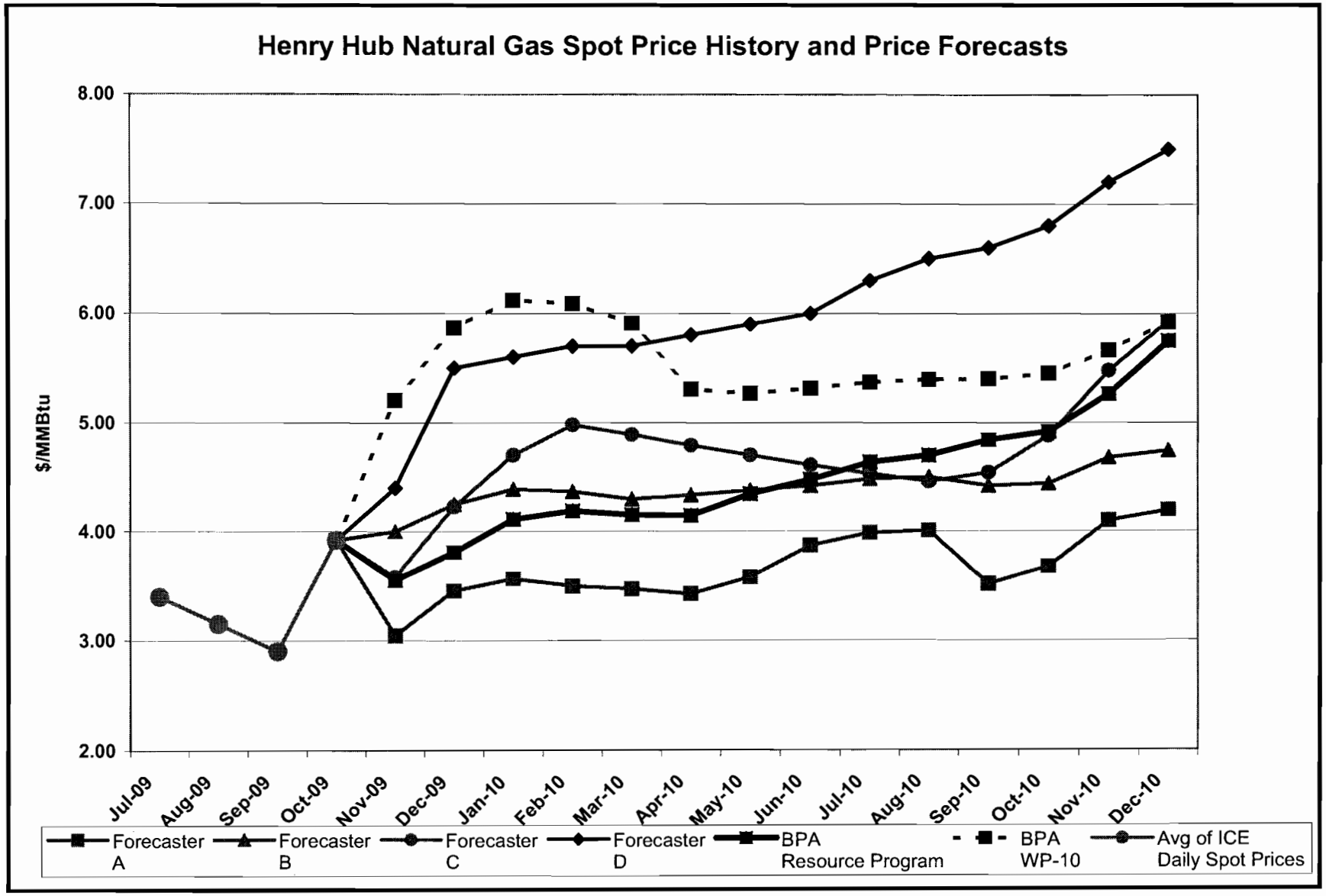

Henry Hub Natural Gas Spot Price History and Price Forecasts
$/MMBtu
8.00
7.00
6.00
5.00
4.00
3.00
2.00
Jul-09
Aug-09
Sep-09
Oct-09
Nov-09
Dec-09
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Forecaster A
Forecaster B
Forecaster C
Forecaster D
BPA Resource Program
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	BPA Revised Market Forecast	HLH Price ($ / MWh)	LLH Price ($ / MWh)
Nov	$45.50	$39.42	not provided	Nov-09	$28.75	$26.38
Dec	$55.50	$47.98	not provided	Dec-09	$30.61	$27.41
Q1 - 2010	$49.50	$43.87	changed; derived LLH	Jan-10	$34.13	$29.51
				Feb-10	$34.46	$29.77
				Mar-10	$33.92	$29.16
Q2 - 2010	$39.00	$25.93	changed; derived LLH	Apr-10	$32.95	$28.05
				May-10	$33.93	$24.45
				Jun-10	$34.33	$26.33
Q3 - 2010	$58.25	$41.80	changed; derived LLH	Jul-10	$37.33	$32.18
				Aug-10	$42.48	$35.63
				Sep-10	$42.86	$38.00
Q4 - 2010	$59.25	$50.07	changed; derived LLH	Oct-10	$43.31	$36.85
				Nov-10	$45.36	$40.59
				Dec-10	$48.81	$43.42
Flat Average		$46.78				

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)

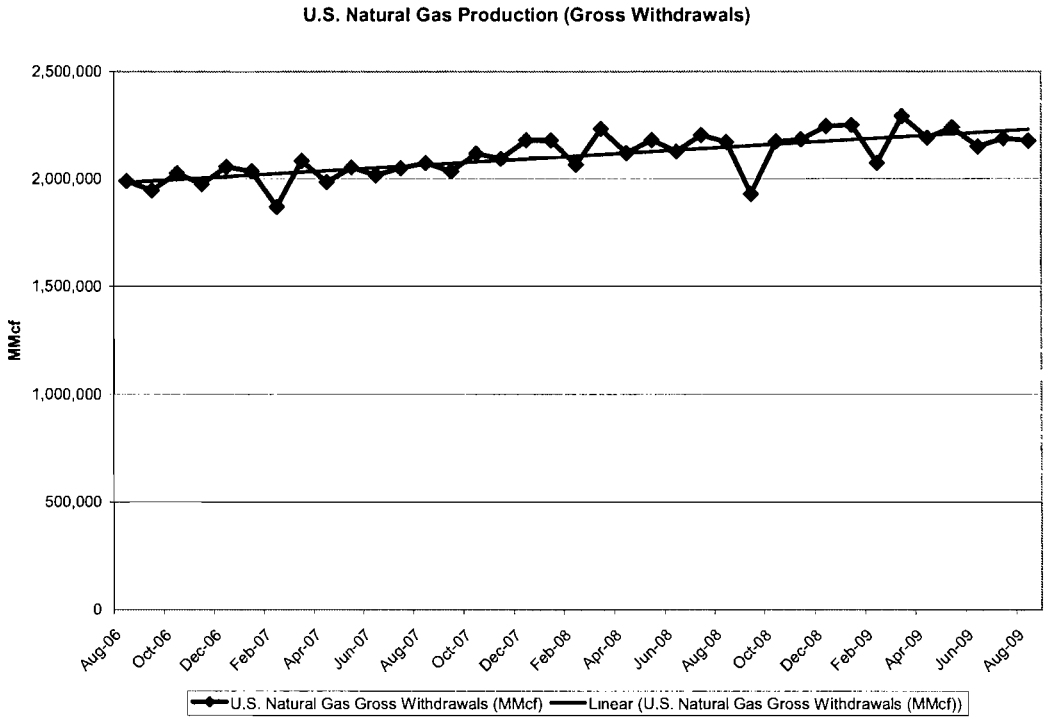
BPA's addition to clarify results provided by Snohomish
BPA's adjustment to values provided by Snohomish

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

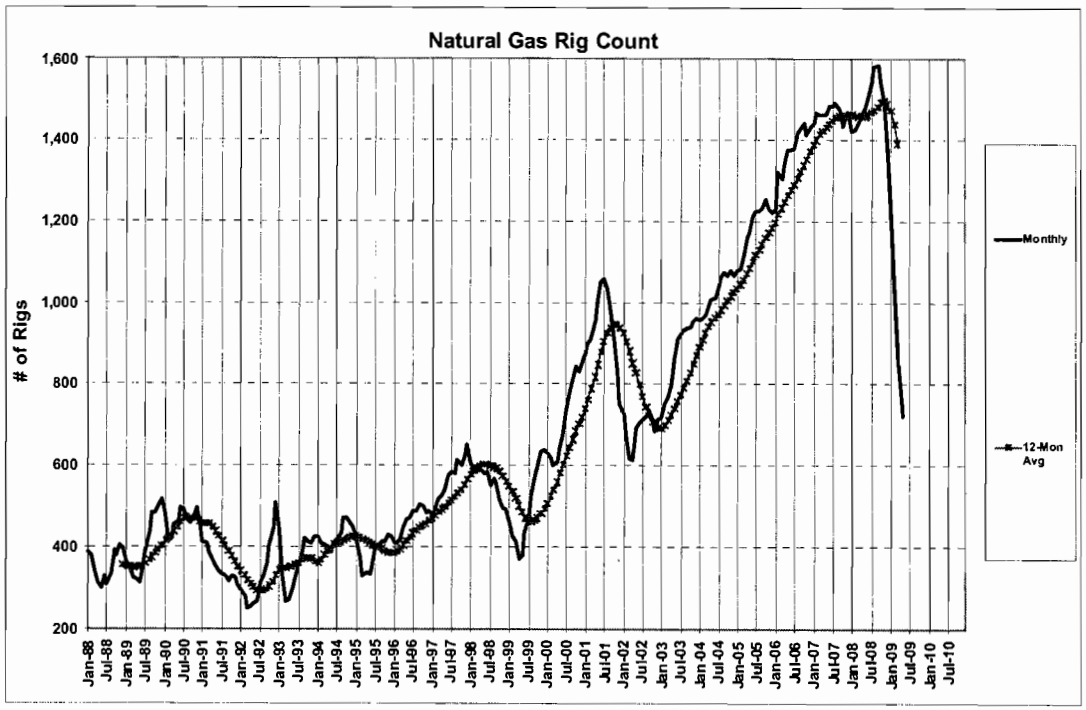
Natural Gas Statistics

Figure 1 – Natural Gas Production



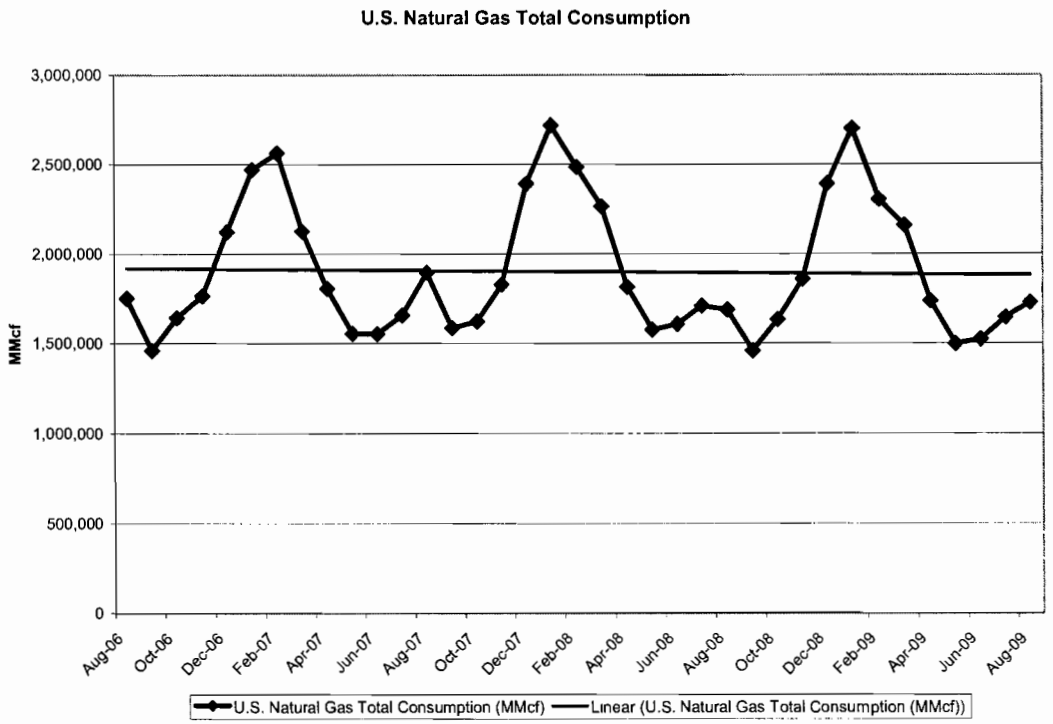
Source: United States Department of Energy, Energy Information Administration, released October 30, 2009.

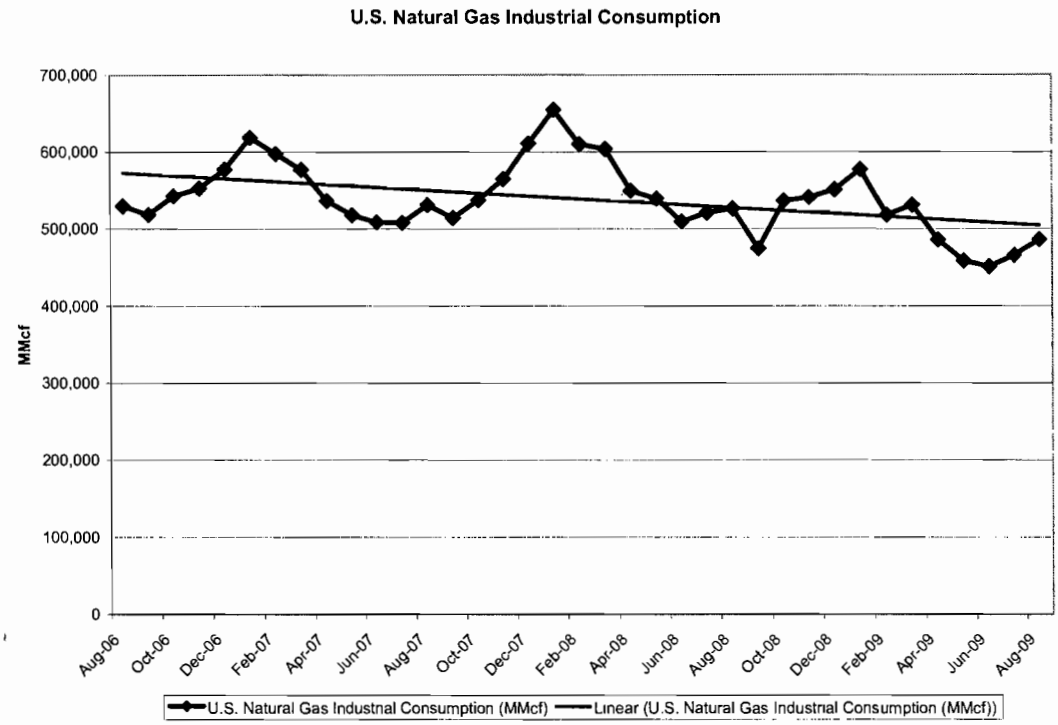
Figure 2 – Natural Gas Rig Count



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

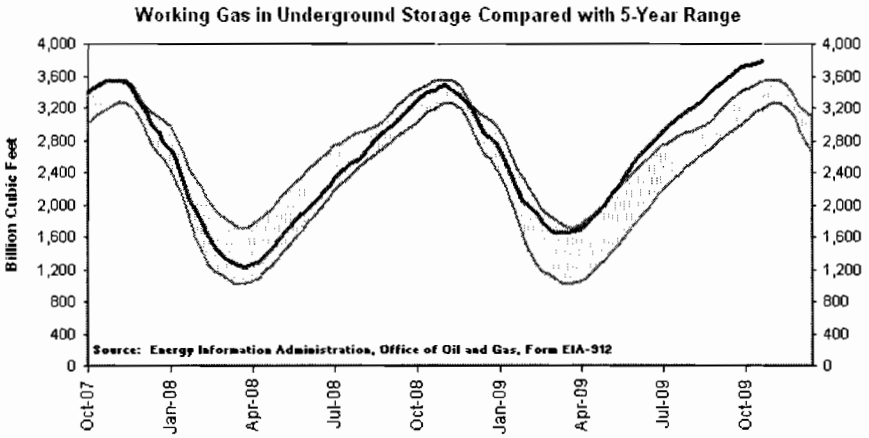
Released: November 5, 2009 at 10:30 A.M. (eastern time) for the Week Ending October 30, 2009.
Next Release: November 13, 2009

Working Gas in Underground Storage, Lower 48 — other formats: Summary TXT CSV

Region	Stocks in billion cubic feet (Bcf)			Historical Comparisons			
				Year Ago (10/30/08)		5-Year (2004-2008) Average	
	10/30/09	10/23/09	Change	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.

Attachment K

Five-Month Extension of 20.5 aMW Power Sale Contract No. 09PB-12106 with Port Townsend Paper Company – Administrator's Record of Decision

Five-Month Extension of 20.5 aMW Power Sale Contract No. 09PB-12106 With Port Townsend Paper Company

Administrator's Record of Decision

On November 13, 2009, Bonneville Power Administration (BPA) executed a power sales contract with Port Townsend Paper Company (Port Townsend) for the sale of up to 20.5 aMW by BPA to Port Townsend for the period November 15, 2009, through December 31, 2010 (Block Contract), and concomitantly issued its rationale for that sale in *Bonneville Power Administration – 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 Record).

In the November Record, BPA described certain additional "tangible and intangible benefits to BPA's operations" that it may accrue in connection with the Block Contract in the event that BPA made additional sales to its direct-service industrial (DSI) customers. November Record at 10. However, BPA indicated that it was not accounting for such benefits in its analysis of the Block Contract, inasmuch as the 20.5 aMW sale, in and of itself, was not of sufficient magnitude to significantly impact the financial benefit to BPA. BPA went on to state, however, that

> [T]he 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.

November Record at 11.

On December 21, 2009, BPA executed a power sales contract with Alcoa Inc. (Alcoa), for the sale of up to 320 aMW commencing December 22, 2009 (Alcoa Contract). The Alcoa Contract is described in *Bonneville Power Administration – Power Sale to Alcoa Inc. Commencing December 22, 2009 – Administrator's Record of Decision*, issued December 21, 2009 (Alcoa Record). In the Alcoa Record, BPA described and analyzed in detail the nature and scope of these additional tangible (quantifiable) and intangible (unquantifiable) benefits to BPA associated with the DSI Service. Tangible benefits include avoided transmission costs to BPA's power marketing function that would otherwise be incurred absent the sales to the DSIs, and higher market prices for BPA's surplus sales as a result of DSI load operation (Demand Shift). See November Record at 10; Alcoa Record at 41.

In light of the foregoing, BPA decided to enter into a letter agreement extending the term of the Block Contract with Port Townsend by five months, to May 31, 2011. As explained in this record of decision, BPA believes the five–month extension is justified under the equivalent benefits analysis because of the additional tangible benefits now shown to accrue to BPA for the period from now to the end of the extension.

Benefits to BPA will equal or exceed costs for the extended Block Contract with Port Townsend

BPA forecasts that the revenues it will accrue from the sale to Port Townsend of up to 20 aMW at the Industrial Firm (IP) Power rate will exceed by approximately $54,000 the forecast revenues BPA could otherwise obtain from selling that power into the market through the extended period of the Block Contract with Port Townsend. See Tables 1-6 below. As a consequence, BPA believes service to Port Townsend under the Block Contract is consistent with *Pacific Northwest Generating Cooperative v. BPA*, 580 F.3d 828 (9th Cir. 2009) (*PNGC II)*, that service to a DSI only can be provided if benefits equal or exceed costs.

BPA's projected monthly revenues were 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 calculated revenues under the Block Contract based on the sale of 20 aMW 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, and ending on May 31, 2011. The energy entitlements are the projected amounts of megawatt-hours to be sold by diurnal period each month. The demand entitlement is the projected megawatt amount consumed during the hour of BPA's system peak. BPA's projected monthly revenues were then accumulated and the result is illustrated in Tables 1 and 2:

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
Feb-11	20,000	7,680	5,760	$1.99	$37.72	$31.73
Mar-11	20,000	8,640	6,220	$1.85	$35.94	$30.08
Apr-11	20,000	8,320	6,080	$1.74	$32.23	$26.95
May-11	20,000	8,000	6,880	$1.44	$31.69	$22.29
Jun-11	20,000	8,320	6,080	$1.32	$31.18	$23.29

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
Feb-11	$39,800	$289,690	$182,765	$512,254	$7,972,016
Mar-11	$37,000	$310,522	$187,098	$534,619	$8,506,635
Apr-11	$34,800	$268,154	$163,856	$466,810	$8,973,444
May-11	$28,800	$253,520	$153,355	$435,675	$9,409,120
Jun-11	$26,400	$259,418	$141,603	$427,421	$9,836,540

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

BPA routinely shapes its inventory to meet the need of its portfolio of contracts and sells its surplus inventory by purchasing and selling in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[1] BPA established its forecast of Mid-Columbia trading hub (Mid-C) electricity prices in the WP-10 rate proceeding to value these purchases and sales.[2] For the period covered by the Block Contract BPA has updated its natural gas forecast from that used in BPA's WP-10 rate proceeding to forecast electricity prices to reflect a more contemporary understanding of natural gas fundamentals and to be consistent with the natural gas forecast used in the November Record, the Alcoa Record, and BPA's draft Resource Program released September 30th, 2009.[3]

In the absence of the Block Contract selling 20 aMW of firm power to Port Townsend every hour BPA would have one less firm power requirement sale in its aggregated portfolio load shape to meet; as such BPA would have 20 aMW of surplus energy to sell in the market. As illustrated in Table 3, BPA forecast the revenues it would otherwise obtain from the market using the same forecasting methodology applied in the WP-10 rate proceeding to incorporate our updated forecast of natural gas prices in the development of our electricity price forecast used in this analysis of the five-month extension.[4]

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

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

[3] BPA's natural gas forecast used in the WP-10 rate proceeding is outlined in section 3.3 of the Market Price Forecast Study. (See WP-10-FS-BPA-03, beginning on page 11.) BPA's more contemporary understanding of natural gas market fundamentals caused a lowering of its natural gas price forecast in 2010 and an increase in 2011. The primary reasons for BPA's recent reductions became apparent in the progression of time since the natural gas price forecast for the WP-10 rate proceeding was constructed; these are: a) continued strength of natural gas production despite steep reductions in rig counts, b) continued slow recovery of natural gas demand – particularly on the industrial side, c) record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2009 hurricane season is nearly over. (See also Short-term Energy Outlooks from the EIA for September and October that have reduced their forecasted Henry Hub Spot Price average for 2010 to $4.78 and $5.02 per Mcf respectively [or $4.64 and $4.87 per MMbtu using EIA's conversion of 1 Mcf = 1.031 MMbtu], *Short-term Energy Outlook*, DOE EIA, September 9, 2009, page 1; *Short-Term Energy and Winter Fuels Outlook*, DOE EIA, October 6, 2009, p. 3.)

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
Feb-11	$50.78	$42.80	$390,015	$246,519	$636,533	$8,306,197
Mar-11	$49.33	$40.83	$426,216	$253,956	$680,172	$8,986,369
Apr-11	$46.35	$38.79	$385,603	$235,843	$621,446	$9,607,815
May-11	$47.15	$32.65	$377,203	$224,647	$601,849	$10,209,665
Jun-11	$46.50	$33.58	$386,879	$204,196	$591,076	$10,800,740

Net Benefit (IP – Market)

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 is illustrated in Table 4:

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

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)
Feb-11	($124,279)	($334,182)
Mar-11	($145,552)	($479,734)
Apr-11	($154,637)	($634,371)
May-11	($166,174)	($800,545)
Jun-11	($163,655)	($964,200)

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

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

Value of Reserves[5]

The Block Contract requires that Port Townsend make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value to BPA of the reserves Port Townsend is required to make available to BPA under the Block Contract. Sales at the IP rate reflect the value of a right

[5] The value of reserves analysis was described and evaluated in the November Record, and the benefit to BPA from reserves provided by Port Townsend were counted in BPA's analysis in the November Record, that monetary benefit to BPA is shown here again for illustrative purposes, and those benefits are not being double-counted.

for BPA to obtain contingency reserves.[6] 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 analysis above, compares a surplus power sale to a sale of power at the IP rate with reserves. We 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.[7] As illustrated by Table 5a, this was done for every megawatt hour not sold to Port Townsend Paper Company:

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

Month	Month ($)	Cumulative ($)
Nov-09	$6,144	$6,144
Dec-09	$11,904	$18,048
Jan-10	$11,904	$29,952
Feb-10	$10,752	$40,704
Mar-10	$11,888	$52,592
Apr-10	$11,520	$64,112
May-10	$11,904	$76,016
Jun-10	$11,520	$87,536
Jul-10	$11,904	$99,440
Aug-10	$11,904	$111,344
Sep-10	$11,520	$122,864
Oct-10	$11,904	$134,768
Nov-10	$11,536	$146,304
Dec-10	$11,904	$158,208
Jan-11	$11,904	$170,112
Feb-11	$10,752	$180,864
Mar-11	$11,888	$192,752
Apr-11	$11,520	$204,272
May-11	$11,904	$216,176
Jun-11	$11,520	$227,696

Avoided Transmission and Ancillary Services Expenses (additional going forward benefits)

When BPA makes a DSI sale, the DSI customers – including Port Townsend – cover the cost of transmission and ancillary services through their own transmission contracts. Market prices, on the other hand, assume power is delivered by the seller to Mid-C. Power Services (PS) is the organization within BPA that is responsible for the management and sale of Federal power. PS must pay the transmission and ancillary

[6] Sales at the IP rate require the provision of the DSI Minimum Operating Reserve – Supplemental. The Block Contract is an IP sale and, accordingly, it requires that Port Townsend make such a contingency reserve available to BPA, as defined in section 2.12 and implemented by Exhibit H to the Block Contract.

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

services costs to move surplus power to the Mid-C delivery point in order to realize the full market value for its surplus sales. PS maintains an inventory of transmission products and services to deliver the surplus power it intends to sell. However, this inventory is not sufficient to deliver all of the surplus power PS would sell under all load and resource conditions, especially under high stream flows. As a result, there is a subset of load and resource conditions under which PS would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales, if PS did not sign contracts to serve the DSI loads -- including the Block Contract with Port Townsend. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding.[8] Since PS' overall marketing strategy is to serve all its loads out of inventory and meet any power deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

PS valued these avoided transmission and ancillary services costs using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS' inventory of transmission products and services. In these computations, both fixed, take-or-pay costs and variable incremental transmission and ancillary service costs were computed under 3,500 load and resource conditions for each month. Incremental transmission and ancillary services costs were computed by comparing the amount of surplus energy available to the monthly excess amount of firm transmission products in the PS inventory. Tariff costs established by BPA's Transmission Services organization were applied to the amount of surplus energy in excess of the PS transmission products inventory. Total monthly transmission and ancillary services costs were computed assuming no service to the DSI, and DSI service of 372 aMW.[9] The average total monthly expense values of the 3,500 games were computed with and without service to the DSI and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 372 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Port Townsend has been allotted 5.4% of this PS benefit in each month as illustrated in Table 5b below. This percent allotment is the result of the proportion of the megawatt amounts in the Block Contract, as depicted in Table 1 above, and as compared to the 372 aMW forecasted for all DSI customers.

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

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

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative ($)
Nov-09	$37,333	$0	$0
Dec-09	$149,138	$1,759	$1,759
Jan-10	$413,785	$18,910	$20,668
Feb-10	$323,044	$14,763	$35,431
Mar-10	$425,880	$19,462	$54,893
Apr-10	$550,208	$25,144	$80,037
May-10	$797,442	$36,442	$116,479
Jun-10	$707,442	$32,329	$148,809
Jul-10	$569,197	$26,012	$174,821
Aug-10	$124,908	$5,708	$180,529
Sep-10	$42,150	$1,926	$182,455
Oct-10	$40,086	$1,832	$184,287
Nov-10	$69,265	$3,165	$187,452
Dec-10	$150,243	$6,866	$194,318
Jan-11	$418,301	$19,116	$213,434
Feb-11	$320,781	$14,659	$228,093
Mar-11	$413,034	$18,875	$246,969
Apr-11	$489,665	$22,377	$269,346
May-11	$764,506	$34,937	$304,283
Jun-11	$669,536	$30,597	$334,880

Demand Shift (additional going forward benefits)

When BPA serves the DSI loads – including Port Townsend – and they operate – as opposed to not operating if BPA does not sell to them – all of BPA's surplus sales realize increased revenues because the mean value of prices for electricity in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets. BPA has forecasted these increased revenues by reducing loads in the Pacific Northwest by 372 aMW in each month for each of the 3,500 games AURORA simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of $0.29 per MWh and by $0.41 per MWh for fiscal years 2010 and 2011 respectively.[10] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from the WP-10 rate proceeding to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including the Block Contract with Port Townsend. For the purposes of this analysis, Port Townsend has been allotted 5.4% of this benefit to BPA in each month as illustrated in Table 5c below. This percent allotment is the result of the proportion of the megawatt amounts in the Block Contract,

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

as depicted in Table 1 above, and as compared to the 372 aMW forecasted for all DSI customers.

TABLE 5c - BPA's Net Benefit Adjustments

Month	Demand Shift Month ($)	Proportional Month ($)	Cumulative ($)
Nov-09	$654	$0	$0
Dec-09	$38,176	$450	$450
Jan-10	$143,990	$6,580	$7,030
Feb-10	$182,763	$8,352	$15,382
Mar-10	$274,682	$12,553	$27,935
Apr-10	$428,112	$19,564	$47,499
May-10	$1,332,323	$60,886	$108,385
Jun-10	$893,459	$40,830	$149,215
Jul-10	$515,175	$23,543	$172,758
Aug-10	$36,163	$1,653	$174,411
Sep-10	($24,805)	($1,134)	$173,277
Oct-10	$3,389	$155	$173,432
Nov-10	($32,059)	($1,465)	$171,967
Dec-10	$37,076	$1,694	$173,661
Jan-11	$443,369	$20,262	$193,923
Feb-11	$289,762	$13,242	$207,165
Mar-11	$638,108	$29,161	$236,326
Apr-11	$614,677	$28,090	$264,416
May-11	$1,525,976	$69,735	$334,151
Jun-11	$1,213,864	$55,472	$389,623

Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA recovers from the nearly 19-month IP sale to Port Townsend (from November 15, 2009 through May 31, 2011) exceed by approximately $54,000 the forecasted revenues that BPA would otherwise obtain from the market. See Table 6 below. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's rate case. That process includes discovery, testimony, rebuttal testimony, and cross examination prior to a final determination by the Administrator. Further, the analysis is marked by thorough and thoughtful consideration of market fundamentals and other factors that insure the integrity of the results.

TABLE 6 - BPA's Net Benefit after Adjustments

Month	Net Revenue or (Cost) (A) Month ($)	Value of Reserves (B) Month ($)	Avoided Tx Costs (C) Month ($)	Demand Shift (D) Month ($)	A + B + C + D Month ($)	Cumulative ($)
	BPA's Adjusted Net Revenue or (Cost)					
Nov-09	$73,704	$6,144	$0	$0	$79,848	$79,848
Dec-09	$108,898	$11,904	$1,759	$450	$123,011	$202,858
Jan-10	$92,640	$11,904	$18,910	$6,580	$130,034	$332,893
Feb-10	$76,127	$10,752	$14,763	$8,352	$109,994	$442,886
Mar-10	$60,141	$11,888	$19,462	$12,553	$104,044	$546,930
Apr-10	$22,107	$11,520	$25,144	$19,564	$78,335	$625,266
May-10	($4,000)	$11,904	$36,442	$60,886	$105,232	$730,497
Jun-10	($18,283)	$11,520	$32,329	$40,830	$66,396	$796,894
Jul-10	($24,130)	$11,904	$26,012	$23,543	$37,328	$834,222
Aug-10	($32,913)	$11,904	$5,708	$1,653	($13,648)	$820,574
Sep-10	($48,465)	$11,520	$1,926	($1,134)	($36,152)	$784,422
Oct-10	($118,310)	$11,904	$1,832	$155	($104,419)	$680,003
Nov-10	($123,124)	$11,536	$3,165	($1,465)	($109,888)	$570,115
Dec-10	($147,541)	$11,904	$6,866	$1,694	($127,077)	$443,038
Jan-11	($126,753)	$11,904	$19,116	$20,262	($75,472)	$367,566
Feb-11	($124,279)	$10,752	$14,659	$13,242	($85,626)	$281,940
Mar-11	($145,552)	$11,888	$18,875	$29,161	($85,628)	$196,312
Apr-11	($154,637)	$11,520	$22,377	$28,090	($92,649)	$103,662
May-11	($166,174)	$11,904	$34,937	$69,735	($49,598)	$54,065
Jun-11	($163,655)	$11,520	$30,597	$55,472	($66,066)	($12,001)

Conclusion

For the foregoing reasons, BPA has signed on this date the letter agreement extending the term of the Block Contract with Port Townsend from December 31, 2010, until May 31, 2011.

Issued at Portland, Oregon, this 24th day of December, 2009.

/s/ Allen L Burns
Acting Administrator and Chief Executive Officer

Attachment L

Power Sale to Alcoa Inc. Commencing December 22, 2009 – Administrator's Record of Decision

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

POWER SALE TO ALCOA INC.
COMMENCING DECEMBER 22, 2009

ADMINISTRATOR'S RECORD OF DECISION

December 21, 2009

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BONNEVILLE POWER ADMINISTRATION
POWER SALE TO ALCOA, INC.
COMMENCING DECEMBER 22, 2009
ADMINISTRATOR'S RECORD OF DECISION

December 21, 2009

I. INTRODUCTION

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

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

The Court required in *PNGC II* that any offer of power to a DSI must be "consistent with sound business principles." See *PNGC II* at 842.. More particularly, careful review of the Court's opinion in *PNGC II* has led BPA to conclude that, in order to offer a sale of

power to a DSI, BPA must conclude based on evidence in the record that the proposed transaction will result in benefits that equal or exceed the costs to BPA of the transaction. In response, BPA has developed an "Equivalent Benefits Test". BPA has determined with respect to the power sales contract with Alcoa that, for a period approximately equal to the first seventeen months of the contract term, service can be provided in a manner that meets the test.

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

II. POLICY DISCUSSION

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

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

BPA believes the sale:

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

BPA's approach is balanced. BPA's current approach to DSI service recognizes that DSIs have historically been an integral part of the Federal system virtually since its

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

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

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

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

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

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

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

The Block Contract is consistent with law. *PNGC I* and *PNGC II* upheld BPA's discretion to serve the DSIs at the IP rate. *PNGC I*, 580 F.3d, 792, 807 (Section 5(d) of the NPA "authorizes but does not obligate the agency to sell power to the DSIs") and *PNGC II*, 580 F.3d 828, 835 (BPA "authorized to sell power to the DSIs at the IP rate") However, BPA believes there is still some uncertainty in the Court's opinions with respect to what the law requires when assessing whether a DSI sale is consistent with

sound business principles. BPA has taken a cautious approach, applying the Equivalent Benefits Test to the Initial Period. As noted above, pursuant to application of that test, the Initial Period of service under the Block Contract will provide BPA with benefits that exceed BPA's cost. In taking this approach, BPA has deferred consideration of other aspects of the Court's rulings, which suggest that decisions regarding DSI service can include consideration of factors that cannot readily be reduced to a monetary amount. For example, in *PNGC II*, the court pointed to "non-financial" benefits that might be provided. 580 F.3d at 835. As noted above, BPA has not developed an analytical framework for consideration of non-financial benefits. BPA will, however, continue to consider how such benefits may be applied consistent with the Court's opinions. This could be particularly important when BPA considers service for the contingent Second Period of the Block Contract, which encompasses five years of service following the Initial Period. BPA's approach is entirely appropriate at this time, in that it provides a significant period of service based on its view of the Court's opinions, while leaving room for additional flexibility at a later date in the event that the Court determines that an equivalent benefits test need not apply to sales under this contract and further clarifies what it means for BPA to enter into a transaction consistent with sound business principles.

III. BACKGROUND

a. Original Contract

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

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

it was based on a rate that was below both the IP rate and market prices. 580 F.3d at 820. Prior to the Court's opinion, pursuant to certain reallocation provisions in the Original Contract, BPA agreed to provide Alcoa an additional 70 aMW in benefits, raising Alcoa's demand entitlement to 390 aMW for the period October 1, 2007 through September 30, 2011.

b. Amendment to the Original Contract

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

c. December Draft Contract

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

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

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

d. *PNGC I*

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

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

e. August Draft Contract

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

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

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

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

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

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

f. *PNGC II*

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

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

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

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

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

g. November Draft Contract

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

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

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

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

IV. BLOCK CONTRACT

a. Summary of Block Contract

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

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

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

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

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

a Second Period. In the event there is no Second Period, then the Block Contract will terminate as specified in section 5.3 or section 6.2.

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

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

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

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

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

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

b. Contract Demand

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

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

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

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

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

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

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

c. Rate Charged for Power Deliveries

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Beginning in FY 2012, BPA has established a completely new rate design for the Priority Firm Preference rate. This new rate design was codified in the Tiered Rate Methodology, adopted by the Administrator in the TRM ROD of November 2008. The first rate adjustment proceeding to establish rates pursuant to the TRM will be the WP-12 rate proceeding which is expected to commence in November 2010. As such, no decisions

have yet been made about how the IP rate will be established after FY 2011. However, the TRM does not in any way remove or modify any ratesetting instructions contained in section 7 of the NPA, including section 7(c) regarding the IP rate, and the Block Contract is explicit that all rate determinations will be made in BPA rate cases.

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

d. Term of the Block Contract

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

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

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

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

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

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

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

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

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

e. Cost Caps

The Block Contract contains cost caps applicable to any Transition Period and Second Period. See Block Contract section 7. The level of the cost caps, and the manner in which BPA will evaluate whether the cost of service to Alcoa is equal to or less than the applicable cost caps, are specified in Exhibit B of the Block Contract. The cost caps will apply only to BPA's evaluation of whether it will provide service under the Block Contract during the Transition and Second Periods. This is because service to Alcoa under the Block Contract during the Initial Period, any increase in the level of service from 285 aMW to 320 aMW, or any extension of the term of the Initial Period, is contingent on BPA determining that it will achieve Equivalent Benefits from such

service. Therefore, the cost caps are unnecessary during the Initial Period or any Extended Initial Period and would provide no additional risk mitigation to BPA.[11]

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

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

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

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

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

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

f. Termination and Take-or-Pay

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

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

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

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

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

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

g. Curtailment and Liquidated Damages

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

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

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

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

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

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

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

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

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

h. Credit Support

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

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

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

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

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

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

i. Section 4.3

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

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

j. Covenants

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

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

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

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

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

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

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

k. Damage Waiver Provision

The damages waiver provision in section 21.11 states:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

I. Reserves

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

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

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

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

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

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

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

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

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

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

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

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

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

m. Transmission

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

n. BPA has the option of conducting additional public review

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

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

V. THE EQUIVALENT BENEFITS TEST

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

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

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

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

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

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

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

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

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

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

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

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

[20] 2009 White Book, page 40.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TABLE 1 - Usage and Rates

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

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

TABLE 2 - BPA's Projected Revenue

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

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

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

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

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

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

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

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

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

Net Benefit (IP – Market)

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

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

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

TABLE 4 - BPA's Net Benefit before Adjustment

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

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

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

Value of Reserves

The Block Contract requires that Alcoa make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value to BPA of the reserves Alcoa is required to make available to BPA under the Block Contract. Sales at the IP rate reflect the value of a right for BPA to

obtain contingency reserves.[33] Specifically, the energy rate tables in the IP-10 rate schedule include an $0.80 per MWh credit for the value of these reserves. Therefore, BPA's net benefit above compares a surplus power sale to a sale of power at the IP rate with reserves. We have adjusted for this by adding back a value of reserves that provides an equal and opposite offset to the $0.80 per MWh credit for the value of reserves in the IP-10 rate schedule.[34] As illustrated by Table 5a, this is done for every megawatt hour not sold to Alcoa:

TABLE 5a - BPA's Net Benefit Adjustments

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

Avoided Transmission and Ancillary Services Expenses

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

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

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

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

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

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

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

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

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

Demand Shift

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

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

TABLE 5c - BPA's Net Benefit Adjustments

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

Conclusion of Equivalent Benefits Test

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

TABLE 6 - BPA's Net Benefit after Adjustments

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

e. Commenter's Issues with the Equivalent Benefits Test

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

These issues are addressed below.

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Forward Price Curve

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

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

BPA will respond to the comments above, but reemphasizes that a sale of firm power pursuant to section 5(d) of the Northwest Power Act is not a sale of surplus power that can be sold at market prices. The IP rate is not a market rate, but instead is a cost based rate established pursuant to the directives of section 7(c) of the Act. Further, for the period over which BPA's current firm power rates apply, BPA has already credited those rates with projected secondary sales. *See* Table 4.8.1, WP-10-FS-BPA-05A at 88. Clearly, the market price forecast is an important component in BPA's forecast of expected net revenues under the Block Contract, serving to measure both the cost associated with purchases, if any, required to serve the Alcoa load, or the lost opportunity cost, if any, of selling the power earmarked for sale to Alcoa into the market instead. However, BPA does not agree with the view expressed in a number of comments that current forward market prices are a better indicator of average market prices over the 17-month term of the Block Contract than BPA's market price forecast given BPA does not normally sell or buy forward 17-month strips of power, but rather manages its inventory closer to the actual delivery month. In simplest terms, "forward market prices" are actual

prices agreed to between a buyer and seller on any given day for power to be delivered at some time in the future, and therefore represent the price at which two parties are willing to transact *that day* for future delivery; but the market price on that future date of delivery may (and almost certainly will be) either higher or lower. For example, Snohomish commented it received a forward price quote of $59.25 on October 15, 2009, for delivery beginning October 1, 2010, of heavy load hour energy at the Mid-Columbia trading hub. See Snohomish comments in PTP090010 at 2 and Attachment A thereto. By contrast, a "forecast" of market prices seeks to determine what the actual market price will be on a given day (or hour) over a certain future period. Using the preceding example, a market price forecast would project the likely actual market price for delivery of heavy load hour energy at the Mid-Columbia trading hub on October 1, 2010, based on market fundamentals.

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

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

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

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

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

Figure 1

Comparison of Daily Spot and IP Rates

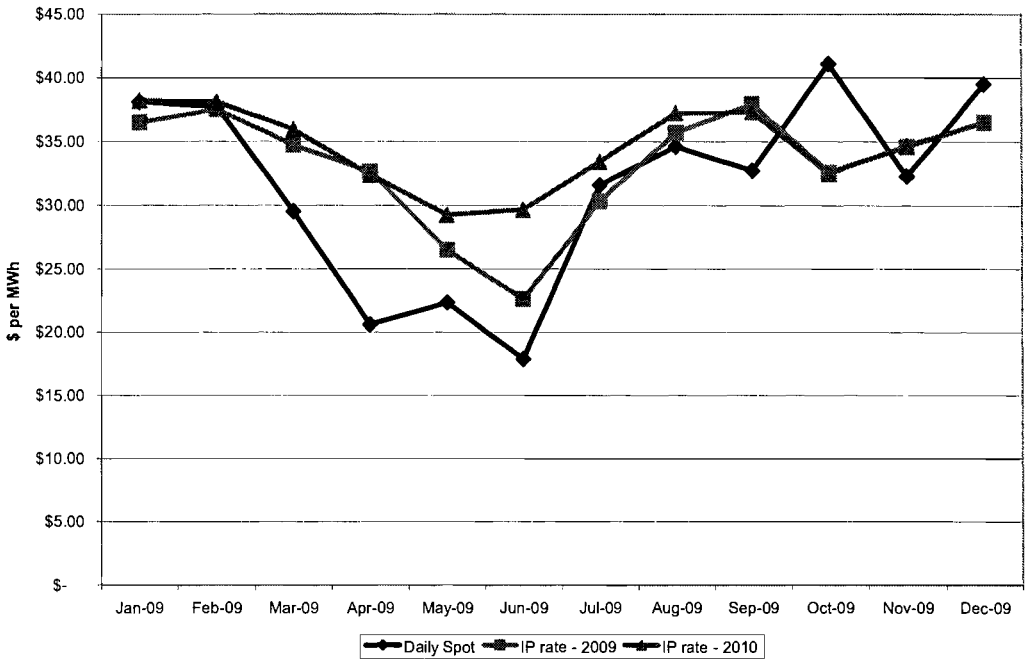

Figure 1 depicts that nine out of the twelve months of calendar year 2009, or seventy-five percent of the time, the monthly average of the daily spot prices was below the IP rate. This is important because BPA is forecasting the average of the daily spot prices at Mid-C, not forward market prices. As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

Figure 2

Annual Comparison of Marketing Revenues and IP Revenues

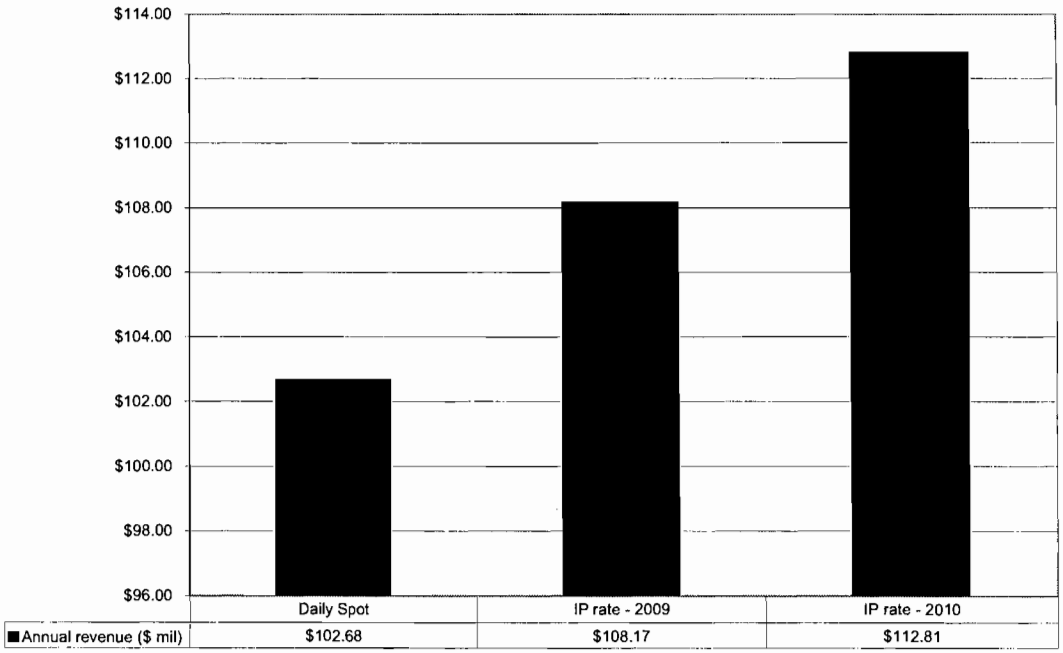

Figure 2 demonstrates that the revenues BPA would have received from the sale at the IP rate in calendar year 2009 would have exceeded by $10 million the revenues BPA would have received from a market sale of the same amount. This provides recent historical evidence to support BPA's expectation of positive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

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

However, some parties, including Snohomish and PPC, appear to argue that even this is not enough. These parties appear to take the position that BPA may not make a sale to a DSI at the IP rate even if such sale is forecast to result in positive net revenues compared

to forecasted market revenues, if BPA could earn even greater revenues by selling the power into the current forward market. Snohomish at 1-2; PPC at 2.

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

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

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

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

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

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

3. Gas Price Forecast

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

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

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

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

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

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

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

BPA's fiscal fourth quarter natural gas price forecast also continues to reflect a more contemporary understanding of natural gas market fundamentals. The primary reasons for BPA's reductions in 2009-2010 remain apparent in the progression of time since the natural gas price forecast was constructed. These are: a) continued strength of natural gas production, despite steep reductions in rig counts, illustrates that BPA's statement in the draft Resource Program that "the production decline lags the decline in demand" remains apparent, b) continued slow recovery of natural gas demand – particularly on the industrial side – continues to reflect the lingering effects of "an economic recession that will first lower natural gas demand," and c) record amount of natural gas in storage continues to demonstrate the anticipated "increase in natural gas storage inventories"

contemplated in the draft Resource Program.[41] Furthermore, with the majority of the hurricane season now over with no impacts on supply occurring, the reduction made in the fiscal fourth quarter natural gas price forecast appears to remain warranted.

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

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

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

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

Figure 3

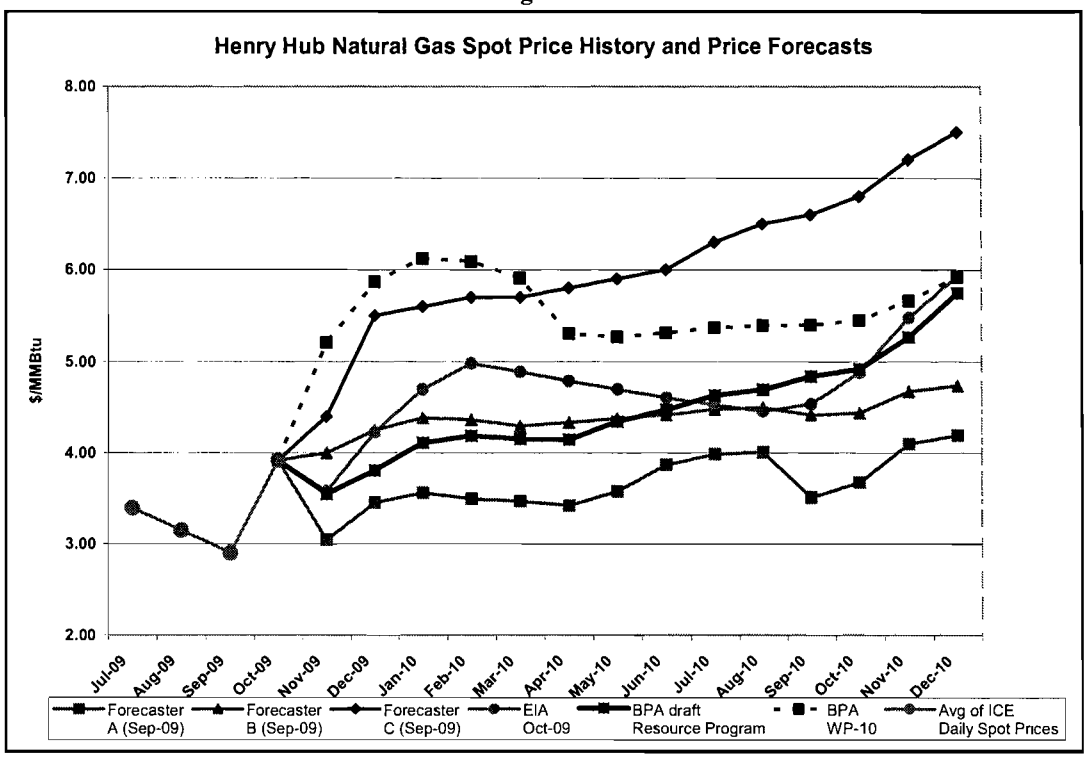
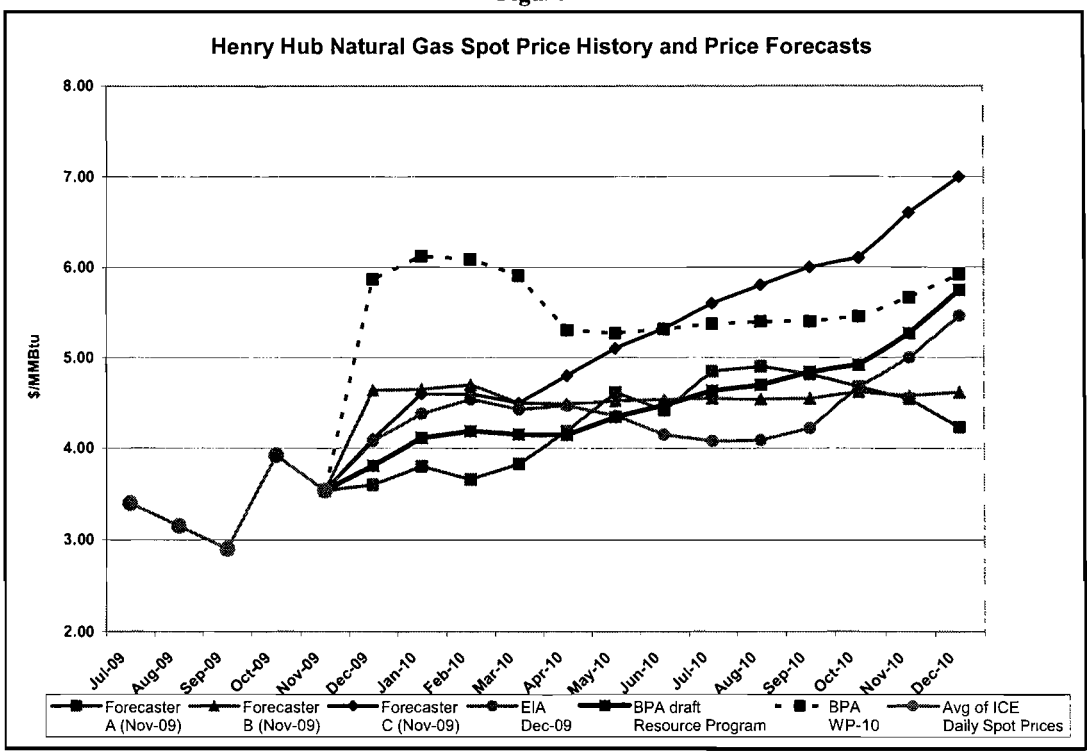


Figure 4: Henry Hub Natural Gas Spot Price Forecasts (vintage November 2009)
Figure 4

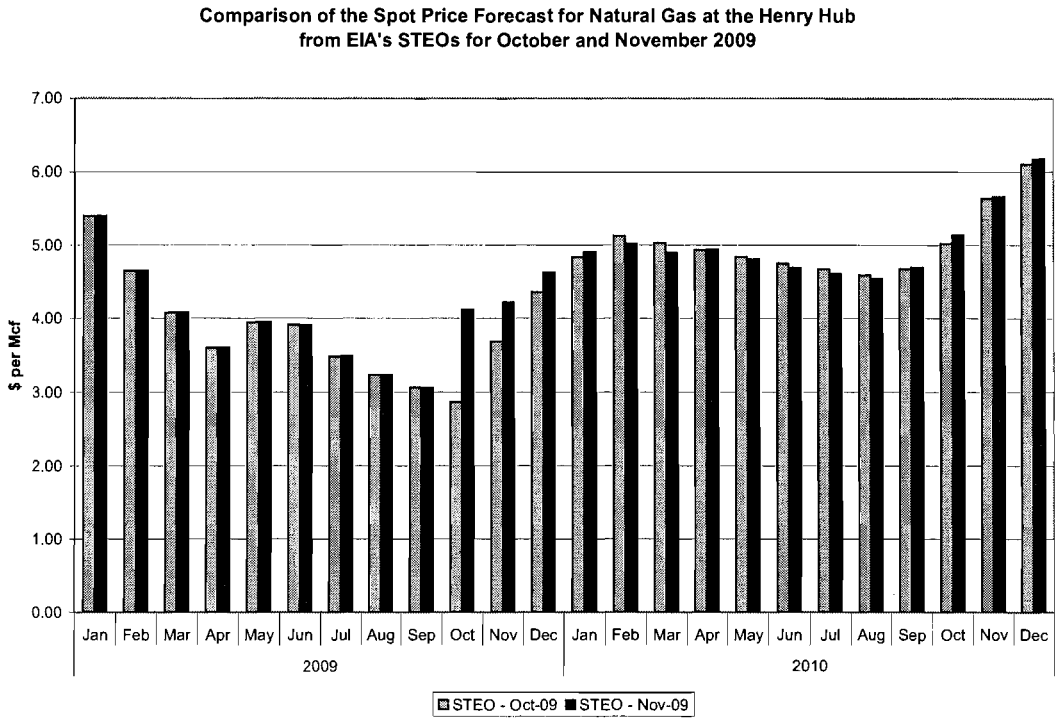


Figures 3 and 4 demonstrate that recent spot market prices for natural gas at the Henry Hub have been in the range of $3 to $4 per MMBtu from July to November 2009. These illustrations also demonstrate that the forecasts of three other industry experts were $4.25 per MMbtu and are now $4.10 per MMBtu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

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

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

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



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

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

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

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

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

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

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

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

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

forecasting, which PNGC believes will be the case, then BPA is underestimating the cost to serve Alcoa under the Block Contract. PNGC at 2.

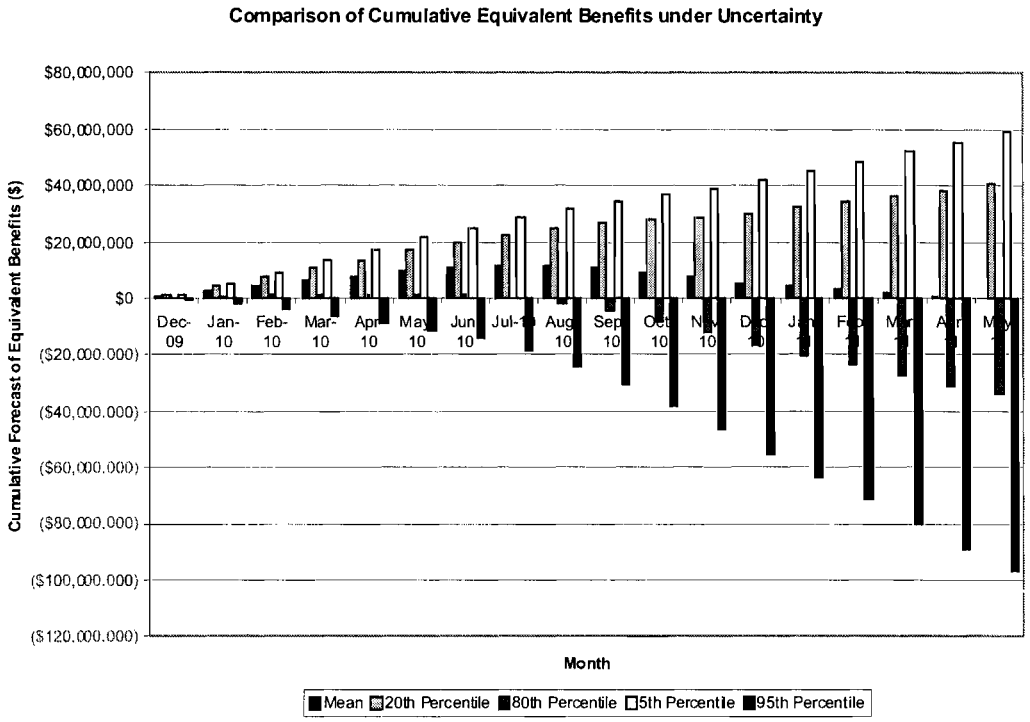
PPC's also argues that BPA is at risk that power prices could change from BPA's forecasts, and that if BPA's forecast is incorrect the costs of the transaction could easily turn out to outweigh any calculated benefits. PPC at 2.

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

(i) Market Price Risk

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

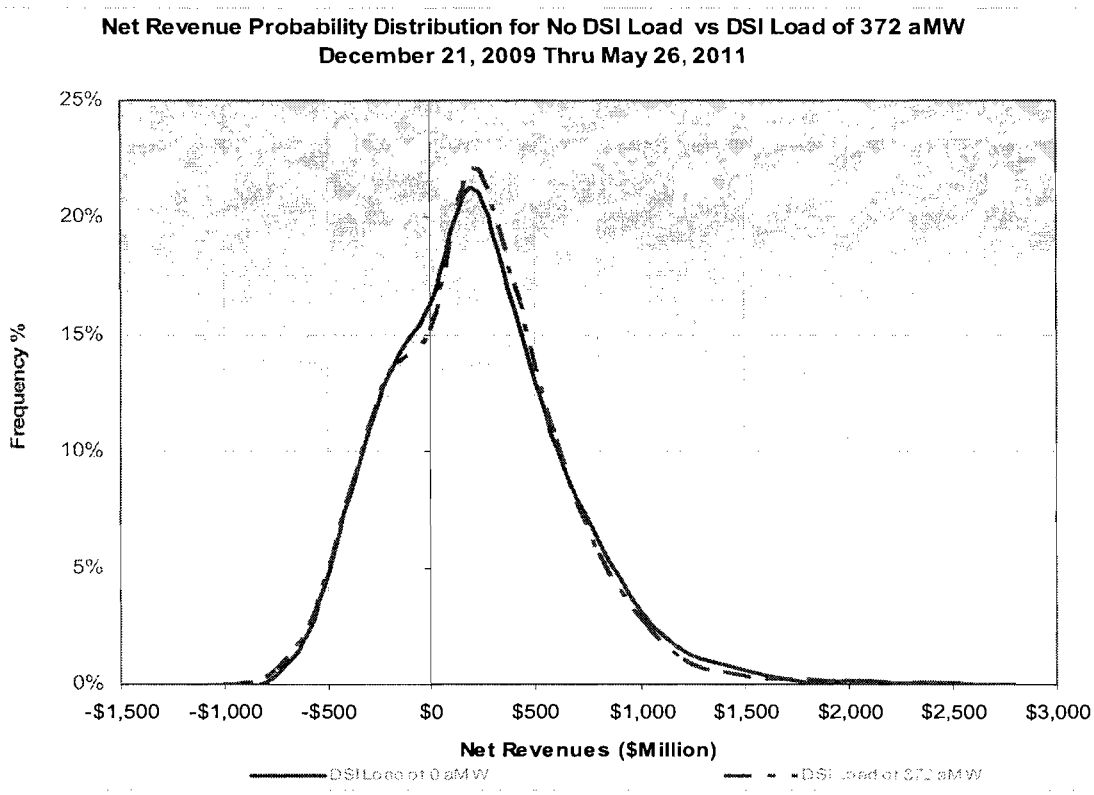
Figure 4: Comparison of Cumulative Equivalent Benefits under Uncertainty



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

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

Graph 1



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

(ii) Curtailment Risk

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

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

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

PPC also argues that BPA would not, in the ordinary course of business, enter into this transaction. PPC at 4. The basis for this conclusion by PPC is unclear. Dealing with the issue of providing service to DSI load has been part of the ordinary course of BPA's business for more than half a century. It does not follow that, simply because such

service is now discretionary, it should be deemed, *ipso facto*, outside the ordinary course of BPA's business or mission. There is no indication, that in making DSI service discretionary, Congress was directing the Administrator to simply cast the DSIs aside and be done with them. To the contrary, by preserving a special rate for service (the section 7(c) rate), and requiring the continuing provision of reserves, Congress appears to have contemplated that BPA might well continue to serve DSI load in the ordinary course of business.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2008 to 2009 [44]	0.675	0.194

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

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

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

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

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

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

[44]Two year figure through October of 2009.

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

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

6. Avoided Transmission and Ancillary Services Expenses

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

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

7. Demand Shift

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

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

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

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

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

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

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

ICNU also argues that if BPA assumes Alcoa will operate with a power sale at the IP rate, then Alcoa will operate with the power that is has secured from a third party for the initial period. ICNU at 4. ICNU argues that if BPA accurately forecasts market prices,

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

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

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

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

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

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

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

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

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

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

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

f. Intangible benefits that accrue or may accrue to BPA

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

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

Waiver of Claims

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

[47] Section 23.2.

[48] Section 25.2.

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

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

Alcoa Agrees not to Challenge Surplus Sales

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

Negative Pricing

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

For the past decade or so, wind projects have been eligible to receive production tax credits (PTCs) that have increased annually to their current level of $21.00/MW/Hr (2008

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Historical Perspective

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

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

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

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

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

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

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

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

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

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

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

Preservation of the DSI load in the 1980's, however, provided a perhaps even greater benefit in the 1990's, when BPA was facing the problem of its cost-based rates being above prevailing market prices. The market for power was routinely offering prices that

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

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

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

1996 Wholesale Power rates Final record of Decision at 18.

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

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

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

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

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

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

Due to the many unanticipated changes that the electricity market has seen over the last two decades, BPA believes it would be short-sighted and unwise to conclude that retention of DSI load could never provide significant value to BPA in the future in much the same way as it has in the past. As the above illustrates, notwithstanding WPAG's comment on the new long-term power sales contracts between BPA and its preference customers, service to diversified customer loads, i.e., public body, cooperative, federal agency, direct service industries, and investor-owned utilities, provides a flexible and sound business approach to meet the uncertainties of the future. Given the current economic crisis and market conditions, it is certainly within the realm of possibility that BPA could find itself in a position similar to the 1990s, where BPA's cost based rates exceed prices available on the market. Recently, market prices have declined significantly while BPA has just proposed a rate increase. In fact, daily prices in the applicable markets have at times been significantly lower than some of BPA's cost-based rates. No one knows what the end result of these volatile market forces will be if the

economy continues to decline, nor does anyone know with certainty what conditions in the power market will be like when the economy begins to improve.

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

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

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

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

In spite of the existence of these contracts, there is no guarantee that, overall, demand could not become depressed in the future and power supplies plentiful. Planning for the future must recognize that market prices are subject to supply/demand market

fundamentals that are cyclical in nature but are also subject to volatility caused by unanticipated events and changes. Poor economic conditions, for example, can cause a decrease in business activity that can lead, in turn, to relocation of business enterprises and consequent population drift, all of which can result in localized suppression of demand for power and, assuming normal supply parameters, lower market prices for power. Current economic conditions are, in fact, having some effect with respect to suppressing demand for power. Similarly, in a market situation where BPA's rates were higher than market prices, having the DSI load available could well help the Administrator in retaining sufficient load to assure Treasury repayment as he weighs the cost and benefits of allowing customers to diversify their supply portfolios, as was done in the mid-90s, in the interest of achieving the lowest rates possible for consumers and diversifying the region's power sources in the interest of maintaining an adequate, efficient, economical and reliable power supply.

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

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

Conclusion of Intangible Benefits

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

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

VI. PNGC II

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

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

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

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

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

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

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

a. BPA's Interpretation of *PNGC II*

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

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

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

The Court elsewhere analogizes DSI sales to the incurrence by a utility of a non-necessary expense. *Id.* at 839, citing *McCarthy v. Middle Tenn. Elec. Membership Corp.*, 466 F.3d 399 (6th Cir. 2006). In the context of providing power at the lowest cost consistent with sound business principles, if the DSI sale comes at a net cost, with the

consequence that other customers' rates are increased, *PNGC II* appears to indicate that sound business principles would be violated. *Id.*

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

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

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

With regard to the first scenario, freeing up power to be sold outside the Northwest, two observations are in order. First, *Kaiser Aluminum & Chemical Corp. v. BPA*, 261 F.3d 843 (9th Cir. 2001), establishes that where BPA has a rate for surplus power sales that provides for the sales at a market rate, regional preference is satisfied if the power is made available first in the region at the same rate it could be sold for out of region. That means that if a DSI is willing to pay the higher rate, it would be entitled to the power. However, in that case, there would be equivalent benefits because DSI revenues and lost

opportunity cost would be equal. Second, when the Court speaks of "reasonably" entering a DSI contract to free up power for sale outside the region, there is no indication that the Court would find the contract reasonable if the DSI contract resulted in a lost opportunity cost to BPA relative to out-of-region sales revenues.

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

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

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

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

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

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

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

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

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

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

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

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

inapplicable to, decisions regarding sales to statutorily identified customer classes, or for that matter, sales of surplus power.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VII. REGIONAL JOB IMPACTS AND COST CAPS

a. Cost Caps

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

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

b. Reduction in Quantity

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

c. Term Reduced from 17 to 7-years

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

d. Socio-Economic Implications

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

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

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

Washington Governor Christine Gregoire offered similar sentiments:

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

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

Despite these expressions of legitimate concern over the economic well-being of the region, public preference groups have attempted to use the Administrators' responsiveness as a means of impugning BPA's motivations and undermining its legal analysis. PPC, for example, posits that the Administrator's long-standing commitment to preserving regional jobs is evidence the contract is not based on sound business

principles. PPC goes on to make an even more startling accusation: "[BPA's] October 30th letter, as well as the contract itself, indicates that one of the main reasons for which BPA is proposing to enter the deal is to continue to try to advance its policy goal of prioritizing smelter jobs over other jobs in the region." WPAG strikes a similar note, arguing that BPA is using the same justification that has already been discredited by the Court: "BPA is again arguing that it has the authority to offer the proposed Agreement because it strikes a reasonable balance between the rate impacts to its other customers and keeping the Alcoa smelter in operation in order to save family wage jobs in the region." (1) citing Burns October 30 Letter, p. 1. ICNU joins this chorus as well, announcing, apparently that the Court has ordered the Administrator to desist from any consideration of the health of the regional economy: "Once again, BPA is relying upon a rationale inconsistent with the 9th Circuit's decision to justify the new Alcoa contract [i.e., strike a balance between minimizing impacts to BPA rates and providing the direct service industries (DSIs) a chance to continue operating in the Pacific Northwest]." (2)

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

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

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

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

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

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

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

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

Alternative 1 has no adverse impact on BPA's other customers. Alternative 2 capped the rate impact on BPA's other customers at $59 million – the equivalent of a $1.00 per MWh change in the PF power rate. Under this alternative, the regional economic study

indicated a long-term net gain in employment between 95 and 1,232 jobs, considering a loss of up to 1,110 jobs in non-DSI related sectors, and a gain of up to 2,342 jobs at the smelters and in related sectors.[55] Alternatives 3b and 4 were both evaluated using a BPA power rate of $31.50 per MWh.[56] Both of these alternatives represented power sales of up to 560 aMW. As illustrated in Table 18-A included here for reference, a range of uncapped, market-priced purchases to support these power sales was then used to calculate BPA's cost for providing this power to the DSIs:[57]

TABLE 18-A - Market Prices and BPA Exposure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

VIII. PROCEDURAL AND OTHER ISSUES

a. Adequacy of Contract Review

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

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

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

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

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

Given the request by its public customers to meet with them to discuss the draft Block Contract, BPA's Deputy Administrator and other BPA staff met with several preference

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

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

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

b. Sequencing of *PNGC I* Remand

PPC argues "BPA cannot plausibly argue that any exigent circumstances compel this cart-before-the-horse approach, since BPA's own analysis shows that Alcoa should be

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

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

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

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

d. Loss of Money to Benefit the DSIs

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

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

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

e. Relationship to BPA's Financial Plan

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

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

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

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

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

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

f. BPA has not allocated Equivalent Benefits to any customers

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

IX. ENVIRONMENTAL EFFECTS

a. NEPA Evaluation

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

b. Comments on Environmental Effects

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

EIS is not Necessary

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

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

As explained above, BPA has reviewed the Block Contract under NEPA and determined that the federal action of continuing to supply power, whether in monetized form or any actual power transfer, would not have the potential for a significant environmental effect. BPA expects to supply power to Alcoa's Intalco Plant from existing generation sources, and these sources would be expected to continue to operate within their normal operating

limits. This power would be supplied to the Intalco Plant over existing transmission lines that connect the existing Intalco Plant to BPA's electrical transmission system, and no physical changes to this system would occur. In addition, the Block Contract would not cause a change in the Intalco Plant's existing operations in such a way that environmental impacts would significantly differ from the currently existing situation. Therefore, BPA has appropriately prepared a Categorical Exclusion for the proposal to continue power sales to Alcoa, and an EIS is not necessary.

No Change in Environment Impacts

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

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

Business Plan EIS Is Not Relevant to this Decision

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

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

X. CONCLUSION

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

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

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

Attachment M

Administrator's Record of Decision Granting Alcoa's Request to Extend the Initial Period of Alcoa's Power Sales Agreement, Contract No. 10PB-12175

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

ADMINISTRATOR'S RECORD OF DECISION GRANTING ALCOA'S REQUEST TO EXTEND THE INITIAL PERIOD OF ALCOA'S POWER SALES AGREEMENT, CONTRACT NO. 10PB-12175

October 29, 2010

BONNEVILLE POWER ADMINISTRATION

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ADMINISTRATOR'S RECORD OF DECISION
GRANTING ALCOA'S REQUEST TO EXTEND THE INITIAL PERIOD OF ALCOA'S POWER SALES AGREEMENT, CONTRACT NO. 10PB-12175

October 29, 2010

I. INTRODUCTION

On December 21, 2009, the Administrator signed a block power sales contract (the "Block Contract") with Alcoa Inc. ("Alcoa"). Under the Block Contract, BPA is selling up to 320 aMW of firm power to Alcoa at the Industrial Firm (IP) power rate over approximately 17 months. Power deliveries began on December 22, 2009, and are scheduled to end May 26, 2011 (the "Initial Period"). Prior to the execution of the Block Contract, BPA provided the draft contract for public comment. BPA's record of decision (the "Alcoa ROD") dated December 22, 2009, addressed the comments received and provided the rationale supporting BPA's decision to enter into the Block Contract, in light of the comments received and the opinions of the United States Court of Appeals for the Ninth Circuit ("Court" or "Ninth Circuit") in *Pacific Northwest Generating Coop. v. Dep't of Energy*, 580 F.3d 792 (9th Cir. 2009) ("*PNGC I*") and *Pacific Northwest Generating Coop. v. BPA*, 580 F.3d 828 (9th Cir. 2009) ("*PNGC II*"). The Block Contract is currently being challenged in the Ninth Circuit.[1]

Section 5.1 of the Block Contract provides that BPA will evaluate extending such firm sale for one additional period of 3 to 12 months (the "Extended Initial Period") upon written request by Alcoa.[2] Alcoa submitted its request to BPA for an extension up to 12 months on September 2, 2010.[3] This record of decision documents BPA's final determination to grant Alcoa's request based on the evaluation of Equivalent Benefits for the Extended Initial Period

Prior to making its final determination whether or not to extend the contract, BPA provided an opportunity for public review and comment regarding its draft evaluation of the Equivalent Benefits Test (the "EBT") for the Extended Initial Period. The public

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[1] On January 22, 2010, Alcoa filed suit in the United States Court of Appeals for the Ninth Circuit contesting the Block Contract.

[2] The Block Contract also provides for power sales to Alcoa for up to an additional 12-month (Transition Period) and an additional 5 years (Second Period) if certain specified conditions, applying appropriately to each period, are met. *See* Alcoa ROD at 18-19.

[3] Letter from Mike Rousseau, Plant Manager, Alcoa, to Mark E. Miller, Account Executive, Bonneville Power Administration (Sept. 2, 2010). *See* Attachment A

review and comment period took place from October 6, 2010, through October 21, 2010. In its request for public comments, BPA stated that the scope of review is limited to the draft determination and that issues or comments pertaining to why BPA entered into the Block Contract, BPA's legal authority, or any other related threshold matters are not within the scope of this determination. *See supra*, section II, for further discussion of the scope of this determination. BPA agrees that issues raised in the pending litigation of the Block Contract, and arguments and responses thereto, are not waived by virtue of not being raised during the comment period for this Equivalent Benefits determination.

Canby, EBT100005, at 1, asks if the decision to provide service for an Extended Initial Period is a new final decision, or if it was encompassed in BPA's final agency action when it signed the contract in 2009. In response, BPA observes that section 9(e)(1) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839 et seq. (the "Northwest Power Act" or the "Act") lists sales of power under section 5 of the Act as a final action subject to judicial review. In practice, this means BPA's contracts for the sale of power, since it is the contract that provides for the sale. Here, Alcoa's current contract is the subject of judicial review and there is no new contract of sale. However, section 9(e)(5) of the Northwest Power Act provides for exclusive Ninth Circuit review not only of "final actions and decisions taken pursuant to this Act" but also "the implementation of such final actions." 16 U.S.C. § 839f(e)(5). Here, as described in section II below, BPA is implementing section 5.1 of the Block Contract. While BPA believes its determination of the EBT would be subject to review under section 9(e)(5) as a final action, particularly since the matter is an administrative determination, we would anticipate that some customers would argue that implementation of a contract is a matter purely of whether BPA has done what its contract requires and should be treated as such.

II. SCOPE OF DETERMINATION

As established in the Alcoa ROD, the EBT is intended to demonstrate that a decision to serve a DSI customer is, as described by the Court, consistent with sound business principles when it can be shown that the benefits to BPA of serving the DSI load would equal or exceed BPA's cost of serving the load during the period of service ("Equivalent Benefits").[4] Comments submitted that pertain to why BPA entered into the Block Contract, legal authority, BPA's reading of *PNGC II*, or any other related threshold matters, many of which were addressed in the Alcoa ROD and are pending review in current litigation, are not within the scope of this determination and are therefore not addressed here.

As indicated in BPA's October 6, 2010, request for public comments, section 5.1 of BPA's power sales contract with Alcoa provides that "[u]pon written request by Alcoa, BPA will evaluate extending the Initial Period by no less than three months and no more than one year ("Extended Initial Period"), and will so extend the Initial Period for the duration requested by Alcoa if BPA determines that it will achieve Equivalent Benefits

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[4] *See* Alcoa ROD, December 22, 2009, at 8-9.

from such Firm Power sales during such Extended Initial Period." Consequently, BPA's final decision in executing the contract encompassed section 5.1, among all the other contract terms. Inasmuch as section 5.1 provides that BPA will extend the Initial Period if it determines it will achieve Equivalent Benefits from such Firm Power sales during such Extended Initial Period, the only determination at issue here is whether Equivalent Benefits exist to justify an Extended Initial Period. For that reason, BPA limited comments in this comment forum to that determination.

BPA's position is not inconsistent with PNGC's observation that BPA has stated in its briefing to the Ninth Circuit on the Block Contract that "[t]he EBT [Equivalent Benefits Test] is a tool developed by BPA to determine *whether* service to a DSI would be consistent with sound business principles, as required by *PNGC II*." PNGC, EBT100011, at 2. PNGC also wonders how addressing the application of BPA's EBT "to the proposed contract extension" can exclude a discussion of whether BPA's actions are consistent with statutory mandates and the Ninth Circuit decisions. BPA's answer is that, as indicated, BPA's earlier final action in executing the Block Contract encompassed all of its terms, including that BPA would provide service for an Extended Initial Period if BPA determined it will achieve Equivalent Benefits for such period. BPA believes the EBT satisfies sound business principles and other legal requirements, all as stated in its earlier ROD, *see generally* Alcoa ROD, and that it in fact may demand too much, as set forth in BPA's brief to the Ninth Circuit in the currently pending case involving review of the Block Contract. Therefore, in executing the Block Contract, BPA already made its determination that the law would be satisfied by applying the EBT to determine whether an Extended Initial Period is justified. The only new determination at issue here is BPA's conduct of the EBT, and BPA will confine its responses here to comments on that determination.

As a consequence of the foregoing, BPA will not here visit or re-visit comments:

- by Alcoa (EBT100006) concerning the legitimacy of the EBT, indirect benefits of serving DSI loads, or other matters not directly bearing on BPA's conduct of the EBT;
- by Pacific Northwest Generating Cooperative (PNGC) (EBT100011) concerning matters other than BPA's conduct of the EBT, including comments on BPA's prior final decision, water conditions for the Initial Period, legal obligations, and pricing based on cost causation;
- by Industrial Customers of Northwest Utilities (ICNU) (EBT100008) concerning legality of DSI service and service obligations to other customers;
- by Public Power Council (PPC) (EBT100001) concerning overall policy context; and
- concerning general economic conditions and the need to preserve jobs, whether DSI jobs (EBT100002, EBT100004) or other jobs in other areas (Sanger/ICNU, EBT100008).

Additionally, BPA is of the opinion that issues related to implementation of sections of the Block Contract that do not pertain to the EBT concerning extension of the Initial

Period are outside the scope of this determination. However, BPA will address the following comment regarding the employment level at Alcoa's Intalco Plant from SUB in order to clarify that BPA believes that the Block Contract is being faithfully performed by Alcoa. SUB, EBT100007 at 8, commented that:

> SUB notes that a comment on this topic from Alcoa indicates 520 workers. Even if this represented 520 FTE (as opposed to full time and part time employees), 520 FTE is not sufficient to meet the criteria in the Alcoa contract [Block Contract] to grant 320 aMW of power. From this perspective, the EBT test for 320 aMW is moot. (Internal citations omitted.)

SUB is correct in that Exhibit G of the Block Contract requires specific employment levels. *See* Block Contract, section 8. This contractual requirement is not related to nor is it a prerequisite of the extension of the Initial Period. However, BPA notes that section 8 of the Block Contract requires that Alcoa shall provide monthly reports to BPA demonstrating its employment levels (full time equivalents, or FTE) by month. Alcoa's September 2010 employment report to BPA, the most recent report made pursuant to section 8, indicates that Alcoa has met its employment obligations under the contract to date by employing a cumulative average of more than 630 FTE, which is approximately 100 FTE above the 528 FTE required. The monthly reports provided by Alcoa pursuant to the Block Contract will be the basis for any action taken under section 8 of the Block Contract.

III. BLOCK CONTRACT – PURCHASE AND SALE OF FIRM POWER FOR THE EXTENDED INITIAL PERIOD

a. Firm Power Amounts

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

As of the contract effective date, BPA would have made available 285 aMW to Alcoa, but Alcoa requested that BPA increase such amount to 320 aMW, pursuant to applicable contract provisions. *See* Block Contract section 5.2. As described more fully in the Alcoa ROD, BPA concluded that it will achieve Equivalent Benefits from the sale of 320 aMW to Alcoa during the Initial Period, and granted Alcoa's request.[5] Pursuant to contractual provisions, BPA's EBT determinations are conclusive and binding on Alcoa, and may not be challenged by Alcoa in any forum. *See* Block Contract sections 5.2 and 25.1.

[5] *See* Alcoa ROD, section IV(a), at 10.

b. Term of the Block Contract

The term of the Block Contract is divided into two main periods, the Initial Period and the Second Period, with the Initial Period encompassing the approximately 17 month period from December 22, 2009, through May 26, 2011, and the Second Period encompassing a five-year period following expiration of the Initial Period, Extended Initial Period, and Transition Period (if any). *See* Block Contract, sections 5 and 6. The Block Contract provides that the Initial Period may be extended at the request of Alcoa, subject to BPA's determination of Equivalent Benefits. Alcoa submitted its written request for an extension of the Initial Period to BPA on September 2, 2010, pursuant to section 5.1.1 of the Block Contract. BPA has determined to extend the Initial Period for twelve months based on its finding that it will achieve Equivalent Benefits from the sale of 320 aMW to Alcoa for the twelve months requested by Alcoa. Pursuant to contractual provisions, BPA's determination is conclusive and binding on Alcoa, and may not be challenged by Alcoa in any forum. *See* Block Contract, sections 5.2 and 25.1.

Therefore, the Initial Period, including the extension, will have a term of 29 months, lasting through May 26, 2012. *See* Block Contract, section 5. In response to Canby Utility Board's comments (EBT 100005 at 1), this extension of the Initial Period will not reduce the duration of the Second Period, if any. With the extension, the maximum potential term of the entire Block Contract will be approximately eight years. The extension of the Initial Period was provided for in the Block Contract and does not represent a change to the original maximum potential term of the contract. *See* Block Contract, section 5.

IV. THE EQUIVALENT BENEFITS TEST

A key element of BPA's response to *PNGC II* was to implement an Equivalent Benefits Test to determine whether BPA could make a power sale to a DSI consistent with the Court's opinion. As established in the Alcoa ROD, the EBT is intended to demonstrate that a decision to serve a DSI customer is consistent with sound business principles when it can be shown that the benefits to BPA of serving the DSI load would equal or exceed BPA's cost of serving the load during the period of service. In this evaluation of extending the Initial Period, BPA analysis demonstrates that it can supply firm power to Alcoa as requested and the need to acquire power to serve the Alcoa load during the Extended Initial Period will be limited because BPA anticipates serving the Alcoa load from inventory under most water conditions. BPA followed the steps of the EBT to determine that it can provide service to Alcoa for an Extended Initial Period of 12 months, during which term the forecast benefits of the sale equal or exceed forecast costs.

In its Draft Determination of Equivalent Benefits dated October 6, 2010, BPA included a calculation of cumulative net benefits that occurred prior to the period at issue in this determination, May 27, 2011 to May 26, 2012. Some commenters suggest that BPA's calculation of cumulative net benefits occurring from the Block Contract outside this 12-month period is outside the scope of comment, should not have been introduced by BPA, and should not, in connection with the equivalent benefits determination made here, be relied upon by BPA or argued by it to justify continued application of the EBT. *See, e.g.*,

SUB, EBT100007, at 2-8; ICNU,,EBT100008, at 2. As SUB states, "The issue at hand is: does any benefit for the May 2011 – May 2012 period support Alcoa's request for an extension of service for the May 2011 – May 2012 period?" SUB for the same reasons takes issue with BPA's various "Cumulative" references that incorporate data outside the period May 2011 – May 2012. BPA appreciates and agrees with the comments, and will so confine its analysis and arguments. By so agreeing, BPA is not expressing any position whether as a policy or legal matter it is inappropriate to gauge Equivalent Benefits on a cumulative basis. As it is, the Block Contract speaks to whether Equivalent Benefits are shown "during such Extended Initial Period" and BPA will so confine its analysis. As a further consequence of this correction, BPA will not here address questions raised by Canby, EBT100005, at 2, and SUB, EBT10007, at 6, regarding the calculations and other matters pertaining to determination of what Equivalent Benefits were actually realized outside the May 2011 – May 2012 period.

a. BPA expects to be surplus during the Extended Initial Period

BPA does not forecast needing to make purchases specifically to serve Alcoa during the Extended Initial Period under most water conditions. However, as explained below, BPA has forecast the need to make some purchases, including some normal "balancing" purchases in some months, to meet its total load obligations during FY 2010 through FY 2013, particularly under critical (*i.e.*, very poor) water conditions.[6]

Pursuant to BPA's most recent load and resources studies contained in the *2010 Pacific Northwest Loads & Resources Study* (the "2010 White Book"), which forecasts loads and resources for both the Federal system and the region as a whole for the 10-year period Operating Year (OY) 2011-2020, BPA is forecast to have a surplus of approximately 1,160 aMW and 1,542 aMW on an average annual basis under the middle 80 percent of historical water conditions for OY 2011 and OY 2012 respectively.[7] The Extended Initial Period includes just over 2 months in OY 2011 (May 27, 2011, through July 31, 2011) and just under 10 months in OY 2012 (October 1, 2011, through May 26, 2012). *See* 2010 White Book, Table 8 at 39, and Exhibits 11-12 at 104-107. Alcoa's load during the Extended Initial Period represents approximately 20 percent of the forecast surpluses. Moreover, the 2010 White Book reflects a deficit of 501 aMW and a surplus of 113 aMW on an average

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[6] 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.

[7] Operating Year (OY) in the 2010 White Book is the 12-month period August 1 through July 31. For example, OY 2011 is August 1, 2010, through July 31, 2011. The value of 1,160 aMW of surplus for OY 2011 includes a DSI load of 271 aMW based on signed contracts for service to the DSIs (Alcoa and Port Townsend) through May 2011. The corresponding value of 1,542 aMW for OY 2012 includes 0 aMW of DSI load. If the 271 aMW of DSI loads were removed from OY 2011 the surplus in OY 2011 would increase from 1,160 aMW to 1,431 aMW.

annual basis under 1937-Critical Water Conditions in OY 2011 and OY 2012 respectively, and does so assuming no augmentation and a DSI load of 271 aMW.[8]

The EBT is not based on 1937 Critical Water Conditions, but largely on BPA's forecasts of average water in the 2010 White Book (Average of the Middle 80 percent of Water Conditions) and BPA's recent streamflow expectations for FY 2011 and FY 2012 that contribute to forecasts of hydroelectric generation – outputs of HYDSIM from late July and early August of 2010 – that better reflect lingering effects of the past two relatively dry water years. As stated in the Alcoa ROD, "BPA has set a portion of its rates for FY 2010 and FY2011 based on 1937-Critical Water Conditions as evidenced by Tables 2.3.1 and 2.3.2" entitled Loads and Resources – Federal System and "another portion of BPA's rates, notably the Secondary Sales and Purchases, for FY2010 and FY2011 were set based on average water."[9] *See* Alcoa ROD at 34. BPA expects this approach – using critical water for one portion of its rate setting and average water for other portions of its rate setting – to continue in the upcoming BP-12 rate proceeding and beyond. As a result, BPA expects on an annual basis to be surplus under average water conditions, and as such does not anticipate the need to alter its purchasing strategy for the sales that will be made to Alcoa during the Extended Initial Period. This does not preclude the fact that BPA may have to make short term purchases during certain times of the year to balance BPA's loads, including Alcoa, and resources.

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

BPA forecasts that the revenues it will earn from the firm sale of 320 aMW to Alcoa at the IP rate during the Extended Initial Period will exceed the forecast revenues BPA could otherwise obtain from selling that power into the market by approximately $4.8 million. *See* Tables 1-6 below. As a consequence, BPA's finding is that service to Alcoa during the Extended Initial Period satisfies the EBT.

In the same manner described in the Alcoa ROD, BPA's projected monthly revenues are determined by multiplying the heavy load hour (HLH) and light load hour (LLH) energy entitlements and demand entitlement by their respective IP rate components for each month. BPA has calculated revenues under the Block Contract based on a continuing sale of 320 aMW, as outlined in Table 1, of firm power each hour to Alcoa under the IP-10 rate beginning May 27, 2011, and ending May 26, 2012. The energy and demand entitlements are the projected amounts to be sold by diurnal period each month in the Block Contract. Since the Block Contract sells the same number of megawatts in every hour of the month, the demand entitlement is the monthly megawatt amount specified in Table 1. BPA's projected monthly revenues are then accumulated and the result is illustrated in Tables 1 and 2:

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[8] 2010 White Book, page 40.

[9] Tables 2.3.1 and 2.3.2 are found in WP-10-FS-BPA-01A at 10-13. Tables 4.6.2, 4.8.1 and 4.8.2 are found in WP-10-FS-BPA-05A at 77, 88-89.

TABLE 1 - Usage and Rates

Month	Alcoa Ferndale Usage			Projected IP Rates			
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)	Effective IP Rate ($ / MWh)
May-11	320,000	15,360	23,040	$1.44	$31.69	$22.29	$27.99
Jun-11	320,000	133,120	97,280	$1.32	$31.18	$23.29	$29.68
Jul-11	320,000	128,000	110,080	$1.61	$33.33	$28.66	$33.33
Aug-11	320,000	138,240	99,840	$1.89	$37.31	$31.40	$37.37
Sep-11	320,000	128,000	102,400	$1.96	$36.49	$32.26	$37.33
Oct-11	320,000	133,120	104,960	$2.05	$31.92	$27.01	$32.51
Nov-11	320,000	128,000	102,720	$2.19	$33.33	$29.58	$34.70
Dec-11	320,000	133,120	104,960	$2.30	$35.24	$31.13	$36.52
Jan-12	320,000	128,000	110,080	$1.96	$38.46	$32.24	$38.22
Feb-12	320,000	128,000	94,720	$1.99	$37.72	$31.73	$38.03
Mar-12	320,000	138,240	99,520	$1.85	$35.94	$30.08	$35.98
Apr-12	320,000	128,000	102,400	$1.74	$32.23	$26.95	$32.30
May-12	320,000	112,640	87,040	$1.44	$31.69	$22.29	$29.53

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$74,323	$486,758	$513,562	$1,074,643	$1,074,643
Jun-11	$422,400	$4,150,682	$2,265,651	$6,838,733	$7,913,375
Jul-11	$515,200	$4,266,240	$3,154,893	$7,936,333	$15,849,708
Aug-11	$604,800	$5,157,734	$3,134,976	$8,897,510	$24,747,219
Sep-11	$627,200	$4,670,720	$3,303,424	$8,601,344	$33,348,563
Oct-11	$656,000	$4,249,190	$2,834,970	$7,740,160	$41,088,723
Nov-11	$700,800	$4,266,240	$3,038,458	$8,005,498	$49,094,220
Dec-11	$736,000	$4,691,149	$3,267,405	$8,694,554	$57,788,774
Jan-12	$627,200	$4,922,880	$3,548,979	$9,099,059	$66,887,833
Feb-12	$636,800	$4,828,160	$3,005,466	$8,470,426	$75,358,259
Mar-12	$592,000	$4,968,346	$2,993,562	$8,553,907	$83,912,166
Apr-12	$556,800	$4,125,440	$2,759,680	$7,441,920	$91,354,086
May-12*	$386,477	$3,569,562	$1,940,122	$5,896,161	$97,250,246

* Extended Initial Period is May 27, 2011 through May 26, 2012.

In this evaluation of a firm power sale to Alcoa during the Extended Initial Period, BPA has continued to use IP-10 energy and demand rates in Tables 1 & 2.

SUB, EBT100007 at 2, commented that the IP-12 rates may be higher or lower than the IP-10 rates used in this determination. SUB is technically correct, inasmuch as the IP-12 rates must be established in the up-coming rate hearing. Nonetheless, BPA has used the monthly energy and demand rates from the IP-10 rate schedule in Table 1 of this determination because they are, based on current information, a conservative forecast of the IP rates for the period from May 2011 through May 2012. The IP-12 rates – which will ultimately apply during the portion of the Extended Initial Period from October 1,

2011, onward – have yet to be adopted. Furthermore, the Initial Proposal in BPA's BP-12 rate proceeding which will include the proposal for IP-12 rates has not been published. However, BPA's recent Integrated Program Review (IPR) conducted in advance of BPA's upcoming BP-12 rate proceeding (which takes public comment on BPA's proposed internal cost levels for the applicable rate period) has documented a net change in average expenses from FY10-11 to FY-12-13 in the neighborhood of 6 percent (see *2010 Integrated Program Review*, Table 12 - Power Expense Changes Between FY 2010-11 Rate Case and FY 2012-13 Final IPR Spending Levels). As a result, it is highly likely that BPA will propose rates in BP-12 that are higher than those adopted in WP-10 in order to fully recover its higher costs and therefore the IP-12 rate is expected to be higher than the IP-10 rate. Therefore, BPA's use of the IP-10 rate for this determination of Equivalent Benefits is conservative in that BPA would receive more revenues than shown in Table 2 of this determination if the rates adopted in IP-12 are higher than those from IP-10.

c. Forecast of revenues that would be obtained by selling an equivalent amount of surplus power.

BPA routinely shapes its inventory to meet the need of its portfolio of contracts and sells its surplus inventory in the Pacific Northwest power market as described in BPA's WP-10 rate proceeding.[10] BPA routinely forecasts Mid-C electricity prices consistent with the methodology described in the WP-10 rate proceeding to value these purchases and sales.[11] For this analysis, BPA updated the inputs and assumptions used to forecast electricity prices as described in Attachment C. In particular, BPA updated its natural gas price forecast – one of the inputs used to forecast electricity prices – to reflect more contemporary natural gas market fundamentals. This forecast of natural gas prices was used in BPA's final Resource Program released September 2010.[12]

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[10] *See* Alcoa ROD at 39. Refer also to section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding for a more complete description of the operating risk factors BPA faces in the course of doing business – in particular "the variation in hydro generation due to the variation in the volume of water supply from one year to the next…" which significantly impacts market prices, our need for shaping purchases and our ability to make surplus sales. *See* WP-10-FS-BPA-04 beginning on page 21.

[11] 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-C electricity prices in the WP-10 rate proceeding. *See* WP-10-FS-BPA-03, beginning on page 1.

[12] BPA's natural gas forecast used in the WP-10 rate proceeding is outlined in section 3.3 of the Market Price Forecast Study. *See* WP-10-FS-BPA-03, beginning on page 11. BPA's more contemporary understanding of natural gas market fundamentals caused a lowering of its natural gas price forecast used in the final Resource Program. The primary reasons for BPA's recent reductions became apparent in the progression of time since the natural gas price forecast for the WP-10 rate proceeding was constructed. These are: a) continued strength of natural gas production despite steep reductions in rig counts, b) continued slow recovery of natural gas demand – particularly on the industrial side – in that growth in natural gas demand is slower than growth in natural gas production, c) near record amount of natural gas in storage, d) reduced risk of hurricane impact on supply now that the 2010 hurricane season has one month remaining. *See also* Short-Term Energy Outlooks from the EIA for September showing the EIA lowered its

In the absence of selling 320 aMW of firm power to Alcoa's Intalco Plant every hour, BPA would have one less firm power requirement sale in its aggregated portfolio load shape. As such, BPA would have approximately 320 aMW of surplus energy to sell in the market on an average annual basis. As illustrated in Table 3, BPA has forecast the revenues it would otherwise obtain from the market by incorporating BPA's updated inputs and assumptions in the development of the electricity price forecast used in this analysis of the Extended Initial Period.[13]

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 ($) (HLH + LLH)	Cumulative Total Extended Initial Period* ($)
May-11*	$33.34	$20.39	$512,115	$469,732	$981,847	$981,847
Jun-11	$33.30	$18.93	$4,433,366	$1,841,179	$6,274,545	$7,256,392
Jul-11	$39.01	$26.61	$4,993,504	$2,929,105	$7,922,609	$15,179,001
Aug-11	$42.08	$30.62	$5,817,221	$3,056,957	$8,874,178	$24,053,179
Sep-11	$39.54	$28.68	$5,060,801	$2,936,601	$7,997,401	$32,050,580
Oct-11	$42.80	$33.28	$5,697,575	$3,493,539	$9,191,114	$41,241,694
Nov-11	$43.23	$33.28	$5,533,260	$3,418,279	$8,951,539	$50,193,233
Dec-11	$45.05	$35.61	$5,996,634	$3,737,185	$9,733,818	$59,927,052
Jan-12	$46.59	$34.53	$5,963,978	$3,800,764	$9,764,742	$69,691,794
Feb-12	$46.48	$34.75	$5,949,490	$3,291,170	$9,240,660	$78,932,454
Mar-12	$45.52	$33.36	$6,292,245	$3,319,492	$9,611,737	$88,544,191
Apr-12	$40.75	$27.72	$5,216,283	$2,838,321	$8,054,604	$96,598,795
May-12*	$38.78	$22.04	$4,368,143	$1,918,767	$6,286,910	$102,885,705

* Extended Initial Period is May 27, 2011 through May 26, 2012.

As detailed in the Gas Price Forecast sub-section further below, BPA's forecasts of natural gas prices for the Henry Hub have been progressing steadily downward recently. BPA's natural gas price forecasts have fallen steadily since the WP-10 Final Proposal was published in July, 2009. The gas prices from the draft Resource Program that was used in the Alcoa ROD was lower than that used in the WP-10 Final Proposal. Subsequently, the natural gas forecast used in the final Resource Program was reduced even further. In addition, as SUB notes in its comments, the EIA released a *Short-Term Energy Outlook* during the comment period that indicated its price expectations for 2011 are 4 percent below what they were in September. As such, it is not unreasonable to assume that BPA's forecast of natural gas prices for the BP-12 rate proceeding could decline further given market developments since July, when the gas price forecast for the final Resource Program was completed. As a result, this gas price forecast is a conservative assumption not only because BPA's resulting forecast of market prices for electricity could decrease further, but also because BPA's $102.9 million of Forecast Revenues Obtained from the Market in Table 3 represents the entire opportunity cost

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forecast Henry Hub Spot Price average for 2011 to $4.76 per MMbtu, *Short-term Energy Outlook*, DOE EIA, September 8, 2010, at 6.

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

contributing to this determination of Equivalent Benefits by BPA. In other words, if the forecast revenues BPA could otherwise obtain from selling power into the market were to decline further while the revenues BPA would earn from the firm sale of 320 aMW to Alcoa at the IP rate remain the same, then BPA's forecast of Equivalent Benefits would improve by the same amount.[14]

Net Benefit (IP – Market)

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

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost)	
	Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$92,796	$92,796
Jun-11	$564,188	$656,983
Jul-11	$13,724	$670,707
Aug-11	$23,332	$694,040
Sep-11	$603,943	$1,297,982
Oct-11	($1,450,954)	($152,972)
Nov-11	($946,041)	($1,099,013)
Dec-11	($1,039,265)	($2,138,278)
Jan-12	($665,683)	($2,803,961)
Feb-12	($770,235)	($3,574,195)
Mar-12	($1,057,830)	($4,632,025)
Apr-12	($612,684)	($5,244,709)
May-12*	($390,749)	($5,635,459)

* Extended Initial Period is May 27, 2011 through May 26, 2012.

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

Consistent with the methodology described in the Alcoa ROD, BPA has identified a number of tangible benefits to BPA that would not be achieved by a market sale of power compared to selling to Alcoa at the IP rate during the Extended Initial Period. BPA

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[14] This pattern of forecasts of natural gas prices progressing steadily downward recently has been observed in the passage of time since the Alcoa ROD as illustrated in Figure 1 (p. 34). So, for example, if BPA's forecast of electricity prices declined 8.7 percent then BPA's analysis would demonstrate how the projected revenues BPA recovers from a 12-month IP sale to Alcoa during the Extended Initial Period (from May 27, 2011, through May 26, 2012) exceed by approximately $37.6 million the forecast revenues that BPA would otherwise obtain from the market – nearly 8 times the mean forecast of $4.8 million. *See also* the Market Price Risk sub-section and Figure 2, *supra* section V.h.

conducted an economic analysis to determine the net value of those benefits for the Extended Initial Period. There were other, less tangible benefits accruing to BPA but assigning a financial value to those would have been more subjective, and based on the analysis below, doing so was unnecessary.[15]

Value of Reserves

The Block Contract requires that Alcoa make contingency reserves available to BPA, reserves that would not be available from making a typical market sale. BPA takes into account the value of the reserves Alcoa is required to make available to BPA during the Extended Initial Period. Sales at the IP rate reflect the value of BPA's right to obtain contingency reserves.[16] Specifically, the energy rate tables in the IP-10 rate schedule include an $0.80 per MWh credit for the value of these reserves. Therefore, BPA's net benefit above compares a surplus power sale to a sale of power at the IP rate with reserves. We have adjusted for this by adding back a value of reserves that provides an equal and opposite offset to the $0.80 per MWh credit for the value of reserves in the IP-10 rate schedule.[17] As illustrated in Table 5a, this is done for every megawatt hour not sold to Alcoa:

TABLE 5a - BPA's Net Benefit Adjustments

Month	Value of Reserves Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$30,720	$30,720
Jun-11	$184,320	$215,040
Jul-11	$190,464	$405,504
Aug-11	$190,464	$595,968
Sep-11	$184,320	$780,288
Oct-11	$190,464	$970,752
Nov-11	$184,576	$1,155,328
Dec-11	$190,464	$1,345,792
Jan-12	$190,464	$1,536,256
Feb-12	$178,176	$1,714,432
Mar-12	$190,208	$1,904,640
Apr-12	$184,320	$2,088,960
May-12*	$159,744	$2,248,704

* Extended Initial Period is May 27, 2011 through May 26, 2012.

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[15] *See* Alcoa ROD, pages 72-82.

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

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

In this determination, BPA has continued to use the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table. The IP-12 rates are not yet established or proposed.

In its comments, PNGC asserts "BPA has vastly overvalued the reserves that it obtains under the Block Contract by means of curtailment." *See* PNGC, EBT 100011, at 3. To make its point PNGC argues that: "BPA's assessment of value is the product of Alcoa's annual megawatt-hour purchase commitment multiplied by the $0.80 per MWh discount that BPA decided to give Alcoa in the WP-10 rate case. This is an arithmetic calculation of the cost of the reserves, not a rational explanation of their economic value." *See* PNGC, EBT 100011, at 3-4. BPA disagrees with PNGC's statement that it has vastly overvalued the reserves that it obtains under the Block Contract. Precisely as PNGC describes, the value of reserves ascribed in this determination of Equivalent Benefits *is* "the arithmetic calculation of the *cost* of the reserves" as established in BPA's WP-10 rate proceeding and included in the IP-10 energy rates adopted in the same proceeding. *See* WP-10-A-02-AP02 at 49.

To further illustrate its point, PNGC extrapolated that "BPA is effectively paying Alcoa $1,250 per MWh for reserves." Assuming, as PNGC does, that the frequency of actual reserve deployments does not change over time, PNGC creates a red herring when it states that BPA is effectively paying Alcoa $1,250 per MWh for reserves *deployed*. The contingency reserves provided by Alcoa are required to be available on *every* hour – whether they are *deployed or not* – consistent with NERC and WECC criteria and consistent with BPA's Business Practices for Operating Reserves established by its Transmission Services organization. As such, BPA holds fewer contingency reserves from the FCRPS *on every hour* than would otherwise be required.[18] As a result, this FCRPS capacity that in the absence of the Block Contract would have been set aside to provide contingency reserves, is now available for another use.[19]

Issues with the economic value of the reserves made available by Alcoa that parties raise will be addressed during the BP-12 rate proceeding. They are only germane to this determination to the extent BPA's continued use of the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table is implicated for FY 2012. It is not. As described earlier, BPA has documented a net change in average expenses from FY10-11 to FY-12-13 in the neighborhood of 6 percent (see *2010 Integrated Program Review*, Table 12 - Power Expense Changes Between FY 2010-11 Rate Case and FY 2012-13 Final IPR Spending Levels). As a result, it is likely that BPA will adopt rates in BP-12 that are higher than those adopted in WP-10 in order to fully recover it higher

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[18] As is made clear in the DSI Reserve Log maintained by BPA and referenced by PGNC in its extrapolation, EBT100011 at 4, BPA has called on the reserves from Alcoa without any forewarning on a variety of days and hours. Alcoa's performance has been compliant with the required criteria set forth in BPA's Business Practices for Operating Reserves established by its Transmission Services organization.

[19] "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." *See* Alcoa ROD at 30-31.

costs. This has two implications for BPA's continued use of the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table: a) the $0.80 per MWh credit is itself based on a formula using a separate cost-based rate; and b) the IP-12 rate is expected to be higher than the IP-10 rate. First, the cost-based rate for Generation Inputs that is an input to BPA's calculation is expected to increase because BPA's expenses are increasing, which, all else being equal, would cause the credit for the value of reserves included in the IP-12 energy rates table to increase in absolute value, not decrease, resulting in a larger credit for the value of reserves. Second, even if BPA were to reduce the credit for the value of reserves in the BP-12 rate proceeding, the difference from this forecast of $0.80 per MWh is likely to be more than offset by the difference from the IP-10 rate used in this determination and the IP-12 energy rates adopted in the BP-12 rate proceeding. For the forgoing reasons, BPA's continued use of the $0.80 per MWh credit for the value of reserves included in the IP-10 energy rates table is conservative.

Avoided Transmission and Ancillary Services Expenses

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

However, this transmission product inventory is not sufficient to deliver all of the surplus power PS would sell under all load and resource conditions, especially under high stream flows. As a result, there is a subset of load and resource conditions under which PS would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales, if PS did not sign contracts to serve the DSI loads. The planned transmission and ancillary services expenses to address both the expected expenses and their uncertainty were addressed in the WP-10 rate proceeding and are expected to be addressed in subsequent BPA rate proceedings.[20] Since PS's overall marketing strategy is to serve all its loads out of inventory and to balance its supply to meet any within-year deficits with short-term purchases, the incremental transmission and ancillary services costs are avoided when BPA makes firm power IP sales to the DSIs.

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[20] Refer to section 4 of the *Revenue Requirement Study*, WP-10-FS-BPA-02 and section 2.4 of the *Risk Analysis and Mitigation Study* in the WP-10 rate proceeding. BPA does not anticipate changing the methodology for addressing planned transmission and ancillary service expenses in the WP-12 rate proceeding.

PS valued these avoided transmission and ancillary services costs for the Extended Initial Period using the same methodology used in the WP-10 rate proceeding to establish the total costs and risks associated with PS's inventory of transmission products and services. In these computations, both fixed, take-or-pay costs and variable incremental transmission and ancillary service costs were computed under 3,500 load and resource conditions for each month. Incremental transmission and ancillary services costs were computed by comparing the amount of surplus energy available to the monthly excess amount of firm transmission products in the PS inventory.

Tariff costs established by BPA's Transmission Services organization were applied to the amount of surplus energy in excess of the PS transmission products inventory. Total monthly transmission and ancillary services costs were computed assuming no service to the DSIs and DSI service of 340 aMW.[21] The average total monthly expense values of the 3,500 games were computed with and without service to the DSIs and the differences were taken to determine the avoided PS transmission and ancillary services costs when PS makes these 340 aMW of IP sale(s) to the DSIs. For purposes of this analysis, Alcoa has been allotted 94.1% of this PS benefit in each month as illustrated in Table 5b below. This percent allotment is the result of the proportion of the megawatt amounts during the Extended Initial Period, and as depicted in Table 1 above, as compared to the 340 aMW forecast for all DSI customers.

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$92,056	$86,641	$86,641
Jun-11	$578,435	$544,409	$631,050
Jul-11	$399,662	$376,153	$1,007,203
Aug-11	$90,001	$84,706	$1,091,909
Sep-11	$58,167	$54,745	$1,146,655
Oct-11	$35,084	$33,020	$1,179,675
Nov-11	$100,669	$94,747	$1,274,422
Dec-11	$135,000	$127,059	$1,401,481
Jan-12	$432,858	$407,396	$1,808,877
Feb-12	$379,106	$356,805	$2,165,682
Mar-12	$434,459	$408,902	$2,574,584
Apr-12	$570,075	$536,541	$3,111,125
May-12*	$650,127	$611,884	$3,723,009

* Extended Initial Period is May 27, 2011 through May 26, 2012.

BPA continues to value avoided transmission and ancillary services costs for the Extended Initial Period using the tariff costs adopted by Transmission Services in the TR-

[21]This number is comprised of 320 aMW for Alcoa and 20 aMW for Port Townsend Paper Company.

10 rate proceeding. The applicable tariff costs from the BP-12 rate proceeding are not yet established or proposed.

SUB, EBT100007 at 4, asserts that the "month to month variation… is proportionately different than the month to month variation in the Alcoa ROD" and PNGC, EBT100011 at 4, claims that BPA's "assumption that power sold to Alcoa can only be sold at Mid-C is incorrect." SUB is correct that the month-to-month variation is different in this determination than it was in the Alcoa ROD. This is because BPA's forecast of the benefits accruing from Avoided Transmission and Ancillary Services reflects the best information currently available to BPA. Specifically, BPA's forecast of the benefit accruing from Avoided Transmission and Ancillary Services costs, as described in the Alcoa ROD at 42-43, reflects the "load and resource conditions under which [BPA's Power Services] would incur incremental costs for transmission and ancillary services to deliver incremental surplus energy sales."

For this determination, BPA updated its inputs using the same methodology used in the WP-10 rate proceeding, including but not limited to the hydro regulation studies that produce forecasts of hydroelectric generation, to develop its 3,500 game distribution of load and resources conditions. As a result, BPA's updated forecast of the financial benefit from avoided transmission and ancillary services costs is higher in some months and lower in others when compared with the same months published in the Alcoa ROD. Specifically, the forecasts of the financial benefit to BPA in May 2011 of avoided transmission and ancillary services costs was $765,645 in the Alcoa ROD (see Alcoa ROD, Table 5b at 44) and is $570,746 in this determination (the sum of $92,056 from Table 5b and $476,690 from Attachment C to the analysis released in October 6, 2010), whereas the forecasts of the financial benefit to BPA in June 2011 of avoided transmission and ancillary services costs was $669,032 in the Alcoa ROD (see Alcoa ROD, Table 5b at 44) and is $578,435 in this determination. Whether or not one's definition of month-to-month variation is looking at the relative change in the same month between the Alcoa ROD and this determination or the relative change between consecutive months, May and June in this example, from the Alcoa ROD and this determination, the conclusion is the same in that the month to month variation is different and the differences are an appropriate reflection of the updated inputs.

In addition, SUB questioned whether the "month to month variation …is due to a shift in market price or some other variable." EBT100007 at 4. As described more fully above and consistent with the Alcoa ROD at 43, tariff costs established by BPA's Transmission Services organization, or our forecast of tariff costs yet to be established, and not market prices, are the input applied to the amount of surplus energy in excess of the PS transmission products inventory resulting from the 3,500 game distribution when assuming no DSI service and assuming 340 aMW of DSI service. The difference between these two results is the forecast of the monthly value of the avoided transmission and ancillary service costs. Therefore, the updated load and resource inputs used in the forecast of the financial benefit to BPA from avoided transmission and ancillary services costs for this determination impact the month-to-month variation of dollars resulting from this benefit, but BPA's updated forecast of market prices does not.

PNGC comments that: "BPA can and does sell power in wholesale markets to other customers, including preference and non-preference customers, with BPA Power as the delivery point, not exclusively Mid-C. The assumption that power sold to Alcoa can only be marketed at Mid-C is incorrect. Therefore, BPA's adjustment based on these assumed avoided costs is improper and invalid." EBT100011 at 4-5. PNGC suggests that if BPA disagrees then BPA should include in the record documentation that BPA cannot sell any or all of the power proposed to be sold to Alcoa without delivering it to Mid-C.

BPA disagrees with PNGC on this point. On the one hand, firm power customers of BPA, such as the DSIs and PF customers, are required to provide their own transmission and ancillary services, at their cost, from different points of receipt (i.e. the federal busbar) within the federal transmission system to ensure the delivery of such power to the location where it will be consumed. On the other hand, the vast majority of BPA's surplus power sales are delivered products, meaning BPA must use transmission, at our cost, to make these surplus sales. As already noted, this is because the market participants typically expect the electricity to be delivered at a market trading hub, such as Mid-C. Similarly, the market price forecast used to establish BPA's forecast revenues obtained from the market in Table 3 above "assume[s] power is delivered by the seller to Mid-Columbia trading hub (Mid-C)", as indicated in the Alcoa ROD at 42. This means that BPA – forecast to be net seller – is expected to incur transmission and ancillary services costs to deliver the power at Mid-C for purchase by others at that point. This is also the same manner that the modeling tools BPA employs in its rate proceedings model BPA's costs and risks associated with transmission and ancillary services. *See* WP-10-FS-BPA-04 at 30. As a result, BPA has rightly included the value of the benefit of Avoided Transmission and Ancillary Services costs in the EBT.

Demand Shift

When BPA serves the DSI loads – including Alcoa – and they operate – as opposed to not operating if BPA does not sell to them – all of BPA's surplus sales realize increased revenues because the mean value of prices for electricity in Western power markets are higher than they would otherwise be had the DSI loads not consumed electricity from Western power markets. BPA has forecast these increased revenues by reducing loads in the PNW by 340 aMW in each month for each of the 3,500 games AURORA$^{xmp®}$ simulated for the forecast used in Table 3 above. This lowered the mean price forecast by a 12-month average of $0.38 per MWh and by $0.45 per MWh for fiscal years 2011 and 2012 respectively.[22] The monthly difference resulting from this lower mean price forecast was then multiplied by BPA's monthly surplus energy from BPA's recent forecasts of hydroelectric generation for FY 2011 and FY 2012 – outputs of HYDSIM

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

from late July and early August of 2010 – to determine the increased revenues available to BPA's surplus sales when BPA makes an IP sale(s) to the DSIs – including a firm power sale to Alcoa during the Extended Initial Period. For the purposes of this analysis, Alcoa has been allotted 94.1% of this benefit to BPA in each month as illustrated in Table 5c below. This percent allotment is the result of the proportion of the average megawatt amounts in the Block Contract, and as depicted in Table 1 above, as compared to the 340 aMW forecast for all DSI customers.

TABLE 5c - BPA's Net Benefit Adjustments

Month	Demand Shift		Cumulative Total Extended Initial Period*
	Month ($)	Proportional Adjusted Month ($)	($)
May-11*	$122,511	$115,304	$115,304
Jun-11	$1,000,365	$941,520	$1,056,824
Jul-11	$411,523	$387,316	$1,444,140
Aug-11	($19,968)	($18,794)	$1,425,346
Sep-11	$26,443	$24,888	$1,450,234
Oct-11	($59,599)	($56,093)	$1,394,140
Nov-11	$31,970	$30,090	$1,424,230
Dec-11	$10,031	$9,440	$1,433,670
Jan-12	$424,453	$399,485	$1,833,156
Feb-12	$371,928	$350,050	$2,183,206
Mar-12	$542,456	$510,547	$2,693,752
Apr-12	$643,772	$605,903	$3,299,656
May-12*	$1,193,297	$1,123,103	$4,422,759

* Extended Initial Period is May 27, 2011 through May 26, 2012.

SUB commented:

> BPA fails to account for the impact associated with BPA's demand shift methodology. Essentially BPA's demand shift analysis shows that market pricing is higher if BPA serves the Alcoa load. This means that BPA balancing purchase costs associated with market purchases to serve preference customers are higher, Tier II purchases made by BPA to serve preference customers are higher, and Tier II market acquisitions not offered by BPA, but purchased by preference customers to meet obligations under BPA contracts, are higher.

EBT 100007 at 6-7. As an example, SUB suggests that recent purchases by BPA to cover Tier 2 load obligations (made in April and May 2010), at $42 and $47/MWh, were $0.45/MWh higher due to demand shift increases and would have been $41.55 and $46.55/MWh but for BPA selling to Alcoa. *See* SUB, EBT100007 at 7.

To the contrary, the demand shift values used for this determination do account for BPA's balancing purchases and sales, and the forecast price impacts on them both, in the same manner described in the Alcoa ROD: "The demand shift analysis used both the

surplus and deficit energy values to account for the impact of surplus energy sales and balancing power purchases in the computations." *See* Alcoa ROD at 48. Moreover, the prices of Tier 2 purchases made by BPA to serve preference customers are not higher by $0.45 per MWh as SUB asserts and do not force BPA "to charge more for Tier 2 service to its preference customers." *See* PNGC, EBT100011 at 5. Commenters appear to be linking this present determination of Equivalent Benefits and its assumption regarding the demand shift to BPA's determination of Equivalent Benefits in the Alcoa ROD to argue an increase in BPA's past costs. BPA disagrees.

BPA has not yet established rates pursuant to its Tiered Rates Methodology (TRM) and, hence, Tier 2 PF rates have not yet been established. The BP-12 rates, when established pursuant to the TRM, are expected to become effective on October 1, 2011. BPA's prior determination of Equivalent Benefits in the Alcoa ROD on December 21, 2009, of which the demand shift was also a part, covered the period from December 22, 2009, through May 26, 2011 – a period occurring entirely before October 1, 2011. From December 21, 2009 until the time of this determination, BPA's obligation to provide firm power to Alcoa any time after May 26, 2011 was contingent upon either a request from Alcoa initiating BPA's evaluation of extending the Initial Period and a determination by BPA that the EBT was satisfied or a ruling from the Ninth Circuit that BPA need not apply the EBT. *See* Block Contract, sections 5.1.1 and 6. To this day, such a ruling has not been made. BPA received Alcoa's request to extend the initial period on September 2, 2010.

This determination of Equivalent Benefits, of which the demand shift is also a part, was initiated in response to Alcoa's request and does include eight months in FY 2012 from October 1, 2011 through May 26, 2012. However, BPA purchased power to meets its obligation to supply 22 aMW of customer Above High Water Mark Load (Tier 2 purchase obligation) for FY 2012 and the 58 aMW of customer Above High Water Mark Load for FY 2013 in April and May 2010.[23] These were purchases made at forward market prices prevailing after BPA's prior determination on December 21, 2009, and before Alcoa's request on September 2, 2010. *See* BPA Bulk Hub Purchase Notification for Service at Tier 2 Rates, dated April 7, 2010 and May 25, 2010. The demand shift is BPA's forecast of the impact an assumed increment of DSI load will have on market-clearing prices for electricity at Mid-C. While forward market prices for future delivery are impacted by the market participants view of what loads might be in the future, market participants, including BPA, did not know whether or not BPA's obligation to provide firm power to Alcoa would be extended past May 26, 2011 at the time BPA's purchases for Tier 2 were made in April and May 2010. Therefore, prices for these Tier 2 purchases were not impacted by the demand shift used in BPA's determinations of Equivalent Benefits for the DSIs.

In addition, any acquisitions by preference customers, or their representatives, to buy power in advance to supply their Above High Water Mark load are similarly unaffected. Even if they were, BPA does not consider direct costs to other parties in the EBT. The

[23] The Tier 2 purchases were made well in advance to lock into a price so as not to be subject to market-clearing prices during their period of delivery.

test is designed to evaluate the impact to BPA only. Nonetheless, issues with cost allocation that parties raise will be addressed during the BP-12 rate proceeding.

e. Conclusion of Equivalent Benefits Test

The preceding analysis demonstrates how the projected revenues BPA would recover from a 12-month IP sale to Alcoa during the Extended Initial Period (from May 27, 2011 through May 26, 2012) exceed by approximately $4.8 million the projected revenues that BPA would otherwise obtain from the market. *See* Table 6. BPA's methodology for making this determination is based, to the extent possible, on modeling tools used in BPA's power rate cases. That process includes discovery, testimony, rebuttal testimony, and cross examination prior to a final determination by the Administrator. Further, the analysis is marked by thorough and thoughtful consideration of market fundamentals and other factors that strengthen the integrity of the results.

TABLE 6 - BPA's Net Benefit after Adjustments

Month	BPA's Adjusted Net Revenue or (Cost)					
	Net Revenue or (Cost) (A) Month ($)	Value of Reserves (B) Month ($)	Avoided Tx Costs (C) Month ($)	Demand Shift (D) Month ($)	A + B + C + D Month ($)	Cumulative Total Extended Initial Period* ($)
May-11*	$92,796	$30,720	$86,641	$115,304	$325,461	$325,461
Jun-11	$564,188	$184,320	$544,409	$941,520	$2,234,437	$2,559,898
Jul-11	$13,724	$190,464	$376,153	$387,316	$967,656	$3,527,554
Aug-11	$23,332	$190,464	$84,706	($18,794)	$279,709	$3,807,263
Sep-11	$603,943	$184,320	$54,745	$24,888	$867,896	$4,675,159
Oct-11	($1,450,954)	$190,464	$33,020	($56,093)	($1,283,563)	$3,391,595
Nov-11	($946,041)	$184,576	$94,747	$30,090	($636,629)	$2,754,967
Dec-11	($1,039,265)	$190,464	$127,059	$9,440	($712,301)	$2,042,666
Jan-12	($665,683)	$190,464	$407,396	$399,485	$331,662	$2,374,328
Feb-12	($770,235)	$178,176	$356,805	$350,050	$114,797	$2,489,124
Mar-12	($1,057,830)	$190,208	$408,902	$510,547	$51,827	$2,540,951
Apr-12	($612,684)	$184,320	$536,541	$605,903	$714,080	$3,255,032
May-12*	($390,749)	$159,744	$611,884	$1,123,103	$1,503,982	$4,759,013

* Extended Initial Period is May 27, 2011 through May 26, 2012.

V. ADDITIONAL ISSUES

This section addresses BPA's approach to several issues related to the EBT, but not directly addressed in the application of the test.

a. Legal implications of serving Alcoa from existing inventory

PNGC, EBT100011 at 3, argues that serving, via the EBT, Alcoa from existing inventory, while making purchases to serve preference customer Tier 2 load, appears to violate BPA's obligations under section 5(a) of the Northwest Power Act because BPA would be allocating higher cost resources to preference customers. PNGC also asserts that in conducting the EBT, BPA proposes to sell secondary energy to Alcoa as firm energy, taking a risk that it may have to acquire power and shift costs to others, contrary to section 7(b)(1) of the Northwest Power Act and sound business principles. Similarly, ICNU argues that "BPA should only provide Alcoa with cost based power if it is consistent with sound business principles and after BPA has met all its preference

customers' net requirements with cost based power at Tier 1 rates." EBT100010 at 2. BPA disagrees with PNGC's and ICNU's arguments. While they were addressed for the most part in the Alcoa ROD, the arguments now arise in the context of BPA's implementation of tiered rates for preference customers beginning October 1, 2011. While the arguments about tiered rates could and should have been been made in the comment process on the Alcoa contract, BPA nonetheless addresses them here in order to clearly convey the important distinction between cost allocation and rate design.

Similar cost recovery and cost allocation issues were addressed, and rejected, at pages 13-18 of the Alcoa ROD as follows:

> In past comments, particularly comments related to the CFAC Amendment, some of BPA's preference customers have expressed a belief that, even if BPA offers to sell power to DSIs at the IP rate, that rate must recover the full incremental costs of any resources obtained to support DSI contracts. *See e.g.,* NRU, CFA090001 at 2 (arguing that "DSIs have no right to continued BPA service" and a discretionary sale must be consistent with "establishing rates at the lowest possible cost consistent with sound business principles"); SUB, CFA090003; and Canby, CFA09002. [Footnote omitted.] Even in the most recent round of comments, preference customer groups have continued to suggest that service to Alcoa would constitute a "subsidy." See e.g., PPC at 9; ICNU at 5; SUB at 18; WPAG at 9.
>
> A central holding of the Court's opinion in *PNGC I* is that, if the Administrator exercises his discretion to offer to sell power to the DSIs, any initial offer must be at the IP rate. 580 F.3d 817. In support of its conclusion that any initial offer of DSI service must be at the IP rate, the Court observed that the legislative history of the Northwest Power Act "contains extensive evidence that Congress intended the IP rate to be the default price for sales of power to the DSIs." *Id.* 814. In this connection, the Court noted that legislative history states that "Section 7(c) prescribes the rates applicable to direct service industrial customers" (H.R. Rep. No. 96-976, pt. 1, at 69) and is the rate which "applies to all 'Industrial Firm' sales to BPA's direct-service industries . . . [for] 1985-86 and all future [sales]." (S. Rep. No. 96-272 at 59) (emphasis added in Opinion). The Court adds that, to the extent BPA decides to exercise its discretion to offer power to the DSIs, the *Kaiser* case "supports . . . our understanding is that BPA does have an obligation to offer the DSIs a cost-based rate—namely, the IP rate—before declaring energy as surplus under § 839c(f) and selling it to the DSIs at a market-based—or other—FPS rate." *Id.* at 817 (emphasis added).
>
> The "cost-based rate" referred to is not, as some preference customers have suggested, one that reflects the prevailing prices for power available on the open market, but is rather the IP rate, a rate that is statutorily tied to

the PF rate, 16 U.S.C. § 839e(c)(2). Thus, the Court recognized that the IP rate is a cost based rate, *i.e.*, a rate that together with BPA's other rates are based on and established to recover BPA's total system costs, and not a rate targeted to recover the incremental costs of resources, as some commenters have argued, that might be needed to replace system capability in order to support all of BPA's contractual obligations.

In addition, the Court set out the applicable rate directive, which supports the view that the IP rate is not an incremental cost rate. See, *id.*, at 16556, citing 16 U.S.C. § 839e(c) (Section 7(c) of the NPA). The general statutory command is that the section 7(c) rate directive requires that the IP rate be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." 16 U.S.C. § 839e(c)(1)(B). The determination of equitability is required to be based upon the rate BPA charges its preference customers, with certain adjustments. 16 U.S.C. § 839e(c)(2). Those adjustments include the inclusion of an "industrial margin" which reflects the "overhead" that preference customers charge their own industrial customers. Also included in the IP rate is a credit for reserves that DSIs provide in connection with 839e(c)(3).

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

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

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

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

> According to petitioners, "Entering contracts to sell power to the DSIs when BPA has none to sell them is unlawful.... The only way the post-2001 contracts with the DSIs can be lawfully performed is to require the DSIs to pay the full costs of service." In other words, petitioners asserted that BPA could not allocate to its preference customers any of the costs of purchasing power at market prices to serve the DSIs.

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

The *PNGC* Court recognized that providing such service at the IP rate, as mandated by Congress, might itself provide some level of subsidy. The Court refers to the IP rate as the rate that BPA "is statutorily required to offer" and reflects "the primary benefit that the class of DSI customers

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

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

In the WP-10 ratesetting process, BPA assumed that it would have a contractual obligation to serve the DSIs at a level of 402 aMW, which included an amount of service to Alcoa. In accord with the *Golden NW* decision, BPA assumed that it would augment the Federal Base System (FBS) resources as needed to meet its expected total obligations, including all PF requirements service to its public customers plus DSI IP service. While BPA did not attribute specific power purchases to specific loads, it can be ascertained from the rate case models that the then-forecasted power purchase expenses, net of additional revenues at the IP rate,

increased an average of $37 million in the two-year rate period ($32 million for FY 2010 and $42 million for FY 2011) when compared to power purchase expenses without the assumed power sale to the DSIs. In addition, the risk of both power purchase prices and loads being higher or lower than the level assumed in establishing the amount of power purchases in the revenue requirement was assessed in the risk analysis performed for the rates being established.

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

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

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

> instructions contained in section 7 of the NPA, including section 7(c) regarding the IP rate, and the Block Contract is explicit that all rate determinations will be made in BPA rate cases.
>
> For all the reasons outlined above, a sale to Alcoa at the IP rate is consistent with statutory requirements and is consistent with sound business principles.

That discussion clearly refutes PNGC's arguments that all costs of DSI service must be borne by the DSIs. That is simply not a requirement of the Northwest Power Act's section 7(b) and 7(c) rate directives.

In addition, PNGC's and ICNU's arguments erroneously confuse cost allocation with rate design, misapprehending that rate design of any preference customer rate cannot result in any preference rate greater than the IP rate. The confusion is best explained by reference to section 7(e) of the Northwest Power Act and its legislative history. Section 7(e) provides: "Nothing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms." 16 U.S.C. § 839e(e). The legislative history of this provision clearly enunciates that section 7(e) distinguishes customer class cost allocation from rate design:

> Section 7(e) clarifies that BPA may continue, as it does under existing law, to charge uniform rates for the sale of electric peaking capacity. <u>This subsection also clarifies that the rate directives contained in this bill only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money.</u> For example, time-of-day rates, seasonal rates, rate structures designed to give BPA customers particular price signals, and other rate forms would be permissible."

H. Rep. No. 96-976, 2d Sess., Pt. 2 at 53 (1980). *See also* H. Rep. No. 96-976, 2d Sess., Pt. 1 at 69 (1980) ("Section 7(e) clarifies that the Administrator may establish a uniform rate for the sale of peaking capacity and that the rate directives of this Act govern the amount of revenue the Administrator collects from each class of customers, not the rate form.").

BPA established its Tiered Rate Methodology ("TRM") and published the TRM Record of Decision ("TRM ROD") on November 10, 2008, following extensive regional discussions and a formal section 7(i) rate process. The TRM establishes a new rate design methodology for the design of preference customer (Priority Firm or "PF") rates. It is the lynchpin for BPA's long-term Regional Dialogue power sales contracts with its preference customers, with the contracts providing that the then-effective TRM "shall govern BPA's establishment, review and revision pursuant to section 7(i) of the Northwest Power Act of all rates for power sold" to the preference customers under their Regional Dialogue contracts. Regional Dialogue Contract Template, section 6.1. The

TRM constitutes a methodology only. It is not an actual rate schedule and serves as a framework for the subsequent development of tiered rates that, once adopted, would apply to sales of power under the new long-term RD contracts.

The fundamental goal of the TRM is to develop a two-tiered PF rate design that differentiates between the cost of service from the existing Federal base system (Tier 1), and the cost of power a customer is eligible to purchase beyond that amount (Tier 2). As explained in the RD Final Policy, the Tier 1 PF rate would be BPA's lowest cost-based PF rate because it would be based on the cost of BPA's existing "Federal Base System" ("FBS") resources, which are BPA's lowest cost resources, and the Tier 2 PF rate would also be a cost-based rate but would likely be higher because it would reflect, in part, BPA's costs associated with acquiring power to serve additional load growth. Both components—PF Tier 1 and PF Tier 2—would satisfy the cost recovery directives of Northwest Power Act section 7(b), governing the establishment of rates for the sale of power to preference customers. They would recover in total (i.e., "the amount of money BPA is to collect from" the preference customer rate class) only those costs properly allocable to preference customers under law. (As an aside, BPA would observe that even before tiered rates, there were significant differences in the rates charged preference customers, based on load shape, time of use, seasonality, demand factor, presence of irrigation load, conservation achievements, Slice or non-Slice election, and other factors.) As a matter of rate design regarding how to recover those costs, BPA determined that tiering the rates would send price signals that would achieve numerous significant national and regional goals, including the promotion of conservation, energy efficiency, and the development of renewable resources; maintaining low and stable preference rates; encouraging the development of regional electric infrastructure; enhancing BPA's financial stability and assurance of Treasury repayment; and providing more secure fish and wildlife funding.

With regards to DSI service, section 10.4 of the TRM is clear that "BPA might provide . . . some level of physical power under a Regional Dialogue contract" to DSIs after 2011. The TRM is also clear that

> [i]f BPA were to make such a sale, it might be necessary for BPA to purchase power to provide such service, as described in section 3.2.1.3. Notwithstanding any other provision in this TRM, all issues associated with the establishment of the Industrial Firm Power (IP) rate under section 7 of the Northwest Power Act will be determined in the applicable 7(i) process. BPA does not intend to tier the IP rate, but it is neither authorized nor prohibited from doing so by this TRM.

Id.

Consequently, BPA will establish PF rates to recover costs in total that satisfy the rate directives of Northwest Power Act section 7(b) governing preference customer rates. It will also establish IP rates to recover costs in total that satisfy the rate directives of Northwest Power Act section 7(c) governing rates for the sale of industrial firm power to

DSI customers. BPA's decision here to extend Alcoa's Initial Period in no way precludes that. Section 7(e) explicitly sanctions differing rate designs for the section 7(b) and section 7(c) rates. If the differing rate designs of those rates result in DSI rates that comply with the section 7(c) cost recovery directives, but are less than one or more of the Tier 2 rates, there is nothing in the law to preclude that and, indeed, the TRM explicitly preserves BPA's IP rate design discretion to do so.

b. Allocation of costs between Slice and Non-Slice customers

As indicated in the Alcoa ROD at 36, "[t]he Slice rate includes the $38 million average annual cost and there is no provision to alter that number through the annual Slice True-Up Adjustment Charge. Thus, no purchased power cost savings will flow to Slice customers." Nothing in this determination changes this circumstance in FY 2010 or FY 2011. However, SUB asserts that "BPA's response in the Alcoa ROD raises the question of how the risk associated with increased costs to serve Alcoa would be distributed amongst customers." EBT100007 at 8. While BPA disagrees with SUB's description of the risk as increased costs to serve Alcoa, cost and risk allocations for FY 2012 and FY 2013 will be addressed in the BP-12 rate proceeding and are not the subject of this determination.

c. Alcoa's business decision to request power at the cost-based IP rate

PPC asserts that "[u]nless BPA's analysis is missing some factors, it would appear that Alcoa is making an irrational business decision to acquire power at above market value. This behavior does not appear consistent with the actions of a sophisticated international business, and leads PPC to believe that BPA has under-estimated the value of the block of power it proposes to sell to Alcoa. EBT100010 at 2. BPA disagrees with PPC's assertion. As described in the Alcoa ROD, Alcoa has "stated that a 'mid to long term contract is desirable' and continued operations at the Intalco Plant 'need cost-based power to operate at 2 -3 lines of production to survive and plan for the future'". *See* Alcoa ROD at 7 and 8. Inasmuch as Alcoa has requested power during the Extended Initial Period and BPA's decision to grant this extension is simply an affirmative response to their request, BPA expects, all else being equal, Alcoa will take power at the cost-based IP rate as offered. As PPC knows, Alcoa has petitioned the Ninth Circuit to invalidate the EBT. BPA believes it is likely that Alcoa has done that so that it can be better assured of long-term BPA service.

d. Market price forecast is a more appropriate comparison

PPC argues, as they have previously, that "a more appropriate comparison would be to survey the market to see what type of revenues a more comparable sale would achieve. As it stands, BPA's analysis fails to demonstrate 'equivalent benefits' because it makes a fundamentally incorrect comparison." EBT100010 at 2. BPA disagrees.

As stated in the Alcoa ROD:

> BPA continues to believe that 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.)

See Alcoa ROD at 50. The circumstances of this determination of Equivalent Benefits for the 12-month extended initial period are no different:

- BPA's tendency "to manage its inventory on a shorter term basis" remains unchanged.
- BPA still "expects to serve DSI load out of its inventory."
- BPA's approach to forecasting market prices used in this determination of Equivalent Benefits remains consistent with BPA's methodology for forecasting secondary revenues used to establish rates.

As such, BPA continues to believe, as stated above, that "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."

PPC's argument continues undeterred, saying that BPA "should provide analysis showing that such a sale to Alcoa provides better value to the agency than a similar sale to other entities would produce." EBT100010 at 3. As was discussed at length in the Alcoa ROD, "BPA does not believe there is any support, in either its enabling statutes or Ninth Circuit precedent, for the proposition that it may make an IP sale to a DSI customer only in the event there is no higher revenue alternative sale available."[24] *See* Alcoa ROD at 53.

e. BPA's use of critical water planning

PNGC argues that:

> BPA again departs from its reliance on critical water planning and assumes that 'under most water conditions' BPA will not have to 'make purchases specifically to serve Alcoa' during the Extended Initial Period.

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[24] *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).

> This implicates both issues of the propriety of abandoning reliance on critical water planning in connection with a decision to contract to sell firm power and BPA's longstanding contention that it makes purchases to augment its inventory, not for a particular customer.

EBT100011 at 2. BPA is not planning to abandon critical water planning for the Extended Initial Period, and BPA has already stated that it will not here visit or re-visit PNGC's claims about what BPA "knew or should have known" at the time of the December 21, 2009 determination in the Alcoa ROD. As stated in the Alcoa ROD, "BPA has set a portion of its rates for FY 2010 and FY2011 based on 1937-Critical Water Conditions as evidenced by Tables 2.3.1 and 2.3.2" entitled Loads and Resources – Federal System and "another portion of BPA's rates, notably the Secondary Sales and Purchases, for FY2010 and FY2011 were set based on average water."[25] *See* Alcoa ROD at 34. BPA expects to continue these practices for the foreseeable future.

As described further above, even though BPA projects no need to do so during the Extended Initial Period of the Block Contract, the Court recognized in separate opinions that BPA may make market purchases to support DSI sales and that BPA "is entitled to charge preference customers a rate that reflects the total cost of all FBS resources, including resources acquired to replace losses in the generation capabilities of BPA's primary resources." *See also* Alcoa ROD at 15-16 (citing *PNGC II*, F.3d at 819; *Golden Nw. Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1044 (9th Cir. 2007)).

f. Curtailment Costs Related to Transmission

SUB summarized in its comments that BPA can incur curtailment costs related to transmission from this transaction, based on SUB's question and BPA's response in the Alcoa ROD. *See* SUB, EBT100007 at 4-5. SUB's question was "Does BPA's transmission inventory to provide long term ***firm*** service allow BPA to redirect the POIs to non-federal points of integration such as Mid-C to provide long term ***firm*** transmission and power service to the DSIs at no additional transmission or ancillary services costs under all power supply conditions?" *Id.* at 5. BPA's response in the Alcoa ROD was: "When BPA uses its contractual right to supply power to Alcoa at non-federal points of integration, BPA does face the risk that Alcoa may incur some congestion costs due to curtailment of [Alcoa's] redirected transmission. BPA has not yet faced a situation where it needed to pay congestion costs due to curtailed non-firm transmission and does not expect to face this condition more than a few hours per year." Alcoa ROD at 68.

BPA's response in the Alcoa ROD was not entirely responsive to SUB's original question, given that SUB specifically referred only to ***firm*** service. The response to the original question should have been that redirecting ***firm*** transmission does not change the transmission or ancillary services cost.

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[25] Tables 2.3.1 and 2.3.2 are found in WP-10-FS-BPA-01A at 10-13. Tables 4.6.2, 4.8.1 and 4.8.2 are found in WP-10-FS-BPA-05A at 77, 88-89.

PPC also commented that it is both "troubling and inconsistent" for BPA to count a "demand shift" to be a benefit, while at the same time not recognizing the costs imposed on it and its customers from transmission problems that are caused by high loads at the Alcoa Intalco Plant. EBT100010 at 3. As indicated in the Alcoa ROD, BPA currently manages PSANI congestion through curtailment protocols which result in no direct financial cost to BPA and hence congestion does not affect BPA's EBT analysis. Alcoa ROD at 71. BPA does not consider direct costs to other parties in the EBT. The test is designed to evaluate the impact to BPA only. Even if BPA were to consider impacts to individual utilities it would be difficult to balance the positive impacts a curtailment at the Intalco Plant has on some utilities, against the negative impacts a curtailment at the Intalco Plant would have on other utilities due to constraints caused by increased or changed power flows throughout the Balancing Authority possibly resulting from a shut down of the Alcoa load.

g. Gas Price Forecast

As described below, BPA's forecast of natural gas prices is based on sound analytics and reflects a reasonable approach and methodology. The gas price forecast component of BPA's electricity price forecast is important because natural gas price movements contribute to price movements in electric power markets in the Pacific Northwest, because 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, are 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 third quarter of its fiscal year.

To analyze the Extended Initial Period, BPA used the most recent published natural gas price forecast it had developed using the same methodology. BPA updated its natural gas forecast with the natural gas price forecast used in BPA's final Resource Program released September 2010. With the exception of the fiscal first quarter, BPA typically updates its natural gas and electricity price forecasts during each quarter to support financial reports.

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 2010-2011, and maintain an increase in its forecast in 2012. BPA stated in the final 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.

2010 Resource Program, Appendix B: Market Uncertainties, Bonneville Power Administration, September 2010, 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 2010-2011 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 since late 2008, 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) near-record amount of natural gas in storage continues to demonstrate the anticipated "increase in natural gas storage inventories" contemplated in the final Resource Program.[26] Furthermore, with the majority of the hurricane season now over with no impacts on supply, the reduction made in the fiscal fourth quarter natural gas price forecast remains 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, 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 typically included in our comparisons are: Bentek Energy LLC (Bentek), Cambridge Energy Research Associates (CERA), the United States Department of Energy's Energy Information Administration (EIA), PIRA Energy Group, and Wood Mackenzie.[27] 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 December 2009 through September 2010.

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[26] In addition, BPA has detailed, with contemporary information from the Energy Information Administration in Attachment B ("Natural Gas Statistics"), the continued strength of natural gas production despite steep declines in rigs, the continued slow recovery of natural gas demand (in that growth in natural gas demand is slower than growth in natural gas production), and the near record amount of natural gas in storage. See also Short-Term Energy Outlooks from the EIA for September showing the EIA lowered its forecast Henry Hub Spot Price average for 2011 to $4.76 per MMbtu, *Short-term Energy Outlook*, DOE EIA, September 8, 2010, at 6. SUB notes in its comments that the EIA released a Short-Term Energy Outlook in October that indicated that price expectations for 2011 are 4% below what they were in September.

[27] With the exception of the EIA, each of these forecasters considers their information to be proprietary. The vintage of each forecast is late April to early August 2010. EIA forecast is from their *Short-term Energy Outlook* released September 8, 2010. As noted in the prior footnote, the EIA's next *Short-term Energy Outlook* was released on October 13, 2010.

Figure 1: Henry Hub Natural Gas Spot Price Forecast

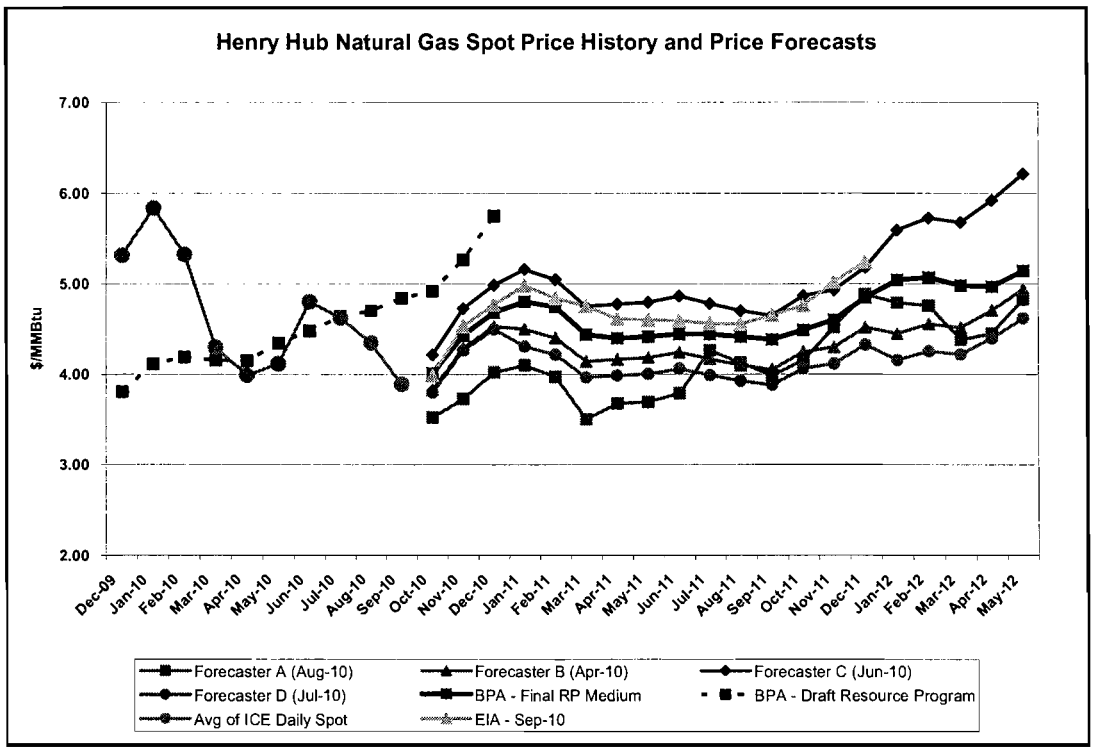


Figure 1 demonstrates that recent spot market prices for natural gas at the Henry Hub have been less than $5 per MMBtu from March 2010 through September 2010. This illustration also demonstrates that the forecasts of five other industry experts are between $3.69 per MMBtu and $4.79 per MMBtu for May 2011 – the starting month of BPA's evaluation of Equivalent Benefits for the Extended Initial Period – and their forecasts remain lower than $5 per MMBtu through at least November 2011 the month in which the EIA forecasts that Henry Hub spot prices for natural gas will average $5.02 per MMBtu. BPA's updated forecast of spot prices for natural gas at the Henry Hub is consistent with the views reflected by these five industry experts. Only two of the five forecasters expect monthly average spot prices for natural gas at the Henry Hub to rise above $5 per MMBtu during the winter of 2010-2011 in their most recent forecast. As a result, BPA believes its medium case natural gas price forecast from the final Resource Program is reasonable, and may be considered conservative, compared to a recent history of monthly average Henry Hub spot prices for natural gas and compared to what other industry experts are expecting. As stated earlier, it is also not unreasonable to assume that BPA's forecast of natural gas prices for the BP-12 rate proceeding could decline further given market developments since July, when the gas price forecast for the final Resource Program was completed.

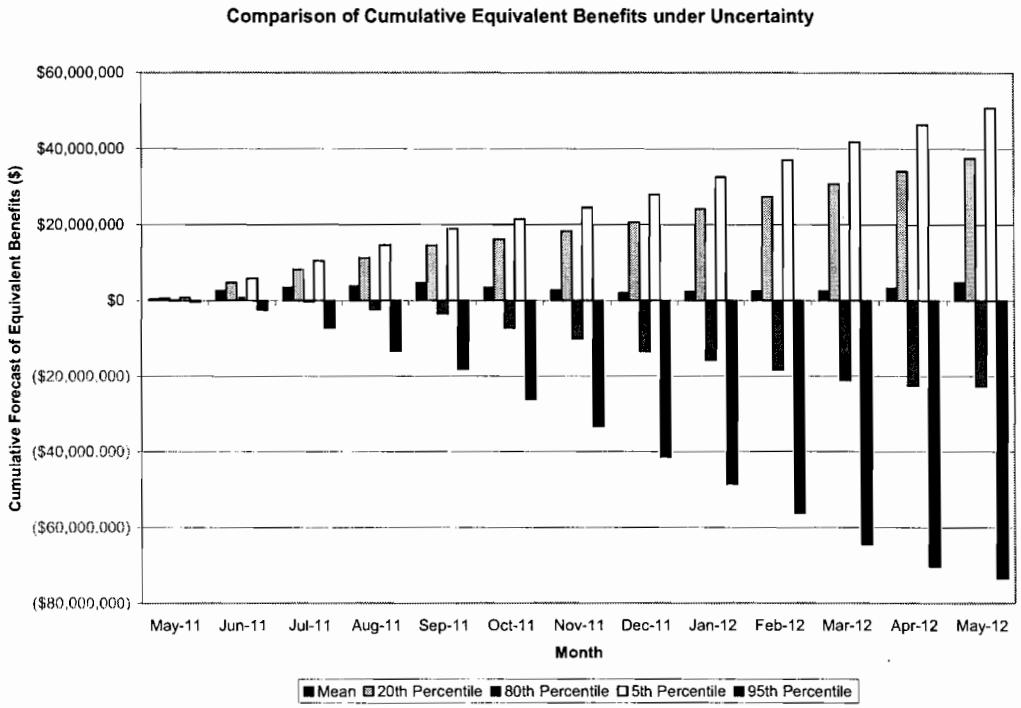
h. Risks are addressed in BPA's Equivalent Benefits Test

While BPA's analysis released in October appears to indicate that costs associated with the Block contract have been less than previously forecast for a portion of the Initial Period, SUB argues that "doesn't mean that BPA didn't put the region at risk." (SUB, EBT10001, at 6.) (BPA repeats its earlier affirmance in this ROD that it is not relying on that analysis for this EBT determination.) Consistent with the Alcoa ROD, BPA continues to believe there are two primary elements of risk in this determination to extend the Initial Period of the Block Contract. First, is the risk of market prices for electricity deviating from the prices forecast by BPA during the Extended Initial Period. The second primary element of risk is the possibility of Alcoa curtailing during the period of the extension. These risks are addressed further below and BPA believes its risks, of which the Block contract is a part, are prudently managed through BPA's operational conduct and rate proceedings. (*See generally* Risk Analysis and Mitigation Study and Documentation, WP-10-FS-BPA-04 and 04A)

Market Price Risk

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

Figure 2: Comparison of Cumulative Equivalent Benefits under Uncertainty



If market prices for electricity are less than expected, BPA is better off financially serving Alcoa during the Extended Initial Period than selling this power on the wholesale electricity market. This is reflected in Figure 2 for the 5th and 20th percentiles. Conversely, if market prices for electricity are higher than expected during the Extended Initial Period, the outcome of this EBT changes such that BPA would be relatively worse off by extending the contract with Alcoa relative to a market sale. This is reflected in Figure 2 above for the 80th and 95th percentiles. These results in isolation, however, do not reflect the impact of this transaction on BPA's overall probability distribution of net revenues, which among other things, takes into account conditions in which a loss from a DSI sale under higher prices than forecast is associated with higher surplus energy revenues for other surplus power sales.

Regarding the financial risk that market prices deviate from the average of BPA's price forecast more broadly, BPA analyzed the probability distribution of its net revenue risk consistent with the methodology used in the WP-10 rate proceeding. *See* WP-10-FS-BPA-04 at 34 and WP-10-FS-BPA-04B at 82. The advantage of this broader approach is that it takes into consideration the net revenue impacts to BPA in conjunction with all the other Operating and Non-Operating Risk Factors addressed in the WP-10 rate proceeding. *See generally* WP-10-FS-BPA-04. Our conclusion is unchanged from the Alcoa ROD in that the probability distributions of BPA's net revenues, one of its broadest measures of financial impact, are not materially different whether it serves 340 aMW of DSI load or does not serve any DSI load during the Extended Initial Period.[28]

Curtailment Risk

Regarding the risk of curtailment, the net revenue risk analyses above indicate that BPA's financial risk exposure is not materially different depending on whether or not Alcoa's Intalco Plant operates in the Extended Initial Period. As assumed in the Alcoa ROD, BPA does not expect Alcoa will curtail the Intalco Plant once 320 aMW of service is made available to it at the IP rate, which is provided during all periods under the Block Contract including the Extended Initial Period, because Alcoa has consistently believed that a seven year contract is sufficient to "permit the Intalco [Plant] to survive through this difficult recession" and "will permit the Intalco smelter to survive."[29] However, if Alcoa did shut the Intalco plant down during the Extended Initial Period, BPA does not expect, on a forecast basis, that this will have either a positive or negative impact on the Equivalent Benefits that BPA has determined above. This is because the correlation between aluminum prices set on the international market and Pacific Northwest electricity prices set regionally was computed to be very weak (.0826), based on historical data from January of 1997 through October of 2009, and very inconsistent over different time-contiguous subsets over this period of time.[30]

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[28] *See* Alcoa ROD at 62.

[29] *See* Alcoa's December 15th letter requesting 320 aMW of firm power attached to the Alcoa ROD, Alcoa in DSL090057 at 5, and Alcoa in DCA090233 at 1, submitted comments for Alcoa ROD released December 22, 2009.

For the foregoing reasons, BPA believes it has adequately addressed the risks associated with the Extended Initial Period. BPA has prudently accounted for, and expects to continue prudently accounting for, actual costs and risks associated with DSI service in setting its rates and has determined that it can reasonably expect to achieve Equivalent Benefits from this extension.

VI. ENVIRONMENTAL EFFECTS

BPA's review of the Block Contract with Alcoa for potential environmental effects that could result from its implementation, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 et seq, included review not just of the Initial Period but the Extended Initial Period, Transition Period, and Second Period, in the event any of these subsequent periods occur. Based on that review, BPA analysis indicates that the Block Contract falls within a class of actions excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA.[31] More specifically, the Block Contract falls within Categorical Exclusion B4.1, found at 10 CFR 1021, Subpart D, Appendix B, which provides for the categorical exclusion from NEPA of actions involving "[e]stablishment and implementation of contracts, marketing plans, policies, allocation plans, or acquisition of excess electric power that does not involve: (1) the integration of a new generation resource, (2) physical changes in the transmission system beyond the previously developed facility area, unless the changes are themselves categorically excluded, or (3) changes in the normal operating limits of generation resources." Because BPA expects to provide service under the Extended Initial Period largely in the same manner and from the same types of sources as under the Initial Period, the Block Contract continues to fall within Categorical Exclusion B4.1. The December 14, 2009 Environmental Clearance Memorandum that documents this categorical exclusion for the Block Contract is posted at BPA's website at: http://www.efw.bpa.gov/environmental_services/categoricalexclusions.aspx.

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[30] *See* Alcoa ROD, section e(4)(ii)5.

[31] *See* Alcoa ROD, section IX beginning at 107.

VII. CONCLUSION

Based on the above application of the EBT, BPA has determined that it can grant Alcoa's request to provide an Extended Initial Period of the Block Contract with Alcoa. The Extended Initial Period will begin on May 27, 2011, and end on May 26, 2012.

Issued at Portland, Oregon, this 29th day of October, 2010.

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