BPA 7(b)(2) METHODOLOGY

INVESTOR OWNED UTILITY PRELIMINARY RESPONSE

10/22/2007

The responses below to the BPA requests for feedback are supplemented in their entirety by the "Pacific Northwest Investor-Owned Utility Comments on Long-Term BPA Regional Dialogue Policy Issues" dated October 31, 2006, which comments (including but not limited to Appendices A and B thereto) are incorporated herein by this reference.

1. Should the portion of the output Mid-Columbia hydro resources sold to PNW investor-owned utilities be included in the 7(b)(2)(D) resource stack as available to the BPA to serve 7(b)(2) customer loads?

BPA REQUEST FOR FEEDBACK:

> *The Legal Interpretation determined that Type 2 resources "are those resources owned or purchased by the 7(b)(2) customers, and not dedicated to their own loads." Certain publicly-owned utilities have sold shares of their hydro resources to investor-owned utilities, and therefore these shares are "not dedicated to their own loads." Therefore, under the current Legal Interpretation, these resources are considered to be Type 2 resources and are included in the 7(b)(2)(D) resource stack. Since these resources tend to be cheaper than alternative resources, the result is lower 7(b)(2) Case rates resulting in an increased rate test trigger. However, section 7(b)(2)(D) uses a different phrase: "not committed to load pursuant to Section 5(b)." The investor-owned utilities are eligible 5(b) customers, and have committed these Mid-Columbia purchases to their load. Therefore, an issue has been raised whether these resources should no longer be treated as Type 2 resources.*

RESPONSE:

The portion of the output of Mid-Columbia hydro resources sold to PNW investor-owned utilities cannot be included in the 7(b)(2)(D) resource stack as available to BPA to serve preference customer loads in the section 7(b)(2) case.[1] Any determination in the 1984 Legal Interpretation that Mid-Columbia resources sold to investor-owned utilities can be included in the 7(b)(2) resource stack is inconsistent with the Northwest Power Act ("NWPA").[2]

[1] BPA projected in its WP-07 case, for example, that, during the Test Period, 846 aMW of Mid-Columbia resources (the "Mid-Columbia resources") would be sold to investor-owned utilities in the region, and erroneously included these resources in the 7(b)(2) resource stack.

[2] This misinterpretation is relatively new in BPA's rate cases and has been used only for the two most recent BPA power cases (WP-96 and WP-02). (Keep *et al.*, WP-

The resources to be included in the 7(b)(2) Case resource stack are specified in the statute. Specifically, section 7(b)(2)(D) of the NWPA states that

> all resources that would have been required, during [the test] period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—
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> (i) purchased from such customers by the Administrator pursuant to section [6 of the NWPA], or
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> (ii) not committed to load pursuant to section [5(b) of the NWPA],
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> and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator[.][3]

Under section 3(19) of the NWPA, the Mid-Columbia resources that have been purchased by investor-owned utilities cannot be classified as "owned or purchased" by the preference agency for purposes of the 7(b)(2) Case. The preference utilities that own dams do not have rights to the power from such dams that has been sold to investor-owned utilities. Section 3(19) of the NWPA defines "resource," with respect to power and the capacity of generating facilities--not as the physical generating facilities themselves--but rather as "electric power, including the actual or planned electric power capability of generating facilities."[4]

Moreover, as BPA correctly points out in its request for feedback, the plain language of the NWPA is in conflict with the Legal Interpretation. Section 7(b)(2)(D)(ii) describes the second type of resources to include those "not committed to load pursuant to section 5(b)." The plain language of section 5(b) makes no distinction between the loads of preference customers and the loads of investor-owned utilities. Section 5(b) addresses the "firm power load of . . . [any] public body, cooperative or <u>investor-owned utility</u> in the Region" and the commitment by any such "public body, cooperative or

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07-E-BPA-27, p. 15, ll. 16-20.) In both of these cases, this misinterpretation had a negligible effect.

[3] 16 U.S.C. § 839e(b)(2)(D). Thus the projected amounts to be charged in the 7(b)(2) Case must be determined assuming that the combined general requirements in such case are met first with available federal base system resources and then from a "resource stack." The last resource to be drawn (if needed) from the resource stack after it is otherwise exhausted is a generic resource to be priced at the "average cost of all other new resources acquired by [BPA]."

[4] 16 U.S.C. § 839a(19)(A). Further, the Mid-Columbia resources purchased by investor-owned utilities clearly do not satisfy the "purchased from such customers by the Administrator pursuant to section [6 of the NWPA]" test in section 7(b)(2)(D) of the NWPA.

investor-owned utility in the Region" of resources to its firm load in the Region.[5] In short, section 5(b) addresses both resources committed to the loads of preference customers and resources committed to the loads of investor owned utilities. Reading section 7(b)(2) and section 5 together demonstrates that resources committed to investor-owned utility loads pursuant to section 5(b) cannot be considered "resources not committed to load pursuant to section 5(b)."

Since Mid-Columbia resources applied to the resource stack in the WP-07 case, for example, were committed to loads under section 5(b), they fail the second portion of the test. Mid-Columbia resources should not be included in the 7(b)(2) Case resource stack because: (1) they are not "owned" by public bodies or cooperatives, and (2) they are committed to load pursuant to section 5(b).

Further--assuming for the sake of argument--that the Mid-Columbia resources were properly included in the 7(b)(2) Case resource stack, the cost of this power in such stack must be no less than the projected market price of power. Because the investor-owned utilities have purchased these resources, there is no basis to assume that the rights of the investor-owned utilities to the Mid-Columbia resources could be bought from them at a price less than market.

In sum, BPA's new Legal Interpretation and Methodology:

(i) should recognize that resources sold by a preference agency to others are not owned by that preference agency for purposes of section 7(b)(2), and

(ii) should not restrict the "dedicated to load" test to preference agency load.

[5] 6 U.S.C. § 839c(b) (emphasis added).

2. Should the Program Case load forecast for preference customer load be increased for conservation that BPA has purchased since December 5, 1980, the enactment date of the NWPA?

<u>BPA REQUEST FOR FEEDBACK</u>:

Section 7(b)(2)(D) specifies that resources "purchased from [preference] customers by the Administrator pursuant to Section 6" are to be included in the 7(b)(2)(D) resource stack. BPA purchases conservation resources pursuant to Section 6. In order to place these resources in the stack to be used to serve 7(b)(2) customer loads, as needed, the Implementation Methodology specifies that this conservation be removed from the preference customer load forecast. This results in 7(b)(2) Case loads being greater than Program Case loads. Section 7(b)(2)(D) says "all resources that would have been required, during such five-year period…" An issue has been raised whether preference customer loads should be increased for purchased conservation, or whether only conservation that was or is acquired in the particular rate case period plus the ensuing 4 years be included in the 7(b)(2) resource stack. A related issue would then be what are the "applicable" 7(g) cost of conservation that are to be subtracted before performing the rate test?

A separate issue is, should the loads continue to be adjusted for past conservation, whether conservation that is beyond its useful lifespan should be excluded from the load adjustment.

Another issue arises from the annual amounts of conservation investments within the 7(b)(2) resource stack being expensed to a significant degree. Should the conservation be 100 percent capitalized and financed through bonds issued by the Joint Operating Agency (JOA). The rationale for this proposed change is that in the first year of the rate test, a large amount of conservation resources can be chosen to meet 7(b)(2) case loads. The current implementation practice is to expense a substantial portion of each year's conservation investment. Proponents of the 100 percent capitalization and debt financed change argue that the JOA would not expense this level of conservation expenditures in a single year (multiple years of investments) due to the resultant "rate shock."

<u>RESPONSE</u>:

No, the Program Case load forecast for preference customer load should not be increased in the 7(b)(2) Case for any conservation.

a. <u>The 7(b)(2) Case Loads Must Reflect the General Requirements Power to be Purchased from BPA, Not the Loads that Would Have Occurred in the Absence of Conservation</u>

First, for both the Program Case and the 7(b)(2) Case, BPA is required to project the amount to be charged, over the test period, "for firm power for the <u>combined general</u>

requirements of public body, cooperative and Federal agency customers."[6] Increasing the load in the 7(b)(2) Case by conservation is inconsistent with this statutory directive because BPA would then be projecting amounts to be charged in the 7(b)(2) Case for a load equal to the sum of (i) the combined general requirements of the preference customers plus (ii) an amount of "load" equal to load reductions from conservation.

Indeed, section 7(b)(4) of the NWPA defines, for purposes of section 7 of the NWPA, "general requirements" as "the public body, cooperative or Federal agency customer's electric power purchased from the Administrator under section [5(b) of the NWPA], exclusive of any new large single load."[7] General requirements are an amount of power that can be purchased from BPA under section 5(b) to meet loads. To the extent conservation reduces those loads, conservation reduces the amount of power that can be purchased under section 5(b). The preference agency loads to be used in the 7(b)(2) Case are (aside from adjustment for DSI loads pursuant to section 7(b)(2)(B)) the Program Case loads, not the Program Case loads that would have occurred in the absence of conservation.

The amount of power that can be purchased by a utility under section 5(b) of the NWPA is limited to the amount by which the utility's firm power load in the region exceeds its resources used to serve its firm load in the region. This amount of power that the utility can purchase from BPA under section 5(b) is inherently lower as a result of conservation. This is true for both the Program Case and the 7(b)(2) Case.

In short, "general requirements" means the power (exclusive of any new large single load) purchased from the Administrator under section 5(b). Preference customers simply do not purchase power from the Administrator to serve load reductions achieved through conservation.

b. Increasing Loads to Ignore Conservation is Not One of the Five Specified Assumptions to be Made for the 7(b)(2) Case

None of the five specified assumptions in section 7(b)(2) requires that the combined general requirements projected for the Program Case be modified as a result of conservation in determining the combined general requirements projected for the 7(b)(2) Case.

c. Excluding Conservation Costs Incurred by BPA is Not One of the Five Specified Assumptions to be Made for the 7(b)(2) Case

BPA is to allocate costs of conservation pursuant to section 7(g), which requires that such costs be "equitably allocate[d] to power rates".[8] Merely because the projected cost of serving 7(b)(2) Case loads are to be determined based on certain resource costs does not require or permit BPA to ignore in the 7(b)(2) Case conservation costs allocated

[6] 16 U.S.C. § 839e(b)(2) (emphasis added).
[7] 16 U.S.C. § 839e(b)(4).
[8] 16 U.S.C. § 839e(g).

pursuant to section 7(g) in the 7(b)(2) Case. None of the five specified assumptions in section 7(b)(2) requires or permits the exclusion of conservation costs from the 7(b)(2) Case. Further, because, as discussed above, the effects of conservation cannot be ignored in the 7(b)(2) Case loads, it follows that the cost of conservation similarly cannot be ignored in the 7(b)(2) Case.

d. <u>The 1984 Implementation Methodology Cryptically, and Contrary to Section 7(b)(2), Ignores the Effect of Conservation on the 7(b)(2) Case Loads</u>

The 1984 Implementation Methodology cryptically, and without adequate explanation, calls for the combined general requirements in the Program Case to be increased by conservation savings in developing the combined general requirements in the 7(b)(2) Case:

> The initial loads will be used in the 7(b)(2) case will be same as those used in the program case, except that they will not include estimates of programmatic conservation savings.[9]

Similarly, the 1984 Implementation Methodology states that the

> costs of billing credits and conservation, although appearing in the [projected amounts to be charged in the Program Case], are not necessarily included in the projected amounts to be charged in the 7(b)(2) Case. This is because billing credits and programmatic conservation are added to the resources used to serve the 7(b)(2) customers only to the extent that they are needed after the FBS [Federal base system] is exhausted and only in the event that they are the least-cost resources to be added. If the FBS is sufficient to serve the 7(b)(2) load, or other available additional resources have lower costs, then billing credits and programmatic conservation will not be added to the 7(b)(2) case.[10]

However, as discussed above, the 7(b)(2) Case loads must reflect the general requirements power to be purchased from BPA, not the loads that would have occurred in the absence of conservation. Thus, the 1984 Implementation Methodology is inconsistent with section 7(b)(2) with respect to conservation.

e. <u>If BPA Continues To Inappropriately Increase the 7(b)(2) Case Loads For Conservation, Those Loads Should Not in Any Event Be Increased (i) for Conservation Acquired Prior to the Particular Section 7(b)(2) Test Period in a Rate Case or (ii) for Conservation Beyond Its Useful Life</u>

As discussed above, the 7(b)(2) Case loads should not be increased for any conservation. However, if 7(b)(2) Case loads were increased for conservation, such loads

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[9] Section 7(b)(2) Implementation Methodology, BPA File No. 7(b)(2)-84, Ex. C at 41 (the "1984 Implementation Methodology").

[10] *Id*. at 5.

should not be increased by conservation acquired prior to the particular section 7(b)(2) test period in a rate case, and conservation prior to that period should not be included in the resource stack. (As also discussed above, none of the costs of conservation should, in any event, be excluded from 7(b)(2) Case costs; accordingly, any conservation included in the resource stack should be included at zero additional cost, assuming the 7(b)(2) Case costs include (as they should) all conservation costs.) The inclusion in the resource stack of conservation acquired prior to the particular section 7(b)(2) test period is improper because such conservation is already reflected in both the Program Case and the 7(b)(2) Case loads.[11]

None of the five specified assumptions for the 7(b)(2) Case require or permit BPA to assume that conservation undertaken in 1985, for example, was not undertaken until the current section 7(b)(2) test period. Indeed, to the extent conservation measures have a limited life and are repeated, the conservation savings would be double-counted. For example, the load reduction achieved by a conservation measure undertaken in 1985 cannot be increased when that measure is repeated in 2005. Increasing 7(b)(2) Case loads by conservation acquired prior to the particular section 7(b)(2) test period would, to that extent, result in double-counting.

Further, there is no basis, in any event, for arbitrarily assuming that conservation continues beyond its useful life.

f. <u>All BPA Conservation Costs Allocated to the Preference Rate Are Required to be Subtracted From the Program Case Costs</u>

The conservation costs to be subtracted from the Program Case before performing the section 7(b)(2) comparison with the 7(b)(2) Case are all BPA conservation costs allocated to the section 7(b)(1) preference rate.

[11] Reflecting conservation in loads without attempting separate quantification of conservation effects also avoids the need to estimate the duration and effectiveness of conservation, such as water heater wraps, undertaken historically.

3. Should section 7(b)(2)(E) reserve benefits be limited to reserves provided by Direct Service Industry (DSI) loads?

BPA REQUEST FOR FEEDBACK:

> *At the time of the enactment of the NWPA, contracts with DSIs provided a number of reserve benefits to BPA, including plant delay reserves, capacity reserves, and interruptible energy reserves. Since 1996, the contracts with DSIs have no longer provided many of those reserve benefits. An issue has been raised whether BPA should expand its recognition of reserve benefits to include other sources, such as surplus sales.*

RESPONSE:

No, section 7(b)(2)(E) reserve benefits should include the benefits of all reserves, including reserves from BPA's surplus power sales in the wholesale power market. The NWPA definition of "reserves" does not limit reserves to those from any particular source.[12] Accordingly, reserve benefits as a result of the Administrator's actions under the NWPA are not limited to the benefits of reserves from any particular source. Indeed, section 5(d)(1)(A) of the NWPA states as follows:

> The Administrator is authorized to sell in accordance with this subsection electric power to existing direct service industrial customers. Such sales provide a <u>portion</u> of the Administrator's reserves for firm power loads within the region.[13]

In other words, BPA's rights to interrupt power sales to the DSIs to benefit firm power sales to BPA's utility customers in the region are not the exclusive source of BPA's reserves under the NWPA.

BPA surplus sales in the wholesale market are made under the NWPA[14] and constitute reserves (and provide reserve benefits) under the NWPA. Reserves include

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[12] The NWPA defines "reserves" to mean:

> the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers. 16 U.S.C. § 839a(17).

[13] 16 U.S.C. § 839c(d)(1)(A) (emphasis added).

[14] BPA makes surplus sales in the wholesale power market pursuant to section 5(f) of the NWPA:

> [BPA] is authorized to sell, or otherwise dispose of, electric power, including power acquired pursuant to [the NWPA] and other Acts, that is surplus to [BPA's] obligations. . . .

16 U.S.C. § 839c(f).

BPA's rights to interrupt, curtail or otherwise withdraw sales of surplus power when necessary.[15] BPA sells surplus energy in the real-time, day-ahead, balance-of-month and forward electricity markets, controlling the duration of those sales so that BPA can withdraw power from the wholesale market when needed for its regional firm power customers. BPA's wholesale market surplus sales thus benefit, and avoid service and cost risks to, BPA's utility firm power loads in the region.[16]

Thus, BPA's "secondary market" or "surplus" power sales in the wholesale power market meet the definition of "reserves" under the NWPA and fulfill the purposes contemplated for BPA reserves under the NWPA. These BPA "secondary market" or "surplus" power sales are substantial.

BPA has not lost reserve benefits because of the diminishment of DSI load. In fact, BPA has reserve benefits from its surplus power sales in the wholesale power market that are superior in several respects to those it previously received from its sales to DSIs. For example, the DSI reserves provided recall or interruption rights only for specified portions of the power sales to the DSIs and only for specified purposes and durations. By contrast, BPA has much more flexibility in its wholesale market surplus sales to establish withdrawal or recall rights through limitation of the term of the sale and otherwise.

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[15] 16 U.S.C. § 839a(17).

[16] BPA has exercised recall rights under contracts and has not renewed surplus sales in the wholesale power market when the power was needed to serve BPA's firm loads. For example:

> With the Northwest facing power shortages as early as this winter, BPA is giving notice to its California customers that long-term contracts for surplus and excess federal power sales will not be renewed. Where contracts have recall or conversion rights, BPA is exercising those rights. BPA sold several hundred megawatts of power to California when the Northwest had surplus and excess power.
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> By law, BPA is directed to sell outside the Northwest only power that is surplus to the region's needs. Buyers have different rights under each contract. Where contract terms allow, BPA can convert energy sales into capacity exchanges or give notice of termination. In contracts that contain no recall or conversion provisions, BPA is notifying California buyers that contracts will not be renewed.

"BPA Recalls California Contracts," BPA Journal (Oct. 2000) at page 3.

> When the cold snap hit, BPA reduced its surplus sales to meet required loads in the Northwest. BPA structures surplus sales to gain revenue while retaining the ability to recall the power when it is needed. Revenue gained from selling surplus power is used to offset power purchases when Northwest loads exceed BPA capacity.

"Power Demand Soars as Temperatures Plummet," BPA Press Release (Feb. 2, 1996) at page 1.

BPA’s traditional method of calculating reserve benefits in order to value reserve benefits—i.e., essentially assuming that reserve benefits provided by BPA surplus sales in the wholesale power market are equivalent to those previously provided by BPA power sales to DSIs—would not properly value reserve benefits provided by BPA surplus sales in the wholesale power market. BPA should not attempt to establish a uniform methodology for valuing reserves to be applied in all rate cases. The value of reserves should be addressed in each rate case based on the particular circumstances present at the time of such rate case. In any event, BPA should recognize that secondary sales do provide reserves and not foreclose the possibility of reflecting such reserves in rate cases.

7. Should BPA reconsider the 7(g) costs that reduce the Program Case rate?

BPA REQUEST FOR FEEDBACK:

> *The rate test uses the Program Case rate exclusive of amounts charged those customers for costs specified in section 7(g) of the NWPA. Those specified costs are conservation, resource and conservation credits (billing credits), experimental resources, and uncontrollable events. Arguments concerning the scope of "uncontrollable events" have been argued in several rate cases since 1984. An issue has been raised whether the scope of "uncontrollable events" should be modified. Further, it has been asked whether it is appropriate to remove any costs from the Program Case rate if those same costs remain in the 7(b)(2) Case rates.*

RESPONSE:

Yes. It is worth noting that BPA has not reflected costs of any uncontrollable event in the 7(g) costs that reduce the Program Case rate since BPA began performing the 7(b)(2) rate step more than 20 years ago. Given the magnitude of BPA's activities, and its exposure to uncontrollable events, it is clear that the criteria that have been applied by BPA in determining whether costs are costs of uncontrollable events are unduly restrictive.

Section 7(b)(2) of the NWPA states that

> [a]fter July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of . . . uncontrollable events, may not exceed in total, as determined by the Administrator, during [the test period], an amount equal to the power costs for general requirements of such customer if, the Administrator [makes the five assumptions specified in section 7(b)(2).][17]

In performing the section 7(b)(2) rate step, BPA failed to subtract at least three categories of costs that are costs of uncontrollable events: (1) BPA's costs associated with two terminated nuclear plants; (2) BPA's costs of Financial Reserves for Risk; and (3) BPA's costs of Planned Net Revenue for Risk ("PNRR").

a. Costs Associated with WNP-1 and WNP-3 Are Costs of Uncontrollable Events

First, the costs associated with two terminated nuclear plants (WNP-1 and WNP-3) are uncontrollable events. These plants were terminated when the Washington Public Power Supply System ("Supply System") was unable to issue bonds to finance their completion. The Supply System's inability to issue bonds was an uncontrollable event and, therefore, BPA's costs with respect to these terminated nuclear plants are

[17] 16 U.S.C. § 839e(b)(2).

uncontrollable events. The fact that BPA made a measured, rational response to these uncontrollable events does not render the events controllable.

b. <u>Costs of Financial Reserves for Risk Are Costs of Uncontrollable Events</u>

Second, BPA's costs of Financial Reserves for Risk are also costs of uncontrollable events. Financial reserves in excess of required working capital ("Financial Reserves for Risk") are reserves carried by BPA to mitigate the impacts of operating and non-operating risks:

> Traditionally, BPA has relied on its cash reserves and the addition of Planned Net Revenues for Risk (PNRR) to its revenue requirement as the primary risk mitigation tools in setting rates.[18]

Financial reserves provide the "fundamental protection against the financial impacts of the risks BPA faces. . . ."[19] BPA projects $381 million of financial reserves as of the beginning of the rate period.[20] BPA also projects that, during the rate period, it will require $50 million of working capital:

> We assume no change to the $50 million level of liquidity reserves (or "working capital") assumed in meeting the Treasury Payment Probability in the 1993 and 1996 rate proposals and the 2002 rate proposal.[21]

Thus, as of the beginning of the rate period, BPA projects Financial Reserves for Risk of $331 million (the difference between $381 million and $50 million). In the absence of the risk of uncontrollable events that give rise to the need for Financial Reserves for Risk, BPA's revenue requirement during the rate period would be $331 million lower, allowing BPA to lower rates in this proceeding so as to collect approximately $110 million per year ($331 million over three years) less over the rate period.

BPA's failure to lower rates by this amount constitutes a cost in the rate period. BPA's failure to lower rates by this amount and the resulting cost are due to the uncontrollable events for which BPA maintains Financial Reserves for Risk. Hence, such costs must be subtracted from the Program Case as section 7(g) costs in performing the section 7(b)(2) rate step.

c. <u>Costs of PNRR Are Costs of Uncontrollable Events</u>

Finally, PNRR should be subtracted as costs of uncontrollable events. The addition of PNRR to BPA's revenue requirement is a primary risk mitigation tool in

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[18] WP-07-E-BPA-08, p. 7, ll. 23-25.
[19] WP-07-E-BPA-04, p. 39, ll. 25-26.
[20] WP-07-E-BPA-04, p. 82, table 5.
[21] WP-07-E-BPA-08, p. 9, ll. 7-9.

setting BPA rates.[22] BPA describes PNRR as the "backstop" in its risk mitigation portfolio:

> PNRR as a way to increase reserves is the backstop in BPA's risk mitigation portfolio: whatever risk is not mitigated by other tools and projected reserves will be mitigated by increases in reserves generated by PNRR.[23]

In other words, BPA's costs to be recovered in BPA's rates in this proceeding are higher by the amount of PNRR. Costs of PNRR are the costs of uncontrollable events. The fact that BPA routinely includes PNRR in its revenue requirements to cover the costs of uncontrollable events does not and cannot force the conclusion that such events are not "uncontrollable events" and that such costs are not the costs of "uncontrollable events."

[22] *See* WP-07-E-BPA-08, p. 7, ll. 23-25.
[23] WP-07-E-BPA-14, p. 7, ll. 7-9.

9. Should residual costs of additions from the 7(b)(2)(D) resource stack from prior rate cases be recognized in subsequent rate tests?

<u>BPA REQUEST FOR FEEDBACK</u>:

When conducting the rate test, BPA does not recognize any effects of adding resources from the resource stack in prior rate cases. BPA treats each rate case's rate test as a stand-alone event with no recognition of costs from prior rate cases. An issue has been raised whether some recognition of costs of added resources from prior rate tests should be recognized in subsequent years' rate tests.

<u>RESPONSE</u>:

Residual costs of additions from the 7(b)(2)(D) resource stack from prior rate cases must be recognized in subsequent 7(b)(2) rate steps. When conducting the section 7(b)(2) rate step, BPA should

(i) only include resources in the resource stack that are then currently available and

(ii) continue in subsequent rate cases the draw of any resources drawn from the resource stack until the end of the term of the power delivery or life of the generator, as the case may be.

Section 7(b)(2) provides no basis for assuming that resources are available currently just because they may have been available historically. For example, there is no basis for assuming that a resource that was available in 1985 was somehow "stockpiled" without storage, maintenance or carrying costs and available in 2008. Adjusting historic costs for inflation does not account for these types of costs and does not justify an arbitrary and unrealistic stockpiling assumption.

Further, simply adjusting historic costs by a general rate of inflation does not properly account for changes in prices (and availability) of materials and fuel. For example, the average wellhead price of gas reported by the EIA was roughly $1.55 per thousand cubic feet (Mcf) in 1995. That cost, adjusted by the consumer price index (inflator of 1.368), would only be $2.12 per Mcf, which is far less than the current price of gas.

Similarly, there is no basis for assuming that a resource with a given life can be acquired for a shorter period at a cost based on its full life. For example, there is no basis to assume that a resource with a twenty-year life can be acquired for five years at a cost based on the twenty-year life of the resource.

Finally, Administrative and General costs allocable to a resource in the resource stack should be included in the resource costs reflected in the resource stack.

10. If BPA continues to provide financial payments to DSI customers in lieu of power, should those payments be subtracted from the 7(b)(2) Case revenue requirement?

<u>BPA REQUEST FOR FEEDBACK</u>:

> *In the 7(b)(2) Case, the DSI loads are served by their local utility. Therefore, BPA subtracts payments to the DSIs from the 7(b)(2) Case revenue requirement because in the 7(b)(2) Case, BPA does not have a contractual relationship with the DSIs. An issue has been raised whether this is the proper treatment of these costs.*

<u>RESPONSE</u>:

If BPA continues to provide financial payments to DSIs in lieu of power, those payments should not be subtracted from the 7(b)(2) Case revenue requirement. There is no statutory basis under section 7(b)(2) for subtracting BPA payments to DSI customers from the 7(b)(2) Case revenue requirement. The 7(b)(2) rate directives do not require or permit financial payments to DSI customers in lieu of power to be subtracted from the 7(b)(2) Case revenue requirement.

The statute does not speak to any distinction in the treatment of benefits to DSIs as financial in lieu of power, which is not surprising considering the history of BPA's service to the DSIs in 1980. Either constitutes BPA service to DSI loads, as recognized in the Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 Administrator's Record of Decision dated June 30, 2005, at page 18:

> 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. 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 <u>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</u>.

(Emphasis added.) Although BPA has chosen to provide financial benefits instead of power to many DSIs, that choice must, as recognized by BPA in the language quoted above, not negatively impact the Residential Exchange Program benefits. Indeed, such negative impact is not contemplated, intended or permitted by the NWPA.

In the 7(b)(2) Case, DSI loads are assumed to be served by the local public utility, which has the effect of increasing overall general requirements loads in that Case. The cost of serving these DSI loads in the 7(b)(2) Case is part of BPA's revenue requirement, because it is captured in the costs projected to serve the now-greater public loads, whether with FBS resources (which diminishes surplus sales revenue), resources from the stack, or market purchases.

To the extent BPA fails to include the financial payments to the DSI customers in the 7(b)(2) Case revenue requirement, BPA must treat such payments as the equivalent of BPA service to DSI customers. Under this approach, the appropriate treatment of the power equivalent of DSI benefits would be as follows: (i) the general requirements loads should be increased in the 7(b)(2) Case by an amount corresponding to the magnitude of the financial benefit and (ii) BPA should reflect the value of reserves attributable to the power equivalent to financial payments.

The power equivalent of the DSI financial benefits of $59 million can be determined by dividing that dollar amount by the appropriate rate. The appropriate rate, as demonstrated by the section 7(f) rate charged by BPA to Clallam PUD for service to a DSI, is the preference rate (currently $27.33/MWh) plus the industrial margin (currently $0.57/MWh).[24] Using these figures as an example, (i) the current BPA financial benefits to DSIs are equivalent to 241.4 aMW, and (ii) this 241.4 aMW is the amount of power that should be added to the general requirements in the 7(b)(2) Case and the amount of power that should be assumed to provide reserves under the 7(b)(3) rate step.

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[24] 2006 Surplus Firm Power Sales Agreement executed by the Bonneville Power Administration and Public Utility District No. 1 of Clallam County, Washington (Contract No. 06PB-11694), Exhibit A, page 1:

> 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.

11. If a DSI is served through a surplus sale to an adjacent preference customer, should the load be treated as a surplus load or a DSI load?

<u>BPA REQUEST FOR FEEDBACK</u>:

> *Currently, BPA sells surplus power to Clallam PUD for transfer to Port Townsend Paper, a DSI. The rate test does not currently recognize this load as a DSI load since the sale to Port Townsend is not made under the IP rate schedule. An issue has been raised whether this loads should be recognized as a DSI load in the 7(b)(2) Case.*

<u>RESPONSE</u>:

If a DSI is served through a surplus sale to a preference customer, the load should be treated as a DSI load for purposes of section 7(b)(2). Specifically, section 7(f) sales should not be used to circumvent the intent of section 7(b)(2). If a DSI is served through a surplus sale to a preference customer, such sale should be treated as a DSI sale within the scope of section 7(b)(2)(A)(ii).

In any event, if BPA fails to treat such surplus sales as DSI load, the price of such surplus sales should be reflected in BPA's projection of surplus sale prices in the 7(b)(2) Case, as discussed in the response to question 12 below.

12. The rate test considers Federal Base System power used for Program Case firm surplus sales as available to serve 7(b)(2) customer loads. How should the rate test treat requirements sales to preference customer load if that sale is made at a 7(f) rate?

<u>BPA REQUEST FOR FEEDBACK</u>:

At times, BPA sells requirements power to preference customers under the FPS rate schedule. Examples of such sales are the pre-Subscription contracts. The rate test recognized this surplus power as an available FBS resource to serve 7(b)(2) customer loads and would use this power before utilizing the 7(b)(2)(D) resource stack. An issue has been raised whether the power used to serve these requirements loads should be available to serve 7(b)(2) customer loads, as well as whether pre-Subscription customers should be included as 7(b)(2) customers.

<u>RESPONSE</u>:

Any sales of power by BPA to a preference customer used to meet its firm power load in the region should be included in the general requirements of preference customers for purposes of the section 7(b)(2) rate step. Preference customers should not be permitted to circumvent the section 7(b)(2) rate step or the intent of the NWPA by purchasing power from BPA styled as purchases at a 7(f) rate if such purchases are in fact used to meet their firm power loads in the region.

If BPA fails to treat 7(f) purchases by preference customers as part of the preference customers' general requirements, BPA must in any event reflect the 7(f) surplus sale rate in such contracts when projecting the price of surplus sales in the 7(b)(2) Case.

Indeed, BPA should reflect its surplus sales rates under all of its surplus sales contracts when it is projecting surplus sale prices in the 7(b)(2) Case. For example, if BPA projects a surplus sale of 17 aMW or more in the 7(b)(2) Case (as it invariably does), then the projected price of 17 aMW of surplus sales in the 7(b)(2) Case should be projected (using current rates) at $27.9/MWh rather than a market price. This is because the 17 aMW BPA sale to Clallam PUD at the 7(f) rate for service to Port Townsend Paper Company is currently roughly $27.9/MWh.

In short, section 7(b)(2) does not require or permit BPA to ignore surplus sales contracts BPA has entered into when projecting the price at which surplus sales will be made in the 7(b)(2) Case.

13. Should the treatment of Type 1 and Type 2 resources be modified?

BPA REQUEST FOR FEEDBACK:

> *The current methodology brings Type 1 and Type 2 resources on as discrete "lumps." Any extra energy recognized due to the discrete lump is sold at market prices. Under current conditions, market prices are often higher than the cost of the added resources, creating a cost benefit for the 7(b)(2) Case. When adopted in 1984, BPA sold surplus power under an established standard rate or spill rate, usually much less than the cost of the added resources. This treatment mitigated the cost of the added resource, but did not provide a cost benefit to the 7(b)(2) Case. An issue has been raised whether this treatment continues to be appropriate given the differences in market conditions.*

RESPONSE:

The treatment of Type 1 resources (resources actually acquired by BPA from preference customers in the relevant rate case) and Type 2 resources (resources owned or purchased by preference customers that are not dedicated to regional loads[25]) should be modified. It is not appropriate to bring Type 1 and Type 2 resources on from the resource stack as discrete "lumps." Particularly in light of development of the wholesale power market and participation by multiple owners in resource development, there is no basis for assuming that either Type 1 or Type 2 resources would only be acquired as discrete "lumps."

Under current conditions, BPA should only assume that resources are drawn from the resource stack in the 7(b)(2) rate step in an amount equal to the amount needed to serve the remaining general requirements of preference customers.

[25] Consistent with the discussion above, Type 2 resources should not include resources owned or purchased by preference customers that are dedicated to any regional loads.

14. Should the 7(b)(3) allocation of the rate protection amount be modified to include an allocation to surplus sales?

<u>BPA REQUEST FOR FEEDBACK</u>:

> *Although this is not an Implementation Methodology issue, it deals with the results of the rate test and may have an impact on the PF Exchange rate under which the 5(c) sales are made to exchanging utilities. Section 7(b)(3) states that "[a]ny amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers." While surplus sales are encompassed by "all other power sold," BPA has not allocated any 7(b)(3) rate protection amounts to surplus for two reasons. First, these sales are made at negotiated market rates that would not be receptive to "supplemental rate charges." Second, since "supplemental rate charges" cannot be added to market-priced sales, any allocation of costs to these sales would reduce the revenue credits to preference customers. Such an allocation would result in the preference customers bearing some of costs of their own rate protection. An issue has been raised whether rate protection dollars should be allocated to surplus sales.*

<u>RESPONSE</u>:

The 7(b)(3) allocation of the rate protection amount, must include an allocation of 7(b)(3) to surplus sales, including those made at market rates. As pointed out by BPA above, section 7(b)(3) expressly requires that "[a]ny amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for <u>all other power sold</u> by the Administrator to all customers." (Emphasis added.)

The legislative history of the NWPA expressly recognizes and acknowledges that amounts allocated pursuant to section 7(b)(3) are to be spread to rates for BPA power, including BPA surplus sales: "The balance of the revenues not recovered due to the rate limit adjustment is then spread to rates for <u>all other BPA power sold, including nonfirm</u>."[26]

The fact that some surplus sales are made at negotiated market rates does not permit or require those sales to be excused from the statutory directive that 7(b)(3) amounts be allocated to them or require that the supplemental rate charge be added over and above the market price.

The supplemental rate charge need not appear as a separately enumerated charge in BPA's rate schedule. In developing the PF Exchange Rate, for example, BPA includes a section 7(b)(3) supplemental rate charge (if any) in the PF Exchange Rate. Such

[26] U.S. Senate Committee on Energy and Natural Resources Report No. 96-272 at 59 (emphasis added).

supplemental rate charge allocated to the final PF Exchange Rate is included in the final PF Exchange Rate and is not separately stated or assessed.

In its rate cases, BPA forecasts surplus sales at forecasted market prices, just as BPA forecasts sales made to DSIs at forecasted DSI rates. BPA can and must make an allocation of section 7(b)(3) amounts (if any) in developing DSI rates. Similarly, BPA can and must make an allocation of section 7(b)(3) amount (if any) to projected market price sales and in forecasting the net revenues to be derived from those sales. In other words, the supplemental rate charge decreases the forecasted net revenues that BPA will have to reduce the PF Rate and the PF Exchange Rate. The result is not that BPA sells surplus power at a rate greater than market prices, but rather that BPA sells power at market price rates, to which rates section 7(b)(3) amounts have been allocated.

Supplemental rate charges allocated to market price sales would reduce the revenue credits from such sales and this was clearly contemplated by the language of section 7(b)(3)--which requires that 7(b)(3) amounts be allocated to all other power sales, which includes surplus sales. In any event, BPA's preference customers are not entitled to all of the revenue benefit of secondary sales. For example, the PF Exchange Rate is by statute identical to the PF Rate, except by the amount of any 7(b)(3) amounts allocated to the PF Exchange Rate. There is no legitimate question regarding the requirement to allocate 7(b)(3) amounts to surplus sales, given the clear language of section 7(b)(3) and its legislative history. Moreover, the shift in recent years of load service away from the DSIs and the development of market prices that substantially exceed BPA's costs have created a bounty for the region's preference customers not contemplated when the NWPA was adopted. Any notion that it would be unfair to allocate 7(b)(3) amounts to surplus sales is without merit.

NEW QUESTION

16. Should the net requirements of any utility be decreased to the extent it both purchases power at Tier 1 rates and participates in the REP?

RESPONSE:

Yes, the net requirements of any utility should be decreased to the extent it both purchases power at Tier 1 rates and participates in the REP.

BPA's has previously indicated that it expects that public power utilities would generally agree to settle their REP rights for nominal amounts, in the overall context of BPA's Proposal, and that such settlement is an essential element of BPA's Proposal. *See* BPA Power Business Line Regional Dialogue Policy Proposal at 20 (issued July 13, 2006). Although public power entities have a right to participate in the REP if they qualify, the legislative history of the NWPA indicates that this was considered unlikely:

> Although all utilities are permitted to enter into such [REP] sales, its benefits are likely to be limited to utilities that are not entitled to service as a preference customer.[27]

In addition, preference utility participation in the REP exposes BPA and its customers to costs that result if preference utilities curtail service from BPA in favor of then-cheaper resources that later turn out to be more expensive than BPA power. Historically, such curtailments of purchases from BPA by preference utilities have been significant:

> In 1994, market prices were dropping and conventional wisdom was that power market deregulation was likely to deliver consistently lower wholesale prices. By 1995, many BPA customers were clamoring to reduce their purchases from BPA so they could take advantage of lower prices offered by the burgeoning population of power marketers. The direct-service industries (DSIs) reduced their take from BPA by around 800 aMW in 1995, and public utilities followed in 1996 with over 1,000 aMW of load reductions. At this time, it was taken as a given by many of BPA's customers that they would no longer rely on BPA to meet all their requirements. The question was whether

[27] H. Report 96-976, Part I (Commerce) at 60.

> BPA could keep its costs low enough to avoid loss of so much load that a major "stranded cost" problem would result.[28]

Of course, the situation has now reversed, and preference utilities are seeking high water marks (HWMs) that will permit them to buy as much power as they can get from BPA at its Tier 1 rate. It would be ironic if the costs these entities incurred while they were away from BPA made them eligible to participate in the REP. Such utilities would benefit from the ability to purchase power at Tier 1 rates *and* participate in the REP based on higher cost resources acquired while they were away from BPA. *Cf.* Residential Exchange Program Settlement Agreement with Clark Public Utilities; Administrator's Record Of Decision, dated Feb. 10, 2006, which states as follows on page 6:

> Cowlitz County PUD (Cowlitz) expressed initial misgivings regarding Clark exchanging the costs of its River Road resource, which was developed in order to forego purchases from BPA and, in retrospect, has proven to be a costly decision.

In light of the foregoing, BPA should include—in any Residential Purchase and Sale Agreement ("RPSA") it enters into with any utility that has refused to settle its REP claims—a provision under which such utility agrees to dedicate to serving its firm load all, or a fraction of, the power purchased from BPA under its RPSA. To the extent the utility receives in-lieu power under its RPSA, all such power should be dedicated to serving the utility's firm load. To the extent the utility participates in the REP (but does not receive in-lieu power), the utility should dedicate a fraction of the amount of power it purchases under the RPSA. This dedication should apply in such circumstances even though the preference utility is selling to BPA an equal amount of power under the REP. The fraction of power purchased that is dedicated should be equal to the fraction of the utility's load served by purchases from BPA at BPA's Tier 1 rate. Such dedication of REP power to serve the utility's load will decrease the net requirements of the utility to the extent it is both purchasing power at Tier 1 rates and participating in the REP.

[28] BPA, "What Led to the Current BPA Financial Crisis? A BPA Report to the Region," at page 3 (Apr. 2003), available at: http://www.bpa.gov/corporate/docs/2003/Report_to_region.pdf.

<u>NEW QUESTION</u>

17. Should BPA adopt a resource stack methodology for identification of resources for the 7(b)(2) Case resource stack and for development and documentation of data needed for such resources?

<u>RESPONSE</u>:

Yes, BPA should adopt a resource stack methodology for application in its general rate cases for the identification of resources for the 7(b)(2) Case resource stack and for development and documentation of data needed for such resources. The resource types and amounts that comprise the 7(b)(2) resource stack can have a significant impact on the results of the section 7(b)(2) rate step and the determination of any section 7(b)(3) amount. This is particularly the case if substantial resources must be drawn from the stack in the 7(b)(2) Case to meet remaining general requirements of the public body, cooperative and Federal agency customers once the available FBS is exhausted.

BPA should develop a resource stack methodology for determining the resources to be included in the 7(b)(2) resource stack and the appropriate costs attributable to those resources. That methodology should provide for the development of pertinent information for each resource, which would include at least the following:

(i) Ownership;
(ii) Status of its dedication to load;
(iii) Immediate and longer-term availability;
(iv) Price availability;
(v) What portion of the output of a given resource should be acquired;
(vi) The duration or lifetime of the contract or other resource; and
(vii) The appropriate costs attributable to each resource.[29]

The methodology should also address determination of "the average cost of all other new resources acquired by the Administrator" with respect to "any additional needed resources."[30]

The resource stack methodology should ensure that the costs used for the 7(b)(2) resource stack are based on verifiable and available financial records. In this regard, the resource stack methodology should be similar to the Average System Cost methodology currently under discussion, which is based on Form 1 data submitted to FERC and subject to FERC audit.

[29] Issues that should be addressed include, for example, the appropriate financing costs attributable to a resource, whether the financing is project specific or part of the overall financing structure of the preference agency.
[30] 16 U.S.C. § 839e(b)(2)(D).